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In accordance with NRS Chapter 719,
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by: /s Lynn DInnocenti

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This filing has been electronically filed and deemed to be signed by an authorized agent or
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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 1 OF 3

NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

TRANSMITTAL LETTER

October 22, 2025

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Docket No. 25-10___- 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.

Dear Ms. Osborne:

Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (the "Companies") hereby submit a Joint Application for approval of an amendment to the 2025-2027 Energy Supply Plan ("ESP"). With this Joint Application, the Companies seek authorization from the Public Utilities Commission of Nevada (the "Commission") to participate in the Extended Day-Ahead Market ("EDAM") being currently set up by the California Independent System Operator Corporation ("CAISO").

The Companies have included with this Joint Application and incorporate herein by reference the following Joint Application Exhibits:

- **Application Exhibit A** is a narrative discussion of the Amendment.
- **Application Exhibit B** is a proposed notice of the Joint Application as required by NAC § 703.162.

In addition, the Joint Application is supported by the Technical Appendix and prepared direct testimony from the following witnesses:

- **Timothy Clausen**
- **Michael Holland**
- **Lindsey Schlekeway**
- **Charles Pottey**
- **David Rubin**
- **Adrien Marshall**
- **Scott Kaufman**
- **Michael Brown**
- **Jenny Naughton**
- **Anna McKenna of CAISO**
- **Stacey Crowley of CAISO**
- **April Gordon of CAISO**
- **Hugo Frech of CAISO**
- **John Tsoukalis of the Brattle Group.**

Certain information set forth in the Technical Appendix is commercially sensitive and/or trade secret information subject to protection pursuant to NRS § 703.190. Specifically, Technical Appendix 2 contains confidential information technology data of the Companies. Disclosure of this information will negatively affect the Companies' ability to defend against cyber and other threats. Appendix A to Technical Appendix 2 contains the EDAM Cost Estimating Model. That Model, which is being presented as an Excel-based workpaper, represents third-party proprietary and copyrighted information of Utilicast L.L.C. Additionally, workpapers supporting testimony of Adrien Marshall contain commercially sensitive information, including customer-specific information.

Workpapers. Electronic files supporting this Joint Application are enclosed with this letter and will also be delivered to the Regulatory Operations Staff and the Bureau of Consumer Protection. The workpapers containing confidential or proprietary information are identified as confidential.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be filed with the Commission's Secretary in a separate envelope stamped "confidential." Redacted versions of confidential information will be submitted for processing and posting onto the Commission's public website.

Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential for a period of five years after which the information may be destroyed or returned. Confidential treatment of the above-described information will not impair the ability of the Regulatory Operations Staff or the Bureau of Consumer Protection to fully investigate the Companies' proposals.

Should you have any questions regarding this filing, please contact me at 775-834-3470 or at roman.borisov@nvenergy.com.

Sincerely,

/s/ Roman Borisov
Roman Borisov
Senior Attorney

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY** in Docket No. 25-10___ upon all parties of record in this proceeding by electronic service to the following:

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DATED this 22nd day of October, 2025.

/s/ Lynn D'Innocenti
Lynn D'Innocenti
Paralegal
Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

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NEVADA POWER COMPANY D/B/A NV ENERGY
AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

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APPLICATION

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___

JOINT APPLICATION FOR AN AMENDMENT TO THE

2025-2027 ENERGY SUPPLY PLAN

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") file this Joint Application (the "Joint Application") for Approval of an Amendment to their 2025-2027 Energy Supply Plan ("ESP") to participate in the Extended Day-Ahead Market ("EDAM") that is being established by the California Independent System Operator ("CAISO"). Participation in the EDAM will enable the Companies to further optimize their power supply portfolios for the benefit of their customers.

The Companies file this Joint Application pursuant to Nevada Revised Statutes ("NRS") § 704.741, Nevada Administrative Code ("NAC") § 704.9504(3), and the July 9, 2024, Order issued by the Public Utilities Commission of Nevada (the "Commission") in Docket No. 23-10019.[1] In this Joint Application, the Companies request authorization to participate in the EDAM beginning in the Fall of 2028 and approval of the corresponding amendments to the ESP in the Power Fundamentals and Portfolio Optimization Procedures segments of the Plan.

The Companies request approval of this Amendment to the 2025-2027 ESP based on the information contained in the narrative, prepared direct testimony filed in support of the Joint Application, and the technical appendix. Since this is an ESP filing, NRS 704.751(1)(a) directs the Commission to issue an order within 135 days of the filing.

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[1] Order at 5 ("Any request by Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy to join a day ahead market shall be made through separate and distinct amendments to their Energy Supply Plan, outside of their now-pending joint application for approval of their Integrated Resource Plan and Energy Supply Plan in Docket No.24-05041.")

I.

THE APPLICANTS

Nevada Power and Sierra are Nevada corporations and wholly owned subsidiaries of NV Energy, Inc. Nevada Power and Sierra are public utilities as defined in NRS § 704.020 and are subject to the jurisdiction of the Commission. Nevada Power is engaged in providing electric service to the public in portions of Clark and Nye counties, Nevada pursuant to a certificate of public convenience and necessity issued by this Commission. Sierra provides electric service to the public in portions of fourteen northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. Sierra owns and operates a certificated local distribution company engaged in the retail sale of natural gas to customers in the Reno-Sparks metropolitan area.

Sierra's primary business office is located at 6100 Neil Road in Reno, Nevada, and Nevada Power's primary business office is located at 6226 West Sahara Avenue in Las Vegas, Nevada. All correspondence related to this Application should be transmitted to the Companies' counsel *and* to the Director of Regulatory Services, as set forth below:

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II.

APPLICATION EXHIBITS

To aid the Commission in considering this Amendment, the Companies have included with this Joint Application and incorporated herein by reference the following exhibits:

Application Exhibit A is a narrative discussion of the amendment.

Application Exhibit B is a proposed notice of the Application as required by NAC § 703.162.

The form of Exhibit A, the narrative, was selected because it is the form used in resource plan filings to provide the Commission and stakeholders with detailed and technical information regarding the inputs, in-depth descriptions of the analytical techniques applied to the questions to be answered in resource plan filings, as well as clear communication of the results and the recommendations for Commission approval.

III.

ADDITIONAL SUPPORTING MATERIAL

The Amendment is supported by the prepared direct testimony of the following witnesses:

1 **Tim Clausen**, Vice President of Regulatory, covers three areas: (1) the basis for seeking authorization to participate in EDAM through an amendment to the ESP and the specific requests the Companies are making in this proceeding; (2) potential reporting requirements; and (3) the relationship of the request to participate in EDAM to the Companies' obligations under Senate Bill 448 ("SB448") (2021). Mr. Clausen sponsors portions of Sections 1, 10, 11, and 13 of Exhibit A.

2 **Michael Holland**, Vice President Resource Optimization. As the overall policy witness, Michael Holland explains why the Companies are requesting the Commission's approval to participate in the EDAM and discusses the implementation process for the Resource Optimization Department, and sponsors portions of Sections 1, 2(B), 2(D), and Section 8 of Exhibit A.

3 **Lindsey Schlekeway**, Market Policy Director, provides a summary of the Gap Analysis prepared for NV Energy by Utilicast L.L.C ("Utilicast").[2] In addition, she addresses the areas of resource sufficiency, the Western Power Pool's Western Resource Adequacy Program ("WRAP"), imbalance reserves, greenhouse gas ("GHG") compliance (including emissions tracking), virtual

[2] Utilicast is a leading provider of consulting services to the energy and utility industry.

bidding, and market monitoring. Ms. Schlekeway sponsors portions of Sections 1, 5(B), 5(F), 5(G), 5(I), and Section 8 of Exhibit A.

4 **Charles Pottey**, Director Transmission and Distribution Planning, explains NV Energy's existing interconnections with external Balancing Authority Areas ("BAA") and the increases to transmission capacity associated with Greenlink and SWIP-North projects. Mr. Pottey also describes other ongoing transmission projects in the West that could impact the day-ahead market and sponsors Sections 4(B) and 4(C) of Exhibit A.

5 **David Rubin**, Federal Energy Policy Director, discusses the Companies' perspective on governance of the day-ahead market options, market monitoring, the changes to the Companies' Open Access Transmission Tariff ("OATT") that will be necessary to participate in EDAM and interoperability with the transmission requirements of WRAP. He also discusses issues related to congestion rent allocation, the additional regulatory steps that will need to take place to effectuate the Companies' EDAM participation, and the updated assumptions that have influenced the Companies' decision to file this amendment. Mr. Rubin sponsors portions of Sections 1, 3, 4(A), 5(A), 5(C), 5(D), 5(E), 5(I), 5(J), 5(K), 5(L), 7, 8, 9, 10, 11 and 13 of Exhibit A.

6 **Adrien Marshall**, Director of Transmission Business Services, discuss how transmission revenues are preserved in the EDAM and Markets+ and the process NV Energy will utilize to update the Western Energy Imbalance Market ("WEIM") Transmission Business Practice. Ms. Marshall sponsors portions of Sections 5(C) and Section 9 of Exhibit A.

7 **Scott Kaufmann**, Vice President of Transmission, provides an overview of WEIM operations, EDAM implementation for transmission operations, resiliency of the day-ahead market system to physical threats, such as wildfire,

seams management and vulnerability to cyber-security threats. Mr. Kaufmann sponsors portions of Sections 2(C),4(D), and 8 of Exhibit A.

8 **Michael Brown**, Director of Energy Services Optimization, discusses demand response and distributed energy resources aspects of the Companies' proposed participation in EDAM and sponsors Section 5(H) of Exhibit A.

9 **Jenny Naughton**, Director of Regulatory Accounting and Reporting, discusses the request for and treatment of the EDAM regulatory asset and the allocation of capital, the accounting for certain new EDAM charge codes and the potential rate and revenue impacts of the Companies joining EDAM. Ms. Naughton sponsors Section 12 of Exhibit A.

10 **Anna McKenna**, CAISO Vice President of Market Design and Analysis, describes the development of EDAM, the overall market design and addresses the topics listed in the Docket No. 23-10019 report regarding the EDAM market design (including congestion management, market monitoring and dispute resolution), the potential EDAM participants, diversity of resources in the EDAM footprint, resiliency of the market to physical threats such as wildfires, transparency of market data, greenhouse gas reporting, and interoperability with WRAP. Ms. McKenna sponsors portions of Sections 3(A), 4(A), 4(D), and 5 of Exhibit A.

11 **Stacey Crowley**, CAISO Executive Vice President of External Affairs, provides 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 FERC, status of the EDAM and applicable timeline for new entrants to join (implementation process), the EDAM Implementation Agreement, and the EDAM exit process. Ms. Crowley sponsors portions of Sections 7 and 8(A) of Exhibit A.

12 **April Gordon**, CAISO Executive Director of Financial Planning and Procurement, discusses the EDAM implementation fee structure, projected ongoing grid management fee costs for EDAM participation and CAISO's overall financial health. Ms. Gordon sponsors portions of Section 8 of Exhibit A.

13 **Hugo Frech**, CAISO's Chief Information Officer and Executive Director of IT Infrastructure, provides an overview of CAISO's Cyber Security Program and discusses the resiliency of the markets to cyber security threats. Mr. Frech sponsors a portion of Section 4(D) of Exhibit A.

14 **John Tsoukalis**, Principal at the Brattle Group ("Brattle"), describes the benefit studies performed by Brattle and sponsors a portion of Section 4(d) and Section 6 of Exhibit A.

In addition, the Companies support this Joint Application with a Technical Appendix consisting of:

- Technical Appendix 1: NV Energy Day-Ahead Market Benefit Study, 2025 Updated Cases, by the Brattle Group, October 2025; and
- Technical Appendix 2: EDAM Gap Assessment by Utilicast L.L.C., May 2025.

Brattle's Study analyzed the benefits of NV Energy joining EDAM, Markets+, or remaining in WEIM. Brattle calculated NV Energy customers' savings of $93.1 million annually with the Companies in EDAM contrasted with a $7.3 million annual cost increase with the Companies in Markets+.[3] Brattle chose 2032 as the year for that comparative analysis as it would represent a time in the near future and, at the same time, following its 2028 anticipated entry into EDAM, NV Energy would be a well-established EDAM market participant by that time.

Utilicast's Gap Assessment describes a conceptual business and software approach, project tasks and costs, and a high-level schedule supporting NV Energy's entry into EDAM.

[3] Technical Appendix 1 at 5.

Notably, the Gap Assessment estimates the costs to join EDAM at $16.15 million[4] and ongoing annual participation costs at $16.52 million.[5]

IV.

COMPLIANCE WITH APPLICABLE AUTHORITIES AND DAY-AHEAD MARKET SELECTION

Pursuant to NAC 704.9504(3), an amendment to the ESP must contain:

(a) A section that identifies the specific approvals requested by the utility;

(b) A section that specifies any changes in assumptions or data that have occurred since the utility's last resource plan was filed; and

(c) As applicable, the information required in subsections 1 to 5, inclusive, and 7 of NAC § 704.9482.

As is customary in the Companies' resource plan filings, Application Exhibit A contains a section that identifies specific approvals and specifies changes in assumptions and data. The Companies' ESP Amendment is narrow. It requests approval of the Companies' participation in the EDAM beginning in the Fall of 2028 and of corresponding amendments and updates to the approved segments of the 2025-2027 ESP. Specifically, the Companies amended (1) the Power Fundamentals segment of the Market Fundamentals subsection within the Market Fundamentals & Price Forecasts Section; and (2) the Current Portfolio Optimization Procedures segment of the Power Portfolio and Optimization Procedures subsection of the Power Procurement Plan Section of the 2025-2027 ESP. These limited and targeted amendments are reflected in Attachment 1 to Exhibit A.

In Commitment 13 of the stipulation resolving Docket No. 13-07021, the MidAmerican Merger Application, the Companies agreed to request the Commission's authorization prior to participating in an organized market such as the EDAM. Commitment 13 provides:

[4] Technical Appendix 2 at 9, Table 2.
[5] *Id.* at 15.

> This [stipulation] does not preclude the participation by the Nevada Utilities in an energy imbalance market or in a market dispatched by an independent system administrator or operator or regional transmission organization, if approved by the Commission.[6]

In its order approving the stipulation in Docket No. 13-07021, the Commission stated:

> [T]he second sentence shall be interpreted to mean that the Nevada Utilities are not precluded from participating in an energy imbalance market or in a market dispatched by an independent system administrator or operation or regional transmission organization, if they obtain authorization from the Commission prior to participating.[7]

The Joint Application carries out Commitment 13 and satisfies the Commission's interpretation of the Commitment.

On October 19, 2023, the Commission opened an investigation regarding regional market activities in the western interconnection relevant to Nevada utilities' obligations pursuant to NRS Chapter 704.[8] In an order issued on July 9, 2024, the Commission approved a report regarding the requirements for a potential application to join a day-ahead market ("DAM"). The report adopted a set of comprehensive criteria to be addressed in this filing:

1. An overview of the DAM, including:
    - Governance of the DAM and the overall organization of the entity that owns the DAM, including the process by which changes to the FERC[9]-approved DAM tariff occur, to include any opportunities for the Commission to participate in the DAM change process prior to a filing at FERC;
    - Overall financial health of organization that owns the DAM, as well as the financial statements of that organization;
    - An explanation of the market monitoring function at the DAM, the dispute resolution process at the DAM, and the functioning of the DAM States Committee;
    - Current non-Nevada utility commitments and the nature of those commitments to the DAM;

[6] Docket No. 13-07021, Order dated December 17, 2013, at Att. 1 at 9.
[7] Docket No. 13-07021, Order dated December 17, 2013, at 14.
[8] Docket No. 23-10019.
[9] Federal Energy Regulatory Commission.

- Diversity of resources available through the DAM;
- Resiliency of the DAM system to physical threats, such as wildfire, and vulnerability to cyber-security threats;
- Transparency of the DAM's market data;
    - Type and location of the data currently available;
    - Type and location of the data that will be available after NV Energy joins;
    - How the Commission can access that data; and
    - Frequency with which the data is/will be available to the Commission;
- GHG emission tracking of resources purchased in the DAM, as well as any "leakage" that might occur;

2. Status of the DAM and applicable timeline for the DAM and NV Energy joining;
    - Copies of all DAM implementation agreements;
    - Any related or required amendments to NV Energy's internal business practices and procedures;
3. Interoperability with WRAP, NV Energy's ESP, and state resource adequacy requirements;
4. Impact on NV Energy's Renewable Portfolio Standard compliance;
5. Roadmap to RTO[10] in compliance with NRS 704.79882 if the DAM is joined;
6. Revisions to the OATT that NV Energy will make once it joins the DAM. Complete tariff language may not be necessary, but an adequate level of detail to allow review of the potential impact on NV Energy's BAA;
7. Concerns regarding impacts of the DAM on non-jurisdictional transmission customers in NV Energy's BAA, including:
    - Pricing and settlement transparency;
    - Participation and representation in the DAM; and
    - Responsibilities of those customers with respect to the resource adequacy and compliance obligations;

[10] RTO stands for a regional transmission organization.

8. Process by which the DAM and NV Energy ensure retail customers are compensated for available transmission capacity, including congestion revenues;

9. All cost-benefit analyses that demonstrate the value of the DAM versus other options, including any viable, alternate DAMs and the "status quo" that examines, at a minimum, the following information:

   - Impact of transfers between markets and balancing areas;
   - Analysis of resource procurements;
   - Any costs related to solar energy curtailment;
   - Use of the most recently available applicable to Nevada-specific inputs;
   - Impact on transmission development and investments currently proposed or in progress for Nevada by NV Energy or other developers; and
   - Impact on generation development currently approved or proposed by NV Energy;

10. Any capital investment in transmission or generation that may be necessary to participate in the DAM or maximize the benefit of the DAM;

11. Costs of utility participation in the DAM, including fees, metering and software requirements. All new costs should be highlighted and estimated based on the most applicable, recent data, even if they are not yet known with precision or are expected to be offset. Any expected offsets should be thoroughly analyzed;

12. Forecast of rate and revenue impacts for the 5 and 10 years immediately after joining the DAM; and

13. Process, timeline, and costs to exit the DAM.

These criteria are addressed in Exhibit A, narrative, to the Joint Application and in the testimony as follows:

	Narrative	Testimony
An overview of the DAM	Section 5	Anna McKenna, Stacey Crowley, April Gordon, Lindsey Schlekeway, David Rubin, Scott Kaufmann, Michael Holland and Adrien Marshall
Governance of the DAM and the overall organization of the entity that owns the DAM, including the process by which changes to the FERC-approved DAM tariff occur, to include any opportunities for the Commission to participate in the DAM change process prior to a filing at FERC	Section 7	Stacey Crowley and David Rubin
Overall financial health of organization that owns the DAM, as well as the financial statements of that organization	Section 5(J)	April Gordon
An explanation of the market monitoring function at the DAM, the dispute resolution process at the DAM, and the functioning of the DAM States Committee	Section 5(I) and (K) and Section 7	Anna McKenna, David Rubin and Lindsey Schlekeway
Current non-Nevada utility commitments and the nature of those commitments to the DAM	Section 4	Anna McKenna and David Rubin
Diversity of resources available through the DAM	Section 4	Anna McKenna, Mike Holland, and John Tsoukalis
Resiliency of the DAM system to physical threats, such as wildfire, and vulnerability to cyber-security threats	Section 4(D)	Anna McKenna, Scott Kaufmann and Hugo Frech
Transparency of the DAM's 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 is/will be available to the Commission	Section 5(K)	Anna McKenna, David Rubin
GHG emission tracking of resources purchased in the DAM, as well as any "leakage" that might occur	Section 5(G)	Anna McKenna and Lindsey Schlekeway

	Narrative	Testimony
Status of the DAM and applicable timeline for the DAM and NV Energy joining: (1) copies of all DAM implementation agreements and (2) any related or required amendments to NV Energy's internal business practices and procedures	Section 8	Anna McKenna, April Gordon, Lindsey Schlekeway, Michael Holland, Scott Kaufmann and David Rubin
Interoperability with the WRAP, NV Energy's ESP, and state resource adequacy requirements	Sections 5(B), 5(C), Section 9	Anna Mckenna and David Rubin
Impact on NV Energy's Renewable Portfolio Standard compliance	Section 5(G)	Michael Holland
Roadmap to RTO in compliance with NRS 704.79882 if the DAM is joined	Section 11	Tim Clausen and David Rubin
Revisions to the OATT that NV Energy will make once it joins the DAM. Complete tariff language may not be necessary, but an adequate level of detail to allow review of the potential impact on NV Energy's BAA;	Section 9	David Rubin
Concerns regarding impacts of the DAM on non-jurisdictional transmission customers in NV Energy's BAA, including: (1) pricing and settlement transparency; (2) participation and representation in the DAM; and (3) responsibilities of those customers with respect to the resource adequacy and compliance obligations	Sections 7, 9, 5(J) and 5(K)	Anna McKenna and David Rubin
Process by which the DAM and NV Energy ensure retail customers are compensated for available transmission capacity, including congestion revenues	Sections 5(C), 5(D), Section 9	Anna Mckenna, Adrien Marshall and David Rubin
All cost-benefit analyses that demonstrate the value of the DAM versus other options, including any viable, alternate DAMs and the "status quo" that examines, at a minimum, the following information: (1) impact of transfers between markets and balancing areas; (2) analysis of resource procurements; (3) any costs related to solar energy curtailment; (4) use of the most recently available applicable to Nevada-specific inputs; (5) impact on	Section 6	John Tsoukalis

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

	Narrative	Testimony
transmission development and investments currently proposed or in progress for Nevada by NV Energy or other developers; and (6) impact on generation development currently approved or proposed by NV Energy		
Any capital investment in transmission or generation that may be necessary to participate in the DAM or maximize the benefit of the DAM	Section 5	Charles Pottey and Michael Holland
Costs of utility participation in the DAM, including fees, metering and software requirements. All new costs should be highlighted and estimated based on the most applicable, recent data, even if they are not yet known with precision or are expected to be offset. Any expected offsets should be thoroughly analyzed	Section 8	April Gordon, Michael Holland, Scott Kaufmann, Lindsey Schlekeway, David Rubin
Forecast of rate and revenue impacts for the 5 and 10 years immediately after joining the DAM	Section 12	Jenny Naughton
Process, timeline, and costs to exit the DAM	Section 8	Stacey Crowley and David Rubin

Based on that criteria and following a thorough evaluation of day-ahead regional market options, the Companies elected to seek Commission authorization to participate in the CAISO's EDAM. The primary factors supporting the Companies' decision are:

- The Companies' positive experience with the WEIM and lower implementation costs resulting from NV Energy's existing WEIM participation;
- The connectivity the Companies have with the anticipated EDAM market footprint versus that of the anticipated Markets+ footprint along with the overall connectivity the anticipated EDAM and WEIM participants have with each other;
- The projected higher customer benefits that will accrue from EDAM resulting from that connectivity;
- The governance of EDAM as enhanced by the Pathways initiative and the recently enacted California legislation Assembly Bill ("AB") 825, including CAISO's ability to respond more expeditiously to events with targeted, expedited stakeholder processes; and

- A preference for certain EDAM market design features including resource sufficiency, resource adequacy and maintaining a voluntary participation relationship to the WRAP program; congestion rent allocation; virtual bidding; GHG accounting and potentially better opportunities to deploy new technologies related to compliance with FERC Order No. 2222.

The Companies recognize that the target entry into the EDAM in the Fall of 2028 is outside the 2025-2027 approved ESP period. However, to effectuate the market entry in the Fall of 2028, the Companies forecast investments and expenses starting within the approved ESP period. As Utilicast's EDAM Gap Assessment demonstrates,[11] the Companies will make substantial investments and incur expenses starting in 2025 covering hardware and software acquisitions, licenses and subscriptions, external fees, vendor costs, consulting and legal support, and internal labor. These costs are estimated at \$16.15 million between 2025 and 2028, with only \$1.82 million of these costs being experienced in 2028 and, thus, outside the approved ESP period. In light of the actions and associated costs the Companies must undertake during the approved ESP period to join the EDAM in 2028, the Companies bring forth this filing to amend the 2025-2027 ESP.

The Companies request Commission approval of this Amendment to the 2025-2027 ESP and find that the ESP, as amended, is prudent pursuant to NAC § 704.9494. The Commission may make that finding if it determines:

1. That the ESP, as amended, balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the Plan;
2. That the ESP, as amended, optimizes the value of the overall supply portfolio of the utility for the benefit of bundled retail customers; and
3. That the ESP, as amended, does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility.

[11] Technical Appendix 2 at 9, Table 2.

The Commission can make each of these findings. Importantly, the Commission recently found the 2025-2027 ESP prudent in Docket No. 24-05041, 2024 Integrated Resource Plan. Through this Joint Application, the Companies are adding an additional portfolio optimization option – a new, day-ahead market – that will further reduce the cost of supply and increase the reliability of supply. The additional option also will allow the Companies to optimize the value of their respective generation portfolios for the benefit of retail customers. By finding that the amended ESP, with a new portfolio optimization element, is prudent, the Commission would be authorizing the Companies to participate in the EDAM in addition to the WEIM.

V.

ESTABLISHMENT OF THE EDAM IMPLEMENTATION REGULATORY ASSET FOR SIERRA

In Docket No. 25-02016, Nevada Power General Rate Case, the Commission approved Nevada Power's request to establish a regulatory asset to record EDAM implementation costs.[12] The Companies respectfully requests approval to establish a regulatory asset for Sierra, at this time, ensuring equitable treatment and regulatory consistency across both companies as they advance EDAM implementation. The precedent set by the Commission's approval for Nevada Power provides a clear and consistent framework. The EDAM regulatory asset request in this Docket is also consistent with the Commission approval of the RTO regulatory asset for the Companies in Docket No. 22-09006.[13] The proposed regulatory asset will capture incremental and necessary costs to join EDAM, including the labor and materials needed to design, build, and test the software and hardware changes necessary for EDAM implementation.

The Companies propose that the costs of the regulatory asset be allocated between Nevada Power and Sierra in the same manner as was ordered by the Commission for the RTO regulatory asset, thus 75 percent to Nevada Power and 25 percent to Sierra.[14] Costs associated with the EDAM implementation will be deferred into a regulatory asset as they are incurred until the implementation is completed in 2028. Once the implementation is complete in 2028 and the

[12] September 16, 2025, Order at 93.
[13] Third Amendment to the 2021 IRP, March 24, 2023, Order at 153-54.
[14] Docket No. 22-09006, March 24, 2023, Order at 153-54.

regulatory asset is moved into rates, the regulatory asset will begin amortizing and will continue amortizing in accordance with the applicable depreciation rates until all costs have been recovered.

VI.

CONFIDENTIALITY

Certain information set forth in the Technical Appendix is commercially sensitive and/or trade secret information subject to protection pursuant to NRS § 703.190. Specifically, Technical Appendix 2 contains confidential information technology data of the Companies. Disclosure of this information will negatively affect the Companies' ability to defend against cyber and other threats. Appendix A to Technical Appendix 2 contains the EDAM Cost Estimating Model. That Model, which is being presented as an Excel-based workpaper, represents proprietary and copyrighted information of Utilicast. Additionally, workpapers supporting testimony of Adrien Marshall contain commercially sensitive information, including customer-specific information.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be filed with the Commission's Secretary in a separate envelope stamped "confidential." Redacted versions of confidential information will be submitted for processing and posting onto the Commission's public website. Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential for a period of five years after which the information may be destroyed or returned. Confidential treatment of the above-described information will not impair the ability of the Regulatory Operations Staff or the Bureau of Consumer Protection to fully investigate the Companies' proposals.

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VII.

PRAYER FOR RELIEF

Nevada Power and Sierra respectfully request that the Commission:

1. Grant the Joint Application;
2. Approve their participation in the CAISO EDAM as prudent;
3. Approve the 2025-2027 ESP with amendments to the Power Fundamentals and Current Portfolio Optimization Procedures portions of the Plan as prudent;
4. Find, pursuant to NAC § 704.9494:
   a. That the ESP of the Companies, as amended, balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the ESP.
   b. That the ESP of the Companies, as amended, optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
   c. That the ESP of the Companies, as amended, does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.
5. Authorize establishment of a regulatory asset for Sierra for the implementation of EDAM costs and approve 75 percent to Nevada Power and 25 percent to Sierra EDAM implementation cost allocation;
6. Grant the request for confidential treatment of information contained in the Joint Application as described above; and
7. Grant any other relief that the Commission deems appropriate based on the Joint Application and the record developed at any hearing held in this matter.

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Respectfully submitted this 22nd day of October, 2025.

NEVADA POWER COMPANY
D/B/A NV ENERGY

SIERRA PACIFIC POWER COMPANY
D/B/A NV ENERGY

By: *<u>/s/ Roman Borisov</u>*

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APPLICATION EXHIBIT A

NARRATIVE

Amendment to the 2025-2027 Energy Supply Plan of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy to Authorize Their Participation in the California Independent System Operator's Extended Day-Ahead Market

TABLE OF CONTENTS

SECTION 1 - EXECUTIVE SUMMARY AND BASIS OF RECOMMENDATION

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") are requesting approval from the Public Utilities Commission of Nevada (the "Commission") of an Amendment to their Joint Energy Supply Plan ("ESP") to reflect the participation of the Companies in the Extended Day-Ahead Market ("EDAM") that is being established by the California Independent System Operator ("CAISO"). Granting this Amendment will enable the Companies to further optimize their power supply portfolios for the benefit of customers. If authorized by the Commission, the Companies anticipate joining EDAM in the Fall of 2028.

As part of the request in this Joint Application and to facilitate the Companies' participation in EDAM, the Companies narrowly amended portions of the approved ESP. Specifically, the Companies amended (1) the Power Fundamentals segment of the Market Fundamentals subsection within the Market Fundamentals & Price Forecasts Section; and (2) the Current Portfolio Optimization Procedures segment of the Power Portfolio and Optimization Procedures subsection of the Power Procurement Plan Section of the 2025-2027 ESP. Attachment 1 contains the amended portions of these Sections.

Following the Commission's authorization in Docket No. 14-04024, the Companies became the second Balancing Authority ("BA")[1] to join the Western Energy Imbalance Market ("WEIM") administered by CAISO. In the intervening decade, the WEIM has grown to encompass twenty-two BAAs across all or portions of eleven Western states, serving approximately eighty percent of load in the Western Interconnection.[2] The WEIM has facilitated significant economic savings and promoted reliable coordination across the West.[3] Through the second quarter of 2025, CAISO has estimated that the WEIM has produced approximately $7.41 billion in customers savings of which NV Energy's share has been $828.17 million.[4] These cumulative financial benefits are illustrated in Figure 1.

Based on the success of the WEIM for real-time operations, the CAISO undertook its EDAM initiative to "improve market efficiency and more effectively integrate renewable resources by optimizing day-ahead unit commitment and scheduling across a larger footprint."[5]

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1 A BA is the entity that integrates resource plans ahead of time, maintains the demand and resource balance within a Balancing Authority Area ("BAA"), and supports interconnection frequency in real time. A BAA is the collection of generation, transmission, and loads within the metered boundaries of the BA. *See* the NV Energy Open Access Transmission Tariff ("OATT") at sections 1.5B and 1.5B1. The OATT can be found on the Companies' OASIS at https://www.oasis.oati.com/NEVP/. *See also*, North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), available at: https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf.

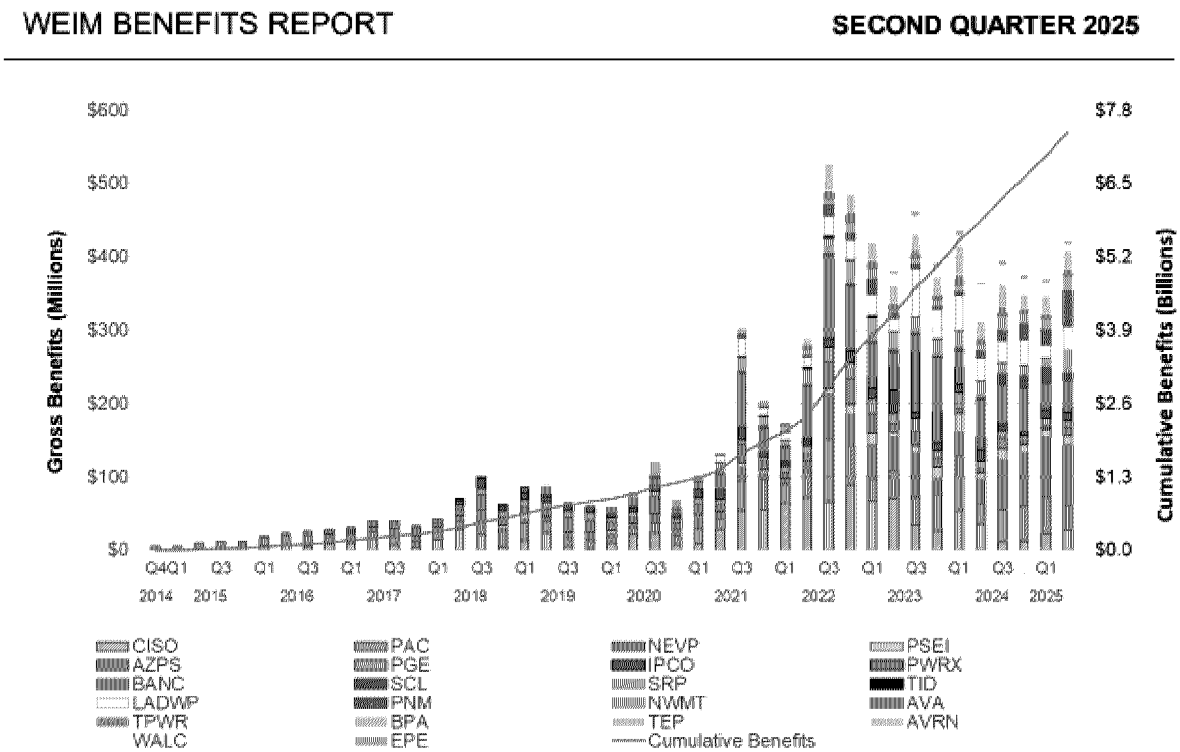
2 *See*, https://www.caiso.com/about/news/energy-matters-blog/evolution-of-the-weim.

3 Direct Testimony of Scott Kaufmann at Q&A 13.

4 *See*, https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q2-2025.pdf.

5 *See* Issue Paper – Extended Day-Ahead Market November 25, 2019, at 3. The document can be found at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

Figure 1
Cumulative WEIM Benefits by Quarter



GRAPH 1: Cumulative economic benefits for each quarter by BAA

A day-ahead market ("DAM") is a centrally organized, financial and physical electricity market where participants submit hourly bids and self-schedules. The market optimization determines the least-cost energy dispatch to serve load while recognizing physical system constraints.[6] Dispatched resources are compensated at their bid or the higher locational marginal price ("LMP") for the energy they offered to supply.[7] Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. Market participants receive settlements from the market operator

6 The market operator uses a security constrained unit commitment ("SCUC") and security constrained economic dispatch ("SCED") accompanied by a nodal network model to create an optimized dispatch plan. "Unit commitment" determines the optimal combination of resources to bring online from those that are available for some or all of the operating day. "Economic dispatch" determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load. To ensure that the unit commitment and economic dispatch are feasible, the optimization is "security-constrained," which means that the optimization must adhere to certain limits (known as "constraints") such as flow across transmission elements and maximum ramp rate of generators.

7 LMPs represent the incremental cost to serve another megawatt ("MW") of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

for all resources and loads cleared through the market.[8] Participation in a DAM can enable production cost savings through more efficient hourly trading, unit commitment, and use of available transmission.

Joining a DAM is not the equivalent to becoming a participating transmission owner in a Regional Transmission Organization ("RTO"). There is no consolidation of BAAs. Transmission control, planning and cost allocation, and resource adequacy and resource planning continue to remain with the member utilities and their respective regulating authorities.[9]

Evaluation of Market Options

While NV Energy would prefer that the expansion of organized market services proceed within the WEIM's expansive and growing footprint,[10] certain of the current WEIM participants have expressed an intention to depart for an alternative DAM being developed by the Southwest Power Pool ("SPP") known as Markets+.[11] Any decision by NV Energy to move away from this status quo and join a DAM would need to provide a clear opportunity to create benefits that not only exceed what NV Energy would continue to experience in a potentially reduced WEIM footprint, but also create additional savings above any additional implementation and ongoing operating costs. The Companies have three alternatives: (1) remain outside a DAM and in the WEIM; (2) join EDAM; or (3) join Markets+.

NV Energy engaged in a thorough evaluation of these options. With respect to EDAM, NV Energy participated in formal stakeholder meetings and numerous additional discussions with CAISO staff, WEIM Entities and other stakeholders,[12] and the Companies' provided extensive written comments.[13] NV Energy also fully participated in the development of Markets+, including funding the Phase 1 tariff development work and serving on numerous committees.[14] The objectives of these activities were: (1) to learn about the design details of the new markets, (2) to seek to have Nevada's interests reflected in key policy decisions, and (3) to gain experience with the respective governance and stakeholder processes. The Companies' actions were not limited to these dueling, resource-intensive DAM development processes. Related to the DAM decision are the Western

[8] The DAM market settles all loads and resources in the day-ahead timeframe, and the real-time market address imbalances between day-ahead positions and the real-time deliveries or usage.

[9] Direct Testimony of Timothy Clausen at Q&A 14.

[10] The South Dakota and Wyoming electric utility subsidiaries of Black Hills Corp and PowerWatch (formally BHE Montana) anticipate joining the WEIM in 2026. Imperial Irrigation District anticipates joining both EDAM and WEIM in 2028. *See*, https://www.westerneim.com/Pages/About/default.aspx and https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx.

[11] Current WEIM Entities that have committed to funding of Markets+ Phase 2 development include: Arizona Public Service Company, the Bonneville Power Administration, Powerex, Puget Sound Energy, the Salt River Project, Tacoma Power, and Tucson Electric Power. This list is taken from SPP's website at: https://www.spp.org/western-services/marketsplus/.

[12] Direct testimony of Mike Holland at Q&A 7.

[13] NV Energy either individually or as part of a group have submitted comments on the EDAM initiative to CAISO on November 25, 2019, March 5, 2020, November 12, 2020, June 16, 2022, September 26, 2022, November 21, 2022, April 28, 2023, July 6, 2023, April 7, 2025, and May 1, 2025. The comments can be found at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

[14] Direct Testimony of Michael Holland at Q&A 7. Following the internal determination to seek authorization to join EDAM, the Companies notified SPP on May 24, 2024, of their intent to withdraw from the Phase 1 Funding Agreement. Consistent with the terms of the Funding Agreement the termination became effective June 23, 2024.

Power Pool's Resource Adequacy Program ("WRAP")[15] and the West-Wide Governance Pathways initiative ("Pathways").[16] NV Energy's participation in these efforts, included having a representative on WRAP's Resource Adequacy Participant Committee and the Pathways' Launch Committee. NV Energy also was a member of the Western Market Exploratory Group ("WMEG").[17] Additionally, the Companies retained the Brattle Group ("Brattle") to perform studies of potential benefits of participation in either DAM.[18] After the Brattle results showed a clear advantage in joining EDAM, the Companies retained Utilicast to perform a "Gap Assessment" - a detailed analysis of the costs and schedule associated with NV Energy's transitioning its current WEIM participation to include EDAM.[19]

NV Energy is differently situated than several of the entities that have expressed a preference for one of the DAMs or the other. The Companies need to seek approval from the Commission, an independent decision maker, in a transparent process.[20] NV Energy has been keenly aware of this requirement and has endeavored to keep the focus on which market will produce the most benefit for the least risk to our customers. NV Energy recognizes the importance of the request in this docket. While not irreversible, the hope is to continue the incremental addition of organized market participation to capture further benefits, without stranding investments.

Primary Factors Supporting the Selection of EDAM

As discussed in this Narrative and in the supporting testimony, the Companies recommendation is to proceed with the activities necessary to join EDAM. The primary factors supporting the Companies' decision are:

- The Companies' positive experience with the WEIM and lower implementation costs resulting from NV Energy's existing WEIM participation;

- The connectivity the Companies have with the anticipated EDAM market footprint versus that of the anticipated Markets+ footprint along with the overall connectivity the anticipated EDAM and WEIM participants have with each other;

- The projected higher customer benefits that will accrue from EDAM resulting from that connectivity;[21]

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15 Information on WRAP can be found on the Western Power Pool's website at: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

16 Information on Pathways can be found on the Western Interstate Energy Board website at: https://www.westernenergyboard.org/wwgpi/.

17 A further description of the WMEG and the materials it developed can be found on the NV Energy OASIS at: https://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/9._Public_Talking_Points_June_2023_-_Final.pdf.

18 *See* discussion in Section 6 of this Narrative and the Direct Testimony of John Tsoukalis.

19 Technical Appendix 2.

20 The Companies file this Joint Application pursuant to the Nevada Revised Statutes ("NRS") Section 704.741, Nevada Administrative Code ("NAC") Section 704.9504(3) and the July 9, 2024, Order in Docket No. 23-10019, Investigation regarding regional market activities in the western interconnection relevant to Nevada utilities' obligations pursuant to NRS Chapter 704. In Commitment 13 of the November 7, 2013, stipulation resolving Docket No. 13-07021 (MidAmerican Merger), the Companies agreed to request the Commission's authorization prior to participating in an organized market such as the EDAM.

21 Direct Testimony of John Tsoukais at Q&As 10 and 14.

- The governance of EDAM as enhanced by the Pathways initiative and the recently enacted California legislation, Assembly Bill ("AB") 825, including CAISO's ability to respond more expeditiously to events with targeted, expedited stakeholder processes; and

- A preference for certain EDAM market design features including resource sufficiency, resource adequacy and maintaining a voluntary participation relationship to the WRAP program; congestion rent allocation; virtual bidding; greenhouse gas ("GHG") accounting and potentially better opportunities to deploy new technologies related to compliance with FERC Order No. 2222.

1. Experience With the WEIM

In 2014, CAISO expanded its real-time market by offering the WEIM as an option for other BAAs in the Western Interconnection.[22] NV Energy was the second entity to join the WEIM, commencing financially binding operations on December 1, 2015.[23] Accordingly, the Companies have already invested in systems to participate in the WEIM and have almost a decade of operating experience in CAISO's real-time market. As noted by Utilicast in the Gap Assessment, "EDAM is essentially an additive market, leveraging nearly all of the functionality of WEIM."[24]

WEIM has demonstrated substantial economic and reliability benefits. CAISO releases reports on WEIM benefits each quarter.[25] Figure 2 contains the results for NV Energy.

Figure 2
NV Energy WEIM Benefits

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
January	0.34	1.07	0.87	1.09	1.10	1.36	1.36	17.93	8.69	20.04
February	0.75	1.31	2.07	2.20	1.80	10.99	1.61	8.34	8.53	22.18
March	0.62	1.12	1.23	2.42	2.46	1.79	1.44	20.92	15.55	39.49
Q1 Total	1.70	3.50	4.17	5.71	5.36	14.14	4.41	47.19	32.77	81.71
April	1.09	2.37	2.55	1.23	2.34	1.52	2.49	20.32	9.82	31.33
May	1.34	2.25	1.98	1.33	1.51	1.88	2.40	8.89	12.24	29.68
June	2.77	1.08	0.81	2.06	0.88	2.80	3.74	16.95	11.59	23.11
Q2 Total	5.20	5.70	5.34	4.62	4.73	6.20	8.63	46.16	33.65	84.12

22 *See* CAISO, Western Energy Imbalance Market (WEIM) (2025), available at https://www.westerneim.com/Pages/About/default.aspx.
23 *Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,305 (2015) at note 4.
24 Technical Appendix 2 at 6.
25 *See*, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx. Information as to how the CAISO calculates benefits can be found at: https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf.

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
July	1.88	2.28	4.07	1.47	1.89	7.44	10.67	25.32	15.54	
August	2.16	3.41	4.96	1.52	4.18	3.08	20.42	19.96	24.62	
September	1.55	2.86	2.06	2.93	2.74	7.52	31.29	15.02	27.41	
Q3 Total	5.60	8.55	11.09	5.92	8.81	18.04	62.38	60.30	67.57	
October	1.00	2.63	1.73	2.47	3.73	2.87	7.38	9.40	30.60	
November	1.47	2.96	1.51	2.63	1.60	3.37	9.69	6.29	23.93	
December	0.60	0.86	1.71	1.52	0.39	3.14	25.26	6.77	18.55	
Q4 Total	3.07	6.45	4.95	6.62	5.72	9.38	42.33	22.46	73.08	
Annual Total	15.57	24.20	25.55	22.87	24.62	47.76	117.75	176.11	207.07	165.83 (YTD)

The total projected benefits for NV Energy's WEIM participation through the second quarter of 2025, as calculated by CAISO, total $828.17 million.[26] As shown in Figure 2, NV Energy's benefits have increased with the expansion of participation. Accordingly, the Companies' benefits may decrease if certain entities depart for Markets+, but NV Energy has a high degree of confidence, as reflected in the Brattle results discussed below, that significant incremental benefits above those realized in WEIM will come from expanding the optimization to the day-ahead timeframe.

NV Energy has seen the reliability benefits associated with a highly interconnected footprint supported by the least-cost, security-constrained dispatch that delivers energy where and when needed both during normal and stressed system operations.[27] EDAM has helped address extreme events including the Bootleg fire in July 2021, the California heat wave during September 2022,[28] and the Northwestern cold event in January 2024.[29]

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26 The total includes NV Energy's reported benefits for December 2015 of $0.84 million.

27 As noted by Scott Kaufmann. NV Energy's Vice President, Transmission, "[a]s a participant in the WEIM, the Companies have access to a wider pool of energy resources to manage natural intra-hour load deviations caused by changes in forecast and changes in the output of variable energy resources, such as solar, geothermal and wind-based renewable generation" and "[b]y utilizing the upcoming forecasts, the market can see a decline and then provide resources to fill that gap within a matter of minutes." Direct Testimony of Scott Kaufmann at Q&A 13.

28 As Scott Kaufmann states, "[t]he Companies were able to import additional energy during the EEA 3 events in summers 2020 and 2021. In an EEA 3 event, all generation resources are on-line, the reserve requirement is not being met, and load shed is imminent. Without strong participation in the market, the Companies may have had to shed load over peak on those days." *Id.* CAISO's all-time peak demand of 52,061 MW was set on September 5, 2022. The next highest of 50,270 MW occurred on July 24, 2006. https://www.caiso.com/documents/key-statistics-may-2025.pdf.

29 Direct Testimony of Anna McKenna at Q&A 9. As described in the Direct Testimony of David Rubin, NV Energy was one of the advocates for the creation of the Assistance Energy Transfer Product to permit an EIM Entity that failed the resource sufficiency evaluation to receive additional imports if supply was available in the market at a scarcity price to help alleviate a stressed system condition. Direct Testimony of David Rubin at Q&A 22.

NV Energy merchant and transmission operations staff have operating experience in the CAISO real-time environment. NV Energy resources are included in the CAISO Master File[30] and the Companies' transmission system topography is part of CAISO's network model. Being part of WEIM results in expected lower implementation costs for both the market operator and NV Energy. Based on estimates from CAISO, NV Energy anticipates the installment payments to CAISO under the EDAM Implementation Agreement to cover the costs for NV Energy's onboarding to be approximately $1.2 million.[31] In contrast, NV Energy's share to build out the Markets+ market would be approximately $15 million.[32] NV Energy projects its total implementation costs for EDAM, including the CAISO fees, would be approximately $16.15 million.[33] While NV Energy did not perform a detailed analysis of the system upgrades necessary to adopt the SPP platform, the Bonneville Power Administration ("BPA") has stated these expenditures would be approximately double the projected EDAM costs.[34]

EDAM is a combination of the existing CAISO DAM and the existing WEIM. In contrast, Markets+ is a new service that includes as a central component the WRAP program which has not been implemented. Clearly, SPP and CAISO are experienced RTOs, and SPP has operated its Western Energy Imbalance Service ("WEIS") Market beginning in 2021,[35] which NV Energy understands will terminate in 2026 as most participants will transition to RTO West.[36] While both EDAM and Markets+ reflect the untried concept of combining a DAM and continued OATT service, NV Energy has more familiarity with and greater confidence in the CAISO's incremental expansion.[37]

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30 The Master File provides CAISO with the ability to store market participant resources' operating parameter data which is then used in different market applications. https://www.caiso.com/systems-applications/portals-applications/master-file#:~:text=The%20Master%20File%20(MFRD)%20provides,update%20their%20information%20as%20needed.

31 Direct Testimony of April Gordon, CAISO's Executive Director of Financial Planning and Procurement at Q&A 5.

32 NV Energy contributed approximately 10 percent of the Markets+ Phase 1 costs before the Companies' withdrawal. The Markets+ Phase 2 Funding Agreement allocates responsibility for $150 million in projected costs. The allocation can be found at: https://www.spp.org/documents/73296/markets%20plus%20phase%202%20exhibit%201%20funding%20agreement.pdf.

33 Technical Appendix 2 at 9 (Utilicast EDAM Gap Assessment). As noted by Ms. Schlekeway, "The Gap Analysis estimated $16,150,000 in total implementation costs which includes a 20 percent contingency adder. These costs included the Companies' labor, vendor costs, consultant costs, legal support, hardware and software acquisitions, licenses and subscriptions, and external fees." Direct Testimony of Lindsey Schlekeway at Q&A 10. Utilicast employed its proprietary Cost Estimating Model to calculate EDAM costs. That model, referenced as Attachment A in Technical Appendix 2, is presented as an Excel based file and submitted as a workpaper.

34 BPA May 9, 2025, Day-Ahead Market Policy Decision at 39-40. The document can be found at: https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/20250509-dam-final-policy.pdf.

35 NV Energy understands that the participants in WEIS include: Black Hills Energy , the City of Farmington NM Electric Utility, Colorado Springs Utilities; Deseret Power Electric Cooperative; Guzman Energy; the Municipal Energy Agency of Nebraska; Platte River Power Authority; Tri-State Generation and Transmission Association; United Power, Inc.; Western Area Power Administration (Upper Great Plains West, Rocky Mountain Region, and Colorado River Storage Projects), Public Service Company of Colorado, and Basin Electric Power Cooperative. https://spp.org/western-services/weis/.

36 Hearing Exhibit No. 101, Direct Testimony and Attachments of Joe Taylor in Public Utilities Commission of Colorado Proceeding No. 25A-0075E dated February 14, 2025, at note 3.

37 As noted by Michael Holland, NV Energy's Vice President Resource Optimization and Planning, "NV Energy's extensive experience with the WEIM is a critical factor in its recommendation to continue market

2. Footprint and Connectivity

The most important factor in delivering economic and reliability benefits through a DAM is the connectivity between NV Energy and the other potential participants as well as the connectivity those entities have with each other. While the market rosters continue to evolve, Figure 3 represents NV Energy's current assessment of the respective memberships.

Figure 3
Anticipated Footprints

Expected to Participate in EDAM (launch year, if available)	Expected to Participate in Markets+ (launch year, if available)[38]	Undecided Entities Currently in WEIM
CAISO (2026)	Arizona Public Service Company (2027)	Avangrid
PacifiCorp (2026)	Salt River Project (2027)	Avista
Portland General Electric (2026)	Tucson Electric Power Company (2027)	Black Hills (South Dakota and Wyoming)
Balancing Area of Northern California (2027)	Powerex (2027)	NorthWestern
LADWP (2027)	Public Service Company of Colorado (2027)	Seattle City Light
Turlock Irrigation District (2027)	BPA[39]	WAPA Desert Southwest[40]
Public Service Company of New Mexico (2027)	Puget Sound Energy	
Imperial Irrigation District (2028)	City of Tacoma	
Idaho Power[41]	Public Utility District No. 1 of Chelan County	
PowerWatch (formerly BHE Montana)	Grant County Public Utility District No. 2	

evolution through the EDAM. This experience provides a strong foundation for efficient integration, operational reliability, and cost-effective implementation, which would not be achievable to the same degree if starting anew with an alternative market such as Markets+." Direct Testimony of Michal Holland at Q&A 10.

[38] *See* Markets+ Participants Executive Committee Meeting Materials for August 5, 2025, at Item,12 Markets+ Readiness Update at slide 6. The document can be found at: https://spp.org/spp-documents-filings/?id=370747.

[39] BPA May 9, 2025, Record of Decision at 139. ("Bonneville has not identified a go-live date for participation but rather, Bonneville would determine the appropriate go-live date through future implementation planning to ensure resources will be available to implement a day-ahead market decision across various agency initiatives.") The Record of Decision can be found at: https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2025-rod/rod-20250509-day-ahead-market-policy.pdf.

[40] Arizona Generation & Transmission Cooperative, which serves the majority of retail load in the Western Area Power Administration's Lower Colorado balancing authority area, has expressed its interest in joining EDAM. Direct Testimony of Anna Mckenna at Q&A 16.

[41] On March 21, 2024, Idaho Power informed CAISO, "[b]ased on the study results and additional analysis performed, we are currently leaning towards EDAM as the preferred day-ahead market in our respective Balancing Authority Area (BAA), subject to necessary regulatory approvals and satisfactory resolution of certain outstanding issues." The letter can be found at: https://www.caiso.com/Documents/Idaho-Power-EDAM-Letter.pdf.

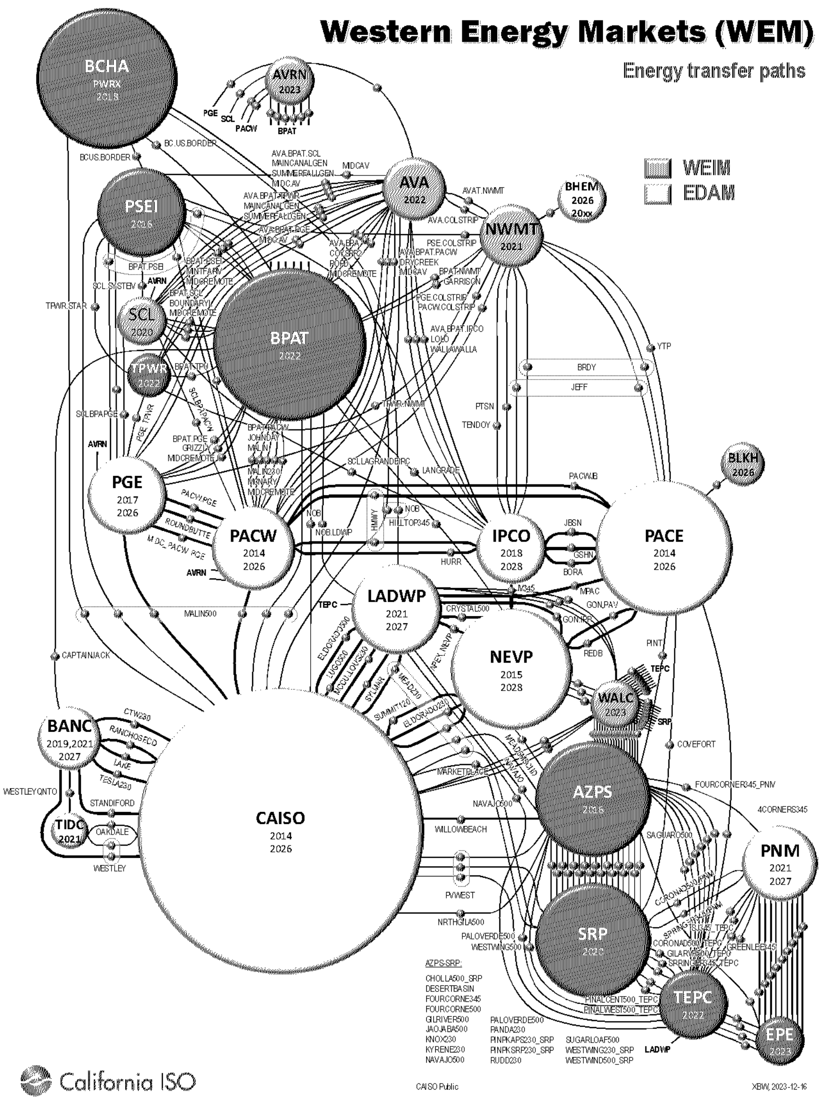
Expected to Participate in EDAM (launch year, if available)	**Expected to Participate in Markets+ (launch year, if available)[38]**	**Undecided Entities Currently in WEIM**
	El Paso Electric	
	Black Hills Colorado	

Figure 4 is derived from a diagram in the WEIM quarterly benefit reports. NV Energy has adopted it to highlight the connectivity of the expected EDAM Entities (light grey). In contrast there is far less transmission between the Northwest, Desert Southwest and Intermountain West zones Markets+ participants (dark grey).

As illustrated in Figure 4 and described by Mr. Pottey in his Direct Testimony,[42] NV Energy has significant interties with the planned EDAM participants. Additionally, the prospective EDAM Entities, for the most part, have transmission ties with each other. In contrast, the announced Markets+ participants are located in zones with interconnectivity primarily with other participants in the same zone but not between the zones.

[42] Direct Testimony of Charles Pottey at Q&A 7.

Figure 4
Market Connectivity



NV Energy not only considered the existing transmission systems, but also the major projects under active development. On April 15, 2024, in response to Procedural Order No. 2 in Docket No. 23-10019, NV Energy provided a map (Figure 5) highlighting the relationship of ongoing major transmission projects in the West to the potential market footprints. As described by Mr. Pottey in his Direct Testimony and in section 4.C of this Narrative,[43] the majority of these new lines are in the BAAs of projected EDAM participants or are anticipated to increase supply diversity by bringing wind into CAISO and the EDAM footprint illustrated in the dark grey shading.

[43] *Id.* at Q&As 16-18.

Figure 5

Market Footprints and Transmission Development

Mr. Pottey further explains that the SWIP-North project in particular increases NV Energy's ON Line capacity from 900 megawatts ("MW") north-to-south to 1,217.5 MW (2,335 MW overall) and increases NV Energy's ON Line capacity from south-to-north from 600 MW to 1,172.5 MW (2,245 MW overall). SWIP-North's capacity is 2,070 MW North-to-South (allocated as 952.5 MW to NV Energy and 1,117.5 MW to CAISO and 1,920 MW South-to-North (allocated as 847.5 MW to NV Energy, 572.5 MW to CAISO and 500 MW to Idaho Power Company). NV Energy's northern Nevada system import limit with Greenlink West, Greenlink North and SWIP-North will be in the range of 4,000 to 4,400 MW. While NV Energy could bring its own transmission capacity to Markets+, it would dilute the benefit of the combined ON Line and SWIP-North project being part of a single, optimized market dispatch.[44]

While EDAM does not address forward firm transmission scheduling between the Northwest and Nevada through California (the "wheel-though" issue),[45] EDAM facilitates access of day-ahead

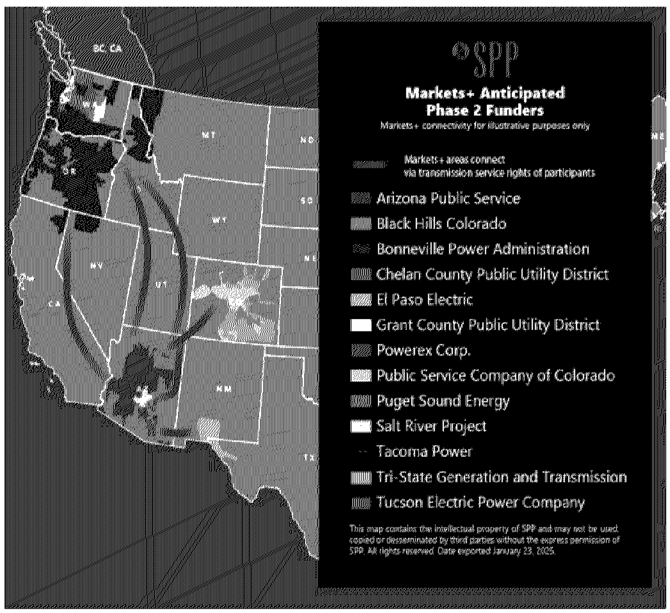
[44] Direct Testimony of Charles Pottey at Q&As 16 and 17.

[45] *See* Motion to Intervene, Protest, and Comments of NV Energy filed in FERC Docket No. ER23-2510 on August 17, 2023. *See also*, NV Energy's complaint filed on May 17, 2021, in FERC Docket No. EL21-74 and the Companies' June 17, 2021, answer in that same proceeding as well as NV Energy's Motion to Intervene and Protest in Docket No. ER21-1790 filed on May 17, 2021.

and real-time supply over Path 66, the California-Oregon Interconnection and Path 65 the Pacific DC Intertie with LADWP's participation in as part of the EDAM market optimization.

Figure 6 is from a presentation made by SPP on May 21, 2025. It illustrates the connectivity between the four non-congruous SPP zones by aspirational arrows. Importantly, NV Energy has limited connectivity with the declared Markets+ participants. As described by Charles Pottey in his Direct Testimony, the only existing line between NV Energy and BPA is Path 76, the Alturas line, with a rating of 300 MW in both directions from Hilltop to Ft. Sage.[46] NV Energy does not have a direct interconnection with Arizona Public Service or the Salt River Project. However, NV Energy has interconnections to Mead and Navajo. Both Arizona Public Service and the Salt River project also have transmission rights to Mead and Navajo.[47]

Figure 6[48]
Illustration of Potential Markets+ Zones



NV Energy has seen no listing of the transmission rights that would facilitate operation of Markets+ across these non-participating systems.[49] Moreover, it would be important to distinguish whether those rights are standard OATT service agreements that only permit changes by the transmission customer until 20 minutes before real-time[50] or are voluntary, non-conforming

46 Direct Testimony of Charles Pottey at Q&A 12.
47 *Id.* at Q&A 11.
48 *See*, https://www.spp.org/documents/73921/phase%20two%20governance%20and%20readiness%20webinar%2020250521.pdf at slide 8.
49 In testimony before the Colorado Public Utilities Commission in Proceeding Number 25A-0075E, Joseph Taylor, Public Service Company of Colorado's Senior Director of Western Markets, stated in response to the question "please describe the scope of transmission assets represented by the likely Markets+ participants" that "I understand than neither SPP staff nor the other utilities have compiled this information" Hearing Exhibit 101 filed on February 14, 2025 at 25.
50 *See* NV Energy's OATT at Section 13.8,

dynamic scheduling agreements[51] that permit changes through real-time and are necessary to accommodate SPP's 5-minute, real-time market.

As noted by BPA,

> Further, the lack of D[ynamic]T[ranser]C[apability] between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.[52]

FERC has confirmed that an OATT service agreement is not a property right on the part of the customer[53] and that transmission customers do not have the unilateral right to opt-out their transmission from EDAM.[54] As stated by FERC,

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> Schedules for the Transmission Customer's Firm Point-To-Point Transmission must be submitted to the Transmission Provider no later than 10:00 a.m. (Pacific Time) of the day prior to commencement of such service. **Schedules submitted after 10:00 a.m. (Pacific Time) will be accommodated, if practicable.** Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. **Scheduling changes will be permitted up to twenty (20) minutes before the start of the next scheduling interval provided that the Delivering Party and Receiving Party also agree to the schedule modification. [Emphasis added.]**

NV Energy's OATT can be found on the OASIS site at: https://www.oasis.oati.com/NEVP/ under the "Tariff" tab.

[51] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261, at P 631 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) ("The Commission denies rehearing of the decision in Order No. 890 to not mandate a dynamic scheduling service in the pro forma OATT."); *see also*, *PáTu Wind Farm, LLC v. Portland General Electric Co.*, 154 FERC ¶ 61,167 (2016) at P 37.

[52] BPA Day-Ahead Market Policy dated May 9, 2025, at 89. The document can be found at: https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/20250509-dam-final-policy.pdf.

[53] *Sw. Power Pool, Inc.*, 191 FERC ¶ 61,177 (2025) at P 15 ("we grant Rehearing Parties' request for clarification and clarify that nothing in the January 16 Order purports to grant transmission customers an ownership right to the transmission capacity over which they take service, nor grants, waives, modifies or otherwise interprets any rights or obligations under the OATT of a non-participating transmission service provider not before the Commission in this proceeding."). In the January 19, 2025, Order on the Markets+ tariff, FERC explained, "the Markets+ Tariff will not force changes in the operations of non-participating transmission service providers' systems" and that "Markets+ Transmission Contributors will be responsible for "coordinating transmission schedule changes, curtailments, and other operational concerns with the non-participating [transmission service provider] and non-participating [balancing authority], in accordance with the applicable governing documents and agreements, including applicable OATTs.". *Sw. Power Pool, Inc.*, 190 FERC ¶ 61,030 (2025) at P. 153 and P 154

[54] *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 370:

> We are unpersuaded by protesters' arguments that firm transmission customers should be allowed to unilaterally opt-out their transmission capacity reservations from the market entirely. Some of these protesters argue that being able to opt out transmission capacity out of the market is necessary to ensure that their use of the transmission system is not subject to congestion charges and to ensure

> We recognize that some commenters would like to contribute their firm point-to-point transmission rights on the PacifiCorp system to Markets+. The Commission has previously found that any Markets+ transmission contributions are permitted, provided that they are allowed under the host BAA's OATT or other governing documents. We find that PacifiCorp's proposal does not bar firm point-to-point transmission customers from contributing their transmission rights to Markets+, insofar as they are able to meet all of the requirements of PacifiCorp's Tariff. Under PacifiCorp's proposed Tariff, any such transmission contribution to Markets+ would be subject to the same congestion charges, redispatch costs, and limitations applicable to every PacifiCorp firm point-to-point transmission customer. We find that there is no obligation under the Commission's regulations, or the *pro forma* OATT, for PacifiCorp to accommodate transmission contributions to Markets+.[55]

SPP has stated "[t]he Commission will need to understand how SPP's inclusive governance model may mitigate the consequences to Nevadans in market design decisions and in critical shortage situations, including SPP's ability to provide NV Energy with access to greater diversity across the Western Interconnection."[56] While NV Energy will discuss concerns with SPP's majority-driven stakeholder process later in this Narrative, supply diversity only occurs with sufficient transmission capability.

3. Customer Benefits

During the Workshop held in Docket No. 23-10019 on April 3, 2024, Brattle presented the results of its Summer 2023 NV Energy EDAM Benefits Study, Fall 2023 Markets+ Benefits Study and January 2024 EDAM/Markets+ Footprint Scenarios (Figure 7).[57] As shown in Figure 8, Brattle-projected EDAM benefits ranged across the scenarios from \$62 million to \$149 million annually.[58] In contrast, Markets+ projected benefits ranged from ***negative*** \$17 million to \$16 million annually.[59] Moreover, NV Energy's greatest benefits were seen in market consisting of CAISO, LADWP, BANC, PacifiCorp, Portland General Electric, Idaho Power, and Seattle City Light, which contained 46 percent of WECC load but 80 percent of solar generation, 70 percent of storage capacity, and 68 percent of wind generation.[60]

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that their intra-day schedule changes are treated in a manner consistent with the Commission's *pro forma* OATT. However, as we are finding that both PacifiCorp's treatment of congestion revenues and its treatment of intra-day schedule changes are consistent with or superior to the *pro forma* OATT, there is no need for such a permissive opt-out to be available to all firm transmission customers.

55 *Id.* at P 250.

56 SPP Comments in Response to Procedural Order No. 3 in Docket No. 23-10019 filed on May 31, 2024, at 3.

57 The presentation is posted on the NV Energy OASIS at: https://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/(2024-04-03)_Brattle_PUCN_Workshop_Slides_v2.pdf.

58 Docket No. 23-10019, April 3, 2024, *NV Energy Day-Ahead Market Benefits Studies* (The Brattle Group) at slide 9, submitted on April 17, 2024, as Attachment 1.

59 *Id.*

60 *Id.* at slide 17.

Figure 7

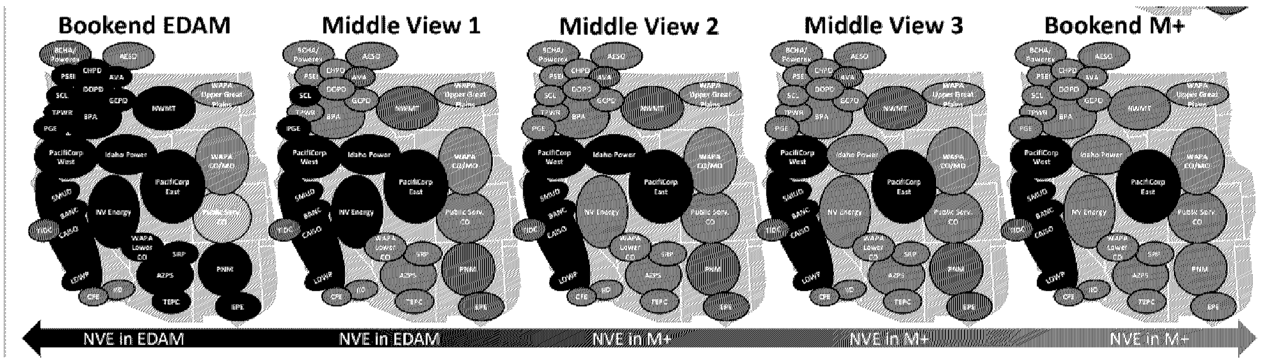

Figure 8

Nevada Energy System Cost by Case ($ Millions)

		BAU	Bookend EDAM	Middle View 1	Middle View 2	Middle View 3	Bookend Markets+
Market Membership	**Metric**	**EIM Only**	**EDAM**	**EDAM**	**Markets+**	**Markets+**	**Markets+**
Adjusted Production Cost	Cost	$485.5	$420.1	$357.0	$425.4	$420.8	$415.4
Wheeling Revenues	Revenue	$15.4	$0.0	$14.9	$0.5	$0.3	$0.4
Trading Revenues:							
Bilateral	Revenue	$72.2	$0.0	$10.2	$4.9	$4.0	$4.2
WEIM	Revenue	$33.2	$30.1	$19.0			
WEIS/Mk+ RT Market	Revenue				$9.3	$11.5	$11.2
EDAM	Revenue		$88.3	$98.0			
Markets+	Revenue				$30.0	$50.3	$52.2
Total System Cost		**$364.7**	**$301.6**	**$214.8**	**$380.6**	**$354.8**	**$347.3**
Benefit to BAU			**$63.1**	**$149.9**	**-$15.9**	**$9.9**	**$17.4**

During the same Workshop, Energy+Environmental Economics ("E3") presented its analysis that showed a projected $9.3 million in annual benefits in a footprint with NV Energy and Idaho Power in EDAM. The "main split" footprint produced greater savings but only if Idaho Power was also in Markets+.[61] For the 2035 Alternative Split 4 scenario, in which PacifiCorp, the California entities, NV Energy and Idaho Power were in EDAM, the projected annual benefit was $59.8 million.[62]

One of the criteria identified in the report approved in the July 9, 2024, Order in Docket No. 23-10019 was a study that incorporated, "[u]se of the most recently available applicable to Nevada-specific inputs." Accordingly, NV Energy retained Brattle to "refresh" its early work based on the most recent data available. As discussed in the Direct Testimony of John Tsoukalis, Brattle updated fuel prices, resource mix data, load projections and new transmission rights and projects.[63]

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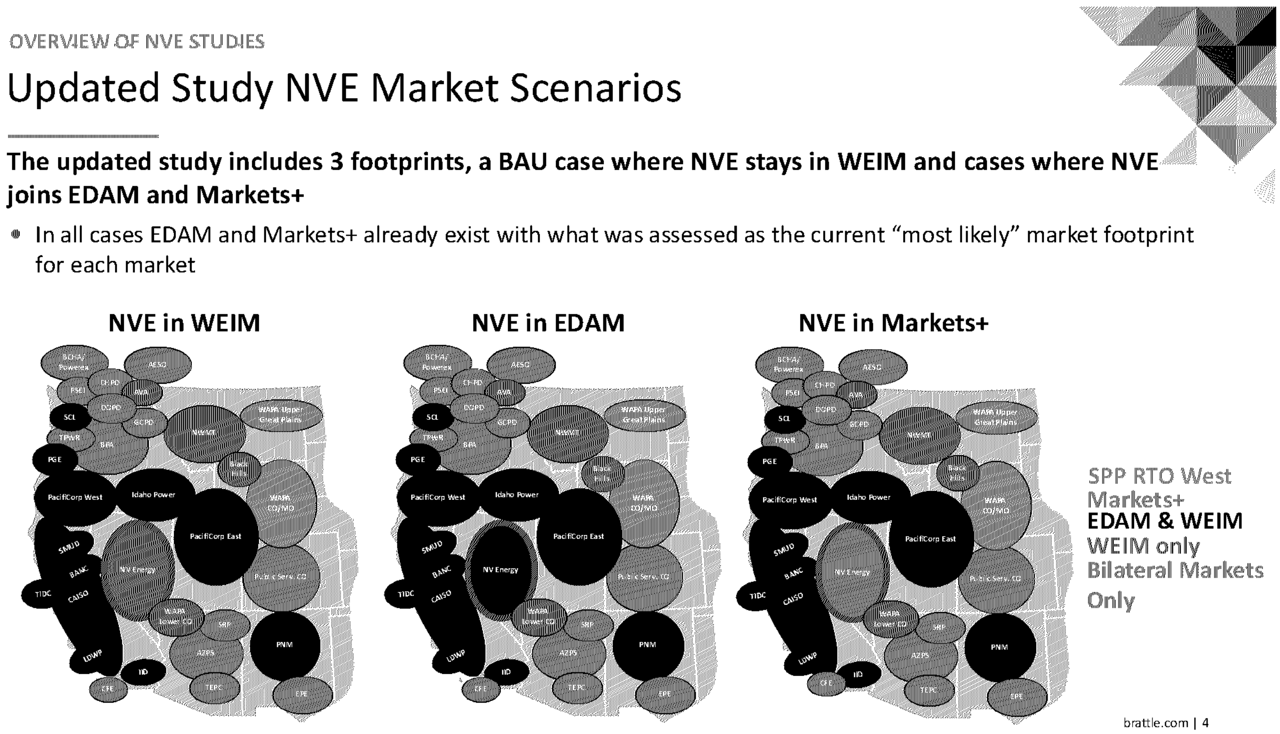
61 Docket No. 23-10019, April 3, 2024, *Western Markets Exploratory Group (WMEG) Cost Benefit Study* (Energy+Environmental Economics (E3)) at slide 21, submitted on April 17, 2024, as Attachment 2. The presentation is also posted on the NV Energy OASIS at: https://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/E3_WMEG_Benefits_Summary_for_NVE_-_Presentation_2024-04-3.pdf.

62 *Id.* at slide 24

63 Direct Testimony of John Tsoukalis at Q&A 24. As shown in the 2025 Brattle study contained in the Technical Appendix 1, updated data included the following:

The 2025 study analyzed the potential benefits for NV Energy in joining either CAISO's EDAM, SPP's Markets+, or remaining in the existing WEIM (the Business as Usual ("BAU") case) using 2032 as the study year.[64] As shown in Figure 9, in all three cases, the market participation assumptions for all the other utilities in the Western Electric Coordinating Council ("WECC") remained the same to isolate the impact of NV Energy's market participation.

Figure 9



- NV Energy's system assumptions were updated by the NV Energy transmission and resource 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 CAISO, Arizona Public Service, the Salt River Project and other entities via both public IRP announcements and other data;
- Public Service New Mexico, Idaho Power, PacifiCorp, El Paso Electric, Turlock Irrigation, and Seattle City and Light have all completed studies with Brattle since the prior NV Energy work that lead to significant changes to their systems' modeling assumptions; and
- Other updates include, breaking out Black Hills Power & Cheyenne Light Fuel and Power from the WACM BAA, making them their own BAA, 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 Council, and adjusting transmission limits on SWIP North and Greenlink in consultation with the NV Energy transmission team.

Technical Appendix 1, Brattle NV Energy Day-Ahead Market Study 2025 Updated Cases October 2025 at 3.

[64] The study year is 2032, which 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. Direct Testimony of John Tsoukalis at Q&A 8.

Brattle examined: (1) adjusted production cost ("APC") savings,[65] (2) short-term wheeling revenues,[66] (3) market congestion revenues,[67] and (4) bilateral trading margins.[68] Brattle did not attempt to quantify potential reliability or environmental benefits.

As shown in Figure 10,[69] the study determined that NV Energy's net system costs are reduced by $93.1 million by joining EDAM but increase by $7.3 million moving from WEIM to Markets+. EDAM produces net benefits in APC, surplus market congestion revenues, and short-term wheeling revenues.

Figure 10

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.

65 APC Savings is 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. Brattle analyzed each of those three components separately – production costs, sales revenue, and purchased power costs and summed 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.

66 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.

67 Market Congestion Revenues 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's generation resources will be paid their LMP and that all NV Energy load will pay their LMP, 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.

68 Bilateral Trading Margins account 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.

69 Technical Appendix 1 at 5.

As noted by Brattle,

> 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.[70]

In contrast,

> 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.[71]

According to Brattle, the benefit calculation is likely to be conservative as it: (1) overstates the efficiency of bilateral markets, (2) uses weather-normalized loads which reduce the market benefits seen in scarcity events; (3) does not fully reflect the limited liquidity of the bilateral market during challenging system conditions, and (4) does not account for sub-hourly trading benefits in the organized markets.[72] In one respect, however, the Markets+ benefits may be overstated as Brattle's study assumed that the resources and loads in the portion of the SPP's RTO West were co-optimized with the Markets+ footprint.[73] NV Energy is unaware of any current plan to combine Markets+ and RTO West in a single optimization.

Market participation is about achieving cost savings and reliability benefits for customers. As with the Companies' participation in the WEIM, all the cost savings and other benefits associated with participation in EDAM will accrue entirely to customers.[74] Primarily, these benefits will be associated with lower fuel and purchase power costs resulting from the enhanced optimization of energy supply resources over the EDAM footprint. The higher savings reflected in the Brattle EDAM results are consistent with the greater interconnectivity that facilitates the higher volume of market transactions.

CAISO estimates NV Energy's share of ongoing administrative costs (the Grid Management Charge) for the combined EDAM and EIM participation would be $15.5 million/year.[75] These are higher than the estimate administrative costs for Markets+ of between $7 to 7.5 million/year.[76] Although, these differences would be partially offset for the first years as SPP recovers its

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[70] Direct Testimony of John Tsoukalis at Q&A 15.
[71] *Id.* at Q&A 12.
[72] *Id.* at Q&A 10.
[73] *Id.* at Q&A 7.
[74] Direct Testimony of Timothy Clausen at Q&A 17.
[75] Direct Testimony of April Gordon at Q&A 7. This estimate also includes the real-time participation costs. There would not be a separate WEIM charge.
[76] According to Antoine Lucas, SPP's ongoing operations costs are estimated at $70 to $75 million per year. Testimony of Antoine Lucas at page 444 lines 17-25, Docket No. 23-10019 Workshop Volume 3 April 10, 2024. NV Energy was responsible for approximately 10% of the Markets+ Phase 1 costs. Depending on the level of participation that percentage could change.

$150 million in implementation costs.[77] The remainder of the difference would need to be offset by the lower internal development costs and higher expected economic benefits.

4. Governance

Based on a decade of experience in the WEIM and participation in both DAM's stakeholder processes, NV Energy has a strong preference for CAISO's governance design as enhanced by Pathways and the recently enacted California AB 825. Factors supporting the Companies' perspective on this critical issue include:

- The success of Pathways' Step 1 in giving the Western Energy Markets ("WEM") Governing Body "primary authority" over market rules is a significant advancement in the independence of EDAM and WEIM oversight. The inclusion of a dual Section 205 filing right between the WEM Governing Body and the CAISO Board of Directors places the WEM Governing Body in a stronger position in a dispute with the CAISO Board of Governors versus the Markets+ Independent Panel ("MIP") who will always be subordinate in a dispute with the SPP RTO Board.

- Implementation of Pathways Step 2, as authorized by AB 825, will further enhance independent oversight of the EDAM and WEIM and provide a platform for expanded service offerings.

- The CAISO initiative-specific stakeholder approach can address emergent issues more expeditiously and efficiently. CAISO's staff-led process can help balance stakeholder interests and protect minority rights. Conversely, NV Energy's experience in Markets+ Phase 1 highlighted concerns with block voting by similarly situated parties.

- The CAISO approach with its greater reliance on written comments provides additional transparency regarding stakeholder positions and can help identify and support important minority views. It can also facilitate earlier involvement by the WEM Governing Body. In contrast, Markets+ initiatives proceed through a hierarchical committee structure before being presented to the MIP.

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[77] *See* FERC Docket No.ES25-33, Application of the Southwest Power Pool, Inc. under Section 204 of the Federal Power Act for an Order Authorizing the Issuance of Securities dated February 21, 2025, at 5:

> Type and Nature of Securities: The Multiple-Draw Term Loan is in an amount of One-Hundred Fifty Million Dollars ($150,000,000) with a three (3) year availability period. The Loan will fund implementation of Markets+ throughout the initial three-year funding period. At go-live of Markets+, SPP will convert the outstanding draws to a term loan with repayments not to exceed seven (7) years. SPP will enter into a credit agreement with the institution to which the Loan will be issued. To the extent execution of the credit agreement constitutes a security requiring Commission authorization, SPP requests such authorization pursuant to this Application.

The February 17, 2025, Resolution of the SPP Board of Directors provides that the Financing was authorized by the Board of Directors on August 6, 2024, on the condition that the Financing must: "(a) be non-recourse to the SPP RTO . . . and (c) be repaid by the Market+ participants, who will serve as the backstop for cost recovery[.]" *Id* at Exhibit B. "SPP will derive the revenues required to repay the Markets+ funding from Schedule 1-B of the Markets+ Tariff which will be paid by Markets+ Market Participants." *Id.* at 9.

- CAISO's expanded market oversight includes not only the market monitoring unit, but also the Market Surveillance Committee and the WEM Governing Body Market Expert, providing significant, independent perspectives on market performance and new initiatives.

5. <u>Market Design and Other Issues</u>

a. Resource Sufficiency and Resource Adequacy

Both DAMs utilize forecasts to establish must-offer requirements. To account for intra-day variations in load and variable energy resource outputs, EDAM includes an imbalance reserve, and Markets+ has flexibility reserve products.[78] However, Markets+ caps the day-ahead must-offer obligation at the WRAP planning reserve requirements during the peak summer and winter binding seasons. [79] Stated another way, the seven-month ahead WRAP planning reserve margins are used ***to lower participants' offer obligations***, even if the day-ahead forecast and flexibility reserve products call for a higher amount. Accordingly, NV Energy has greater confidence that EDAM's resource sufficiency evaluation will promote day-ahead market run participation by the necessary resources and to handle intra-day uncertainty. This helps promote stable market prices while ensuring there is enough supply to maintain reliability.

Both DAMs have a post-market run "RUC" process (EDAM's residual unit commitment and Markets+' reliability unit commitment). NV Energy is concerned that the lower must-offer obligations in the peak seasons, combined with the disaggregated zones with limited transmission interconnectivity will trigger high shortage prices in Markets+. NV Energy is a load-serving entity with a net-short position. Many elements of the Markets+ design appear to favor entities with long supply positions. These include fast-start pricing and the higher conduct and impact thresholds used to mitigate the exercise of market power. These design elements increase LMPs and associated costs to loads.

Additionally, Markets+ converts the voluntary WRAP into a mandatory requirement. As discussed in the Companies' ESP Update in Docket No. 25-08027, NV Energy has determined it is not in customers' interest to participate in WRAP.[80] Components of the decision not to enter WRAP included the potential to incur extreme penalties under the WRAP, uncertain planning reserve margins ("PRMs"),[81] significant amount of new NV Energy capacity being brought on line with

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[78] There are three flexibility reserve products in Markets+: (1) short-term flex up; (2) short-term flex down; and (3) mid-term flex up. These products are analogous to the ramp capability and uncertainty reserve products in SPP's Integrated Marketplace. *See* SPP's Filing Letter in Docket No. ER24-1658 at 54.

[79] SPP states "that due to a limited must-offer obligation that exists within WRAP, participants may elect not to offer all available resource capacity for Markets+ commitment and dispatch while still satisfying the must-offer obligation." Markets+ Acceptance Order at note 416 (quoting SPP's Filing Letter in Docket No. ER24-1658 at 37).

[80] Docket No. 25-08027, Direct testimony of Lindsey Schlekeway at 3 (Q&A 7) ("the Companies have made the decision to withdraw from the WRAP due to inherent risks that outweigh the program's current benefits for both the Companies and their customers").

[81] Further complicating program compliance is the volatility of the PRMs. Year-over-year changes have ranged from minor adjustments to swings as large as 10 percent. For a monthly peak load of 10,000 MW, this could translate to an unexpected need for 1,000 MW of additional capacity which is an unrealistic burden within such a short

construction schedules being challenged by supply chain and tariff issues, potentially large shifts in load forecasts, and the potential limited benefits associated with the WRAP operations program,[82] especially in its current zonal structure.[83] [84]

As discussed in the Direct Testimony of Lindsey Schlekeway, NV Energy has had concerns with the proposed design of the imbalance reserve product.[85] There have been and will continue to be improvements in the resource sufficiency test, under the oversight of the WEM Governing Body's primary authority. CAISO has worked with the Companies' Resource Optimization department to better understand the relationship of the proposed imbalance reserves to NV Energy's existing, stand-alone management of reserves for intra-day uncertainty.[86] NV Energy and the other LSEs in CAISO and the other EDAM Entity footprints will continue to monitor and improve the imbalance reserve product. Accordingly, NV Energy has greater confidence in the EDAM resource sufficiency approach, combined with the footprint and interconnectivity, to maintain reliability at just and reasonable prices.

b. Congestion Rent Allocations

NV Energy's evaluation of the DAM proposals is based on two key principles with respect to allocation of congestion revenues:[87] (1) the allocation should provide a means of holding OATT customers harmless to the extent possible from any financial consequences ***from the actual use*** of their firm transmission rights; and (2) firm OATT customers should be treated equally – there should be no winners and losers. As NV Energy stated in comments to CAISO submitted on August 16, 2022,

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timeframe. This level of variability is too large to occur on such a short timeframe leaving little to no time for a participant to react and procure the additional supply. *Id.* at 3-4 (Q&A 8).

82 WRAP is untested and the Companies question whether the holdback will be required or will be available if a heat wave occurs and Nevada needs to call on the program to supply holdback. The concept of holding back capacity for program participants has been the perceived benefit such that there is an agreement between the program members to supply energy if a participant has surplus to another participant that might be deficient. As implemented, the program models the participants at two subregions separating the southwest from the northwest participants. Accordingly, holdbacks may be of limited value if weather events occur over large areas of the desert southwest. *Id.* at 8-9 (Q&A 12).

83 The program does not model the participants at their respective market participation, rather WRAP models the participants in two separate sub regions with limited transmission connectivity between them. This modeling approach does not consider the vast majority of transmission that has been proven to be used and available through the WEIM. It is notable that the program has strict firm transmission requirements and that the ATC that is determined in real-time is not firm enough to qualify for the program rules. However, there has been sufficiently more transmission capability that has occurred through market participation than the 500 MW assumed by the program between the participants that will remain in the WEIM, have either signed an EDAM implementation agreement, or stated a position of leaning towards EDAM. Therefore, it is the Companies perspective that the current WRAP program undervalues this transmission capability which eliminates any major diversity benefit from occurring in the forward showing resulting in higher PRMs. *Id.* at 7-8 (Q&A 11).

84 *Id.* at 3-9 (Q&As 7-12).

85 Direct Testimony Lindsey Schlekeway at Q&A 25.

86 NV Energy's day-ahead desk operator uses an uncertainty reserve calculator developed in accordance with Energy and Environmental Economics to calculate additional flex reserves that are required for variable energy resource ("VER") uncertainty. *See* Technical Appendix 2 at 20, section 3.1 (Utilicast Gap Assessment).

87 Congestion rent (also referred to as congestion revenue) is the amount collected by the market operator when there is a difference in the LMP between two points on the transmission network due to congestion. This issue is discussed in Section 5(D) of the Narrative.

> While other stakeholders have sought payment directly to the customer, NV Energy supports the proposed treatment of congestion revenue as a means of ensuring that all OATT customers are treated equally. After any OATT customers with firm transmission rights are protected from congestion costs resulting from intra-day changes to their transmission schedules as permitted by the OATT, congestion shortfalls or surpluses would be allocated on a load ratio share.[88]

Based on these criteria, NV Energy finds EDAM has a clearly superior congestion allocation methodology. The EDAM congestion design as enhanced by CAISO's Tariff amendment accepted in FERC Docket No. ER25-2637, in conjunction with the approved sub-allocation approaches in the PacifiCorp and Portland General Electric OATTs, better protect customers' actual use of their OATT rights. As FERC explained:

> We find that PacifiCorp's proposed two-step sub-allocation of congestion revenues is just and reasonable and not unduly discriminatory or preferential, and consistent with or superior to the Commission's *pro forma* OATT. PacifiCorp's Step One allocation of congestion revenue, which reverses day-ahead congestion price differentials associated with balanced self-schedules of firm point-to-point and network transmission customers, will insulate balanced self-scheduled transmission use from EDAM's congestion exposure up to the congestion revenue that CAISO allocates to the PacifiCorp BAAs. Additionally, we find that PacifiCorp's Step Two allocation of congestion revenue will mitigate the congestion costs borne by entities that economically bid into EDAM.[89]

While both the EDAM and Markets+ congestion allocation methodologies are novel designs, untested by actual system operations, NV Energy has significant structural concerns with the Markets+ approach. First, Markets+ allocates congestion based on the total OATT reservations for point-to-point and Network Integration Transmission Service ("NITS") coincident peak usage. These reservations are based on the total transfer capabilities of the lines – there is no simultaneous feasibility test that RTOs use to determine the quantity of financial rights that can be awarded for purposes of providing a congestion hedge. In other words, for sold-out paths, there is a significant risk of customers experiencing a shortfall in their congestion hedge. Moreover, the Markets+ congestion revenue allocation is based on reserved capacity not actual usage. If Markets+ starts with the potential shortfall and then allocates a pro rata capacity share to customers who did not

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[88] The comments can be found at: https://stakeholdercenter.caiso.com/Comments/AllComments/403bc91b-8c28-456d-bb1e-5ea1a95a8b7d#org-a3113bf2-0692-45bc-9903-29f4010e7487. The one exception to allocation of transfer and congestion revenue to the BA acting as the transmission provider is with respect to "Bucket 2" transmission. OATT transmission customers with firm point-to-point rights of a month or longer over an EDAM interface can elect to provide the transmission capacity to the market on a daily basis in exchange for a percentage of transfer revenue over that interface. A number of factors justify the limitation to firm point-to-point reservations of a month of longer including: (1) network customers cannot assign transmission capacity; (2) normally, CAISO as an independent system operator, would not be an eligible customer under an OATT. This "assignment" is a special exception designed to facilitate market activities, and the limitation does not take away any transmission customer's right to reassign transmission to other eligible customers on other days; and (3) especially at the start of a new market, it may be important not to create an incentive for customers with short term transmission reservations (hourly or daily) to remove valuable transmission capacity from the bilateral market which would limit the ability of load serving entities to engage in short term bilateral procurement to meet the resource sufficiency evaluation requirements.

[89] *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 147.

use their rights, this can exacerbate any under-recovery by customers who actually schedule and incur congestion. The potential for a shortfall of a hedge against incurred congestion costs is compounded in Markets+ by the inclusion of conditional firm transmission reservations in the denominator for allocation of rights, even during the period where the condition is in effect.

The Markets+ congestion allocation methodology has the potential to create winners and losers. For example, NV Energy is currently developing the Greenlink transmission project. In the Markets+ design, a firm point-to-point customer with a reservation of a month or longer will get all of the congestion revenue in proportion of the capacity amount of the reservation, even if they have not scheduled on that reservation and incurred a congestion cost to offset. In accordance with FERC's transmission pricing policy, that same customer will only pay a system average rolled-in access charge rate for the reservation.[90] However, since the line is new and has a lower than average depreciation, the remaining revenue requirements associated with Greenlink will be paid for by other NV Energy customers, mostly NITS customers, including native load. In other words, these customers are supporting the revenue requirement associated with the generation of the congestion revenue but are not seeing any corresponding benefit. It is one thing to provide a protection for actual congestion cost incurrence. It is quite another to pay revenues only to certain customers who are not fully supporting the costs of the facilities underlying their reservation.

A similar concern arises with respect to network customers. Markets+ will allocate congestion revenues based on the coincident peak as noted above. This can lead to over-recovery as there may be many hours where the usage is less than the coincident peak as well as potential under-recovery if a NITS customer experiences non-coincident peak hours. NV Energy's concern about firm customers not being sufficiently hedged is consistent with SPP's statement in the SPP Markets+ filing letter that, "Market Participants with firm transmission service should receive ***some offset***, even if not a perfect offset, for the redispatch costs they will incur as a result of their contribution of transmission rights for use in Markets+ that benefits the broader market."[91] It remains to be seen how much protection "some offset" will provide customers, including native load's network rights

In addition to the potential for under-recovery, NV Energy is concerned about the relation between the ability of transmission customers to opt their transmission capacity out of the market when they want to engage in physical deliveries and not be exposed to potential under-recovery of congestion costs and then opt it back in when they are not using it to gain any additional revenue. For example, a customer could opt-out capacity for the summer season and then return it to the market for the remainder of the year. This can diminish the amount of capacity available for market optimization.

NV Energy recognizes that CAISO's proposal is interim.[92] The Companies view CAISO's response to the interventions in the PacifiCorp and Portland General Electric dockets as a sign of

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[90] FERC's policy is that "when facilities are integrated and thus provide system-wide benefits, facilities' costs are generally rolled-in and charged to all customers served." *Pinnacle West Capital Corp.*, 131 FERC ¶ 61,143, at P 42, *reh'g denied*, 133 FERC ¶ 61,034 (2010); *see also Sierra Pacific Power Co. v. FERC*, 793 F.2d 1086, 1088 (9th Cir. 1986) ("FERC favors rolled-in cost allocation when a system is integrated.").

[91] March 29, 2024, Markets+ Tariff Transmittal letter at 29 (emphasis added).

[92] *Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025) at P. 37 ("We disagree with protesters that a deadline for further deliberation should be mandated as we find that CAISO's current allocation methodology for

responsiveness. As noted by the American Clean Power Association, Interwest Energy Alliance, and Renewable Northwest, "CAISO should be commended for its rapid response to these concerns and for its efforts to incorporate stakeholder feedback on its proposals and, ultimately, develop a reasonable solution to a complex topic on a very short timeline."[93] NV Energy also agrees with the statements of the Natural Resource Defense Council and Western Resource Advocates,

> CAISO's proposal reflects a strong commitment to addressing the long-term needs of EDAM entities and their customers. We support the initiation of a targeted stakeholder process aimed at developing a long-term solution. We also support efforts at CAISO to monitor and study relevant market design elements, such as binding transmission constraints, parallel flows, self-scheduling activity, and congestion revenue allocation, both prior to EDAM startup and once it is operational, as insights from initial EDAM operations will be crucial in informing further design refinements.[94]

While CAISO's congestion allocation methodology has garnered significant recent attention, the approach is more consistent with NV Energy's objectives of maintaining the financial certainty and equality for all customers using their firm transmission rights. The challenges noted with the Markets+ design may be based on specific factors related to NV Energy's system, but that is the concern the Companies have – if these problems surfaced under Markets+, would they be addressed or would the advantaged parties seek to maintain that outcome?

c. Virtual bidding

NV Energy appreciates that both CAISO and SPP in their respective DAM designs have taken steps to recognize the challenges and risks of implementing virtual bidding as part of a novel market design. While virtual bidding can enhance market efficiency, there have been enough examples of this product causing significant uplifts without commensurate benefits to warrant a cautious approach to implementation.[95] While both DAMs have provisions to curtail virtual bidding if it becomes problematic, NV Energy finds that the CAISO approach is more reasoned than SPP's mandatory implementation at six months.

d. GHG

Both DAMs have programs to facilitate compliance with the California and Washington GHG pricing programs. An important element of the design is that these states should not export the cost of GHG compliance onto customers in other states. As explained in the Direct Testimony of Lindsey Schlekeway, the Companies have concerns with the Markets+ program and the

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congestion revenue is just and reasonable. Moreover, we will not direct CAISO to delay the go-live date of a market expansion that the Commission has already found to be just and reasonable").

[93] July 17, 2025, Comments of American Clean Power Association, Interwest Energy Alliance, and Renewable Northwest in FERC Docket No. ER25-2637 at 3.

[94] July 17, 2025, Comments Natural Resources Defense Council and Western Resource Advocates in FERC Docket No. ER25-2637 at 4.

[95] *See, e.g., Barclays Bank PLC*, 161 FERC ¶ 61,147 (2017); *California. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,070 at P 18 (2011); *California. Indep. Sys. Operator Corp.*, 152 FERC ¶ 61,234 (2015).

specifications regarding Type 1A resources.[96] Specifically, if Type 1A is not dispatched to its full contractual amount, then it still is unavailable to the non-GHG market footprint even if it were an economic option. This essentially withholds the capacity that is available to serve part of the market footprint from serving the remaining part of the footprint.[97] In a second scenario, the Type 1A resource may be a marginal resource setting prices within the Markets+ footprint or being dispatched above the load that it serves in the GHG zone resulting in an uneconomic outcome for the non-GHG zone in which it would bear the compliance costs.[98]

e. New Technologies and FERC Order No. 2222

While both EDAM and Markets+ have provisions to facilitate participation by demand response providers, CAISO's FERC Order No. 2222 compliance filing has been accepted and implemented.[99] In contrast, even in the SPP RTO, compliance with Order No. 2222 is not expected until 2030.[100] Moreover, SPP and certain Markets+ participants appear to be taking a view that Order No. 2222 only applies to RTO markets and, since Markets+ is a separate service offering, the requirement to comply with Order No. 2222 is inapplicable.[101]

<u>Timing of the Request</u>

NV Energy understands that the future of the Western market is uncertain and that both EDAM and Markets+ are works in progress. While there may be a temptation to "wait and see" what develops, a number of factors support the Companies coming forward with this request at this time.[102] First, it is important to note that the WEIM is likely to change and the Companies need to protect Nevada's interests within the potential of a more divided West, by seeking to maximize customer benefits. Second, organized markets are constantly evolving, and it is unlikely there will be a static point in the future without some uncertainty as to the market design. The WEIM participants have demonstrated a shared objective of a well-functioning market between the CAISO Board, the WEM Governing Body, CAISO management and staff, the Department of Market Monitoring, participating utilities, Western regulators (through the Body of State Regulators), and other stakeholders. The expectation is not that issues will not arise, but rather when they do, parties will work to determine just and reasonable solutions to be reflected in the FERC-approved CAISO tariff.[103]

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96 Direct Testimony of Lindsey Schlekeway at Q&A 31.
97 *Id.*
98 *Id.*
99 Direct Testimony of Anna McKenna at Q&A 44.
100 *See* SPP's December 13, 2024, Compliance filing in Docket No. ER22-1697 at 51 ("Given the practical impossibility of implementing a multi-nodal aggregation by the third quarter of 2025, SPP proposes a new implementation date of the second quarter of 2030, assuming that the Commission issues an order approving the instant compliance filing by March 1, 2025.")
101 Exhibit No. 101, Direct Testimony and Attachments of Joseph C. Taylor filed with the Colorado Public Utilities Commission on February 14, 2025, in Proceeding No. 25A-0075E at 34 ("FERC Order 2222 applies to regional grid operators, and because SPP will not be operating Markets+ in its capacity as an RTO, the order does not apply to Markets +.").
102 Direct testimony of Mike Holland at Q&A 8.
103 *Id.*

The Commission approved NV Energy's application to join WEIM on August 29, 2014, prior to PacifiCorp's going live in November of that year. The EDAM recommendation is an incremental step from the proven WEIM foundation. Even with that experience, EDAM implementation will be an extensive effort. Approval of this filing is needed to support the Companies' entry into the EDAM in the Fall of 2028. Given the anticipated benefits of extending participation to the day-ahead time frame, delay represents potential foregone benefits. Accordingly, the Companies are coming forward with the request at this time.

The Companies recognize that the target entry into the EDAM in the Fall of 2028 is outside the 2025-2027 approved ESP period. However, to effectuate the market entry in the Fall of 2028, the Companies forecast investments and expenses starting within the approved ESP period. As Utilicast's EDAM Gap Assessment demonstrates,[104] the Companies will make substantial investments and incur expenses starting in 2025 covering hardware and software acquisitions, licenses and subscriptions, external fees, vendor costs, consulting and legal support, and internal labor. These costs are estimated at $16.15 million between 2025 and 2028, with only $1.82 million of these costs being experienced in 2028 and, thus, outside the approved ESP period. In light of the actions and associated costs the Companies must undertake during the approved ESP period to join the EDAM in 2028, the Companies bring forth this filing to amend the 2025-2027 ESP.

Relation to Senate Bill 448

NV Energy proposes participation in EDAM to capture additional customer benefits, beyond those currently being realized through the Companies' participation in the WEIM. How EDAM may serve as a pathway to the Companies joining an RTO is an important factor, but one that should be considered wholistically with the other criteria in determining a best-interest, least-regrets approach to capture benefits for the Companies' retail and transmission customers.

Senate Bill ("SB") 448 (2021)[105] recognizes the potential for RTO participation to bring benefits to Nevada, if such participation is: (1) viable and (2) in the best interests of the Companies and its customers.[106] The Companies understand that, to be viable, the RTO must meet all of the identified

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104 Technical Appendix 2 at 9, Table 2.

105 SB 448 (2021) is codified at NRS 704.79881-704.7989.

106 *See* NRS 704.79886(2)(b). For NV Energy, "best interests" includes reliability, economic, and environmental regulatory compliance components. Consideration of joining an RTO would require extensive analysis of additional issues. These could include: (1) identification of additional market features and determination of projected additional economic benefits – for example though consolidation of BAAs or co-optimization of ancillary services; (2) transition of the interconnection queue and process from the NV Energy OATT to the market operator's tariff; (3) the process for converting existing transmission service agreements to the market operator's tariff; (4) the methodology for establishing transmission rates and review of transmission revenue issues and potential cost shifts; (5) the resource adequacy program and must offer requirements; (6) an overall cost/benefit analysis; (7) the changes in the governance structure beyond that for the DAM; (8) the role of the Commission, especially over critical areas of resource adequacy and transmission cost allocation; and (9) conditions for entry and exit.

statutory criteria,[107] including the requirement that governance be independent.[108] Viability also includes interconnectivity – the Companies must have sufficient transmission interchange with a footprint of sufficient size and resource diversity to secure the potential benefits of coordinated dispatch.

As explained in the testimony of David Rubin,[109] the CAISO's Board of Governors, selected by the Governor of California, is not independent, and NV Energy recognizes that Pathways Phase 2 has much work to accomplish before serving as a platform for a Western RTO.

In addition, the Companies lack direct connectivity with the current SPP RTO and the expected footprint of SPP's anticipated RTO West.[110] While SPP claims it "can provide a clear path forward to RTO membership,"[111] NV Energy is unaware of any plan to effectuate a transition from Markets+ to RTO West. To the contrary, Markets+ will have a separate optimization,[112] a separate cost responsibility[113] and must prepare a seams agreement with RTO West.[114] Indeed, in its May 9, 2025, Record of Decision, BPA notes it will not sell power out of the Western Interconnection and provides further:

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107 NRS 704.79882. These include:

- Approved by FERC;
- Separate control of transmission facilities from control of generation facilities;
- Implements policies/procedures to minimize pancaked transmission rates;
- Improves service reliability within Nevada;
- Achieves the objectives of an open and competitive wholesale electric generation marketplace, elimination of barriers to market entry and preclusion of control of bottleneck electric transmission facilities;
- Operates to substantially increase economical supply options for customers;
- Structure of governance or control that is independent of the users of the transmission facilities;
- Policies promote positive performance to satisfy electricity requirements of customers;
- Promotes and assists new economic development in Nevada; and
- Capable of maintaining real-time reliability of the transmission system, ensuring comparable and nondiscriminatory access and necessary service, minimizing system congestion and further addressing real or potential transmission constraints.

108 NRS 704.79882(7) states: "Has a structure of governance or control that is independent of the users of the transmission facilities, and no member of its board of directors has an affiliation with a user or with an affiliate of a user during the member's tenure on the board so as to unduly affect the regional transmission organization's performance."

109 Direct Testimony of David Rubin at Q&A 9.

110 At this time entities expected to participate in RTO West include Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Platte River Power Authority, Tri-State Generation and Transmission Association, Western Area Power Administration (*Upper Great Plains-West region, Colorado River Storage Project, and Rocky Mountain region). RTO west is projected to commence operation in 2026.* The list can be found on SPP's RTO expansion page at: https://www.spp.org/western-services/rto-expansion/.

111 SPP Comments in Response to Procedural Order No. 3 in Docket no. 23-10019 filed on May 31, 2024, at 7.

112 As BPA notes, "RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint. May 9, 2025, Day-Ahead Market Policy ("BPA Market Policy") at note 24. https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/20250509-dam-final-policy.pdf.

113 *See* the Markets+ Phase Two Funding Agreement approved in FERC Docket No. ER25-1372, 191 FERC ¶ 61,071 (2025) at P 2 and P 4.

114 *See* FERC's Order approving the RTO West tariff, *Sw. Power Pool, Inc.*, 190 FERC ¶ 61,169 (2025) at P 92. As noted in Section 5(L) of the Narrative, "seams" arise from trading barriers between adjoining wholesale electricity markets. Seams agreements seek to minimize the operational and reliability impacts of seams.

> SPP is the Markets+ market operator, meaning it will provide services and run the market solution algorithm based on data submitted by Western entities participating in Markets+. Neither SPP nor any participant in another SPP-operated market will have generation or load in Markets+. While SPP operates other markets, the Markets+ market run will not include co-optimization with SPP's eastern RTO footprint, its Western Energy Imbalance Service footprint, or its proposed RTO West footprint.[115]

Summary of Request

While continuing to explore all market options consistent with the incremental approach favored by other utilities in the region, NV Energy should not delay in seeking to capture additional benefits for its customers. The Companies maintain that EDAM participation is the best course to pursue. If, however, the Commission determines it is better to wait until EDAM has demonstrated its viability, the Companies would recommend continuing participation in WEIM. Given the lack of connectivity; limited projected benefits and challenges with WRAP compliance, the Companies do not recommend joining Markets+. With substantially lower implementation costs and greater utilization of existing assets and experience, EDAM represents the preferred option to expansion of organized market participation for Nevada. Accordingly, the Companies seek Commission approval to join CAISO's EDAM in the Fall of 2028.

In accordance with the July 9, 2024, Order in Docket No. 23-10019, the Companies are submitting this request to join EDAM as an ESP amendment.[116] The Companies ask that the Commission approve this ESP Amendment and find that the ESP, as amended, is prudent pursuant to NAC § 704.9494. The Commission may make that finding if it determines:

1. That the ESP, as amended, balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan;

2. That the ESP, as amended, optimizes the value of the overall supply portfolio of the utility for the benefit of bundled retail customers; and

3. That the ESP, as amended, does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility.

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115 *See* BPA May 9, 2025, Day-Ahead Market Policy Record of Decision at 140 ("BPA Record of Decision"). The Record of Decision can be found at: https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2025-rod/rod-20250509-day-ahead-market-policy.pdf.

116 Ordering paragraph 3.

SECTION 2 – NV ENERGY'S PARTICIPATION IN THE WESTERN ENERGY IMBALANCE MARKET

A. Background of NV Energy's Participation in the WEIM

On April 16, 2014, the Companies filed an application with the Commission designated as Docket No. 14-04024, for approval of amendments to their Energy Supply Plan Portfolio Optimization Procedure to participate in the WEIM that was being established by the CAISO. At that time, PacifiCorp was the only other entity that was in the process of joining WEIM. The Order issued on August 29, 2014, granted the application[117] and recognized:

> that the issue presented by the Joint Application is essentially whether the Companies should spend approximately $11.2 million to develop the option to participate in the CAISO EIM.... The Commission finds that the Companies should develop this option, and further finds that the potential benefits of interregional dispatch savings, reduced flexibility reserve, and reduced renewable energy curtailment, each of which could be gained from developing NV Energy's participation in the EIM, ultimately outweighs the uncertainties surrounding the modeling assumptions made in the Economic Analysis.[118]

The Order also established, *inter alia*, that the Companies provide (1) status updates addressing CAISO's market implementation activities, (2) status updates on changes to the governance structure, and ongoing quarterly reports on benefits and market performance.[119]

NV Energy entered the WEIM in December 2015. Presently, the WEIM is comprised of twenty-two BAAs across all or portions of eleven Western states and serving approximately eighty percent of the load in the Western Interconnection.[120] A list of the current and future participants is provided in Figure 11. A map illustrating the WEIM footprint is provided as Figure 12.

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117 August 29, 2014, Order in Docket No. 14-04024 at 47, P 131.
118 *Id.* at 43, P 122.
119 *Id.* at 50, Ordering P 3.
120 *See*, https://www.caiso.com/about/news/energy-matters-blog/evolution-of-the-weim.

Figure 11[121]
List of WEIM Participants and Year of Entry

Entity	Year of Entry
California ISO	2014
PacifiCorp	2014
NV Energy	2015
Arizona Public Service	2016
Puget Sound Energy	2016
Portland General Electric	2017
Powerex	2018
Idaho Power Company	2018
Balancing Area of Northern California	2019
Seattle City Light	2020
Salt River Project	2020
Turlock Irrigation District	2021
Public Service Company of New Mexico	2021
Los Angeles Department of Water & Power	2021
NorthWestern Energy	2021
Tacoma Power	2022
Avista	2022
Tucson Electric Power	2022
Bonneville Power Administration	2022
WAPA Desert Southwest Region	2023
El Paso Electric	2023
Avangrid	2023
BHE Montana	Planned 2026
Black Hills Power	Planned 2026
Imperial Irrigation District	Planned 2028

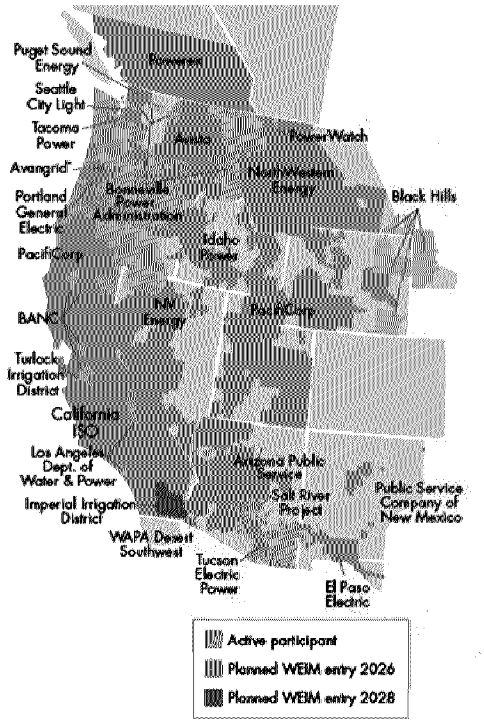
NV Energy attributes the substantial growth in the WEIM to the demonstrated economic, reliability and environmental benefits from participation as well as the decrease in bilateral trading opportunities as more intra-day activity has shifted to market bidding and dispatch.[122]

121 *See* https://www.westerneim.com/Pages/About/default.aspx.

122 For example, Avista cited as a decision to join EDAM a "[r]eduction in current optimization opportunities" https://www.westerneim.com/Documents/Presentation-JoiningEIM-Avista.pdf at 8. WAPA Desert Southwest noted a "[f]undamental shift observed in the Unites States electrical industry impacting Bulk Electric System Operations, marketing, and planning, particularly in the West." https://www.westerneim.com/Documents/Presentation-WEIMRegionalIssuesForum-WAPA-DSW-Update-Sep12-2023.pdf at 5. Similarly, Tacoma noted is decision to join WEIM was influenced by: (1) real-time trading volumes with historically largest real-time counterparties being dramatically lower; (2) counterparties electing to join EIM; (3) real-time transactions taking place earlier with EIM entities than non-EIM entities; (4) once EIM bids are in, no need to make bilateral trades, and (5) liquidity of "later" transactions significantly reduced or even eliminated if wind generators enter the EIM. https://www.westerneim.com/Documents/Presentation-EIMBusinessCase-Tacoma.pdf at 8. As articulated by BPA,

> Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets. The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result

Figure 12[123]
Map of WEIM Participants



*Avangrid office; generation only BAA with distribution across multiple states.
Map boundaries are approximate and for illustrative purposes only.
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B. Customer Savings

WEIM has demonstrated substantial economic and reliability benefits. CAISO releases reports on WEIM benefits each quarter.[124] As illustrated above in Figure 2, NV Energy's total projected benefits for Companies' WEIM participation through the second quarter of 2025 as calculated by CAISO total $828.17 million. The quarterly benefits have grown over time supported by the participation of new BAAs, which compounds the benefits for adjacent BAAs through additional transfers. Accordingly, the potential departure of WEIM Entities to Markets+ could have an impact on WEIM and potential EDAM benefits. That having been said, not all entities appear to be fully participating in the WEIM today. Thus, the ultimate impacts will not be known until the new markets are implemented, including potential seams agreements.

> in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

BPA Market Policy at 7.

[123] *See* https://www.westerneim.com/Pages/About/default.aspx.

[124] *See*, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx. Information as to how the CAISO calculates benefits can be found at: https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf.

For example, among the WEIM Entities that are also transmission providers, only BPA relies solely on transmission donated by its customers under the "interchange rightsholder process."[125] In other words, BPA does not make firm Available Transfer Capability ("ATC")[126] (unsold transmission) or non-firm ATC (unscheduled transmission) available to the WEIM. The WEIM Quarterly Benefits Reports also provided wheeling data. As shown on Figure 13, for the size of its system, BPA facilitates a more limited quantity of WEIM wheel-through transactions.

Figure 13.
EIM Wheel Through Transfers (MWh) [127]

	Q1 24	Q2 24	Q3 24	Q4 24	Q1 25	Q2 25
NVE	157,685	381,828	229,444	166,564	441,646	388,671
AVA	42,175	53,072	61,934	40,218	59,241	68,166
AVRN	45,541	55,493	75,571	50,095	79,884	107,822
APS	415,680	508,707	333,313	356,176	526,179	413,625
BANC	399	6	--	--	--	--
BPA	99,265	77,980	86,237	85,059	98,322	63,331
CAISO	1,158,366	736,433	788,815	814,970	737,758	581,943
EPE	257	635	318	381	968	4,582
IPC	158,176	198,542	251,225	184,624	301,349	233,497
LADWP	118,962	149,473	118,184	183,805	135,723	112,953
NWMT	51,733	49,778	52,755	20,005	50,484	60,210
PACE	108,768	130,914	269,192	129,548	112,493	152,941
PACW	360134	419,025	371,253	320,376	416,464	384,732
PGE	61,875	139,676	76,983	102,048	126,830	190,053
PNM	52,568	52,940	56,110	21,031	26,133	28,702
PSE	104,490	184,018	200,448	146,867	176,001	179,358
PWRX	13,749	9,644	18,879	27,293	11,248	22,001
SCL	18,066	13,057	6,905	10,562	13,741	12,219
SRP	45,698	88,836	14,623	11,054	26,246	57,455
TEPC	151,599	79,919	143,024	100,356	109,031	105,690
TIDC	-	--	--	--	--	--
TPWR	23,241	32,184	20,773	22,504	17,942	20,387
WALC	431,498	430,880	509,067	401,898	321,853	374,706

Similar to BPA not fully participating with its transmission system, Powerex appears not to be participating significantly with its resources. In FERC Docket No. 17-1796, involving the Powerex WEIM Implementation Agreement, Powerex stated:

[125] *California Independent System Operator Corp.* 170 FERC ¶ 61,168 (2020) at P 26 ("We are not persuaded by NV Energy's and PacifiCorp's assertions that Bonneville should be required to make firm and non-firm ATC available in order to participate in the EIM. As NV Energy and PacifiCorp acknowledge, the CAISO tariff expressly allows for the use of either the ITR or ATC mechanisms and does not require that an EIM entity use a specific mechanism to make transmission available for EIM transfers.")

[126] NERC defines ATC as "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows". The NERC Glossary of Terms can be found at: https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf.

[127] *See*, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

> Powerex believes that the proposed participation framework has the potential to generate significant benefits across the EIM footprint. By facilitating Powerex's participation using residual hydroelectric generation capability and net load deviations of the BC Hydro system, the proposed participation model has the potential to confer significant benefits across the EIM footprint in the form of increased diversity in generation and load imbalances, access to additional flexible generating capability, enhanced EIM greenhouse gas ("GHG") benefits, and access to additional transmission rights to support EIM transfers.[128]

Despite the accommodations made to facilitate Powerex's entry into the WEIM in that docket, Powerex appears primarily to buy from the market. This pattern is illustrated in Figure 14 which comes from the Department of Market Monitoring Quarterly Report for the Second Quarter of 2025.[129]

Figure 14

Appendix Figure A.62 Average hourly 15-minute market transfers

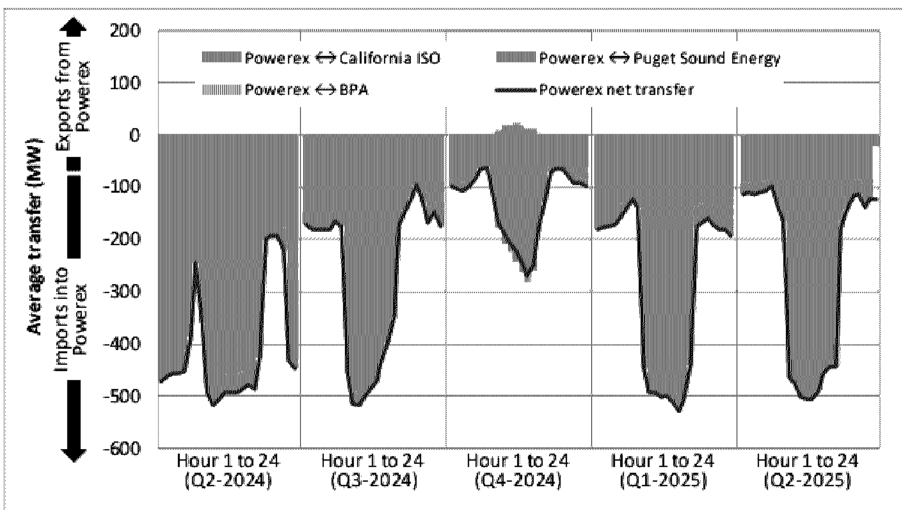

Figure 15 shows that in contrast to the Powerex pattern, NV Energy engages in both buying and selling in WEIM. These purchases lower production costs and the sales results in credits similar to those from bilateral transactions. This is not in any way a criticism of the actions of BPA or Powerex. It is meant only to illustrate that in the DAM decision; the Companies have considered past participation experience associated with contributions to market transmission availability and resource liquidity. Both DAM options permit load-serving entities ("LSEs") to self-supply, but NV Energy has concerns with the ability of customers to "opt-out" and "opt-in" their transmission reservations from the market optimization in Markets+. This aspect of the design is discussed later in the Narrative.

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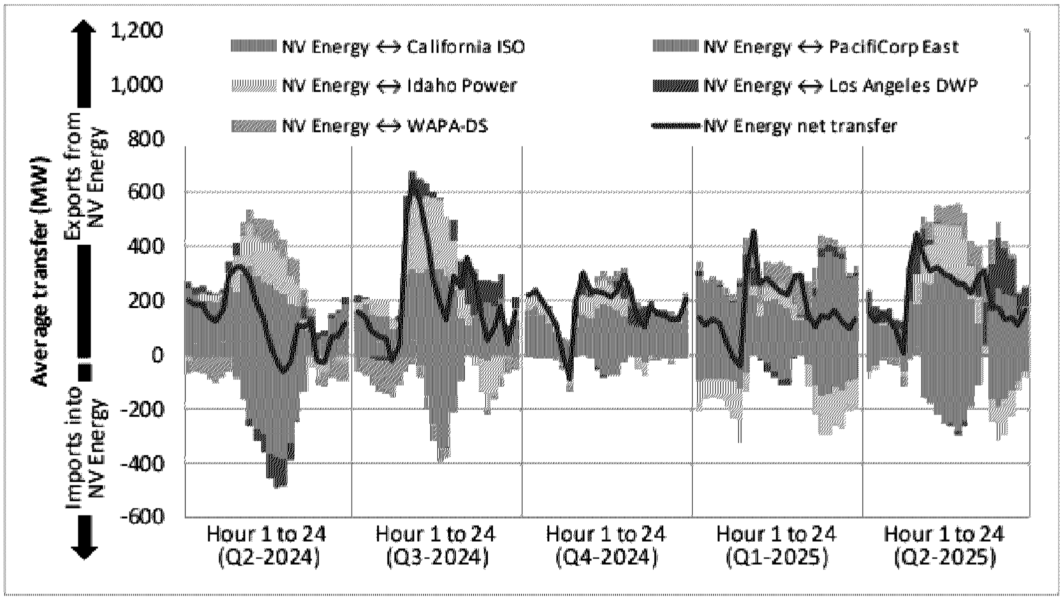
128 *See* Powerex Motion to Intervene and Comments in FERC Docket No. ER17-1796 filed on June 28, 2017, at 6.

129 The Department of Market monitoring reports can be found at: https://www.caiso.com/documents/2025-second-quarter-report-on-market-issues-and-performance.pdf.

Figure 15
NV Energy WEIM Transfers [130]

Appendix Figure A.42 Average hourly 15-minute market transfers



C. Reliability Benefits

The WEIM allows energy transfers across BAs, providing access to the least-cost electricity in the region. This increased coordination between areas is particularly helpful during weather and wildfire events that may impact one part of the Western interconnection but not another. In these cases, participants are able to sell their excess electricity generation to areas in need, creating economic benefits for the seller and operational and reliability benefits for the buyer. When a region is under stress conditions in real-time, the increased coordination through the WEIM provides additional benefits as the market's automated processes dispatch transfers in a timeframe after the bilateral market. Given the diversity benefit of the WEIM, these transfers can reduce the probability of an area calling for emergency assistance as the market has automatically resolved the stressed condition.[131]

[130] The report can be found at: https://www.caiso.com/documents/2025-second-quarter-report-on-market-issues-and-performance.pdf.

[131] As noted by Scott Kaufmann in his Direct Testimony at Q&A 13:

As a participant in the WEIM, the Companies have access to a wider pool of energy resources to manage natural intra-hour load deviations caused by changes in forecast and changes in the output of variable energy resources, such as solar, geothermal and wind-based renewable generation. Most notably, as variable renewable energy has increased significantly over the past decade, the need for very quick response has become increasingly important. By utilizing the upcoming forecasts, the market can see a decline and then provide resources to fill that gap within a matter of minutes. The timing can be slightly different, but we regularly see a response within approximately 12 to 20 minutes which is generally sufficient to reliably maintain the load-to-generation balance appropriately for NERC requirements, including BAL-001-2 R2. Without WEIM the Companies would have to manually identify solutions and dispatch internal generation, either up to down, to maintain reliability. This would be very difficult and may not result in an optimized reliability or

At the February 9, 2022, WEM Governing Body and CAISO Board of Governors joint meeting, NV Energy brought forth a reliability concern with respect to the consequences associated with failing the WEIM resource sufficiency test – specifically, that the then-current failure approach would prohibit additional supply from flowing to a WEIM Entity in an emergency condition.[132] Given the wide-spread participation of Western BAAs in the WEIM, the ability to address emergencies through the bilateral market had been significantly reduced. Thus, NV Energy requested that CAISO develop a mechanism to make excess supply that is voluntarily bid into the market, but not needed by WEIM Entities that passed the WEIM resource sufficiency test, be made available to the distressed WEIM Entity at an appropriate scarcity price. Following a stakeholder process, CAISO filed a tariff amendment with FERC in Docket No. ER23-1534 to introduce a new Assistance Energy Transfer product.[133] FERC approved the amendment on May 31, 2023,[134] noting "the proposal allows CAISO to optimally dispatch supply and provide access to resources that were not otherwise available."[135] For NV Energy, the experience with this initiative demonstrated the ability of the CAISO stakeholder process to recognize the important reliability benefit of the proposal and to take expeditious action, allowing for stakeholder consideration, tariff development, and systems implementation.

With the expansion of WEIM to EDAM, the market operator would be able to see dependencies across different parts of the system that individual BAAs with a more limited view may not.[136] This may help alleviate issues in an earlier timeframe allowing for more effective and efficient solutions. In addition, a larger and more closely coordinated market could increase the options for addressing reliability issues.[137] Again, these benefits are dependent on the interconnectivity of the participants in the market.[138]

> economic solution. In addition, it was advantageous to be a part of WEIM during the last several summers when Energy Emergency Alerts ("EEA") levels were declared throughout the interconnection. The Companies were able to import additional energy during the EEA 3 events in summers 2020 and 2021. In an EEA 3 event, all generation resources are on-line, the reserve requirement is not being met, and load shed is imminent. Without strong participation in the market, the Companies may have had to shed load over peak on those days.

[132] NV Energy's comments can be found at: https://www.caiso.com/documents/public-comment-letter-nv-energy-eim-resource-sufficiency-enhancements-feb-7-2022.pdf.

[133] Under the current Assistance Energy Transfer program, the surcharge associated with assistance energy transfers is calculated by multiplying the applicable energy bid cap, either $1,000/MWh or $2,000/MWh, by the lesser of: (1) the dynamic WEIM transfers or (2) the amount by which the BAA area failed the resource sufficiency evaluation.

[134] *California Independent System Operator Corporation,* 183 FERC ¶ 61,146 (2023).

[135] *Id.* at P 18.

[136] Direct Testimony of Scott Kaufmann at Q&A 22 ("Oversight of a larger, more diverse group of resources will allow the market to develop economic solutions that also optimize the transmission system. These solutions will be able to estimate transmission flows using all inputs which will include generation, imports/exports, and wheel-throughs and will ensure that all transmission limits are honored").

[137] Direct Testimony of Scott Kaufmann at Q&A 22:

> Over the last approximately six summers, there have been times when resources throughout the interconnection have been scarce. Having all loads and available resources in a single place will allow the market to identify those critical times and needs several days ahead. This could allow entities to begin planning, expediting generation or transmission returns to service, issuing no-touch orders, and coordinating internally.

[138] As noted by Scott Kaufmann in his Direct Testimony, today, if solar forecasts for the day-ahead are showing outputs that are below normal, the Companies would generally plan to startup thermal units. Given the large

D. NV Energy Experience

The Companies attribute the increase in customer benefits over time not only to the larger WEIM footprint, but also to the enhanced analytics of the Resource Optimization department that has improved approaches to bidding in the real-time market. Similarly, NV Energy's transmission department has worked with CAISO's systems and tools, including the use of load conformance, to help maintain reliable system operations.[139]

As noted in the Direct Testimony of Michael Holland,

> NV Energy is already deeply familiar with the systems, terminology, and communication protocols required for successful participation in CAISO's markets. This includes established processes for coordinating with CAISO, managing data flows, and ensuring compliance with market rules. NV Energy has invested significant time and resources to build and validate its Generation Resource Data

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geographic footprint of the anticipated EDAM entities, there will be diversity in those variable renewable resources. Taking advantage of energy from outside of the system could prevent unnecessary starts and cycling on the thermal system. Direct Testimony of Scott Kaufmann at Q&A 22.

[139] *See* NV Energy's Motion to Intervene and Comments in Support filed on December 26, 2018, in FERC Docket No. ER19-538. In accordance with section 29.34(d)(1) of the CAISO Tariff, CAISO develops short-term and mid-term Demand Forecasts by Demand Forecast zone within each EIM Entity BAA. Under section 29.11(d)(4) of the CAISO Tariff, an EIM Entity is exempt from under-scheduling and over-scheduling charges under section 29.11(d)(1) of the CAISO Tariff if it uses the Demand Forecast prepared by the CAISO in its EIM Resource Plan and submits EIM Base Schedules for its resources within +/- 1% of the CAISO Demand Forecast. While the CAISO strives to provide an accurate forecast, there are a multitude of factors that can cause variations between the forecast and actual real-time system conditions, including (1) inaccurate load forecast, (2) Area Control Error ("ACE") adjustments, (3) variable energy resource deviations, (4) a generator outage that has not yet been input to the market, (5) generator testing, (6) reliability curtailments due to transmission/equipment outages, and (7) weather inflections.
Each EIM Entity grid operator has direct access to its BAA load forecast through an interactive display provided in the real-time market system and to a field for making load conformance adjustments to the load forecast. The EIM Entity grid operator uses this field to directly inform the CAISO's systems of any load forecast adjustments that impact the ability of the EIM Entity to maintain ACE values within the requirements of applicable reliability standards and would otherwise not be reflected in a timely manner in the market input data. NV Energy as the BA and the CAISO's computer-generated dispatch instructions must work together to maintain reliable system operations. While the EIM Entity can issue a manual dispatch where necessary, it would be highly problematic if the CAISO's model was trying to move generators in the opposite direction due to an inaccurate load forecast. Accordingly, the CAISO Tariff in section 27.12.1 provides, "The EIM Entity operator may conform the EIM demand forecast prior to the CAISO executing a Real-Time Market run to obtain a Real-Time Market solution that is feasible and accounts for known system conditions of the respective EIM Entity's BAA for reliable operations. System operators conform the CAISO Forecast of CAISO Demand or EIM Demand through an adjustment of the respective forecast." In approving the provision, FERC stated:

> Through load conformance, system operators are able to quickly address reliability concerns, reducing manual dispatches and associated uplift payments. We also find that CAISO's proposed tariff provisions provide beneficial transparency to stakeholders regarding CAISO's load conformance practices.

Cal. Indep. Sys. Operator Corp., 166 FERC ¶ 61,138 (2019), at P 24. *reh'g denied, Cal. Indep. Sys. Operator Corp.*, 170 FERC ¶ 61,131 (2020). The Department of Market Monitoring reports on each participating BAs use of load conformance in the quarterly and annual reports. These can be found at:. https://www.caiso.com/market-operations/market-monitoring.

Template (GRDT), which is a cornerstone of the CAISO Master File—the central data repository used across multiple CAISO applications.[140]

NV Energy has already undergone the time and expense to incorporate its generation and transmission assets into the CAISO systems. For example, the Master File is the data repository used for many applications at the CAISO. These applications are illustrated in Figure 16.

Rather than initiating a new market integration from the ground up, NV Energy is able to build upon existing functions and infrastructure. This includes leveraging its current settlement systems, such as the Base Schedule Aggregation Portal ("BSAP") and Open Access Technology International ("OATI"), which are already configured to exchange data with CAISO for pre-market validation and ongoing operations. NV Energy's familiarity with these systems ensures a smoother transition to EDAM, minimizing risk and reducing implementation timelines.[141]

The integration of a new resource into WEIM involves a rigorous process: network model and forecast preparation, regulatory and testing compliance, market setup, trial operations, and full commercial participation. NV Energy has successfully navigated this process for its generation and transmission assets, including the development of a validated full network model and the execution of all necessary regulatory agreements. These assets are now fully represented in CAISO's Master File and are actively participating in WEIM.[142]

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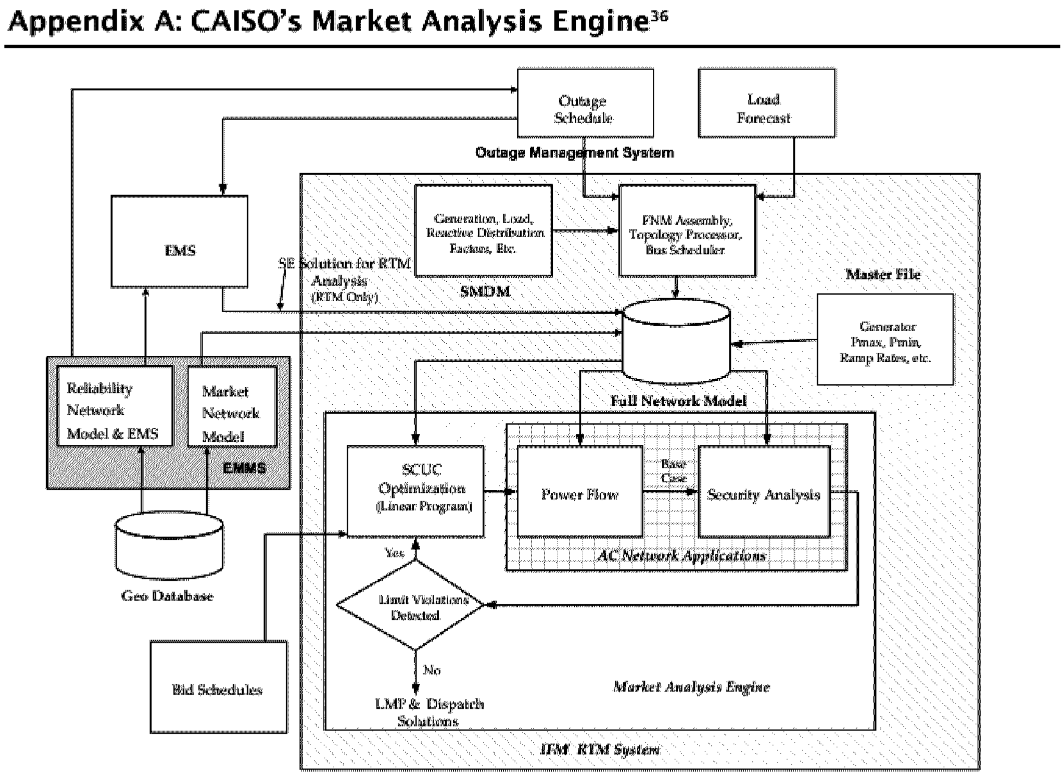
140 Direct Testimony of Michael Holland at Q&A 10.
141 *Id.*
142 *Id.*

Figure 16



Importantly, EDAM builds directly on the WEIM framework, utilizing the same Master File and network model. This continuity allows NV Energy to capitalize on its prior investments and operational experience, ensuring a more efficient and reliable expansion into day-ahead market operations. In contrast, selecting Markets+ would require NV Energy to replicate this entire process from the beginning, including rebuilding network models, reconfiguring settlement systems, and retraining personnel—resulting in significant additional cost, time, and risk.[143]

SECTION 3 – DESCRIPTION OF THE DAY-AHEAD MARKETS

A. Development of CAISO's EDAM

CAISO began development of EDAM in 2019.[144] CAISO and fourteen WEIM Entities[145] contracted with Brattle and E3 to conduct a "feasibility assessment" - a high-level production cost

143 *Id.*

144 *See* CAISO, Initiative: Extended day-ahead market, available at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market (the EDAM Initiative documents are chronologically organized from October 2019 through August of 2025, currently).

145 These included Arizona Public Service, Avista, BANC. CAISO. Idaho Power, LADWP. NorthWestern, NV Energy, PacifiCorp, Public Service Company of New Mexico, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light and the Salt River Project. The Feasibility Assessment was presented at a CAISO stakeholder meeting on October 3, 2019 and can be found at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market. The list of participants can be found on slide 1.

modeling study intended to inform EIM Entities about proceeding with the EDAM design process.[146] The EIM Entities presented the results of the assessment at a CAISO stakeholder meeting on October 3, 2019. Potential benefits of EDAM included: (1) production cost savings through more efficient day-ahead hourly trading and use of available transmission, more efficient day-ahead unit commitment and day-ahead schedules at hourly granularity throughout the footprint prior to real-time; (2) diversity of imbalance reserves; and (3) potential environmental benefits such as reduced renewable curtailment.[147]

The assessment showed estimated total production cost savings of between $119 to $227 million per year for a range of scenarios.[148] Significant drivers include assumptions regarding natural gas prices, restrictions on CAISO export limits and costs associated with transmission. The feasibility assessment also concluded that EDAM has the potential to reduce greenhouse gas emissions and curtailments of non-emitting variable energy resources.[149]

Based on the results of the assessment, the EIM Entities sent a letter to the WEM Governing Body and the CAISO Board of Directors stating, "[a]fter careful assessment, we believe that it is time to take the next incremental step toward market expansion and consider formation of an Extended Day-Ahead Market, or EDAM, that would potentially facilitate day-ahead unit commitment and optimization across the EIM footprint."[150] The letter included principles and elements regarding issues to be addressed in the stakeholder process. In response, CAISO released its initial EDAM Issue Paper on October 10, 2019.[151] The CAISO released its Bundle One Straw Proposal on July 20, 2020; the initial full Straw Proposal on April 28, 2022; a revised Straw Proposal on August 16, 2022; an initial Draft Final Proposal on October 31, 2022; and a Final Proposal on December 7, 2022.[152]

As described in the Direct Testimony of Anna McKenna, EDAM was the product of a multi-year stakeholder effort that involved:

- Sixty working group meetings;
- More than twenty 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.[153]

146 *Id.* at slide 6.

147 *See CAISO Briefing on the Extend Day-Ahead Market Initiative* (Sept. 18, 2019) at slide 6, available at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

148 *Extended Day-Ahead Market: Feasibility Assessment, Update from EIM Entities* (Oct. 3, 2019) at slide 18, available at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

149 *Id.* The Feasibility Assessment estimated system-wide impacts based on the difference between simulations of 2028 EDAM and business-as-usual (BAU) cases. Every EIM participant with a signed implementation agreement as of the start of the study was assumed to participate in the EDAM against a baseline of continuation of the current market structure. *Id.* at slide 7.

150 A copy of the letter can be found at: https://www.caiso.com/library/board-of-governors-energy-imbalance-market-governing-body-eim-gb-joint-general-session-meeting-sep-18-2019-board-eim-gb-1.

151 CAISO Initiative: Extended day-ahead market, available at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

152 *Id.*

153 Direct Testimony of Anna McKenna at Q&A 13.

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,[154] FERC accepted in part, subject to condition, and rejected in part the CAISO's filing.[155] The only component FERC rejected was the EDAM access charge, without prejudice to the submittal of a future filing in which CAISO provided additional support for its proposal. 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.[156] Accordingly, CAISO has the FERC approvals necessary to commence EDAM operations. In the December 20, 2023, Order, FERC found:

> D[ay]A[head]M[arket]E[nhancements] 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.[157]

The 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 Administration – Sierra Nevada Region; (4) the Los Angeles Department of Water and Power, (5) the Turlock Irrigation District; (6) Public Service Company of New Mexico and (7) the Imperial Irrigation District.[158] PacifiCorp is expected to go live in May 2026. Portland General Electric is expected to commence operations in October 2026. BANC, LADWP, Turlock, and Public Service Company of New Mexico are expected to join in Fall 2027. The Imperial Irrigation District and NV Energy would enter EDAM in Fall 2028.

Other Western BAs have also publicly indicated intent or interest to participate, but have not yet executed an EDAM Implementation Agreement. PowerWatch (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

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154 *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 (2023) ("EDAM Acceptance Order").

155 The CAISO made its compliance filing on February 16, 2024, and it was accepted by FERC on April 30, 2024.

156 *Cal. Indep. Sys. Operator Corp.*, 187 FERC ¶ 61,154 (2024).

157 EDAM Acceptance Order at P 42.

158 The Implementation Agreements can be found at: https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx. As discussed in Section 8(A) of the Narrative, the EDAM Implementation Agreement is a *pro forma* that was accepted by FERC in Docket No. ER23-2686 as Appendix B31 of the CAISO Tariff. The agreement can be found at https://www.caiso.com/documents/appendixb31-edam-entityimplementationagreement-asof-dec21-2023.pdf.

retail load in the Western Area Power Administration's Lower Colorado BAA area expressed its interest in joining EDAM.[159]

PacifiCorp filed proposed changes to its OATT to implement EDAM on January 16, 2025, in Docket No. ER25-951. PacifiCorp received a deficiency letter from FERC on March 27, 2025, and provided its response on April 28, 2025. Portland General Electric filed their EDAM OATT on April 3, 2025, in FERC Docket No. ER25-1868. Portland General Electric also received a deficiency letter and provided a response on July 30, 2025. FERC issued orders on August 29, 2025, accepting both the PacifiCorp and Portland General Electric OATT changes.[160]

One of the significant issues raised in the PacifiCorp and Portland General Electric dockets involved the allocation of congestion payments. In response, CAISO conducted an expedited stakeholder process and filed a tariff amendment in FERC Docket No. ER25-2637 on June 26, 2025. CAISO proposed to allocate congestion revenue associated with parallel flow within an EDAM BAA due to a binding transmission constraint within another EDAM BAA to the EDAM BAA where the congestion revenue accrued (rather than the BAA area where the transmission constraint arose). This treatment would be afforded for the exercise of eligible firm transmission service rights through submission of a balanced day-ahead self-schedule associated with a contract reference number that facilitates the use of such transmission rights.[161] Also on August 29, 2029, FERC approved the CAISO proposal.[162]

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159 Direct Testimony of Anna McKenna at Q&A 16. 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. *Id* at Q&A 18.

160 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) and *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025).

161 The CAISO will continue to allocate internal congestion revenue arising from a binding transmission constraint within an EDAM BAA—i.e., congestion revenue not associated with parallel flow—to that same EDAM BAA, using the same methodology approved in the EDAM Acceptance Order. As explained above, the Commission has already found this methodology for allocating congestion revenue to the EDAM BAA where the transmission constraint arose to be just and reasonable. *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 at P 42 (2023) at PP 434-35.

162 *Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025). See also, *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 149:

> Separately, we note that CAISO has proposed to revise its congestion revenue allocation approach under EDAM so that CAISO will allocate to EDAM Entities the portion of congestion revenue that is associated with balanced day-ahead self-schedules over qualifying firm OATT service rights in the EDAM BAAs where the congestion revenue accrued… in a concurrent order, we accept CAISO's proposed tariff revisions, finding that they are just and reasonable and not unduly discriminatory or preferential as they ensure that long-term firm transmission customers are able to hedge against day-ahead congestion charges in EDAM. We believe that these tariff revisions may help to address some of the concerns that protesters raised in this proceeding.

B. Development of Markets+

SPP began its effort to develop Markets+ in 2021[163] and produced a market offering in late 2022.[164] During the months that followed, SPP and interested utilities worked on a funding methodology to further build out the market design and its associated tariff, which resulted in the start of Phase 1.

SPP's Markets+ is a new, stand-alone market design being developed to serve as both a day-ahead and real-time balancing market. Similar to EDAM, Markets+ would optimize all supply and demand across the footprint to produce day-ahead schedules. These transactions are then re-optimized in the sub-hourly 5-minute market. Markets+ also includes a day-ahead flexibility reserve product. WRAP participation is a requirement for Markets+ and participants are assumed to be resource sufficient after passing WRAP's forward-showing requirement. There is a Markets+ must-offer obligation that requires the participant to submit supply offers equal to or greater than the sum of their load, flex obligation, WRAP adjustment (holdback sale or purchase), and net position (forward purchases minus forward sales).

Phase 1 was intended to cover a 21-month period starting with execution of the Phase 1 Funding Agreement and ending with the approval of the Markets+ tariff by FERC. Early during Phase 1 discussions, the decision was made to focus on the Markets+ tariff to achieve an earlier FERC filing and to develop the protocols after filing the tariff at FERC.

NV Energy signed the Phase 1 Funding Agreement on February 27, 2023. The initial Phase 1 funding fee of $9,700,000 was allocated to the funding utilities on the basis of net energy for load ("NEL")[165] as reported to WECC and NERC.[166] NV Energy's load ratio share was approximately 10 percent, which covered the period up to SPP's FERC filing which occurred on March 29, 2024. After filing the tariff at FERC, the post-Phase 1 monthly obligation provisions of the Phase 1 Funding Agreement required parties to pay their NEL share of $500,000 per month to fund SPP's costs. Following the internal determination to seek authorization to join EDAM, the Companies notified SPP on May 24, 2024, of their intent to withdraw from the Phase 1 Funding Agreement. Consistent with the terms of the Funding Agreement the termination became effective June 23, 2024.

SPP filed the Markets+ Tariff in FERC Docket No. ER24-1658.[167] On July 31, 2024, FERC issued a Deficiency Letter. SPP responded on September 20, 2024. On January 16, 2025, FERC issued

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[163] *See, for example*, November 17, 2021, Webinar. The slides can be found at: https://www.spp.org/documents/66073/11172021%20markets%20plus%20information%20session%20presentation.pdf.

[164] Markets+ A proposal for SPP's Western Day-Ahead Market and Related Services. https://www.spp.org/documents/68382/markets%20plus%20final%20vs%20draft.pdf.

[165] Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange

[166] Under the Phase 1 funding Agreement which was based on NV Energy's 2021 NEL of 32,272,548, the Companies were responsible for approximately 10% of the costs. https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.spp.org%2Fdocuments%2F69116%2Fmarkets%2520plus%2520exhibit%2520a%2520phase-one%2520funding%2520agreement%2520.xlsx&wdOrigin=BROWSELINK.

[167] Submission of Tariff to Establish Markets+ of Southwest Power Pool, Inc., Docket No. ER24-1658-000 (Mar. 29, 2024) ("Markets+ Filing").

an order conditionally accepting the Markets+ Tariff.[168] SPP made its compliance filing on February 18, 2025, and it was accepted by FERC on April 17, 2025.[169]

Phase 2 is an approximately 28-month process that involves the development, testing and implementation of systems needed to facilitate Markets+ go-live. To finance these activities, SPP filed the Phase 2 Funding Agreement with FERC on February 21, 2025, in Docket No. ER25-1372. Under the agreement, the "Funding Participants" will provide the collateral backstop for the $150 million in third-party financing that SPP will obtain in order to develop the systems, processes, and operations necessary to implement Markets+.[170] The Funding Agreement obligates each Funding Participant to provide an amount of collateral in the form of cash or a letter of credit based on the funding participant's Phase 2 pro rata share of the Markets+ total cost less the funding participant's Phase 1 payments and post-phase 1 payments.[171]

The Phase 2 Implementation Costs will include the cost of sharing resources with the SPP RTO, including facilities and office expenses, and costs such as administrative, human resources, information technology, legal, accounting, and insurance. According to SPP, the Funding Agreement provides for these expenses to be included in the Markets+ implementation costs in order to ensure that the SPP RTO members are not subsidizing the implementation of Markets+.[172] The financing will be repaid after Markets+ goes live when the Phase 2 implementation costs will be incorporated into the rates charged to all Markets+ market participants through Schedule 1-B under the Markets+ Tariff. If a Funding Participant wishes to withdraw from the Funding Agreement, the Funding Participant must pay its Phase 2 Obligation to SPP to protect the remaining Funding Participants from the withdrawing Funding Participant's actions.[173]

FERC accepted the Markets+ Funding Agreement on April 22, 2025.[174] As of SPP's July 16, 2025, report to FERC in Docket No. ER24-1658, nine entities: Arizona Public Service Company; BPA; City of Tacoma; Powerex; Public Utility District No. 1 of Chelan County; Public Utility District No. 2 of Grant County; Puget Sound Energy; Salt River Project; and Tucson Electric Power Company have executed the agreement.[175]

As presented by SPP in a May 21, 2025, webinar, Markets+ is anticipated to go live in October 2027.[176] This is illustrated in Figure 17 which contains the projected Markets+ timeline. To go live

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168 *Sw. Power Pool, Inc.*, 190 FERC ¶ 61,030 (2025) ("Markets+ Acceptance Order").

169 *Sw. Power Pool, Inc.*, 191 FERC ¶ 61,040 (2025).

170 *See* SPP's Filing Letter in FERC Docket ER25-1372 at 1 and note 9. Breakdown of the $150 million responsibility can be found at: https://www.spp.org/documents/73296/markets%20plus%20phase%202%20exhibit%201%20funding%20agreement.pdf.

171 On June 30, 2025, SPP announced it had reached agreement with Simmons Bank for the $150 million funding. https://www.spp.org/news-list/marketsplus-phase-two-development-begins-with-secured-financing/.

172 SPP's Filing Letter in FERC Docket ER25-1372 at 4.

173 *Id.* at 6-7.

174 *Sw. Power Pool, Inc.*, 191 FERC ¶ 61,071 (2025).

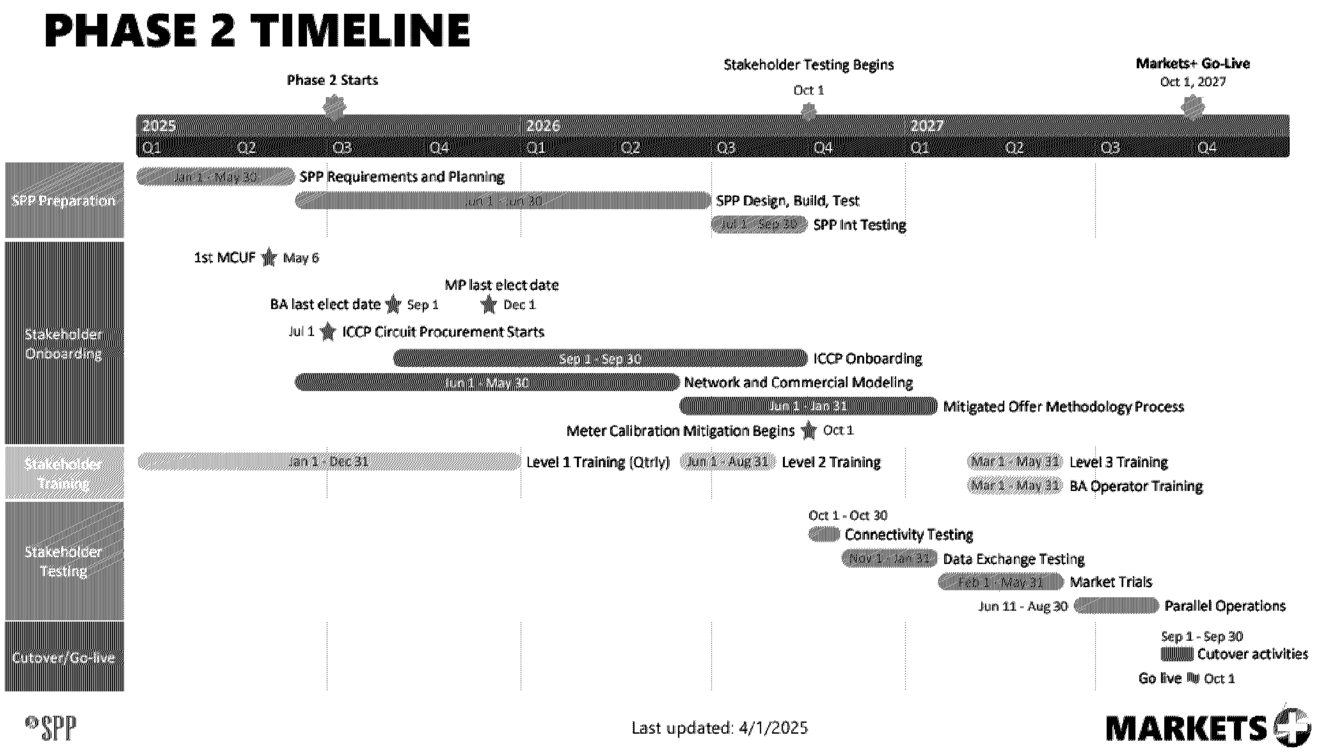
175 The report can be found at: https://www.spp.org/documents/74344/20250716_1st%20informational%20report%20-%20submission%20of%20tariff%20to%20establish%20markets%20plus_er24-1658-000.pdf.

176 *See*: https://www.spp.org/documents/73921/phase%20two%20governance%20and%20readiness%20webinar%20202

by October 2027, BAs were to declare their intention by September 1, 2025. Arizona Public Service Company, Salt River Project, Tucson Electric Power, Public Service Company of Colorado, and Powerex have indicated they expect to be part of the initial class.

Similar to EDAM, Markets+ will require participating transmission owners to file proposed changes to their OATT to facilitate participation in the new market. At this time, no filings have been made. In addition, the Markets+ design requires that any LSE in a participating BAA must be a binding member of WRAP[177] as approved in FERC Docket No. ER22-2762 and amended in FERC Docket No.ER25-559. This means that the LSE is subject to all WRAP obligations, administrative costs, and potential penalties.

Figure 17
Markets+ Timeline[178]



C. Western Markets Exploratory Group

WMEG was formed in 2021 as a coalition of western utilities focusing on developing long-term approaches to improve market efficiencies in the West and incorporating lessons learned from existing regional markets. The purpose of WMEG was to support members' analyses of ongoing discussions of potential new market, transmission, and governance structures for entities operating

50521.pdf at slide 8. SPP noted that Markets+ was a "separate footprint and separate services from the RTO expansion area."

177 *See* the Markets+ Tariff's definition of "resource Adequacy Program" and Attachment A Section 5.1.1.

178 Phase Two Governance and Readiness June 30, 2025, Webinar at slide 7. https://spp.org/documents/74202/phase%20two%20governance%20and%20readiness%20webinar%2020250630.pdf

in the WECC. In addition to NV Energy, the group included Arizona Electric Power Cooperative, Arizona Public Service, Avista Corp., Balancing Authority of Northern California, Black Hills Energy, BPA, Chelan County PUD No. 1, El Paso Electric Company, PUD #2 of Grant County, Idaho Power Company, Los Angeles Department of Water & Power, NorthWestern Energy, PacifiCorp, Platte River Power Authority, Portland General Electric, Public Service New Mexico, Puget Sound Energy, Salt River Project, Seattle City Light, Tacoma Power, Tri-State Generation & Transmission Association, Tucson Electric Power, Xcel Energy Colorado, and Western Area Power Administration.

The WMEG members hired Utilicast from March 2022 to June 2023 to provide subject matter and facilitation expertise for the effort and later hired E3 to perform a production cost study of several market footprints, including different levels of participation in either the CAISO EDAM or SPP Markets+. The WMEG created task forces composed of subject matter experts from the various WMEG entities and Utilicast. These task forces provided technical oversight and input for the production costs study, took deeper dives into various market issues, and evaluated other potential regional collaboration options. The output from these various task forces were memorialized in either the production cost study inputs or through the development of various white papers.

The WMEG Straw Proposal phase considered many aspects of regional collaboration. These considerations, questions, analysis, options, and results are captured in several documents:

1. Straw Proposal Phase – Deliverables Overview – Provides context for the overall effort and integrates the results of the Production Cost study and the Non-Production Cost Modeling.

2. Updated Roadmap – An update to the Initial Roadmap which provides discussion of potential next steps based on the results of the Straw Proposal Phase.

3. Western Day Ahead Market Production Cost Impact Study – Provides context on key modeling assumptions underpinning the Production Cost study and highlights the aggregated results.

4. Non-Production Cost Benefit Study – Provides context on functions or features which were not included in the Production Cost Model and provides qualitative and quantitative estimates of costs and benefits for these functions and features.

5. Seams White Paper – Describes likely seams issues which can exist between Markets and legacy BAAs as well as non-market functions of interest to WMEG and approaches that could be used to mitigate the seams.

6. Consolidated Balancing Authority (CBA) White Paper – Describes the primary operational and compliance components that would be impacted by consolidating BAs.

7. Market Design Straw Proposal for CBS (Cost Benefit Study) – Briefly describes EDAM and Markets+ proposals and why the WMEG chose to consider them for the Straw Proposal Phase.

8. Transmission Rate Sub-Group (TRSG) White Paper – Analyzed issues which may arise in creating a future de-pancaked transmission service tariff, discussed how transmission service revenue distribution can mitigate issues, and reviewed how other regions have addressed these issues.

These documents can be found on the Companies' OASIS site at: https://www.oasis.oati.com/NEVP/ under the Western Market Development tab.

Jack Moore of E3 provided slides and testified as to the WMEG benefit study methodology at the April 3, 2024, Commission Workshop in Docket No. 23-10019.[179] The E3 study work, both the regional and NV Energy specific results, were also provided with NV Energy's October 2, 2023, Comments in Docket No. 23-05013.[180] E3 used production cost modeling to determine savings and the individual benefit results for the various footprints compared to a Business as Usual ("BAU") case for the following three study years: 2026, 2030 and 2035.[181] To implement this study, E3 created multiple scenarios using the PLEXOS production cost model to simulate both day-ahead and real-time market operations.[182] E3 worked closely with WMEG to incorporate generation, load and transmission data provided and reviewed by individual WMEG members to most accurately represent the current and expected Western power system. E3 also simulated a range of additional market integration steps in the later year scenarios to explore potential changes in the system as well as features such as improved market-to-market coordination, consolidation of BAs with a regional ancillary services market, and coordination of transmission development such as would take place in an RTO. [183]

The BAU case included current real-time market participation (WEIM and WEIS) with only bilateral markets in the Day-Ahead, as well as aligned day-ahead and real-time market participation in a WECC-wide case and a split footprint.[184] Some members chose to evaluate several additional split footprints to consider how their individual benefits might change in different plausible market footprint configurations with other WMEG members. Figure 18 illustrates several of the footprints studied.

On a WECC-wide basis, the EDAM Bookend case shows a cost reduction of $60 million when compared to the BAU case.[185] That total was comprised of a $20 million net cost increase for WMEG members and an offsetting $80 million in net cost savings for non-WMEG members.[186] The Main Split case indicated a WECC-wide $221 million cost increase relative to the BAU

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[179] Docket No. 23-10019, April 3, 2024, *Western Markets Exploratory Group (WMEG) Cost Benefit Study* (Energy+Environmental Economics (E3)), submitted on April 17, 2024, as Attachment 2.

[180] Investigation related to examining process, modelling, and analytical improvements to NV Energy's integrated resource planning.

[181] Docket No. 23-05013, October 2, 2023, Comments of Sierra Pacific Power Company and Nevada Power Company, Attachment 1, June 2023 *Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study* (prepared by E3) at 3-4.

[182] *Id.* at 5.

[183] *Id.* at 6-8.

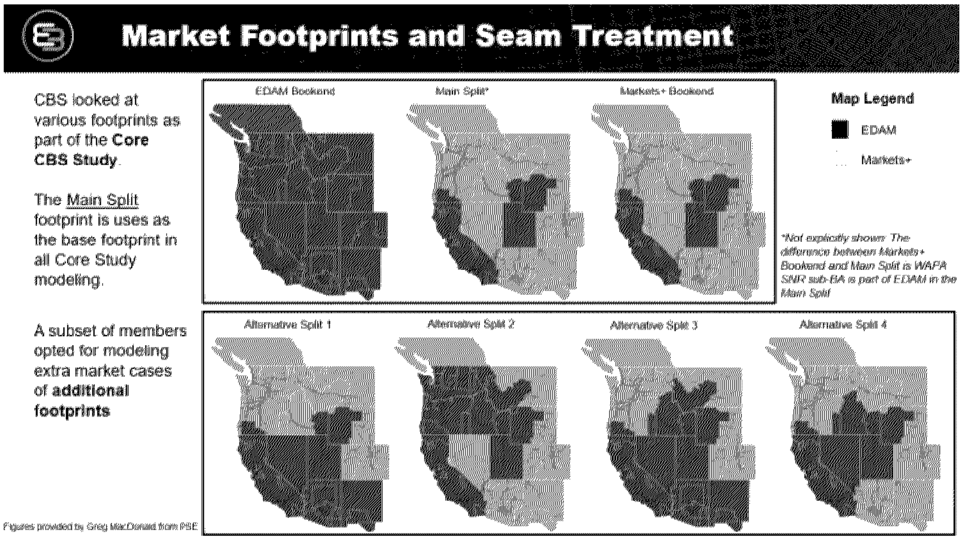
[184] *Id.* at 6.

[185] Docket No. 23-10019, April 3, 2024, *Western Markets Exploratory Group (WMEG) Cost Benefit Study* (Energy+Environmental Economics (E3)) at slide 12, submitted on April 17, 2024, as Attachment 2.

[186] *Id.*

case.[187] That total was made up of a $26 million cost savings for WMEG members and a $274 million cost increase for non-WMEG members.[188] As noted by Mr. Moore, there was significant variation within the WMEG entities in these studies.[189] These results are illustrated in Figure 19 which is taken from the June 2023 Report.

Figure 18



Short Market Footprint Description:

BAU	Bilateral trading (no centralized market) in DA; EIM & EIS cover most of WECC in RT stage
EDAM Bookend	All US WECC in EDAM; BC Hydro only in M+
Markets+ Bookend	PAC, CAISO, LADWP, TIDC, BANC (not WAPA SNR) in EDAM; rest of WECC in M+ (including WAPA SNR)
Main Split	PAC + all of California (including WAPA SNR) in EDAM; rest of WECC in M+
Alt Split 1	PAC + California (excluding Wapa SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in M+
Alt Split 2	PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in M+
Alt Split 3	PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in M+
Alt Split 4	PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in M+ [Same as M+ Bookend, but NV & ID move to EDAM]

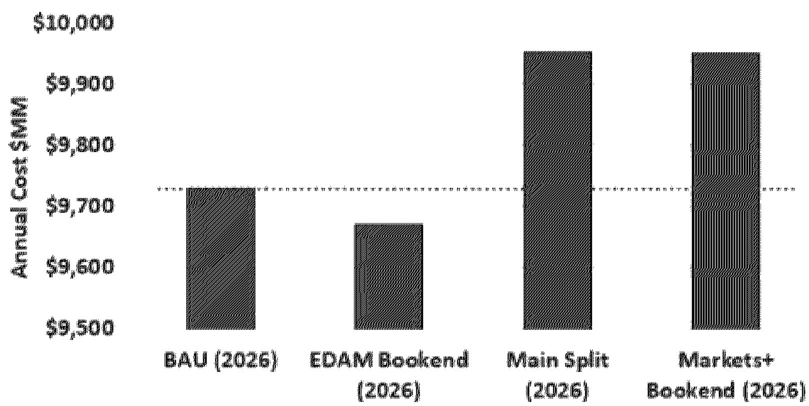
187 *Id.* at slide 13.

188 *Id.*

189 *See,* Docket No. 23-10019, April 3, 2024, Workshop, Tr. at 189.

Figure 19[190]

Figure 3-1 Annual Regionwide Adjusted Production Cost by 2026 Study Case



Note: Y-axis in chart does not start at $0.

The NV Energy-specific results are summarized in Figures 20 and 21.

Figure 20[191]

NVE Results:
WMEG Key Cases 2026

NVE in:	EIM only	EDAM	EDAM	M+
Cost (Revenue) in Million $	BAU (2026)	EDAM Bookend (2026)	Alt Split 4 (2026)	Main Split (2026)
Load Cost	810.5	771.3	769.0	818.1
Generation Cost	356.9	348.0	419.9	391.8
Reserve Cost	0.0	0.0	0.1	0.1
Generation Revenue	-686.8	-644.4	-715.6	-720.6
Reserve Revenue	0.0	0.0	-0.1	-0.1
Wheeling Revenue	-7.8	-4.1	-3.5	-27.0
Congestion Revenue	-13.8	-18.8	-18.3	-30.7
GhG Revenue	0.0	-0.4	-1.8	0.0
Net Cost	459.0	451.5	449.6	431.5
vs. BAU (2026)	**0.0**	**-7.5**	**-9.3**	**-27.5**
vs. Alt 4				***-18.2***
excluding Wheeling & Congestion				
Net cost excl w & cong	480.5	474.4	471.5	489.3
vs. BAU (2026)	**0.0**	**-6.1**	**-9.1**	**8.7**
vs. Alt 4				***17.8***

[190] Docket No. 23-05013, October 2, 2023, Comments of Sierra Pacific Power Company and Nevada Power Company, Attachment 1, June 2023 *Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study* (prepared by E3) at 12.

[191] Docket No. 23-10019, April 3, 2024, *Western Markets Exploratory Group (WMEG) Cost Benefit Study* (Energy+Environmental Economics (E3)) at slide 21, submitted on April 17, 2024, as Attachment 2.

Figure 21[192]

NVE Results 2030 & 2035

NVE in:	EIM only	EDAM	M+	EDAM	M+	EDAM	M+
Cost (Revenue) in Million $	BAU (2026)	Alt Split 4 (2026)	Main Split (2026)	Alt Split 4 (2030)	Main Split (2030)	Alt Split 4 (2035)	Main Split (2035)
Load Cost	810.5	769.0	818.1	859.6	896.2	843.5	1004.5
Generation Cost	356.9	419.9	391.8	429.5	418.3	403.3	437.3
Reserve Cost	0.0	0.1	0.1	0.1	0.0	0.4	1.5
Generation Revenue	-686.8	-715.6	-720.6	-810.8	-835.0	-762.3	-956.6
Reserve Revenue	0.0	-0.1	-0.1	-0.2	0.0	-0.3	-1.3
Wheeling Revenue	-7.8	-3.5	-27.0	-3.3	-36.7	-13.4	-34.1
Congestion Revenue	-13.8	-18.3	-30.7	-23.0	-27.9	-72.0	-34.2
GhG Revenue	0.0	-1.8	0.0	-0.7	0.0	0.0	0.0
Net Cost	459.0	449.6	431.5	451.3	415.0	399.2	417.2
vs. BAU (2026)	**0.0**	**-9.3**	**-27.5**	**-7.7**	**-44.0**	**-59.8**	**-41.8**
vs. Alt 4			***-18.2***		***-36.3***		***18.0***
Excluding Wheeling & Congestion Revenue:							
Net cost excl. w&c	480.5	471.5	489.3	477.5	479.5	484.6	485.4
vs. BAU (2026)	**0.0**	**-9.1**	**8.7**	**-3.0**	**-1.0**	**4.1**	**4.9**
vs. Alt 4			***17.8***		***2.0***		***0.9***

SECTION 4 -ANTICIPATED FOOTPRINTS

A. Anticipated Membership in EDAM and Markets+

This section represents the Companies' understanding of the anticipated market footprints as of the time of this filing. NV Energy notes that the respective lists may change as DAM development proceeds in the West.

1. Anticipated EDAM Footprint

- Anticipated to go-live in EDAM in 2026
  - CAISO
  - PacifiCorp (executed Implementation Agreement)
  - Portland General Electric (executed Implementation Agreement)

- Anticipated to go-live in EDAM in 2027
  - BANC (Sacramento Municipal Utility District, Western Area Power Administration Sierra Nevada Region, Modesto Irrigation District, City of Redding) (executed Implementation Agreement)
  - Los Angeles Department of Water and Power (executed Implementation Agreement)
  - Public Service Company of New Mexico (executed Implementation Agreement)
  - Turlock Irrigation District (executed Implementation Agreement)

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192 *Id.* at slide 24.

- Anticipated to go-live in EDAM in 2028
  - Imperial Irrigation District (executed Implementation Agreement)
  - NV Energy (Implementation Agreement execution pending Commission authorization)

- Other entities likely to participate in EDAM
  - Idaho Power Company
  - Power Watch, LLC
  - WAPA Desert Southwest and Arizona Electric Power Cooperative, Inc.

2. Anticipated Markets+ Footprint

- Entities that have committed to go live in Markets+ in October 2027
  - Arizona Public Service
  - Powerex
  - Salt River Project
  - Tucson Electric Power
  - Public Service Company of Colorado (Xcel Energy)

- Other entities likely to participate in Markets+
  - BPA
  - PUD No. 1 Chelan County, WA
  - PUD No. 1 Douglas County, WA
  - El Paso Electric Company
  - PUD No. 2 Grant County, WA
  - Puget Sound Energy
  - Tacoma Power
  - Black Hills- Colorado

3. Anticipated RTO West Footprint

- Basin Electric Power Cooperative
- Colorado Springs Utilities
- Deseret Power Electric Cooperative
- Municipal Energy Agency of Nebraska
- Platte River Power Authority
- Tri-State Generation and Transmission Association
- Western Area Power Administration (Upper Great Plains-West (UGP-West) region, Colorado River Storage Project and Rocky Mountain region)

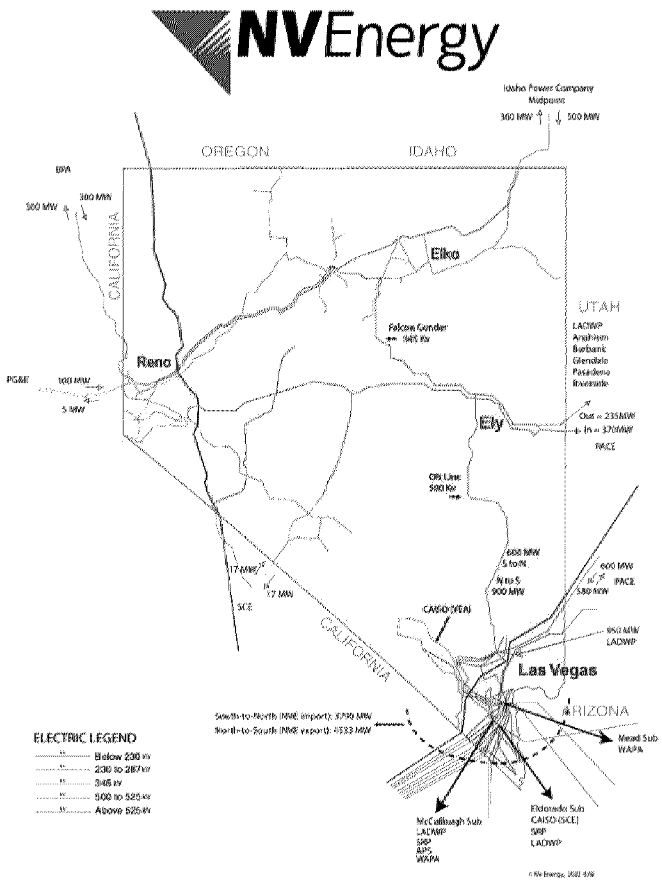
4. Uncommitted Entities

- Avista
- Avangrid
- Seattle City Light
- NorthWestern Energy
- Black Hills Power, Inc., Cheyenne Light, Fuel and Power Company

B. NV Energy's Existing Interconnectivity

The consolidated Nevada Power and Sierra BAA encompasses approximately 45,000 square miles. The Nevada Power service area covers approximately 4,500 square miles, with approximately 1,071,000 electric customers and 1,969 miles of transmission lines with voltages ranging from 69 to 525 kilovolts ("kV").[193] The Sierra transmission service area encompasses more than 40,000 square miles, with approximately 386,000 electric customers and 3,036 miles of transmission lines ranging from 55 kV to 525 kV.[194] Figure 22 identifies the major external interties, which are also listed in Table 1.

Figure 22



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193 Direct Testimony of Charles Pottey at Q&A 6.

194 *Id.*

TABLE 1[195]

NVE Region	Path Description				Rating (MW)	
	WECC #	Name	Definition	Metering Point	N-S (E-W)	S-N (W-E)
SPPC	16	Idaho-Sierra	Midpoint (IPCo) – Humboldt (SPPC) 345-kV line	Idaho-NV Border	500	300
SPP	24	PG&E-Sierra	Drum-Summit 1 115 kV Drum-Summit 2 115 kV Spaulting-Summit 60 kV	Summit 1 115 kV Summit 2 115 kV Summit 60 kV bus	150	160
SPPC	29	Intermountain-Gonder 230 kV	IPP (LADWP) – Gonder 230 kV line	Gonder 230 kV	250 (241)	NA
SPPC	32	Pavant – Gonder 230 kV; Intermountain-Gonder 230 kV	Osceola-Black Rock 230 kV Gonder-Intermountain 230 kV	NV-UT state line Gonder 230 kV	500	235
SPPC	52	Silver Peak-Control 55 kV	Silver Peak-Control 55 kV (2 lines)	California-Nevada border	17	17
SPPC	76	Alturas Project	Hilltop 230/345 kV transformer (BPA), Hilltop-Fort Sage 345 kV line	Hilltop 230 kV	300	300
NPC	35	TOT 2C	Red Butte-Harry Allen 345 kV line; Harry Allen 345 kV phase shifting and 345 kV/230 kV transformers	NV-UT border	600	580
NPC	49	East of the Colorado River	Navajo-Crystal 500 kV line (NVE rights)	Navajo 500 kV	522	522
NPC	NA	Crystal – McCullough line	Crystal – McCullough 500 kV line (NVE rights)	Navajo 500 kV	617	617
NPC	77	Crystal – Harry Allen	2 x 500/230 kV transformers at Crystal 500 kV	Crystal 500 kV	950	NA
NPC	81	Southern Nevada Transmission Interface	Harry Allen – Mead 500 kV	Mead	4533	3790
			Arden – Mead 230 kV	Mead		
			Equestrian – Mead 230 kV #1 and #2	Mead		
			Greenway – Mead 230 kV	Mead		
			Henderson – BC Tap – Mead 230 kV	Mead		
			Henderson – Mead 230 kV	Mead		
			Equestrian – Mead 69 kV #1 and #2	Mead		
			Lakes Las Vegas – Mead 69 kV	Mead		
			Mead – Searchlight 69 kV	Mead		
			Faulkner - McCullough 230 kV	McCullough		
			McCullough – Nevada Solar One 230 kV	McCullough		

195 Direct Testimony of Charles Pottey at Q&A 7.

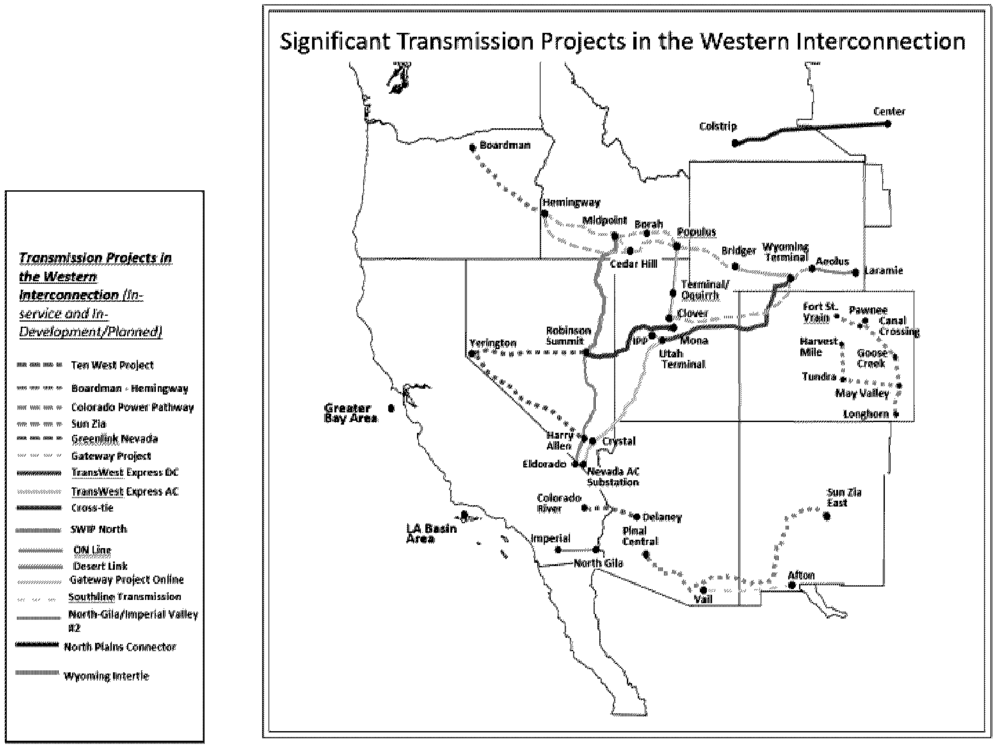
NVE Region	Path Description				Rating (MW)	
	WECC #	Name	Definition	Metering Point	N-S (E-W)	S-N (W-E)
			McCullough – Tolson 230 kV	McCullough		
			Laughlin – Mohave 500 kV	Mohave		
			Eldorado – Magnolia 230 kV	Eldorado		
			Eldorado – Nevada Solar One 230 KV	Eldorado		
			Northwest – Desert View 230 kV	Desert View		
			Indian Springs – Mercury 138 kV	Mercury		
			Amargosa Sandy 138 kV	Sandy		
NPC	84	Harry Allen – Eldorado 500 kV	Harry Allen – Eldorado 500 kV line	Harry Allen 500 kV	3496	1390
NPC	89	Southern Nevada Transmission Interface Plus (SNTA+)	SNTI (Path 81) + Harry Allen – Eldorado 500 kV line	Mead/McC/Mohave/Eldorado/VEA/Harry Allen	6257	4681

C. Relation of Market Footprint to Ongoing Transmission Development

As explained by Mr. Pottey, the Companies do not anticipate transmission system additions solely to facilitate EDAM participation.[196] Rather the Companies would take advantage of the exiting facilities as enhanced by a number of recently completed and ongoing major transmission projects in the West. These are illustrated in Figure 23, which was developed for a presentation by Neil Millar, CAISO's Vice President, Infrastructure and Operations Planning, before the June 18, 2025, WEM Governing Body General Session.

196 Direct Testimony of Charles Pottey at Q&A 8.

Figure 23[197]



Greenlink West, which NV Energy will construct as part of the first phase of Greenlink Nevada, will be a 358-mile, 525 kV transmission line from Las Vegas to Yerington, Nevada. The first sub-segment of Greenlink West is a 325-mile, 525 kV transmission line from Northwest Substation in Las Vegas to Fort Churchill Substation in Yerington. This sub-segment will have two renewable energy collector substations in Amargosa and Esmeralda counties. The second sub-segment of Greenlink West is a 33-mile, 525 kV transmission line within Las Vegas from Harry Allen Substation to Northwest Substation. The 525 kV Greenlink West line would travel along the western portion of Nevada and create a second connection between the northern and southern systems in addition to the One Nevada Line ("ON Line")—the existing 525 kV line that currently is the only connection between the Sierra Pacific and Nevada Power systems. In combination with ON Line, Greenlink West will increase resiliency by eliminating the single contingency between the northern and southern systems resulting from the loss of ON Line. Greenlink West will pass alongside the BLM-designated Solar Energy Zones of Amargosa Valley, Gold Point, and Millers, and it will thus unlock interconnection capabilities in areas that have at least several gigawatts of estimated renewable generation potential.[198]

Greenlink North, the second major segment of Greenlink Nevada, will be a 235-mile, 525 kV transmission line from Fort Churchill Substation in Yerington to Robinson Summit Substation in Ely, Nevada. The Greenlink North route runs through a renewable energy zone in central Nevada. In addition to Greenlink West and Greenlink North, NV Energy will construct three 345 kV

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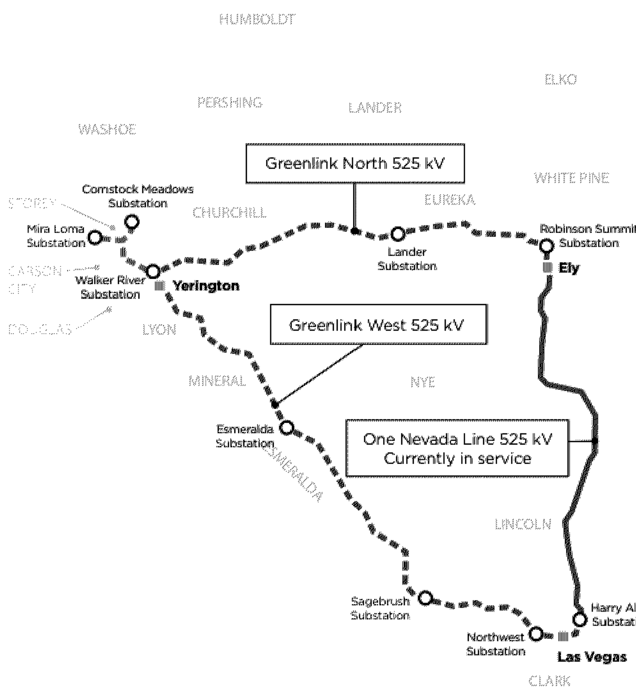
[197] CAISO Briefing on West-Wide Transmission Activities WEM Governing Body General Session June 18, 2025 - https://www.westerneim.com/Documents/Briefing-on-California-ISO-West-wide-Transmission-Activities-Presentation-Jun-2025.pdf at slide 7.

[198] Direct Testimony of Charles Pottey at Q&A 14.

transmission lines that are referred to as the Common Ties from Fort Churchill Substation to the load pockets in the Reno area. The Common Ties include the expansion of the Fort Churchill Substation and the construction of a new 525/345/230/120 kV substation. The first Common Tie is a 44-mile, 345 kV transmission line to Mira Loma Substation in Reno. The second and third Common Ties are a pair of 37-mile, 345 kV transmission lines to Comstock Meadows Substation within the Tahoe Reno Industrial Center ("TRIC") area.[199] The Greenlink projects are illustrated in Figure 24.

Figure 24
Greenlink



Greenlink West adds 985 MW of North-to-South Total Transfer Capacity ("TTC") and 1,258 MW of South-to-North TTC between northern and southern Nevada. Greenlink West and Greenlink North combined add 1,372 MW of North-to-South TTC and 1,745 MW of South-to-North TTC. Greenlink West increases the Northern Nevada import limit from 1,275 MW to 2,000 MW. Greenlink North adds an additional 800 MW to the Northern Nevada import limit for a total of 2,800 MW.[200]

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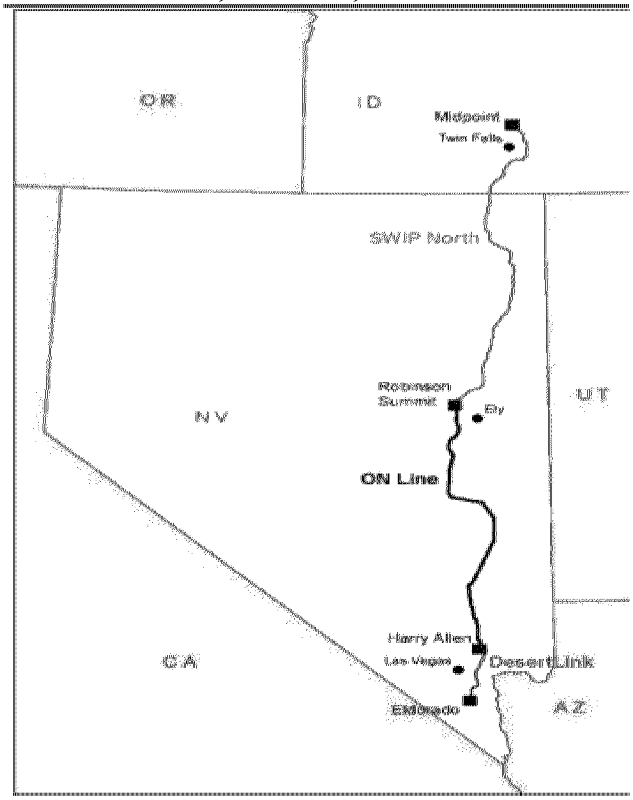
199 *Id.*
200 *Id.* at Q&A 15.

Figure 25 depicts the Southwest Intertie Project-North Transmission Line ("SWIP-North"),[201] consisting of a 285-mile 500 kV transmission line, series compensation facilities and shunt reactors to be located at or near Robinson Summit and Midpoint, interconnection upgrades at Robinson Summit and Midpoint (including, but not limited to, 500/345 kV phase shifting transformers and shunt capacitors at Robinson Summit), and associated upgrades on ON Line (including but not limited to series compensation facilities).[202] The SWIP-North project is expected to enter service by late 2028.[203]

Figure 25
SWIP-North, ON Line, and Desert Link



In accordance with the Transmission Use Agreement,[204] the SWIP-North project increases NV Energy's ON Line capacity from 900 MW North-to-South to 1,217.5 MW (2,335 MW overall)

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201 The figure can be found in the April 23, 2025, Filing Letter of Great Basin Transmission, LLC in FERC Docket No. ER25-2025 at 5.

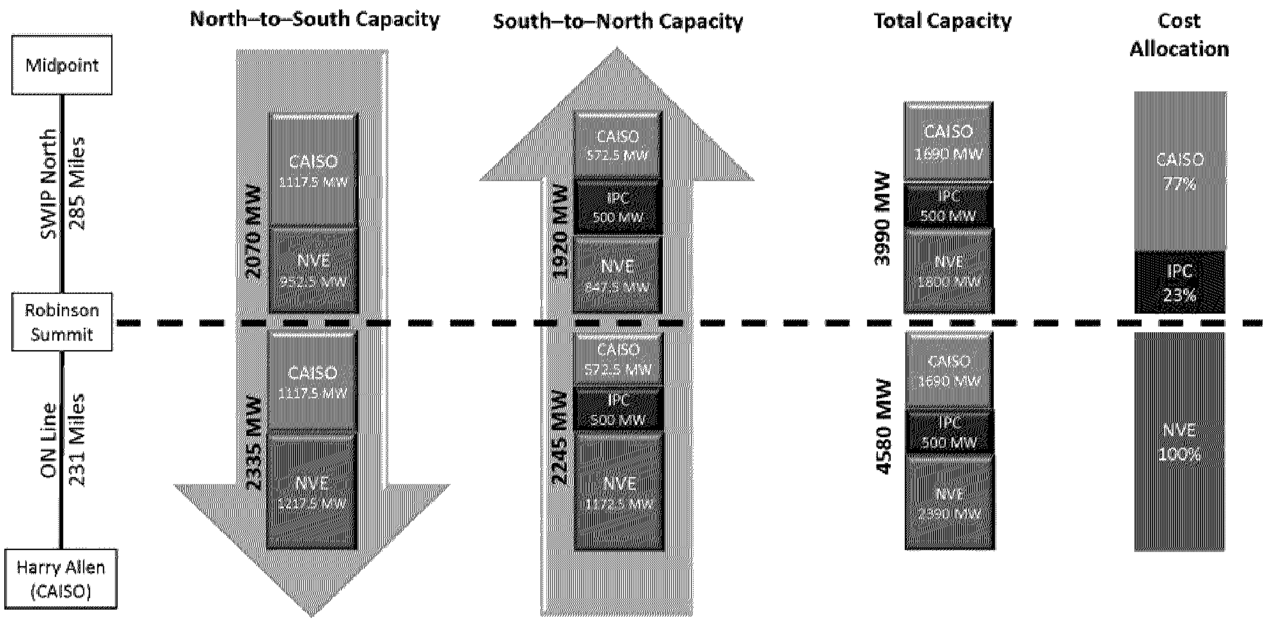
202 *Id.* at 4.

203 *Id.*

204 Nevada Power Co. & Sierra Pac. Power Co., Docket No. ER20-2295 (Aug. 17, 2020) (delegated letter order) (accepting the Second Amended and Restated Transmission Use Agreement).

Under the TUA, NV Energy has been and will continue to be responsible for 100% of the capital and operating costs of ON Line, through 25% ownership and a long-term lease arrangement associated with Great Basin South's 75% ownership. Great Basin is responsible for 100% of the capital and operating costs of SWIP-North, through 100% direct ownership. NV Energy and Nevada ratepayers have been responsible for 100% of the costs for ON Line for more than a decade and will continue to pay 100% of the costs despite the capacity allocation referenced above. In exchange, NV Energy and Nevada ratepayers will not contribute to any of the costs of SWIP-North, but they and increases NV Energy's ON Line capacity from South-to-North from 600 MW to 1,172.5 MW (2,245 overall).[205] SWIP-North's capacity is 2,070 MW North-to-South (allocated as 952.5 MW to NV Energy and 1,117.5 MW to CAISO and 1,920 MW South-to-North (allocated as 847.5 MW to NV Energy, 572.5 MW to CAISO and 500 MW to Idaho Power Company).[206] NV Energy's northern Nevada system import limit with Greenlink West, Greenlink North and SWIP-North will be in the range of 4,000 to 4,400 MW.[207] These allocations are illustrated in Figure 26.

Figure 26
Allocation of ON Line and SWIP-North Capacity



PacifiCorp's Gateway projects are illustrated in Figure 27. Aeolus to Mona/Clover (Gateway South – Segment F) is a new 416-mile, high-voltage 500-kV transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line was energized in 2024.

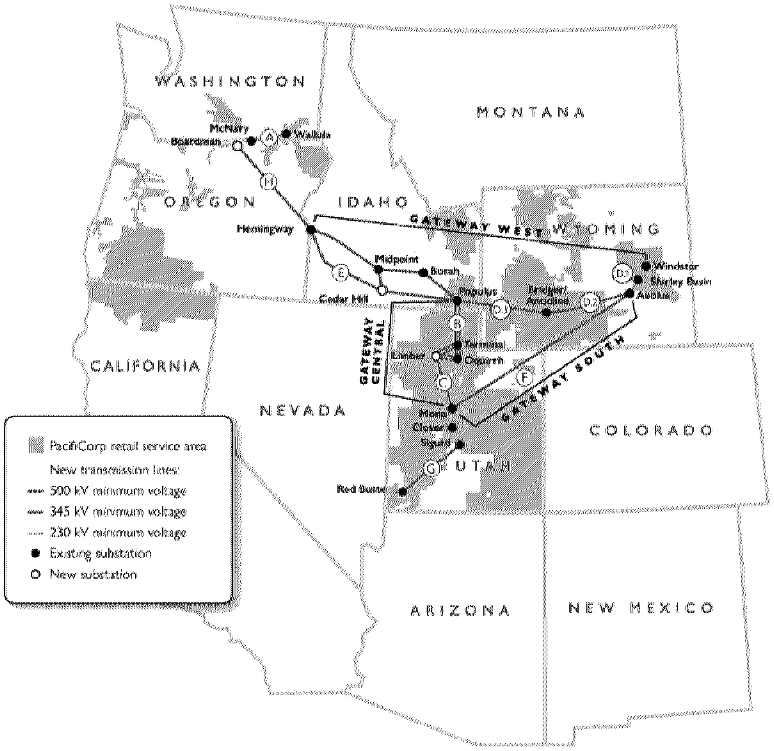
will be allocated a share of the increase in the capacity of ON Line and a share of the capacity of SWIP-North. This significant benefit for Nevada was part of the reason the PUCN staff endorsed and the PUCN approved the joint development of ON Line and the associated TUA in 2010.
April 23, 2025, Filing Letter of Great Basin Transmission, LLC in FERC Docket No. ER25-2025, Exhibit No. GBT-114 Direct Testimony and Exhibits of Mark D. Milburn at 9-10.

205 Direct Testimony of Charles Pottey at Q&A 17.

206 *Id.*

207 *Id.* at Figure Pottey Direct 4.

Figure 27



Windstar-to-Populus (Gateway West – Segment D) consists of three key sub-segments: (1) D1 is a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming and has been placed into service; (2) D2 is a single-circuit 500-kV line that was completed in November 2020; and (3) D3 is a single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho. The line is scheduled in service in 2034 at the earliest.[208]

Populus-Hemingway (Gateway West - Segment E) consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho. PacifiCorp is continuing to permit the projects specifically transmission segment between Midpoint-to-Hemingway portion of Segment E.

Boardman-to-Hemingway (Segment H now called Longhorn-to-Hemingway) is a 500-kilovolt line that would run approximately 2900 miles from the proposed Longhorn substation near Boardman, Oregon, to the Hemingway substation near Melba, Idaho, southwest of Boise, Idaho. Idaho Power is working on the project with PacifiCorp. Idaho Power is leading federal, state and

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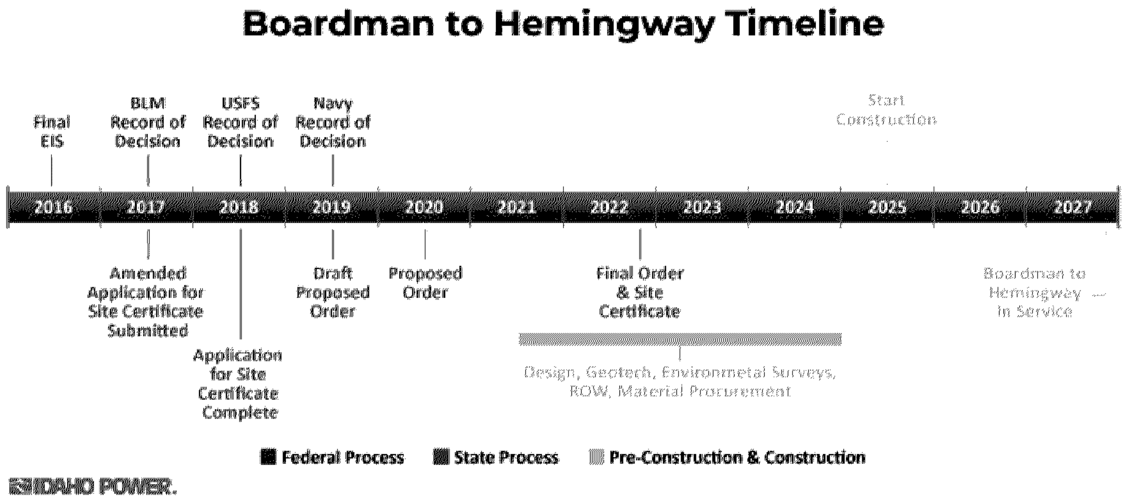
[208] https://www.pacificorp.com/transmission/transmission-projects/energy-gateway/gateway-west.html.

local permitting efforts, as well as the engineering and construction processes. Figure 28 is the projected timeline.

Figure 28[209]



The following is a brief description of other projects listed in Figure 23.

- Ten West Project – (formally known as Delaney to Colorado River) connects substations in Tonopah, Arizona and Blythe, California with a new 125 mile 500kV power line and is under the operational control of CAISO. The project was approved by the CAISO Board in the 2013-2014 transmission planning process and became operational in June 2024.[210]

- North Gila/Imperial Valley is a proposed 500 kV AC transmission project that will extend approximately 90 miles and will be constructed between southwest Arizona and southern California. The line will parallel the existing North Gila-Imperial Valley line, also known as the Southwest Power Link (SWPL), and will connect the existing 500 kV North Gila substation with the existing 500 kV Imperial Valley substation. The line will be under CAISO's operational control with an expected completions date of December 2031.[211]

- SunZia is a 552-mile, high-voltage direct current ("HVDC") bi-pole transmission facility connecting up to 3,021 MW of wind generation in New Mexico, with 2,131 MW currently planned for delivery to California via Pinal Central to the Palo Verde substation using entitlements across Arizona.[212] SunZia Transmission commenced construction in 2023 and

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209 https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/purpose-and-need/.

210 https://www.prnewswire.com/news-releases/ten-west-link-transmission-line-becomes-operational-expanding-the-grid-between-california-and-the-desert-southwest-302171933.html.

211 HorizonWest presentation at slide 2. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/ceqa-permitting/quarterly-general-order-131-e-reports/hwt-q1-2025-go-131-e-report.pdf.

212 Direct testimony of Anna McKenna at Q&A 20.

expects commercial operations to begin in the first half of 2026. SunZia Transmission is an indirect wholly-owned subsidiary of Pattern Energy Group LP ("Pattern Energy")[213] The SunZia Subscriber Participating Transmission Owner application was approved by the CAISO Board in May 2024 and by FERC on September 4, 2024, in Docket No. ER24-2471-000.[214]

- 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 AC transmission line from IPP to TWE Crystal and an interconnection to the CAISO's Harry Allen – 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 – Eldorado 500 kV transmission line. Subsequently, the capacity of the HVDC line from Wyoming to IPP will increase to the full 3,000 MW. TransWest Express expects to be in commercial operation in late 2027.[215] CAISO received an application from TransWest Express on September 16, 2022; filed the Applicant Participating Transmission Owner Agreement with FERC on January 13, 2023, in Docket No. ER23-838; and received approval by FERC on March 14, 2023. CAISO 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 13, 2024.

- Crosstie is a proposed 314 mile, 500-kilovolt (kV) line connecting PacifiCorp's Clover 500 kV substation in Utah with NV Energy's Robinson Summit 500 kV substation with a 1,500 MW bi-directional rating. The proposed project is highlighted in Figure 29. On September 20, 2024, the Bureau of Land Management and United States Department of Agriculture-Forest Service released a Final Environmental Impact Statement for the project.[216]

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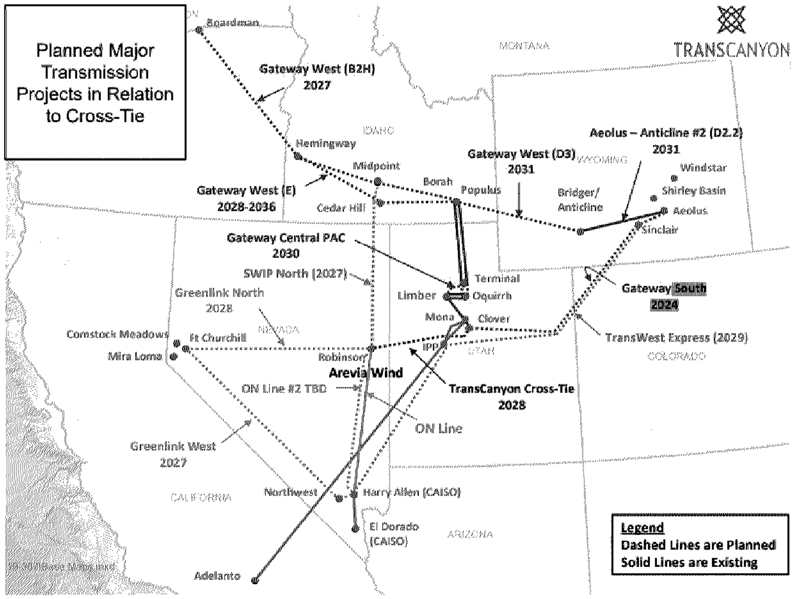
213 https://www.caiso.com/documents/sunzia-transmission-llc-pto-application.pdf.

214 CAISO has received FERC approval for a new Subscriber Participating Transmission Owner 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. Direct Testimony of Anna McKenna at Q&A 20.

215 BLM National NEPA Register at: https://eplanning.blm.gov/eplanning-ui/project/2030465/510.

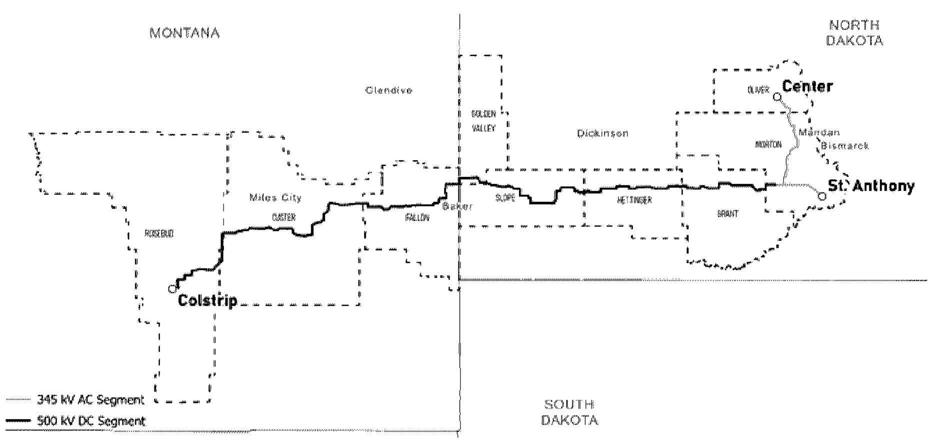
216 https://www.transcanyon.com/projects/Cross-Tie-Transmission-Line/default.aspx.

Figure 29



North Plains Connector is an approximately 420 mile and up to 525 kilovolt high voltage direct current (HVDC) transmission line connecting the U.S. Eastern and Western electric grids in Montana and North Dakota. North Plains Connector is entering the permitting phase and initiating regulatory filings, with approvals expected in 2026. Construction is expected to commence in 2028, and the line is expected to be operational in 2032.[217] Figure 30 is a map of the anticipated route. As proposed, the NPC would extend approximately 420 miles from near Colstrip, MT, to two separate end points in North Dakota: one near Center, ND, and the other near St. Anthony, ND.

Figure 30[218]



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217 https://northplainsconnector.com.

218 Comments of Grid United in FERC Docket No. AD25-4 filed on February 25, 2025, at 3.

Utilities accounting for 75 percent of the line's capacity have now signed MOUs to participate in North Plains Connector.[219]

- On May 28, 2024, Portland General Electric signed a nonbinding memorandum of understanding for a 20 percent ownership share (600 MW) of the project.[220]

- On November 4, 2024, Avista Corporation signed a nonbinding memorandum of understanding for 10 percent ownership (300 MW) of the project.[221]

- On December 9, 2024, Puget Sound Energy signed a nonbinding memorandum of understanding for 750 MWs of the project.[222]

- On December 12, 2024, NorthWestern Energy signed a nonbinding memorandum of understanding for 10 percent (300 MW) of the project.[223]

- On January 8, 2025, BHE U.S. Transmission Energy signed a nonbinding memorandum of understanding for 10 percent (300 MW) of the project.[224]

- Colorado Power Pathway Power Pathway is a 560-mile, 345 kV double-circuit network transmission. Public Service Company of Colorado commenced construction activities in 2023. Public Service Company of Colorado intends to bring the Colorado Power Pathway online in three stages between 2025 and 2027. Segments 2 and 3 should be online first, in mid-2025. Segments 1 should come online next, in mid-2026. Segments 4 and 5 should follow by late 2027.[225]

- Southline is designed to connect the transmission systems of the El Paso and Tucson Electric.[226] The proposed line transmission line would run between the Afton substation west of Las Cruces, New Mexico, and the Apache substation in Willcox, Arizona, as well as the upgrade of a Western Area Power Administration transmission line between the Apache substation and Vail substation east of Tucson, Arizona. Southline expects

219 https://www.brkenergy.com/news/article/bhe-u.s.-transmission-joins-grid-united-for-north-plains-connector-transmission-project#:~:text=HELENA%2C%20Montana%20%E2%80%93%20January%208%2C,North%20Plains%20Connector%20transmission%20project.

220 https://portlandgeneral.com/news/2024-05-pge-joins-grid-united-and-allete-in-east-west-transmission-line.

221 https://investor.avistacorp.com/news-releases/news-release-details/avista-joins-pge-grid-united-and-allete-3000-megawatt-east-west.

222 https://www.globenewswire.com/news-release/2024/12/09/2993873/0/en/Puget-Sound-Energy-signs-on-to-largest-share-of-North-Plains-Connector-transmission-project.html.

223 https://www.businesswire.com/news/home/20241212484368/en/NorthWestern-Energy-to-Participate-in-Regional-Transmission-Projects.

224 https://www.brkenergy.com/news/article/bhe-u.s.-transmission-joins-grid-united-for-north-plains-connector-transmission-project#:~:text=HELENA%2C%20Montana%20%E2%80%93%20January%208%2C,North%20Plains%20Connector%20transmission%20project.

225 Public Service of Colorado March 21, 2024, Answer in EL24-74 at 16-17.

226 https://southlinetransmission.com.

construction to begin in 2026. The first phase of the project could be operational by 2028, with the full project online by 2029.[227]

- Rio Sol would be a 550-mile, 500 kV high voltage alternating-current transmission project with approximately 1,600 MW of transmission capacity that has been in development since 2006.The Rio Sol Project has a proposed eastern terminus in central New Mexico (near Corona, New Mexico) and a western terminus at or near the Pinal Central substation in central Arizona (near Coolidge, Arizona), with several intervening substations proposed along the route.[228] Project construction is proposed to begin in 2026 with commercial operations in 2028.[229] The project received FERC approval to negotiated rate authority on July 5, 2024, in Docket No. ER24-1726.[230]

- Wyoming Intertie would be an approximately 106-mile, up-to-1,800 MW, high-voltage transmission line connecting the Eastern and Western Interconnection grids, The project would stretch across Carbon, Albany, and Platte Counties to connect substations near Medicine Bow and Wheatland. The route is under development while Wyoming Intertie works with stakeholders and landowners.[231]

D. Implications of the Footprint – Diversity and Reliability

The report approved in the July 9, 2024, Order in Docket No. 23-10019 requested information on the resiliency of the DAM system to physical threats, such as wildfire.[232] As noted above and described in more detail in the Direct Testimony of Anna McKenna, over the last decade of operations, the WEIM has demonstrated significant reliability benefits during Western heatwaves and wildfire conditions which jeopardized grid reliability.[233] In July 2021, the Bootleg wildfire in

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227 https://southlinetransmission.com/frequently-asked-questions/#:~:text=Southline%20expects%20to%20begin%20construction,El%20Paso%20and%20Tucson%20areas

228 *See* El Rio Sol Filing Letter dated April 4, 2024, in Docket No. ER24-1726 at 1.

229 *El Rio Sol Transmission, LLC.* 188 FERC ¶ 61,007 (2024) at P 4.

230 *El Rio Sol Transmission, LLC.* 188 FERC ¶ 61,007 (2024).

231 https://wyomingintertie.com.

232 The report also requested information on the vulnerability to cyber-security threats. As explained in the Direct Testimony of Hugo Frech, CAISO's Chief Information Security Officer and Executive Director of IT Infrastructure at Q&A 5,

> 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.

233 Direct Testimony of Anna McKenna at Q&As 9-11.

Oregon 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 BAAs and quickly redispatched generation across other available transmission paths to support reliability and continue to serve demand.[234]

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.[235]

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 BAAs 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.[236]

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 [237]

Again, the departure of WEIM participants would be unfortunate, but a critical core of connected entities has committed to EDAM. As noted in the Direct Testimony of Anna McKenna, the projected EDAM footprint contains and represents a very diverse set of resources, representing nearly 50 percent of the demand and close to 50 percent of the installed generating capacity in the Western interconnection. Considering the EDAM entities which have executed implementation agreements, along with those which have expressed interest and leaning for participating in EDAM including NV Energy, the total installed generating capacity exceeds 145,000 MW of a diverse set of resources. Figure 31 illustrates the diversity of the resource fleet in the projected EDAM footprint by generation technology type.[238]

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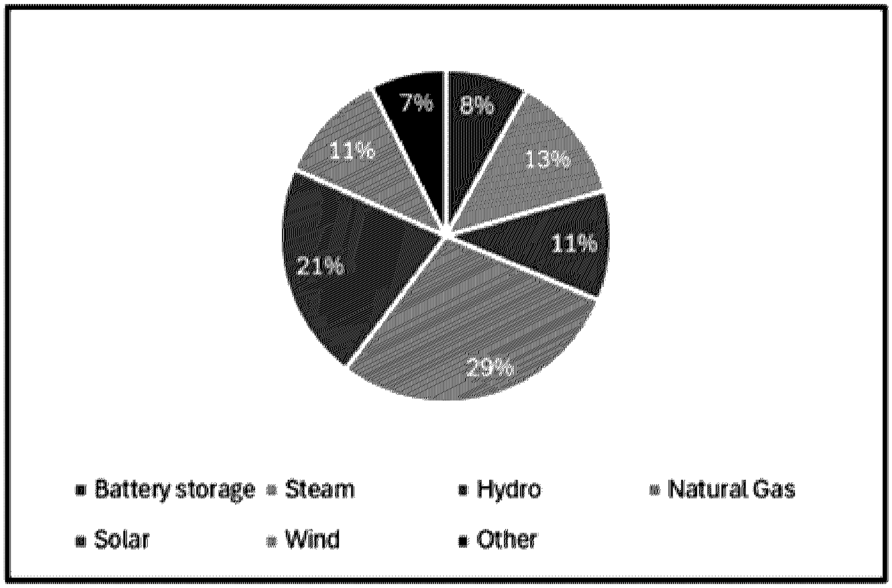
234 Direct Testimony of Anna McKenna at Q&As 9-11 and Direct testimony of Scott Kaufmann at Q&A 13.
235 Direct Testimony of Anna McKenna at Q&A 9.
236 *Id.*
237 *Id.*
238 *Id.* at Q&A 21.

Figure 31[239]



The resource diversity composition allows the market to optimally commit and dispatch 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.[240]

This resource diversity, combined 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.[241]

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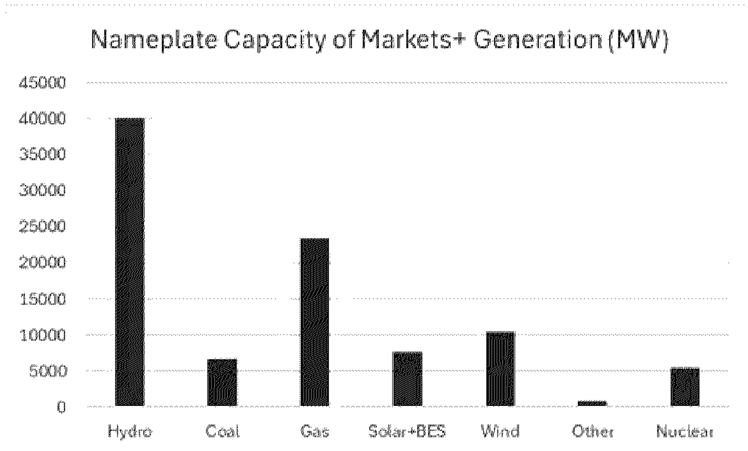
239 *Id.*
240 *Id.*
241 *Id.*

This is not to say that the announced Markets+ participants would not have a diverse set of resources. As noted in testimony of Public Service Company of Colorado, Markets+ could include the following:[242]

Figure 32

Figure JCT-D-2 Nameplate Capacity of Markets+ Generation



With respect to Markets+, however, questions would remain as to deliverability both in the day-ahead optimization and real-time dynamic capability. This issue is illustrated in the Direct Testimony of John Tsoukalis of the Brattle Group.[243] Figure 33 shows the diversity of resources in Brattle's BAU case.[244] Figure 33 shows 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.

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242 Exhibit No. 101, Direct Testimony and Attachments of Joseph C. Taylor filed with the Colorado Public Utilities Commission on February 14, 2025, in Proceeding No. 25A-0075E at 25.

243 Direct Testimony of John Tsoukalis at Q&A 14.

244 The business as usual case keeps NV Energy in WEIM and places the declared participants in EDAM and Markets+ as follows:

NVE in WEIM

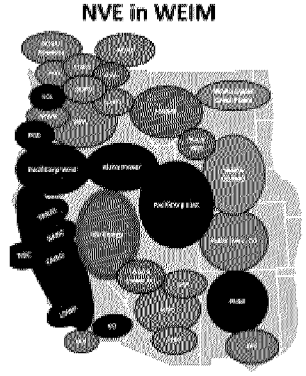
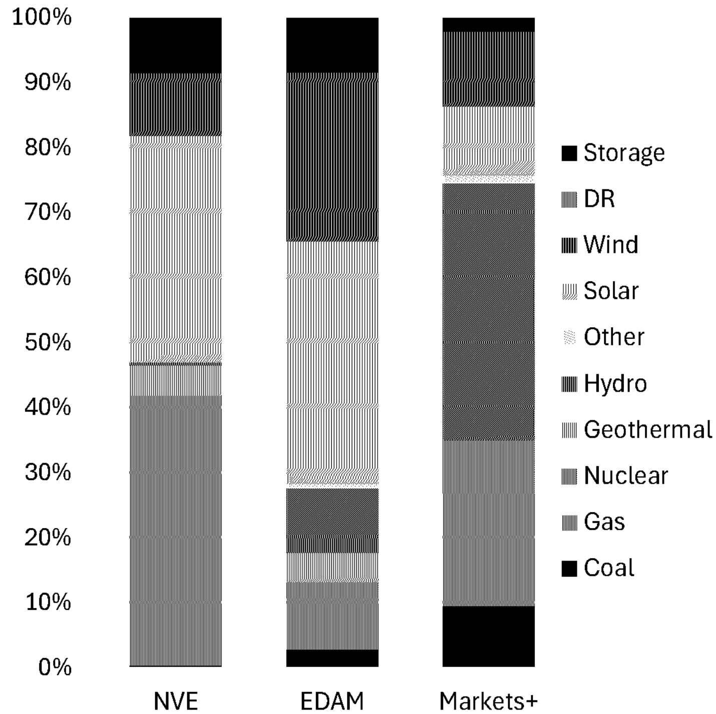


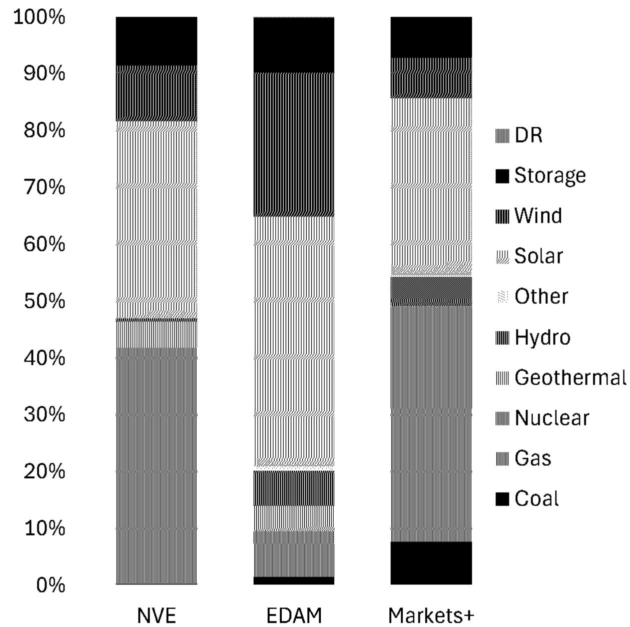
Figure 33



As Mr. Tsoukalis explains, however, Figure 33 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. Figure 34 shows the generation share in each market footprint weighted by NV Energy's total transfer capability to each member in the two markets, compared to NV Energy's generation. Therefore, Figure 34 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.[245]

[245] Direct Testimony of John Tsoukalis at Q&A 14. For example, Portland General Electric and Seattle City Light have hydro resources, but there is no direct interconnection between those two utilities and NV Energy, so that generation is not included in Figure 34 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 Portland General Electric and Seattle City Light to NV Energy. The EDAM will be able to execute those types of transactions when its economic to do so, but Figure 34 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.

Figure 34



In Markets+, BPA and other expected members in the Pacific Northwest have large hydro resources, but the transfer capability between NV Energy and the Pacific Northwest is relatively small, so the amount of hydro is also relatively small. Figure 34 helps illustrate why NV Energy customers experience a reduction in production cost benefits in EDAM.[246] The availability of low-cost wind in the EDAM footprint (mostly in the PacifiCorp East 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.

SECTION 5 – MARKET DESIGN

A. Participation Overview

The report approved in the July 9, 2024, Order in Docket No. 23-10019 requested information on any capital investment in transmission or generation that may be necessary to participate in the DAM or maximize the benefit of the DAM.[247] As explained in the Direct Testimony of Michael Holland and Charles Pottey, the Companies will not need to add generation or transmission to participate in a DAM.[248] Rather participation would provide additional benefits from the Companies' existing supply portfolio and transmission system and any future additions. Stated another way, the DAM would not be the driver of capital investment in generation or transmission

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246 Direct Testimony of John Tsoukalis at Q&A 14. *See also,* the discussion in section 6 of the Narrative.
247 *See* Att. 1 at 10.
248 Direct Testimony of Michael Holland at Q&A 34 and the Direct Testimony of Charles Pottey at Q&A 8.

but would enhance the usefulness of the assets. In the following sections, the Companies discuss the important features of the two DAM designs.

1. EDAM

EDAM leverages CAISO's existing day-ahead market and builds on the successful WEIM platform. EDAM optimizes all supply and demand across the market footprint while respecting transmission limitations to produce optimized day-ahead schedules. All generation and load within a participating EDAM BAA must either bid or self-schedule in the market. These transactions are then re-optimized in the WEIM's sub-hourly 15- and 5-minute markets. EDAM requires participants to demonstrate sufficient energy, capacity, flexibility, and transmission on a day-ahead basis, consistent with forecasted demand. All load, generation, and transmission will participate under the EDAM Entity's OATT.

CAISO's existing day-ahead market operates in four stages: bid submission, market power mitigation, the Integrated Forward Market ("IFM"), and the RUC process. During bid submission,[249] scheduling coordinators for generation resources submit separate bids for energy, ancillary services, and RUC capacity, while LSEs submit bids for load. Following bid submission, CAISO conducts a market power mitigation screen to identify and mitigate potentially uncompetitive supply bids, ensuring that the resulting market prices from the IFM are competitive.

The IFM is a financial market where bid-in supply clears against bid-in load and ancillary services requirements.[250] After market power mitigation, CAISO issues schedules for energy and ancillary services. The market optimization software runs in two phases: the scheduling run, which produces resource schedules, and the pricing run, which determines market-clearing prices for energy LMPs and ancillary services. The final step is the RUC process, in which CAISO procures additional capacity to address any shortfall between the physical supply cleared in the IFM and the supply needed to meet CAISO's demand forecast.[251]

In EDAM, there will be four main participant roles, with each represented by a Scheduling Coordinator.

- BA (EDAM Entity): The EDAM Entity will enter into an addendum to its EIM Entity Agreement with CAISO and will function much like the EIM Entity does today. It will process certain EDAM-related settlements and be the primary interface between the NV Energy transmission department and CAISO. As the NV Energy EDAM Entity Scheduling Coordinator, NV Energy will be responsible for obligations related to scheduling, settlement, system security policy and procedures, billing and payments, confidentiality, compliance with standards of conduct requirements, and dispute resolution. The NV Energy EDAM Entity would act as the scheduling coordinator for all transmission customers, not otherwise represented by an applicable CAISO Scheduling Coordinator Agreement.

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249 *See* CAISO, Tariff section Scheduling Coordinator Certification and section 4.5.3 Responsibilities of a Scheduling Coordinator.

250 EDAM Acceptance Order at P 5.

251 *Id.*

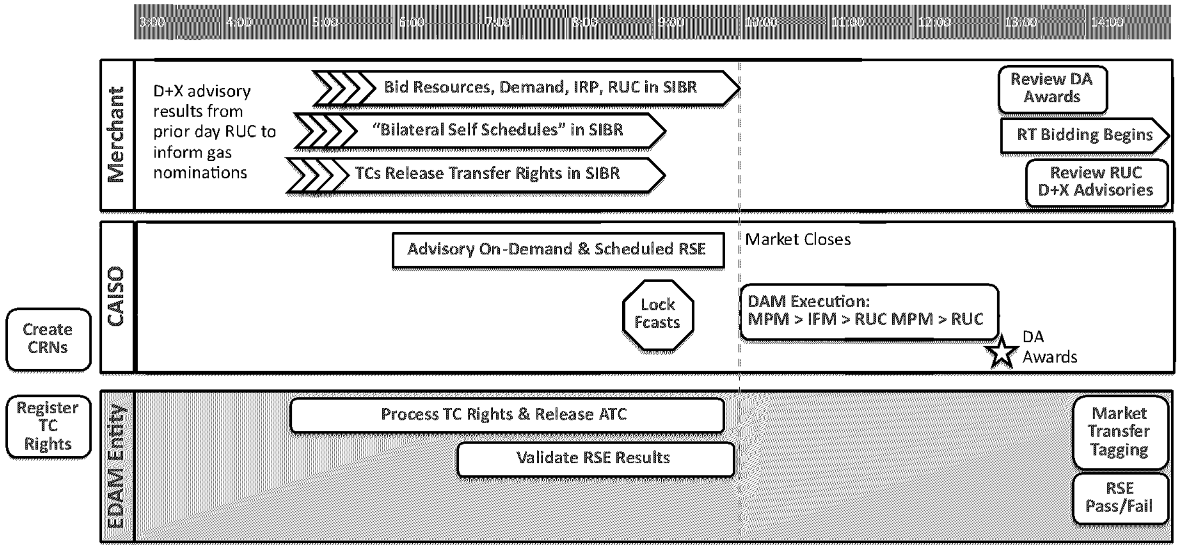
- Resource Owner/Operator (EDAM Resource and EDAM Resource Facility): Generators and demand response providers will be referred to as EDAM Resource Facilities (the facility itself) and EDAM Resources (the operator of the EDAM Resource Facility). EDAM Resources will need to be represented by an EDAM Resource Scheduling Coordinator. While in WEIM certain resources are currently permitted to be designated as non-participating, they will now be required to enter into a new EIM Participating Resource Agreement with an EDAM Addendum.

- Transmission Service Provider (EDAM Transmission Service Provider): This role refers to the owner/operator of transmission facilities in an EDAM BAA, which may or may not be the EDAM Entity.

- LSE (EDAM Load-Serving Entity): An entity serving load in the NV Energy BA will be considered an EDAM Load-Serving Entity. EDAM Load-Serving Entities will have the option to have their own Scheduling Coordinator and interact directly with the CAISO for the purpose of load settlements.

EDAM will optimize all resources and loads within the market by identifying efficient resource commitments and energy transfers to ensure scheduled and forecast loads are met. Loads and resources will be subject to day-ahead and real-time market pricing under CAISO's LMP pricing model. EDAM will not "co-optimize" ancillary services. Under EDAM, a load-serving entity in a NV Energy BAA will have its resources and loads optimized by the market on a full day-ahead basis, as compared to under the EIM where the use of base schedules of resources and loads leaves the market only to address imbalances. All transmission customers will have the ability to choose between economic bids and self-schedules. As with all LMP-based markets, market participants will be subject to the three basic elements of such bid-based, security constrained economic dispatch systems – i.e., energy, congestion, and losses. Figure 35 highlights the different roles of NV Energy's merchant function, the Companies' transmission department as the EDAM Entity and CAISO as the market operator.

Figure 35

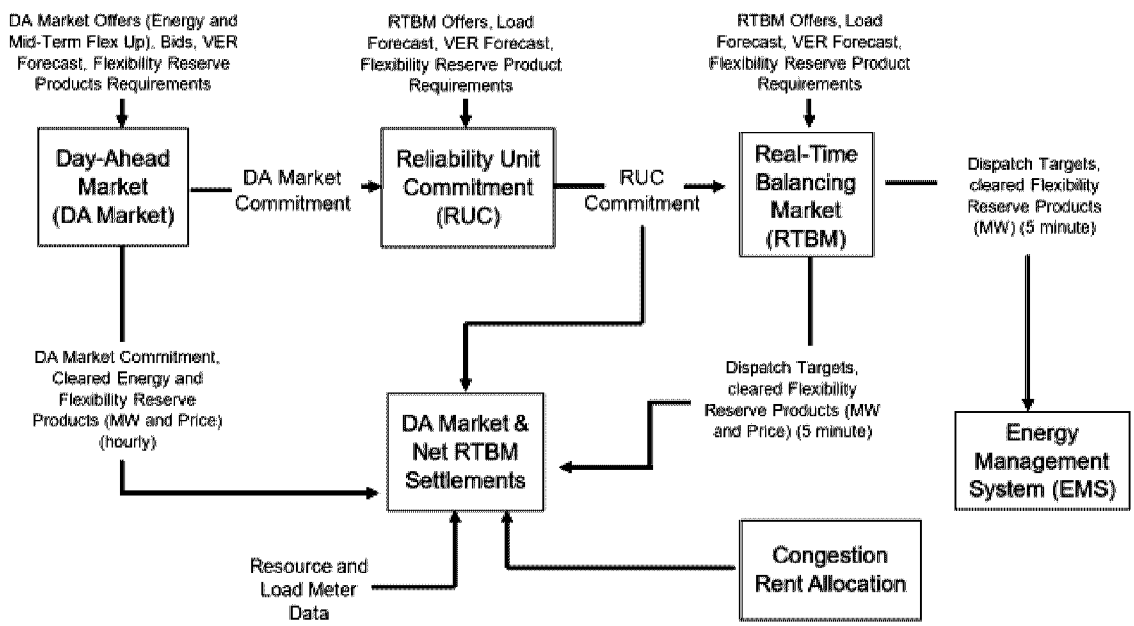


2. Markets+

Markets+ is a centralized day-ahead and real-time unit commitment and dispatch energy and flexibility reserve market. The key features of Markets+ are: (1) a financially binding market in which all cleared supply and demand is settled; (2) a day-ahead market for energy and flexibility reserves products cleared on a least-cost, co-optimized basis respecting the flow-based limitations on the transmission system; (3) day-ahead market cleared energy supply that is paid at the generator settlement location and load charged at the load settlement location; (4) a balancing market operating continuously in real-time to balance the system; (5) firm transmission service holders that are eligible to receive day-ahead congestion rents to provide a congestion hedge between generation and load; (6) transmission service providers and BAAs that retain their roles and responsibilities; (8) SPP as the market operator using the transmission capability made available in Markets+; (9) transmission service used to deliver Markets+ energy that is provided at no cost; and (10) a mechanism to compensate transmission service providers for potential foregone short-term transmission sales resulting from market operations through a "Market Transmission Charge" or "MTU Charge" that will be collected from each market transaction (load, generation, imports and exports).

Both the day-ahead and real-time segments of Markets+ provide participants with the ability to submit offers to sell energy and flexibility reserves, and to submit bids to purchase energy. Energy and flexibility reserve products will be simultaneously optimized in the SCUC and SCED algorithms. Generation offers are prepared based on physical constraints such as minimum load, maximum loads, ramp rates, minimum offline or online times as well as the three-part offer of start-up costs ($/start), running costs ($/hour), and incremental costs ($/MWh). By the close of the day-ahead market, and on an ongoing basis in the real-time market, Markets+ transmission service providers must communicate operational transmission capability and Markets+ Transmission Contributors must communicate their transmission capacity available to the market operator for deriving a market solution utilizing a simultaneous co-optimization methodology. SPP will economically dispatch energy and clear flexibility reserve products across the Markets+ footprint using Markets+ transmission contributors' capacity and transmission service providers' transmission capability less any capacity not available for market use as reflected by Service Flow Constraints ("SFC"). In addition to the initial SFCs, the applicable BAs must update their submitted SFCs to account for transmission capacity opted into the market and opted out of the market. Figure 36 presents and overview of the Markets+ process.

Figure 36[252]
Overview of Markets+ Energy and Flexible Reserve Products



Inputs to the day-ahead market algorithm consist of: (1) day-ahead market resource offers, demand bids, virtual energy offers, and virtual energy bids are submitted by market participants prior to the close of the day-ahead market; (2) through interchange transactions as submitted by market participants and confirmed prior to the close of the day-ahead market; (3) export interchange transaction bids; (4) import interchange transaction offers; (5) BA operating reserve requirements; (6) flexibility reserve products requirements (market-wide and reserve zone min and max); (7) transmission system topology consistent with network model in place for upcoming operating day; (8) scheduled outages (resource and transmission); (9) service flow constraints; (10) market operator load capacity requirements; and (11) local reliability issue commitments.[253]

SPP Markets+ allows market participants to self-schedule resources by submitting minimum and maximum loads coupled with a must run commitment status to reflect the desired scheduled generation. The market participant receives the market price for a self-scheduled resource but is

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252 *See* Market Protocols SPP Markets+ Revision 0 at Exhibit 3-1. The document can be found at: https://www.spp.org/documents/73199/marketsplus%20protocols%20-%20combined%20-%20mpec%20approved%20as%20of%2020250131.pdf.

253 *Id.* at section 4.3.1.1

not eligible for any make-whole payments. Alternatively, a minimum load coupled with must-run status would allow for a generator to respond to prices between minimum load and maximum load.

Markets+ will not procure regulation and contingency reserves. These products will continue to be managed by individual BAs under the terms of their OATTs. Markets+ will procure flexibility reserve products from the portion of a generator's dispatchable range that is reserved for potentially increasing net obligations for future dispatch intervals. Flexibility reserves will accommodate the ramp capability available to address uncertainty in load and generation forecasts. These products pre-position resources with ramp capability to manage net load variations and uncertainties, provide transparent price signals to incent resource flexibility, and allow for fewer pricing excursions that could otherwise arise if system ramping were limited.

B. Resource Adequacy, Resource Sufficiency, Reliability, Resiliency, and Inter-Relationship with WRAP

A core component of the DAMs is the means to ensure overall day-ahead resource sufficiency. These requirements should ensure adequate supply and prevent inappropriate leaning on the capacity of other BAAs. The resource sufficiency programs also need to be able to respond to intra-day differences between day-ahead forecasts and shorter-term horizons before real-time. EDAM does not require any changes to the Companies' integrated resource planning processes or PUCN resource adequacy requirements. Markets+ requires participation in WRAP.[254] With respect to facilitation of WRAP participation by LSEs and transmission customers, FERC has found both DAMs to be interoperable with WRAP.[255]

1. EDAM

a. Resource Sufficiency Evaluation

EDAM's Resource Sufficiency Evaluation ("RSE") ensures that each BAA can meet its own obligations before it engages in transfers with other BAAs.[256] Before the first run of the day-ahead market, the RSE will assess each BAA's demand obligations and supply options to ensure there are sufficient resources to meet forecasted demand, imbalance reserve requirements, and ancillary service obligations.[257] CAISO will provide the results to each BAA as guidance to help them

[254] *See* Markets+ Tariff Part I defining "Resource Adequacy Program" as WRAP and Appendix 3 to Attachment A "Attestation Regarding Resource Adequacy Program and Participation in the Western Resource Adequacy Program (WRAP)".

[255] EDAM Acceptance Order at P 313 (We agree that CAISO's proposed framework is compatible with WRAP). Markets+ Acceptance Order at P. 120 ("[w]e find that SPP's proposed Markets+ Tariff is just and reasonable and not unduly discriminatory or preferential with regards to the use of transmission in Markets+"). FERC noted, "We further expect each prospective Markets+ TSP will explain how its OATT is interoperable with WRAP, including whether, and if so, how opted-in transmission capability can be used to satisfy a market participant's obligation under WRAP to sell surplus energy to a deficient WRAP participant in an operating day." *Id.* at P 121.

[256] CAISO EDAM Filing, Transmittal Letter at 145.

[257] CAISO EDAM Filing, Transmittal Letter at 17. each BA in the EDAM area will submit its demand forecast and variable energy supply forecast to establish its daily demand requirement prior to 9:00 a.m., either by using the CAISO's forecasting system or a direct submission from an approved forecasting provider. CAISO Tariff sections 33.31.1.2.1.1 and 33.31.4. The demand forecast component is the largest component of the RSE, and is a representation of the expected next day demand within the EDAM BAA. The second component, imbalance reserve obligations,

establish resource sufficiency before the final evaluation at around 10:00 a.m., just before the day-ahead market run.[258]

BAAs that pass the final binding EDAM resource sufficiency evaluation will be "pooled" together for the WEIM RSE.[259] BAAs that do not pass the EDAM RSE will be assessed the applicable failure surcharge. If the integrated forward market can satisfy the forecasted needs of the BAA to cure its deficiency, then the BAA will be included in the pool. This pooling approach benefits eligible BAAs by accounting for the diversity benefit of procured imbalance reserves through the day-ahead market. If a BAA does not cure the failure through the integrated forward market, then the BAA area will not be included in the pool, and the BAA will be evaluated individually for purposes of the WEIM RSE.[260]

To accommodate delivered firm energy WSPP Schedule C contracts, CAISO will utilize a registration system to prevent double counting and ensure sufficient resource integrity before classifying such resources or programs as eligible for the EDAM RSE.[261] Emergency supply or load modification programs that inform a BA's next-day operating plan may be accounted for through manual forecast adjustments, consistent with the methodology under the WEIM RSE.[262]

EDAM will enable each BA to utilize a configurable net export transfer constraint to communicate to CAISO the amount of its resources that can be optimized to support EDAM transfers to another BAA.[263] This mechanism enables each BA to control its supply to meet its own needs before assisting others.

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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. And the third component, ancillary services 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. Direct testimony of Anna McKenna at Q&A 25.

258 The CAISO will perform "advisory" runs of the EDAM RSE and provide the results to each balancing authority every 30 minutes between 6:00 a.m. and 9:00 a.m. each day. The CAISO will perform the final binding run of the EDAM RSE at approximately 10:00am Pacific Time. Direct Testimony of Anna McKenna at Q&A 25. In each advisory and binding run, the EDAM RSE application will establish the hourly quantity of upward sufficiency or downward insufficiency for each BA in the EDAM area looking across three components in the day-ahead timeframe: forecasted demand, imbalance reserves, and ancillary services requirements. CAISO Tariff sections 33.31.1.2 and 33.31.1.3. To perform the evaluation, the EDAM RSE application will model an EDAM BA's entire load and supply on a single bus. Direct Testimony of Anna McKenna at Q&A 25. The EDAM RSE application will not reflect a full security constrained economic dispatch because it does not include transmission constraints or calculate resultant power flows. The computation time requires trade-offs between the number and frequency of advisory runs prior to the final binding EDAM RSE and the accuracy of the application itself. Stakeholders ultimately agreed that, while modeling transmission constraints would have some benefits, it would not increase the accuracy of the test sufficiently to justify the significant effort and complexity of implementing such modeling at this time. CAISO EDAM Filing, Transmittal Letter at 151.

259 CAISO Tariff section 33.31.1.4.

260 CAISO EDAM Filing Transmittal Letter at 144.

261 *Id.* at 152.

262 *Id.* at 152; CAISO Tariff at section 33.31.4.1.

263 CAISO Tariff section 33.31.3 (EDAM will include a configurable constraint to permit a BAA in the EDAM Area to enable an hourly limit on the amount of net EDAM Transfer exports, where the total net export EDAM Transfer constraint cannot be reduced below the higher of zero or the transmission service made available to support a net export in the EDAM RSE under Section 33.18.2.1).

The RSE program will penalize BAAs that fail one of the several components of the RSE test and will allocate revenue collected under those surcharges to BAAs that passed the test for that period.[264] There are three types of surcharges: the EDAM RSE On-Peak Upward Failure Insufficiency Surcharge,[265] the EDAM RSE Off-Peak Upward Failure Insufficiency Surcharge,[266] and the EDAM RSE Downward Failure Insufficiency Surcharge.[267] Scheduling coordinators for EDAM entities that fail the EDAM RSE by more than a *de minimis* amount,[268] including failing entities that cured their failure through the IFM, will be allocated the applicable EDAM RSE failure surcharge. The surcharge for failure of the EDAM RSE is intended to be a proxy for the cost of procuring a block of energy from the bilateral market.

The EDAM RSE failure multiplier reflects the severity of the failures, denoted by three tiers. Tier 1 failures are *de minimis* failures and the EDAM RSE failure multiplier will be set to zero. Tier 2 failures are those of a magnitude less than or equal to fifty percent of the entity's upward imbalance reserve requirement and increase the failure multiplier from zero to 1.25. Tier 3 failures are those of a magnitude greater than fifty percent of the entity's upward imbalance reserve requirement and increase the failure multiplier to 2.[269] 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 thirty-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.[270]

b. Imbalance Reserves

The Day-Ahead Market enhancement proposal approved by FERC contained two new day-ahead market bi-directional products that will be procured on a co-optimized basis with energy: (1) Imbalance Reserves and (2) Reliability Capacity.[271] Imbalance Reserves are a flexible reserve product designed to reduce 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-

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264 CAISO Tariff sections 33.11.2.2.1, 33.11.2.2.2, and 33.11.2.2.3.

265 The EDAM RSE On-Peak Upward Failure Insufficiency Surcharge will be calculated as the product of three values: (1) the failure quantity, (2) the applicable surcharge price, and (3) a scaled adder for severe and persistent failures. The quantity is based on the failing entity's highest deficiency during the sixteen on-peak hours. The surcharge price is the applicable trading hub price (e.g., Mid-Columbia or Palo-Verde). 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.

266 The EDAM RSE Off-Peak Upward Failure Insufficiency Surcharge will also be the product of three values. However, unlike the on-peak charge, which applies in each of the sixteen on-peak hours, the EDAM RSE Off-Peak Upward Failure Insufficiency Surcharge applies only in the failed hour.

267 CAISO Tariff sections 33.11.2 and 33.31.1.5. CAISO will calculated the Downward Failure Insufficiency Surcharge as the product of two values to reflect: (1) the failure quantity and (2) the applicable surcharge price (based on marginal energy cost of the failing BAA). CAISO Tariff section, 33.11.2.1.3.

268 Defined as the higher of 10 MW or an amount less than or equal to one percent of the BAA's upward imbalance reserve requirement for the hour. CAISO Tariff section 33.31.1.5.1(i).

269 CAISO Tariff Appendix A definition of "EDAM RSE Failure Multiplier".

270 CAISO Tariff Appendix A definition of "EDAM RSE Failure Scaling Factor". 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 directly 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. Direct Testimony of Anna McKenna at Q&A 27.

271 CAISO Filing Letter in Docket No. ER23-2686 at 2.

time ramping needs not covered by hourly day-ahead market schedules.[272] Imbalance Reserves will ensure the IFM schedules sufficient dispatch capability to meet net load imbalances between the day-ahead and real-time markets.[273] 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.[274] Co-optimized procurement of Imbalance Reserves improves unit commitment, enhances market efficiency, improves CAISO's ability to effectively meet real-time operational needs, and increases the feasibility of IFM exports.[275]

CAISO will set the procurement targets for Imbalance Reserves Up and Imbalance Reserves Down based on an uncertainty range above and below day-ahead cleared physical supply.[276] The net load imbalance forecast uncertainty range will be based on the historical uncertainty in the day-ahead load, solar, and wind forecasts.[277] 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.[278]

The demand curve for Imbalance Reserves will have a maximum willingness to pay of $55/MWh.[279] That is, if insufficient Imbalance Reserves offers at or below $55/MWh are available to meet the minimum procurement requirement, CAISO will relax the procurement constraint.[280] CAISO will procure Imbalance Reserves on a nodal basis based on deployment scenarios similar to those CAISO currently uses to procure the Flexible Ramping Product in the WEIM.[281] Although, CAISO does not propose to enforce all transmission constraints in the deployment scenarios.[282] Instead, CAISO will employ a flexible activation/deactivation of individual transmission constraints in deployment scenarios in response to optimization performance, market performance, or operational experience.[283]

CAISO will also implement a tunable parameter, the deployment factor, to control the proportion of Imbalance Reserves awards that must be deliverable in the deployment scenarios.[284] The deployment factor will determine how much of the Imbalance Reserves procured would have to be feasible in the scenario; that is, the optimization will still aim to procure the minimum required

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272 *Id.* at 47.
273 *Id.*
274 *Id.* at 100.
275 *Id.* at 54. *See also*, Direct Testimony of Anna McKenna at Q&A 28.
276 To recognize the diversity benefit of participating in EDAM, the CAISO will establish daily imbalance reserve requirements for each BAA that account for the breadth and depth of the broader geographic EDAM footprint and the supply options made available therein. Each balancing authority's imbalance reserve requirements will be fixed at 9:00 a.m., thereby providing entities with certainty as to their resource sufficiency obligations that can be addressed prior to the final binding EDAM RSE at 10:00 a.m. CAISO Filing Letter in Docket No. ER23-2686 at 145 - 146.
277 Direct Testimony of Anna McKenna at Q&A 28.
278 CAISO Filing Letter in Docket No. ER23-2686 at 69.
279 CAISO Filing Letter in Docket No. ER23-2686 at 69; CAISO Tariff section 31.3.1.6.2
280 *Id.* at 70.
281 EDAM Acceptance Order at P 63.
282 *Id.*
283 *Id.*
284 EDAM Acceptance Order at P 64.

quantity of Imbalance Reserves, but the deployment factor will allow the optimization to procure a certain proportion that is not deliverable. CAISO proposes to initially set the deployment factor for both the up and down deployment scenarios at 100 percent, meaning the optimization would ensure all Imbalance Reserves are deliverable in the deployment scenarios.[285] Resources will be subject to unavailability charges if a resource is unavailable to provide their day-ahead Imbalance Reserves award.[286]

The Reliability Capacity product will be procured to meet positive or negative differences between cleared physical supply in the IFM and the day-ahead net load forecast.[287] Currently, the RUC process serves this function, in part, but only procures capacity in the upward direction. With the proposed bi-directional Reliability Capacity product, CAISO will be able to procure additional capacity (upward) or decommit capacity (downward) in the RUC process.[288] Like Imbalance Reserves, a resource receiving a Reliability Capacity award is obligated to make economic energy bids in the real-time market for the quantity it was awarded. Both products are co-optimized in the IFM.

CAISO will procure both Reliability Capacity Up and Down. Reliability Capacity Up is a new name for the existing RUC capacity awards.[289] Under the proposal, Reliability Capacity will be procured to meet positive or negative differences between cleared physical supply in the IFM and the load forecast.[290] The new Reliability Capacity Down product should reduce the need for manual operator intervention in many cases of oversupply.[291]

c. Assistance Energy Product

WEIM assistance energy transfers will continue to be available as a tool to cure real-time insufficiency.[292] Section 29.34(m) of the CAISO Tariff "freezes" imports into an EIM Entity that fails the resource sufficiency. In Docket No. ER23-1534, FERC approved a means for a BA to voluntarily elect to receive assistance energy transfers through the WEIM for an additional cost called the EIM Assistance Energy Transfer Surcharge. Revenues from this surcharge are allocated to all of the other BAAs in the EIM area that have net exports and passed the upward capacity and flexibility tests in the resource sufficiency evaluation. The surcharge is set at the level of CAISO's

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285 *Id.*
286 *Id.* at P 66.
287 *Id.* at P 193. 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.
288 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. Direct Testimony of Anna McKenna at Q&A 29.
289 EDAM Acceptance Order at P 64 at P 193.
290 CAISO Acceptance Order at P 193.
291 *Id.*
292 *See* CAISO Tariff section 29.34(n)(3).

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: (i) the quantity of the upward capacity test or the upward flexibility test insufficiency for the EIM BAA, whichever is higher; or (ii) the quantity of net EIM transfers into an EIM BAA, excluding base transfers identified on all after-the-fact E-Tags. Revenue from the assistance energy transfers are allocated to the entities that passed the resource sufficiency evaluation and are supplying the assistance energy.[293] Assistance Energy Transfers serve as a useful insurance policy for a BAA that experiences unexpected or extreme events.[294]

2. Markets+

There are three elements associated with the Markets+ resource adequacy and resource sufficiency requirements: (1) all participating "Load Responsible Entities"("LREs")[295] must participate in WRAP, (2) LSEs must make a daily amount of resource capacity available for commitment throughout the Markets+ operations horizon, and (3) for purposes of relieving a capacity shortage, market participants must, subject to limited exceptions, identify and make available additional supply that was not otherwise offered to Markets+.[296]

The day-ahead must offer requirement includes the following:[297] (1) the hourly mid-term load forecast that is attributed to the market participant;[298] (2) the flexibility reserve product obligation representing the short-term flex up and mid-term flex up obligation amount; (3) the WRAP operations program hourly holdback;[299] (4) the net position (the sum of the market participant's

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293 Direct Testimony of Anna McKenna at Q&A 30.

294 CAISO recently filed to make Assistance Energy Transfers a permanent feature of the market in FERC Docket No.ER25-3491. NV Energy supported the request.

295 The Markets+ Tariff defines "Load Responsible Entity" as a "Market Participant with registered load in Markets+. Markets+ Tariff, Part I, Section 1 (Definition of Load Responsible Entity). Under the WRAP Tariff, a "Load Responsible Entity is:

> is an entity that (i) owns, controls, purchases and/or sells resource adequacy supply, or is a Federal Power Marketing Administration or an International Power Marketing Entity, and (ii) has full authority and capability, either through statute, rule, contract, or otherwise, to: (a) submit capacity and system load data to the WRAP Program Operator at all hours; (b) submit Interchange Schedules within the WRAP Region that are prepared in accordance with all NERC and WECC requirements, including providing E-Tags for all applicable energy delivery transactions pursuant to WECC practices and as required by the rules of the WRAP Operations Program; (c) procure and reserve transmission service rights in support of the requirements of the WRAP Forward Showing Program and Operations Program; and (d) track and bilaterally settle holdback and delivery transactions.
> Subject to the above-mentioned criteria, an LRE may be a load serving entity, may act as an agent of a load serving entity or multiple load serving entities, or may otherwise be responsible for meeting LRE obligations under the WRAP.

WRAP Tariff at Section 1 Definitions. The WRAP Tariff can be accessed at: https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf.

296 Markets+ Acceptance Order at P 284.

297 Markets+ Protocols at 4.2.1.1.

298 SPP will develop short-term load forecasts and mid-term load forecasts for each forecast area. The short-term load forecast produces values on a rolling 5-minute basis for at least the next 3 hours. The mid-term load forecast produces hourly values for the next hour through seven (7) days. Markets+ Protocols at section 4.1.2.1.

299 In the WRAP operations program, participants with excess capacity share that capacity with participants that are short on capacity. Participants who fail to comply with binding aspects of the operations program are subject to potential delivery failure charges in the WRAP. The adjustment to the Markets+ must offer amount would either be a

power purchases and sales); and (5) the market storage resources self-charge schedule represented hourly in resource offer, if any. The must offer obligation can be met by self-schedule energy only, a combination of self-schedule energy and economic offer range, or economic offer range only, by submitting resource offers with a commitment status of market, self, or reliability must run in the day-ahead market.[300]

The WRAP has a binding summer season (June 1 to September 15) and a binding winter season (November 1 to March 15).[301] During these binding periods, the Markets+ must offer requirement is capped at the WRAP requirement.[302] In the forward showing program, WRAP participants' peak load is forecasted and a planning reserve margin ("PRM") is established based on a probabilistic analysis to satisfy a loss of load expectation of not more than one event-day in ten years.[303] As part of the forward showing program, WRAP participants demonstrate in advance that they have sufficient qualified capacity resources (and supporting transmission) to serve their peak load and share of the PRM.[304] WRAP participants who fail to comply with binding aspects of the forward showing program are subject to a significant deficiency charge.[305]

A "Day-Ahead Must Offer Penalty" is a charge to a market participant that does not satisfy the day-ahead must offer obligation.[306] SPP will distribute any collected Day-Ahead Must Offer

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positive value to represent an increase to a market participant's must offer obligation, or a market participant receiving a WRAP holdback would include the MW value as a negative value to represent a decrease to the market participant's must offer obligation.

300 Markets+ Protocols at section 4.2.1.1.

301 The WRAP Tariff defines "Binding Season" as "The Summer Season or the Winter Season," which are defined as "A period of time that commences on June 1 of a Year and terminates on September 15 of the same Year," and "A period of time that commences on November 1 of a Year and terminates on March 15 of the immediately following year," respectively. See WRAP Tariff, Part 1, Section 1 (Definition of Binding Season).

302 A market participant's forward showing capacity requirement is the amount of capacity required for the market participant to demonstrate adequacy for the resource adequacy program for each month during a binding season. The monthly value adjusted down by the contingent reserve requirement that is part of the WRAP sharing calculation, serves as the maximum quantity for the relevant operating day, within the corresponding operating month. If a market participant does not meet the forward showing capacity requirement the maximum quantity for the relevant operating day within the corresponding operating month is adjusted down by the deficit capacity amount. Markets+ Protocols at section 4.2.1.1. "SPP anticipates that requiring WRAP participation for Market Participants with load registered in Markets+ will support reliability of the Markets+ Footprint by making sufficient capacity resources available in the operating timeframe of Markets+." SPP Filing Letter in Docket No. ER24-1658 at 35.

303 Northwest Power Pool D/B/A Western Power Pool, Western Resource Adequacy Program Tariff ("WRAP Tariff"), Part II, Section 16. The Forward Showing Program requires WRAP participants to show, seven months in advance of each WRAP winter and summer season, that they have sufficient capacity to meet a required planning reserve margin and have reserved at least 75% of the transmission necessary to deliver energy from that capacity to their load. Markets+ Acceptance Order at P 5.

304 *Id.* at Part II, Section 16.

305 The Deficiency Charge is the product of the Monthly Deficiency times a Cost of New Entry ("CONE") value and a CONE Factor. WRAP Tariff at section 17.2. To preserve a strong incentive for a participant to minimize the number of its deficiencies over a season, the monthly based CONE value is doubled (i.e., multiplied by 200%). *Id.* at Tariff sections 17.2.2 & 17.2.4. The Tariff defines the CONE value as the annual capital and fixed operating costs to install a hypothetical new peaking gas plant. *Id.* at section 17.2.5

306 Markets+ Tariff, Attachment A, Section 9.2.16. The Day-Ahead must offer obligation is calculated in accordance with Attachment A, Section 5.1.1(A) and 5.1.1(B). The Day-Ahead Must Offer Penalty is calculated in accordance with Attachment A, Section 5.1.1(C).

Penalty for an operating hour to market participants who are compliant for that operating hour, weighted by resource capacity in excess of the must offer obligation for that operating hour.[307]

SPP will begin the Day-Ahead RUC process no earlier than forty-five minutes following the posting of the day-ahead market results to assess capacity adequacy during the day-ahead period and the remainder of the current operating day.[308] The results will be posted no later than two and a half hours later. There is also an intra-day RUC process performed at least every four hours.[309] SPP will assess capacity adequacy during the operating day and commit Resources as needed.

Markets+ includes a "reliability backstop" mechanism in the RUC process, which requires market participants to identify additional supply that, while not offered in the Day-Ahead Market, is available for RUC commitment if necessary.[310] SPP proposes that it will use demand curves to reflect scarcity prices in both the day-ahead market and RTBM during times of flexibility reserve product shortages, either on a market-wide or reserve zone basis. SPP proposes to use downward-sloping stepped demand curves with a maximum price based on the lesser of the average cost of committing a fast-start resource to cure the ramp deficiency or $1,000/MWh, and with a minimum scarcity price of $10/MWh for short-term flex up and mid-term flex up and $0/MWh for short-term flex down. SPP proposes that the demand curves contain six equal price increments depending on the severity of the shortage and will be updated every month based on the data from the last three months, similar to the demand curves for the ramp capability and uncertainty products in SPP's Integrated Marketplace.[311]

In Real-Time, the must-offer obligation includes: (1) hourly cleared day-ahead market energy schedules, (2) hourly day-ahead flexibility reserve product awards, hourly RUC awards, hourly WRAP operations program holdbacks, hourly net position changes, and hourly market storage resource self-charge schedules.[312] A corresponding "Real-Time Must Offer Penalty" will be charged to a market participant that does not satisfy the real-time must offer obligation.[313]

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307 *Id.* at Attachment A, Section 9.2.17.

308 Markets+ Tariff, Attachment A, Section 2.2

309 Markets+ Protocols at section 4.4.1.

310 Markets+ Tariff Attachment A, Section 2.2.2(2)(b). For any future hours in which the market operator anticipates a capacity shortage, the market operator will notify market participants and participating BAs identifying the hours in which resources that were in "Not Available" commitment status are expected to be required and the hours in which self-schedule uncommitted export interchange transactions are expected to be curtailed. Following this notification, market participants are required to confirm with the market operator that the resources in "Not Available" commitment status selected as part of the DA RUC execution are available to be committed. Such availability will be subject to the market participant's contractual rights and obligations and any operational limitations related to the resources in "Not Available" commitment status as determined by the market participant and/or participating BA. Once this verification is complete, if the market operator commits such resources, they will be considered as "Market" commitment status for settlement purposes. Markets+ Protocol at section 4.4.1.3.

311 Markets+ Acceptance Order at P 278, citing Markets+ Tariff at Attachment A, section 3.6.1.

312 Markets+ Protocols section 4.2.1.2.

313 Attachment A, Section 9.3.25. SPP will distribute any collected Real-Time must offer penalties for an Operating Hour to Market Participants that are compliant with the Real-Time must offer obligation for that Operating Hour, weighted by Resource capacity in excess of the must offer obligation for that Operating Hour. *Id.* at Attachment A, Section 9.3.26.

3. NV Energy Evaluation

Both DAMs utilize forecasts to establish must offer requirements. To account for intra-day variations in load and variable energy resource outputs, EDAM includes an imbalance reserve, and Markets+ has flexibility reserve products.[314] However, Markets+ caps the day-ahead must offer obligation at the WRAP planning reserve requirements during the peak summer and winter binding seasons. [315] Stated another way, the seven-month ahead WRAP planning reserve margins are used ***to lower participants offer obligations***, even if the day-ahead forecast and flexibility reserve products call for a higher amount. Accordingly, NV Energy has greater confidence that EDAM's resource sufficiency evaluation will promote day-ahead market run participation by the necessary resources and to handle intra-day uncertainty. This helps promote stable market prices while ensuring there is enough supply to maintain reliability.

Both DAMs have a post-market run "RUC" process (EDAM's residual unit commitment and Markets+' s reliability unit commitment). NV Energy is concerned that the lower must offer obligations in the peak seasons, combined with the disaggregated zones with limited transmission interconnectivity will trigger high shortage prices in Markets+. NV Energy is a load-serving entity with a net-short position. Many elements of the Markets+ design appear to favor entities with long supply positions. These include fast-start pricing and the higher conduct and impact thresholds used to mitigate the exercise of market power. These design elements increase LMPs and associated costs to loads.

Additionally, Markets+ converts the voluntary WRAP into a mandatory requirement. As discussed in the Companies ESP Update in Docket No. 25-08027. NV Energy has determined it is not in customers' interest to participate in WRAP.[316] The potential to incur extreme penalties under the WRAP combined with the uncertain planning reserve margins ("PRMs"),[317] significant amount of new NV Energy capacity being brought on line with construction schedules being challenged by supply chain and tariff issues, potentially large shifts in load forecasts, and the potential limited

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314 There are three flexibility reserve products in Markets+: (1) short-term flex up; (2) short-term flex down; and (3) mid-term flex up. These products are analogous to the ramp capability and uncertainty reserve products in SPP's Integrated Marketplace. *See* SPP's Filing Letter in Docket No. ER24-1658 at 54.

315 SPP states "that due to a limited must-offer obligation that exists within WRAP, participants may elect not to offer all available resource capacity for Markets+ commitment and dispatch while still satisfying the must-offer obligation." Markets+ Acceptance Order at note 416 quoting SPP's Filing Letter in Docket No. ER24-1658 at 37.

316 Direct testimony of Lindsey Schlekeway in the Update Docket 25-08 at 3 (Q&A 7) ("the Companies have made the decision to withdraw from the WRAP due to inherent risks that outweigh the program's current benefits for both the Companies and their customers").

317 Further complicating program compliance is the volatility of the PRMs. Year-over-year changes have ranged from minor adjustments to swings as large as 10%. For a monthly peak load of 10,000 MW, this could translate to an unexpected need for 1,000 MW of additional capacity which is an unrealistic burden within such a short timeframe. This level of variability is too large to occur on such a short timeframe leaving little to no time for a participant to react and procure the additional supply. Direct testimony of Lindsey Schlekeway in the Update Docket 25-08 at 3-4 (Q&A 8).

benefits associated with the WRAP operations program,[318] especially in its current zonal structure,[319] were components of that decision.[320]

Moreover, NV Energy would have concerns about turning voluntary WRAP participation by OATT customers into a mandatory requirement. The amount of capacity available on a seven-month ahead basis, supported by firm transmission is a limited commodity in the West. There is the potential exercise of market power forcing commercially unreasonable prices equal to or just below the significant WRAP penalties. With respect to Markets+, NV Energy has concerns that the smaller zones with limited interconnectivity can increase the potential for uncompetitive conditions. As noted previously, there is also the question of the market monitor's ability to fully and effectively oversee the WRAP program. As a voluntary program, FERC did not require a market monitor for the WRAP. There is only an "independent evaluator" to conduct an annual review of WRAP's performance.[321] Indeed, the Western Power Pool continues to emphasize the voluntary nature of WRAP,

> The WRAP is a first-of-its-kind voluntary resource adequacy planning and compliance framework, developed by industry participants and other entities outside of an organized [FERC]-approved regional transmission organization or independent system operator. Participants voluntarily choose to execute the Western Resource Adequacy Program Agreement ("WRAPA"), and, once committed by that agreement, are obligated to comply with WRAP requirements or face charges for noncompliance. The key word is voluntarily. Participants must choose whether to execute the WRAPA not only to obtain the benefits of the WRAP,

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318 WRAP is untested and the Companies question whether or not holdback will be required or will be available if a heat wave occurs and Nevada needs to call on the program to supply holdback. The concept of holding back capacity for program participants has been the perceived benefit such that there is an agreement between the program members to supply energy if a participant has surplus to another participant that might be deficient. As implemented, the program models the participants at two subregions separating the southwest from the northwest participants. Accordingly. Holdbacks may be of limited value if weather events occur over large areas of the desert southwest. Direct Testimony of Lindsey Schlekeway in the Update Docket 25-08 at 8-9 (Q&A 12).

319 The program does not model the participants at their respective market participation, rather WRAP models the participants in two separate sub regions with limited transmission connectivity between them. This modeling approach does not consider the vast majority of transmission that has been proven to be used and available through the WEIM. It is notable that the program has strict firm transmission requirements and that the ATC that is determined in real-time is not firm enough to qualify for the program rules. However, there has been sufficiently more transmission capability that has occurred through market participation than the 500 MW assumed by the program between the participants that will remain in the WEIM, have either signed an EDAM implementation agreement, or stated a position of leaning towards EDAM. Therefore, it is the Companies perspective that the current WRAP program undervalues this transmission capability which eliminates any major diversity benefit from occurring in the forward showing resulting in higher PRMs. Direct Testimony of Lindsey Schlekeway in the Update Docket 25-08 at 7 to 8 (Q&A 11).

320 Direct Testimony of Lindsey Schlekeway in the Update Docket 25-08 at 3 to 9 (Q&As 7 to 12).

321 *NW. Power Pool*, 182 FERC ¶ 61,063 at 12 (2023).

> WPP also explains that it will engage an Independent Evaluator to conduct an annual review of WRAP's performance. However, WPP states that, since WRAP is not an organized market, the Independent Evaluator will not function as a typical market monitor; instead, the Independent Evaluator will analyze prior-year program performance, accounting and settlement, and program design. According to WPP, the Independent Evaluator will make recommendations for improvements to WRAP design but will not monitor individual Participants or day-to-day operations and will not have decision-making authority.

> but also to undertake the obligations, including demonstrating sufficient capacity to serve load and a WPP-established Planning Reserve Margin ("PRM"), or face deficiency charges for failure to demonstrate sufficient capacity.[322]

With Markets+, WRAP is no longer voluntary.[323] ***It becomes a mandatory capacity market outside the purview of any market monitor*** as it is a separate program under a separate tariff, with a separate governance process overseen by a separate board.[324] The WRAP forward showing program requires WRAP participants to demonstrate, seven months in advance of each WRAP winter and summer season, that they have sufficient capacity to meet a planning reserve margin and have reserved at least 75 percent of the transmission necessary to deliver energy from that capacity to their load.[325] There may be a limited number of entities who are both long in capacity and have firm delivery rights over the scarce transmission available in the West.

While SPP engages in a bit of sophistry noting that no "loads" are required to join WRAP only "load serving entities,"[326] FERC's Order on Markets+ is more on point,

> With regard to NTUA's concerns about WRAP being unproven or not yet implemented, we note that WRAP's non-binding test period and transition period is intended to assist potential participants by allowing them to better prepare before WRAP becomes binding and fully implemented and, indeed, to help avoid potential non-compliance penalties and operational costs in the future. We disagree with NTUA that WRAP will result in undue complexity (and operational costs) for Markets+. We find that the proposal includes the tariff provisions necessary to implement the requirement that load-serving participants in Markets+ participate in WRAP. ***We also note that participation in Markets+ is voluntary, and individual entities may evaluate on their own whether the rules are unduly complex and will make their own determination about whether to join.***[327]

Accordingly, FERC is clear – if you have concerns about elements in a mandatory WRAP program, don't join Markets+ — although the choice is at the BA level and not with individual LSEs.

As discussed in the Direct Testimony of Lindsey Schlekeway, NV Energy has had concerns with CAISO's proposed design of the imbalance reserve product.[328] There have been and will continue to be improvements in the RSE, under the oversight of the WEM Governing Body's primary authority. CAISO has worked with the Resource Optimization department to better understand the

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322 Western Power Pool's November 25, 2024, Filing Letter in FERC Docket No. ER25-559 at 1-2.

323 See SPP, Proposed Markets+ Tariff, attach. A, § 6.10 (Load Responsible Entity Obligation) (0.0.0). SPP's Tariff defines "Load Responsible Entity" as "Market Participant with registered load in Markets+". SPP, Proposed Markets+ Tariff, pt. I, § 1.L (Definitions) (0.0.0) (defining Load Responsible Entity).

324 Markets+ Tariff Attachment C, section 4.1 "The Market Monitor will not monitor bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by SPP, except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these unmonitored markets."

325 *NW. Power Pool*, 182 FERC ¶ 61,063 at PP 53-56 (2023).

326 *See* SPP's Deficiency Answer at 46-47.

327 Markets+ Acceptance Order at P 301 (emphasis added).

328 Direct Testimony of Lindsey Schlekeway at Q&A 25.

relationship of the proposed imbalance reserves to the Companies' existing management of reserves for intra-day uncertainty.[329] NV Energy and the other LSEs in CAISO and the other EDAM Entity footprints will continue to monitor and improve the imbalance reserve product. Markets+ may well identify the need for and develop its own imbalance reserve product. Accordingly, NV Energy has greater confidence in the EDAM resource sufficiency approach, combined with the footprint and interconnectivity, to maintain reliability at just and reasonable prices.

C. Transmission Availability and Cost Recovery

By maintaining separate OATT service under separate tariffs, the DAM options in the West introduce additional challenges from the RTO tariff that have combined transmission service requests and market operations into a single offering. The objective is to maximize the amount of transmission available to the market and avoid creating "phantom congestion" where valuable transmission capacity is unscheduled by a transmission customer but not utilized in the market dispatch.

Under both DAM options, NV Energy would continue its role as an OATT transmission service provider offering both firm and non-firm service. Requests for new or additional transmission service will be studied and granted in the same manner as today. Revenue recovery will continue through the same OATT schedules. Neither DAM modifies OATT curtailment priorities.[330]

As the transmission is made available to the DAM on both day-ahead and real-time basis for use in the market without any additional OATT transmission reservation charge, there is the potential for reduction in the OATT transmission provider's short-term firm and non-firm revenue as potential bilateral transactions become market bids. Overall, this reduction in friction and optimized use of existing facilities should produce significant production cost benefits. Nevertheless, both DAMs recognize this potential for lost transmission revenue credits and provide a mechanism to prevent cost shifts by a means of make-whole recovery.

1. Transmission Availability

a. EDAM

Under the EDAM design, a participating BA will provide information to CAISO regarding the amount of transmission capacity available prior to the start of the day-ahead market. This allows

[329] NV Energy's day-ahead desk operator uses an uncertainty reserve calculator developed in accordance with Energy and Environmental Economics to calculate additional flex reserves that are required for VER uncertainty. *See* Technical Appendix 2 at 20 (Utilicast Gap Assessment).

[330] Under NV Energy's FERC-approved OATT there is a distinction between transmission curtailment and resource insufficiency. Transmission curtailment is a reduction in non-firm or firm transmission service in response to a transmission system outage or derate. Non-firm schedules are curtailed first. If the transmission de-rate makes it impossible to accommodate all firm schedules, there is a *pro rata* reduction of all the firm schedules that can alleviate the problem. NV Energy OATT at sections 13.6, 14.7, and 33.5. On the other hand, if a network customer, including NV Energy on behalf of native load, has not scheduled and delivered sufficient resources to cover their load, and the shortage is impacting the reliability of the BAA, that customer is directed to immediately implement their Transmission Reduction Plan in accordance with their Network Operating Agreement.

the EDAM to utilize all transmission capacity available to it, including any unsold firm transmission capability, while honoring existing transmission rights and legacy transmission contracts. The EDAM framework will make all unused (firm ATC) and unscheduled capacity (non-firm ATC) available for market optimization through the tariff of the EDAM Entity.[331] 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 NITS. Transmission between BAA participating in EDAM will be available to support the transfer of energy, imbalance reserves and reliability capacity within three categories of transmission.

The first category of transmission available for transfers is the BA's external supply resources needed to support its day-ahead resource sufficiency evaluation.[332] A BA that has LSEs with contracted supply in another BAA participating in EDAM will be supported by a transfer system resource. Prior to the day-ahead market, the BA will communicate to the CAISO the transmission capability available at each of its internal interties that will be available in the day-ahead market and support a transfer at that intertie location.[333] These transfers support the EDAM resource sufficiency evaluation and the resulting diversity benefit that result from the transfer of energy and capacity in the day-ahead market.

The second category of transmission is transmission customer point-to-point rights.[334] 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 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);[335] or (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

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331 CAISO EDAM Filing in FERC Docket No. ER23-2686, Transmittal Letter at 14.

332 CAISO Tariff section 33.18.2.1.

333 The LSE must also procure firm, conditional firm or network integration transmission service to deliver the supply to its BAA (CAISO Tariff section 33.18.2.1). With respect to the CAISO BAA, this would include any procurement or reservation of available transfer capability to deliver the supply to its BAA (CAISO Tariff section 33.18.4).

334 CAISO Tariff, section 33.18.2.2.

335 The Scheduling Coordinator for a transmission customer of an EDAM Transmission Service Provider, EDAM Legacy Contract or EDAM Transmission Ownership Right must notify the CAISO and the EDAM Transmission Service Provider prior to 9:00 a.m. the morning of the Day-Ahead Market if it intends to release its long-term and monthly firm and conditional firm point-to-point registered transmission service rights across an EDAM Internal Intertie. The Scheduling Coordinator representing the transmission rights may determine, on a daily basis, whether to make the full amount or only a portion of its registered transmission service rights available for EDAM Transfers for that day only or a longer timeframe, provided such release is consistent with the registered transmission rights and the EDAM Transmission Service Provider tariff. Released transmission service rights cannot be reclaimed or scheduled for the duration of the trade date for which they have been released. The EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider will ensure that information on such released transmission service rights is communicated to the CAISO for association with an EDAM Transfer System Resource. The released transmission capacity utilized by the Day-Ahead Market will be settled by the CAISO with the Scheduling Coordinator for the transmission rights. CAISO Tariff, Section 33.18.2.2.2.

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.[336]

The third category of transmission considered in the extended day-ahead market is the unsold (firm) ATC available at transfer locations prior to the day-ahead market.[337] The EDAM Entity Scheduling Coordinator will determine the amount of unsold firm ATC at an EDAM Internal Intertie prior to 10:00 a.m. on the morning of the Day-Ahead Market, accounting for reserve sharing group obligations or other specific circumstances and arrangements as provided in the EDAM Transmission Service Provider's OATT.[338] The unsold transmission capability as communicated by the EDAM Entity will be available for EDAM transfers.

The market will honor firm OATT rights with a high scheduling priority when such rights are registered and bid-in as a balanced self-schedule.[339] As explained in CAISO's EDAM filing, "[a] transmission customer that submits a self-schedule before the start of the day-ahead market will be assigned a higher market clearing scheduling priority to allow these transactions to clear ahead of other self-schedules and economic bids."[340] The high scheduling priority afforded to OATT

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336 CAISO EDAM Filing Transmittal Letter at 14-15; CAISO Tariff, section 33.18.2.2.

337 CAISO Tariff, section 33.18.2.3. As with the other categories of transmission considered by the day-ahead market, transmission service providers make unsold firm available transmission capability on interfaces available to the market only at the interfaces between two BAAs participating in EDAM. After the market close of the day-ahead market through to the publication of day-ahead market results, the OATT transmission service provider cannot make further sales. After the publication of day-ahead market results, the CAISO will produce a report identifying the amount of unsold transmission capability the day-ahead market optimized, so the transmission service provider can resume sales of the transmission after the day-ahead market results are published. CAISO EDAM Transmittal Letter at 134.

338 In accordance with NERC Standard MOD-008-1, NV Energy maintains a Transmission Reliability Margin ("TRM") to facilitate its obligations under the Northwest Power Pool's Reserve Sharing Agreement. Paths capable of receiving reserves are in both the Northern and Southern sub-systems, The TRM split is as follows:

Table 8---TRM for Reserves Allocation

TRM Allocation	TRM MW
Total TRM	375
Northern Allocation	175
Southern Allocation	200

The Companies' Transmission Reliability Margin Implementation Document can be found on the NV Energy OASIS at:
https://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/1512_-_Transmission_Reliability_Margin_Implementation_Document_TRMID_2022.pdf.

339 CAISO Tariff section 33.18.2.2.3. The market will honor firm OATT rights with a high scheduling priority when such rights are registered through NV Energy and bid-in as a balanced self-schedule. As explained in the CAISO filing, "[a] transmission customer that submits a self-schedule before the start of the day-ahead market will be assigned a higher market clearing scheduling priority to allow these transactions to clear ahead of other self-schedules and economic bids." CAISO EDAM Filing, Transmittal Letter at 4. The high scheduling priority afforded to OATT service means that the market algorithm will redispatch all economic bids and non-OATT self-schedules before disrupting an OATT schedule. This scheduling priority will provide OATT customers with a high degree of confidence in the physical flow of their OATT schedules.

340 CAISO EDAM Filing, Transmittal Letter at 4. The 10:00 a.m. submission deadline is a key element of EDAM and allows the day-ahead market to identify the volume of transfers between BAAs and ensure EDAM BAAs can serve load reliably through the market.

service means that the market algorithm will redispatch all economic bids and non-OATT self-schedules before disrupting an OATT schedule. This scheduling priority will provide OATT customers with a high degree of confidence in the physical flow of their OATT schedules.[341]

Under the FERC-approved EDAM framework, the CAISO will prioritize intra-day scheduling changes on firm transmission service equal with cleared day-ahead schedules.[342] If directed by an EDAM Transmission Service Provider; however, the CAISO will grant some intra-day self-schedules priority in the real-time market over other real-time and day-ahead schedules.[343] The CAISO explained to FERC that this provision aimed primarily to facilitate interoperability with the WRAP.[344] As FERC explained:

> Under CAISO's proposal, 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 if practicable. Specifically, CAISO states that EDAM will attempt to accommodate any intra-day schedule changes via redispatch and if there is an infeasibility, CAISO will notify the EDAM Entity, which is then responsible for resolving the infeasibility through its OATT procedures.[345]

In the EDAM Acceptance Order, FERC considered comments expressing concerns about the potential effects of the EDAM on the WRAP. FERC "agree[d] that CAISO's proposed framework is compatible with WRAP" and found 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."[346]

Recognizing the need to allow flexibility for EDAM Entities to accommodate the unique circumstances around certain physical assets and/or contractual rights, the CAISO Tariff also gives the EDAM Entity discretion to hold back ("carve out") certain transmission from the market.[347] In

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341 With respect to use of CRN, FERC has stated:

> We recognize that this extra step in which the EDAM Entity would need to inform CAISO that a firm transmission customer has made an intra-day schedule change with a higher priority than EDAM transfers may necessitate some changes to the deadlines in an EDAM Entity's OATT to ensure that it would be able to meet EDAM's deadlines. We note that the Commission has previously accepted changes to *pro forma* OATT deadlines proposed by WEIM Entities to facilitate their participation in the WEIM.

EDAM Acceptance Order at P 312.

342 CAISO Tariff, 33.18.2.2.3. As recognized by FERC, such scheduling changes will be responsible for any resulting market impacts. CAISO EDAM Order, 185 FERC ¶ 61,210 at P 310.

343 CAISO Tariff, 33.18.2.2.3.

344 EDAM Acceptance Order at P 313 (discussing explanation from CAISO).

345 *Id.* at P 310 (citation omitted).

346 *Id.* at P 313.

347 *See* CAISO Tariff section 33.18.3.3 ("Transmission Not Available in the Day-Ahead Market"). If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.").

other words, determining the nature and extent of transmission carve-outs would be the transmission service provider's prerogative—not the transmission customer's. 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."[348] In the August 29, 2025, order on the Portland General EDAM OATT, FERC found, "Portland's proposal to hold back, or "carve out," limited transmission capacity associated with certain discrete transmission facilities to fulfill contractual obligations and maintain reliability is just and reasonable and not unduly discriminatory or preferential and consistent with or superior to the *pro forma* OATT."[349]

b. Markets+

The Markets+ Tariff defines two sources of transmission.[350] The first is from Markets+ transmission service providers who have signed a Markets+ Transmission Service Provider Agreement which obligates them to contribute their flow-based transmission capability less that which is not available to Markets+.[351] SPP states examples of transmission capability that would not be available to Markets+ are the (1) transmission service rights of entities on a Markets+ transmission service provider's host BAA who have pseudo-tied out of Markets+, (2) transmission capability of a non-participating transmission service provider within a participating BAA, or (3) transmission rights of transmission customers who are not participating in Markets+.[352]

The second potential source of transmission is form "Markets+ Transmission Contributors," market participants who contribute their transmission rights on the system of a transmission service provider that is not participating in Markets+.[353] FERC accepted this provision, but required SPP on compliance "to clarify that a Markets+ Transmission Contributor's contribution of transmission capability abides by the non-participating transmission service provider's OATT" and "Markets+ Transmission Contributors will be responsible for "coordinating transmission schedule changes, curtailments, and other operational concerns with the non-participating [transmission service provider] and non-participating [balancing authority], in accordance with the applicable governing documents and agreements, including applicable OATTs."[354] FERC also noted Markets+

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[348] CAISO Filing Letter in FERC Docket No. ER23-2686 at 16 ("Due to the inefficiencies created by such arrangements that limit the benefits of EDAM to ratepayers, the CAISO expects such carveouts to be rare.").

[349] *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025) at P 189.

[350] Markets+ Tariff, Attachment D, section 1.0.

[351] Markets+ Acceptance Order at P 47. See also Markets+ Tariff Attachment A, section 8.3 Obligation to Communicate Transmission Capability and Attachment D, section 1.1:

> Markets+ Transmission Service Providers will have the obligation to make available the otherwise unused physical capability of the transmission facilities under their tariffs for purposes of providing Markets+ Transmission Capability to support the delivery of Energy and to operate the facilities under their tariffs in accordance with Good Utility Practices. Otherwise unused physical capability includes, at a minimum, unscheduled transmission capability for transmission reservations available for Markets+ use and capability for which there is no network, firm, or non-firm point-to-point transmission service reservations.

[352] Markets+ Acceptance Order at P 47.

[353] SPP Markets+ Transmittal Letter in Docket No. ER24-1658 at 23; *see also* SPP, Markets+ Tariff, pt. I, section 1.M (Definitions) (defining Markets+ Transmission Contributor).

[354] Markets+ Acceptance Order at P 152 and 154. In a February 18, 2025, Compliance Filing, added the following to Markets+ Tariff Attachment D, Section 1.0:

> A Markets+ Transmission Contributor's contribution of transmission capability must abide by the non-participating transmission service provider's OATT or other governing documents. The

Transmission Contributors remain financially responsible for procuring ancillary services associated with their transmission service and any redispatch costs on the non-participating transmission system that might be incurred, as explained by SPP in its Deficiency Response.[355]

The Markets+ Tariff provides transmission customers of Markets+ transmission providers,[356] the ability to "opt-out" the transmission rendering the reserved capacity unavailable for use by SPP in the market dispatch.[357] The only restrictions reflected in Attachment D, section 1.2 of the Markets+ Tariff are that opt-outs can occur no more than once a month for a minimum period of one month[358] and notification of any opt-out can be no later than 15 days prior to the start of the upcoming calendar month.[359] If a Markets+ transmission service provider submitted an opt-out on its system, but the transmission rights are not scheduled for the transmission customer's use elsewhere, the Markets+ transmission service provider can make the associated capability available for Markets+ use based on the specifics of the Markets+ transmission service providers' OATT.[360]

Markets+ will respect the transmission rights of non-participating transmission service providers and non-participating transmission customers. SPP will utilize service flow constraints in its market commitment and dispatch software to prevent Markets+ from infringing on transmission rights not specifically made available to the market.[361] Figure 37 is taken from the Markets+ protocols illustrating the Markets+ transmission approach.

> Markets+ Transmission Contributors are responsible for coordinating transmission schedule changes, curtailments, and other operational concerns with the non-participating transmission service provider and non-participating balancing authority, in accordance with the applicable governing documents and agreements, including applicable OATTs.
>
> The Markets+ Transmission Contributor remains financially responsible for procuring ancillary services associated with their transmission service and any redispatch costs on the non-participating transmission service provider's system that may be incurred.

355 Markets+ Acceptance Order at P. 154.

356 There does not appear to be any restrictions on which OATT customers can opt out. The Markets+ Tariff defines "Markets+ Transmission Capacity Opt-Out" in Section 1 as "[t]Transmission capacity rights owned by a transmission customer on a participating Markets+ Transmission Service Provider's system that is not available for Markets+ Transmission Capability or transmission capacity rights owned by a Markets+ Transmission Contributor that it designates as unavailable for Markets+ Transmission Capability." While the Markets+ protocols state only that, "[q]ualifying transmission eligible for opt-outs include, but are not limited to, PTP Transmission service rights used to support delivery outside of Markets+: (a) Pseudo-tied generation or load out; or (b) Dynamic or fixed bilateral wheels unavailable for Markets+ optimization." Markets+ Protocols at section 8.2.2.1.

357 SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes). Markets+ transmission service providers/ BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline. The opt-out of transmission rights removes that capacity entirely from the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule.

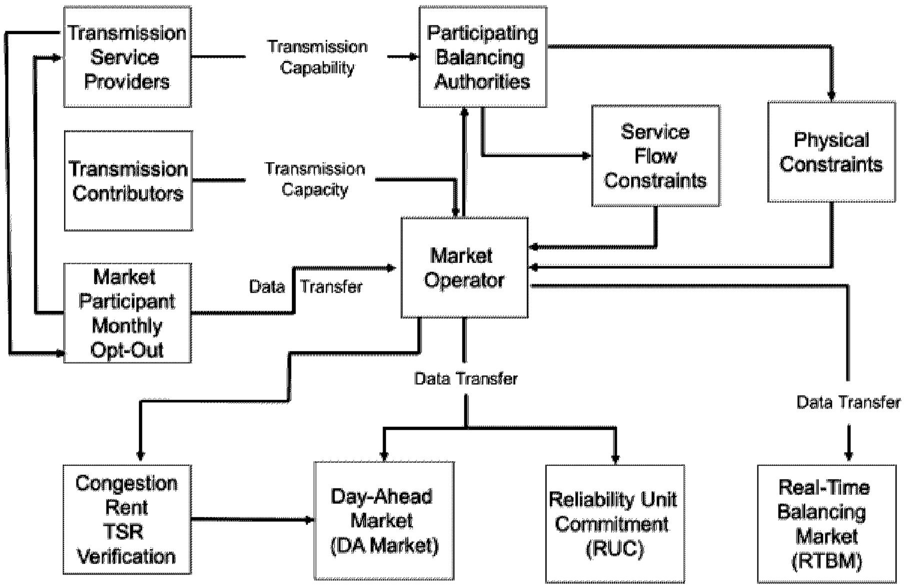
358 Markets+ Acceptance Order at P 77. Section 1.2 of Attachment D in the Markets+ Tariff describes the duration and timing requirements for transmission capacity opt-outs.

359 Markets+ Tariff, attach. D, § 1, § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).

360 Markets+ Acceptance Order at P 47.

361 *Id.* at P 45.

Figure 37
Markets+ Identification of Transmission Capability[362]



c. NV Energy Evaluation

NV Energy strongly prefers the EDAM transmission paradigm. The EDAM Tariff appropriately balances interests, maximizing the transmission capacity each EDAM Entity makes available to the market while respecting existing OATT transmission service rights and customer expectations.[363] The EDAM will accept intra-day self-schedules by firm transmission customers, even after the close of the Day-Ahead market until T-20 before the operating hour.[364] The market dispatch will accord such self-schedule changes a priority that is equal to other real-time self-

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362 Market+ Protocols Version 0 at Exhibit 8-1. https://www.spp.org/documents/73199/marketsplus%20protocols%20-%20combined%20-%20mpec%20approved%20as%20of%2020250131.pdf. In addition, section 4.5 of Attachment C of the Markets+ Tariff states that the SPP Market Monitor will monitor for the exercise of transmission market power.

363 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. Direct Testimony of Anna McKenna at Q&A 31.

364 EDAM Acceptance Order at P. 318 ("CAISO explains that it will accept schedule change submissions from an EDAM balancing authority throughout the real-time market up to T-20. We agree with CAISO that EDAM transmission service providers would have to establish in their respective OATTs any interim (T-57 to T-20) transmission customer schedule submission deadlines that accommodate their participation in EDAM").

schedules and equal to day-ahead self-schedules.[365] The market will redispatch to accommodate such intra-day schedules. CAISO has explained the importance of equal priority:

> Unwinding transfers awarded based on transmission capability that becomes available when firm transmission service is not scheduled by 10:00 a.m. the day prior to operation would adversely affect other entities that depend on such market transfers, including other resource adequacy program participants, further eroding the confidence in transfers, reducing market efficiency, and possibly creating an inappropriate arbitrage opportunity.[366]

FERC found, "that CAISO's proposal strikes an appropriate balance between preserving a transmission customer's rights under an EDAM transmission service provider's OATT and ensuring that there is confidence that EDAM transfers will be delivered."[367]

Section 33.18.2.2.3 of the CAISO Tariff allows an EDAM Entity to instruct CAISO to afford intra-day self-schedules of firm transmission customers higher priority than EDAM day-ahead schedules. PacifiCorp and Portland General have used this authority to create one exception whereby certain intra-day schedule changes will receive a "higher" CAISO market scheduling priority if associated with a WRAP forward showing obligation (or another FERC-accepted regional resource adequacy program).[368] NV Energy is not sure if it has any long term firm

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365 CAISO Tariff at Section 33.7.5.

366 CAISO EDAM Filing, Transmittal Letter in FERC Docket No. ER23-286 at 136-137.

367 CAISO Acceptance Order at P 307. FERC noted that:

> section 13.8 of the *pro forma* OATT requires schedules for firm point-to-point transmission service to be submitted to the transmission service provider no later than 10:00 a.m. of the day prior to service and provides that "[s]chedules submitted after 10:00 a.m. will be accommodated, if practicable."**[367]** Under CAISO's proposal, 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 if practicable. Specifically, CAISO states that EDAM will attempt to accommodate any intra-day schedule changes via redispatch and if there is an infeasibility, CAISO will notify the EDAM Entity, which is then responsible for resolving the infeasibility through its OATT procedures.

Id. at P 310.

368 PacifiCorp's OATT at Attachment T, section 4.1.3.6.1. Portland General Electric OATT at Attachment P. section 6.1.2.2.3. FERC noted in the EDAM Acceptance Order,

> 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.

EDAM Acceptance Order at P313. In its August 29, 2025, order on the PacifiCorp OATT changes to implement EDAM, FERC found,

> PacifiCorp's proposed Tariff revisions relating to the use of its transmission system by EDAM are just and reasonable and not unduly discriminatory or preferential. As discussed below, we find that PacifiCorp's proposal regarding the intra-day scheduling rights of firm point-to-point and network transmission customers are consistent with or superior to the *pro forma* OATT. We also find that the

reservations that would be used for this purpose, but the Companies would be willing to include a similar provision.

By keeping the unscheduled transmission (non-firm ATC) in the market dispatch, the CAISO minimizes "phantom congestion" whereby otherwise available transmission is kept out of the market and stranded. By utilizing pricing parameters in the optimization to hold these customers harmless with respect to their existing OATT schedule change rights, CAISO addressed potential interoperability issues with WRAP.[369] Only if the schedule changes are persistent and cause concerns with the redispatch would the transmission capacity by "carved out".[370] This is not to say that an OATT customer's schedule could never be curtailed if there is a derate on the system, but rather that the risk is no different than under their pre-EDAM rights.

NV Energy's has two significant concerns with the Markets+ approach related to: (1) the Markets+ Transmission Contributors and (2) opt outs. Clearly, Markets+ can optimize on a flow basis the transmission capacity made available by participating transmission service providers on their own systems. With respect to OATT service agreements on third party systems; however, absent a dynamic service agreement, these will not be available for flow-based, real-time optimization. As noted above, under the OATT transmission customers only have the right to make scheduling changes up to 20 minutes before real-time. SPP's real-time market runs on a 5-minute basis. SPP has not reconciled these conflicting timeframes.

> proposed Tariff revisions will allow firm transmission customers to meet their obligations under WRAP and other Commission-approved resource adequacy programs.

PacifiCorp, 192 FERC ¶ 61,197 (2025) at P 237.

369 As stated by FERC,

> We disagree with various commenters' arguments that Portland's proposal to give higher intra-day market scheduling priority only to transmission schedules identified in WRAP's forward showing program is insufficient to ensure WRAP transactions flow on firm transmission service because the forward showing only requires WRAP participants to demonstrate that they have firm transmission rights for a portion of their qualified capacity contribution. Under the proposed Tariff, WRAP participants (and other firm transmission customers) are still able to make intra-day schedule changes and have their transmission schedules accommodated in a manner consistent with or superior to the *pro forma* OATT via market redispatch even if a schedule change is not related to a WRAP forward showing. Thus, while it is true that Portland is proposing to give only intra-day schedule changes associated with a transmission customer's WRAP forward showing capacity a higher market scheduling priority than cleared day-ahead schedules, this higher scheduling priority is not strictly needed, because firm transmission flows before non-firm transmission. Therefore, we find that contrary to various protesters' assertions, Portland's proposed Tariff revisions will not prevent any party from fully participating in WRAP and it is just and reasonable to provide only WRAP forward showing capacities the higher priority. Because intra-day firm transmission schedules will be accommodated, we also find Portland's proposal to provide CAISO with the intra-day schedules associated with WRAP participant's firm transmission service twice per year just and reasonable. We find that Portland's proposed Tariff is sufficiently clear that it will accommodate firm transmission use associated with other Commission-approved resource adequacy programs.

Portland General Electric Co., 192 FERC ¶ 61,195 (2025) at P 194.

370 The ability to carve out transmission is preserved under proposed section 33.18.3.3. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

From the perspective on NV Energy's DAM selection, the issues involving limitations on the ability of transmission associated with Markets+ Transmission Contributors focus on limitations of scheduling rights to enable real-time dispatch. In other words, the transmission can be scheduled in accordance with OATT rights day-ahead, but it would not be available for real-time dispatch. This issue is illustrated in the interactions NV Energy has had with Powerex.

In comments submitted on December 6, 2024 in Docket 23-10019, Powerex stated they had requested 800 MW in the northbound and southbound directions in a new line with BPA and 200 MW northbound to Idaho Power.[371] Powerex claims that an OATT transmission customer has: "(1) the firm priority to deliver their supply to their load on the specified delivery path; (2) the economic benefit associated with the market price differences between the two endpoints of the delivery path, and (3) the freedom to choose the transactions and regional programs and regional markets that it wishes to participate in."[372]

NV Energy agrees that firm OATT service provides both physical and financial deliverability components.[373] While no one is depriving Powerex of the freedom to choose what market Powerex itself joins it is quite another thing to insinuate that Powerex would have a right to turn over NV Energy's transmission capacity to another market for real-time dispatch absent NV Energy's voluntary consent.[374] Consistent with the approach taken by PacifiCorp and Portland General Electric, NV Energy would not vest a customer with the unilateral right to carve-out rights over the NV Energy system. As FERC noted in the SPP Markets+ Order on Rehearing, a transmission service right does not equate to an ownership right.[375] Today a NV Energy transmission customer has a right to make changes down to 20 minutes ***before*** real- time.[376] After that deadline, the ability

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371 Powerex December 6, 2024, comments in Docket 23-10019 at 1.

372 *Id.* at 2.

373 NV Energy will explain why the Companies believe the EDAM congestion approach provides greater assurance in section 5.D of the Narrative.

374 *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261, at P 631 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) ("The Commission denies rehearing of the decision in Order No. 890 to not mandate a dynamic scheduling service in the pro forma OATT."); *see also*, *PáTu Wind Farm, LLC v. Portland General Electric Co.*, 154 FERC ¶ 61,167 (2016) at P. 37.

375 *Sw. Power Pool, Inc.*, 191 FERC ¶ 61,177 (2025) at P 15 (we grant Rehearing Parties' request for clarification and clarify that nothing in the January 16 Order purports to grant transmission customers an ownership right to the transmission capacity over which they take service, nor grants, waives, modifies or otherwise interprets any rights or obligations under the OATT of a non-participating transmission service provider not before the Commission in this proceeding.). In the January 19, 2025, Order on the Markets+ tariff, FERC explained, "the Markets+ Tariff will not force changes in the operations of non-participating transmission service providers' systems" and that "Markets+ Transmission Contributors will be responsible for "coordinating transmission schedule changes, curtailments, and other operational concerns with the non-participating [transmission service provider] and non-participating [balancing authority], in accordance with the applicable governing documents and agreements, including applicable OATTs.". Markets+ Acceptance Order at P 153 and P 154.

376 NV Energy OATT at sections 13.8 and 14.6. As noted by FERC in its order on the EDAM Tariff,

> As CAISO notes in its answer, the deadlines for transmission customer schedule submissions to an EDAM transmission service provider belong in the transmission provider's OATT. CAISO explains that it will accept schedule change submissions from an EDAM balancing authority throughout the real-time market up to T-20. We agree with CAISO that EDAM transmission service providers

to use the unscheduled transmission reverts back to the transmission provider – in WEIM, with a 15-minute unit commitment and a 5-minute dispatch, this unscheduled transmission is a very valuable right.

Powerex also noted:

> NV Energy recently offered Powerex long-term transmission service agreements associated with transmission upgrades on one of these two transmission corridors. To provide Powerex the necessary certainty that it will continue to receive the three core benefits associated with investment in firm transmission service, Powerex proposed that additional provisions be included in the agreements. These proposed provisions were intended to provide contractual protections to Powerex from any potential future changes to NV Energy's transmission tariff that may strip one or more of the core benefits away, while also clarifying that Powerex would be able to use its firm transmission rights to participate in its preferred regional programs, including WRAP and Markets+.
>
> NV Energy responded promptly that it would not provide the requested contractual assurances, and that it would only agree to use the boilerplate language in its *pro forma* agreement.[377, 378]

As a non-discriminatory provider of open-access transmission service, NV Energy must process a transmission service request in accordance with the OATT and offer the *pro forma* service agreement. As noted previously, FERC has repeatedly found dynamic scheduling to be a voluntary service offering. Accordingly, there are numerous reasons why NV Energy rejected the Powerex request.

- First, Powerex was requesting NV Energy overrule the FERC's decision in the PacifiCorp and Portland General Electric EDAM OATT proceedings, ***even before FERC ruled against Powerex***. In its August 29, 2025, Orders FERC,

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> would have to establish in their respective OATTs any interim (T-57 to T-20) transmission customer schedule submission deadlines that accommodate their participation in EDAM.

CAISO EDAM Acceptance Order at P 318.

377 Powerex December 6, 2024, comments in Docket 23-10019 at 8.

378 Specifically, Powerex claimed it "will be essential for Powerex to include non-*pro forma* provisions in any service agreements related to the new transmission line that will ensure":

1. If NV Energy joins a regional market such as EDAM, NV Energy will provide a mechanism (*e.g.*, a limited "carve out") for Powerex to schedule use of the transmission service outside of that regional market and not be exposed to financial settlements associated with that market;
2. the reservation, scheduling and curtailment priority of the transmission service will be maintained at the highest priority through real-time operations; and
3. Powerex will be permitted to contribute or use the transmission service in any regional program or organized electricity market approved by FERC, even if NV Energy does not join or participate in the same regional program or organized market. Direct Testimony of David Rubin Testimony at Q&A 40.

- o disagreed with protesters who argue that their transmission rights are being devalued because firm transmission customers will be exposed to congestion costs, which they allege is inconsistent with the *pro forma* OATT;[379]

- o disagreed with protesters who argue that because PacifiCorp's proposal introduces uncertainty to the cost of transmission through its proposed treatment of congestion, it may have unintended consequences such as inhibiting remote generation from serving load and undermining the incentive to invest in transmission upgrades and expansion;[380]

- o found that Powerex's arguments regarding "initial schedules" and schedule changes are misplaced, and PacifiCorp will allow schedule changes up until T-20, which will be accommodated barring conditions that require curtailment of firm transmission schedules;[381]

- o found that PacifiCorp's proposal does not bar firm point-to-point transmission customers from contributing their transmission rights to Markets+, insofar as they are able to meet all of the requirements of PacifiCorp's Tariff;[382]

- o disagreed with arguments that the EDAM Order implied that giving firm point-to-point customers' schedule changes a higher priority than cleared day-ahead schedules is required for a proposal to be consistent with or superior to the *pro forma* OATT.[383]

- o found that there is no obligation under the Commission's regulations, or the *pro forma* OATT, for PacifiCorp to accommodate transmission contributions to Markets+;[384] and

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379 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P. 151.

380 *Id.* at P. 157

381 *Id.* at P 243

382 *Id* at P 250 ("Under PacifiCorp's proposed Tariff, any such transmission contribution to Markets+ would be subject to the same congestion charges, redispatch costs, and limitations applicable to every PacifiCorp firm point-to-point transmission customer. We find that there is no obligation under the Commission's regulations, or the *pro forma* OATT, for PacifiCorp to accommodate transmission contributions to Markets+")

383 *Id.* at P 246 ("In the EDAM Order the Commission noted that "the EDAM proposal preserves the rights of firm transmission customers because they may submit intra-day schedule changes up until T-20 of a scheduling interval and have a higher market scheduling priority than EDAM transfers if CAISO is so notified by the EDAM transmission service provider").

384 Id. at P. 250,

> We recognize that some commenters would like to contribute their firm point-to-point transmission rights on the PacifiCorp system to Markets+. The Commission has previously found that any Markets+ transmission contributions are permitted, provided that they are allowed under the host BAA's OATT or other governing documents. We find that PacifiCorp's proposal does not bar firm point-to-point transmission customers from contributing their transmission rights to Markets+, insofar as they are able to meet all of the requirements of PacifiCorp's Tariff. Under PacifiCorp's proposed Tariff, any such transmission contribution to Markets+ would be subject to the same congestion charges, redispatch costs, and limitations applicable to every PacifiCorp firm point-to-point transmission customer.

  - was unpersuaded by protesters' arguments that firm transmission customers should be allowed to unilaterally opt-out their transmission capacity reservations from the market entirely.[385]

- Second, a dynamic service agreement is equivalent to carving out the transmission capacity. This is due to the need to be able to account for changes in e-tags *through real-time*. Were NV Energy to accede to Powerex' request, NV Energy's other customers, including native load would not get the benefit of using any transmission capacity unscheduled twenty minutes before real time. NV Energy's other customers would lose this benefit even though:

  - Powerex would be requesting this voluntary, special service while paying only the standard OATT rate; and

  - The service between the Northwest and Southwest would include the newer Greenlink facilities with lower than average depreciation – in other words, by paying an average system rate Powerex would be depriving remaining transmission customers of any benefit from and access to the very facilities they were helping pay for, even if Powerex or Markets+ did not utilize the transmission capacity;

- Third, while NV Energy potentially could require Powerex to pay an incremental rate associated with a new line from BPA to Nevada, Powerex would then get transmission from Northern Nevada to Arizona, without any financial contribution to the revenue requirement of the facilities. Under FERC's transmission pricing policy, NV Energy can charge the higher of an incremental or rolled-in rate but not both.[386] Thus, Powerex would only pay for the new line and not the costs for any rolled-in facilities. Moreover, Powerex would then transfer not only all of the capacity of the new line to Markets+, but also the corresponding in-Nevada capacity on Greenlink or other lines depriving NV Energy's other customers of any access to the transmission they are fully supporting.

- Fourth, as the BA, NV Energy is responsible in EDAM for maintaining reliability in its BAA. Having to manage flows that could change substantially every 5-minutes resulting from the dispatch of Markets+ while becoming familiar with the EDAM would put an unwarranted stress on NV Energy transmission operations.

Powerex states, ***"Notably, without the third-party investment of Powerex and others, some of these transmission expansion opportunities and upgrades to NV Energy's transmission system may not move forward, and a larger share of the cost of the upgrades and expansion projects***

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[385] *Id.* at P 370.

[386] In Order No. 888, the Commission stated that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy Statement. *See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Policy Statement, 59 FR 55031 at 55037 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005 at 31,146 (1994), *order on reconsideration*, 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

that do occur will ultimately fall on Nevada's electricity consumers."[387] If the transmission capacity for a new line is to be carved out for use in Markets+ without all of the corresponding costs being born by the Markets+ participants, it is questionable that the project should proceed. Moreover with respect to Powerex' prognostications, FERC has stated,

> We disagree with Powerex's arguments regarding the effects that accepting PacifiCorp's proposed Tariff will have on transmission development in the Western Interconnection and the potential that native load customers will be responsible for a greater share of PacifiCorp's annual transmission revenue requirement due to a loss of firm point-to-point transmission customers. We find that these arguments are speculative.[388]

NV Energy's actions have been protective of its native load customers and system reliability. It is not surprising that other EDAM BAs have expressed similar concerns with regard to the Markets+ Transmission Contributor methodology that led FERC to require SPP's compliance filing, specifying the need to comply with the external transmission provider's OATT, correspondingly raising the question of the amount of transmission available for the Markets+ market dispatch.

NV Energy's concern with opt-outs also goes to uncertainty as to the transmission capacity that will be available to Markets+ and the opportunity for strategic bidding that can arise with the ability of customers to move in and out of the market. Similar issues have been raised by the SPP market monitor and several Markets+ State Committee members.

In Comments submitted on April 29, 2025, in FERC Docket No. ER24-1658, the SPP market monitor expressed, "concerns with the current opt-out because it allows transmission to be removed from the market without regard to economics or reliability but with an impact on both"[389] Similarly, the comments of the Markets+ State Committee noted, "[s]ome MSC members have strong concerns about the lack of guardrails around the monthly opt-out provision for transmission and its potential implications for the exercise of market power, particularly given the market participants' ability to opt-out transmission capability monthly with only fifteen days' notice."[390]

In response, FERC has directed SPP to report on,

> the daily quantity of capacity opted-out per transmission facility, any (if available) rationale provided by the market participant for opting-out the capacity, the type of

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387 Powerex December 6, 2024, comments in Docket 23-10019 at 8 (emphasis in original).

388 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 253. *See also*, *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025) at P 188

389 Comments submitted on April 29, 2025, in FERC Docket No. ER24-1658 at 47-48. ("Transmission opt-outs could even be used to isolate resources to create a local monopoly or to make other resources unavailable. As an extreme example, though the MMU does not expect this to happen, all transmission could be opted out of Markets+ under the proposed tariff language. Allowing transmission capacity to be removed from the market with no limitations or conditions could undermine several Markets+ processes.") The market monitor recommended that if transmission opt-outs are permitted that they be allowed no more than annually with enough lead time to inform all downstream processes and that the tariff include sufficient detail to describe the opt-out and opt-in deadlines and limitations. *Id.* at 48.

390 Comments of the Markets+ State Committee dated April 29, 2024, in FERC Docket No. ER24-1658 at 5-6.

> capacity that has been opted-out (i.e., firm or non-firm), and when the capacity is opted back in for each Markets+ TSP and Market+ Transmission Contributor. Similarly, SPP should report to the [FERC] the quantity of capacity removed or added to Markets+ on an intraday basis, any (if available) rationale provided for modifying the capacity, and the type of capacity that has been modified in the intraday timeframe. Such report shall include all transmission capabilities relevant to Markets+, including those offered by Markets+ Transmission Contributors.[391]

NV Energy's understanding is that Markets+ may offer unscheduled transmission capacity, including potentially capacity associated with carve outs to the day-ahead market on a non-firm basis, meaning this transmission could be recalled after the day-ahead market run by the individual transmission customer. If the real-time market cannot accommodate the change through redispatch, granting the customer this opportunity to recall this transmission capacity may pose a reliability challenge for the participating Balancing Authority Areas expecting market flows on this non-firm transmission.

In summary, NV Energy has greater confidence in EDAM's methodology of making transmission available for market use and the reliance on the interconnected transmission systems. NV Energy recognizes that certain EDAM Entities will utilize transmission over external systems to participate in EDAM, including the use of existing dynamic rights. However, the core of the EDAM market is the interconnected systems of transmission providers with adjoining BAAs. Moreover, the opt-out provisions of the Markets+ Tariff create uncertainty as to the overall amount of transmission available for market dispatch and whether or not that transmission will be there at peak times.

2. Access Charge

Under both DAMs transmission service providers will continue to recover their cost of service through their OATT rates. However, because the DAMs will make significant use of transmission capacity not scheduled in the day-ahead timeframe, the transmission service providers may experience a loss of short-term and non-firm sales that currently provide revenue credits to long-term firm and network transmission customers.

a. EDAM

To backfill any lost revenue from forgone short-term sales, the EDAM market design provides the opportunity for the participating transmission service providers to recover their lost revenue through the EDAM Access Charge. After FERC initially rejected the EDAM Access Charge proposal without prejudice to further refinement,[392] CAISO re-filed the EDAM Access Charge in Docket No. ER24-1746. In that proceeding, FERC found that the "…EDAM access charge is a just and reasonable mechanism to avoid unintended cost shifts among ratepayers."[393]

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391 Markets+ Acceptance Order at P 88.
392 EDAM Acceptance Order at P 465.
393 *Cal. Indep. Sys. Operator Corp,* 187 FERC ¶ 61,154 (2024) at P 38.

The three components of projected lost revenue under the EDAM Access Charge model are governed by the CAISO tariff and include:

- Historical transmission revenues from sales of short-term firm and non-firm transmission products under the transmission provider's tariff, and for historical wheeling access charge revenues for CAISO transmission owners;
- A portion of revenues associated with new approved transmission builds (i.e., network upgrade costs) that increase the transfer capability between EDAM BAAs based on the proportional ratio of historical short-term sales to the overall historical transmission revenues; and
- Revenues for use of the transmission system when wheeling through transfer volumes in an EDAM BAA are greater than total import and export transfer volumes for the BAA.

As to the first bullet, these are potential shortfalls associated with expected revenues from sales of hourly non-firm point-to-point, daily non-firm point-to-point, weekly non-firm point-to-point, monthly non-firm point-to-point, hourly firm point-to-point, daily firm point-to-point, weekly firm point-to-point, and monthly firm point-to-point transmission service. 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 or applicable regulator for the preceding 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. EDAM transmission providers will continue to maintain their OATTs and sell different transmission products, which reduce and place downward pressure on EDAM recoverable revenues. All costs related to sales with an EDAM transmission owner's merchant function are ineligible to be recovered through the EDAM access charge.[394]

With regard to the second bullet, the EDAM access charge includes a percentage of the projected revenue from the new network upgrades equal to the EDAM transmission owner's ratio of: (a) the non-firm and short-term firm point-to-point historical EDAM recoverable transmission revenues to (b) the EDAM transmission owner's total revenue requirement. The purpose of this component is to recognize that a significant transmission upgrade, such as Greenlink, would increase the Companies' ability to generate additional short-term firm and non-firm revenue.[395]

The third bullet allocates additional revenue to transmission providers that facilitate wheeling within the market footprint in excess of the total net EDAM transfers into and out of that BAA. In periods where this excess occurs, the EDAM entity, on behalf of the EDAM transmission service provider, will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission service provider's non-firm hourly point-to-point transmission rate. This component ensures equitable treatment for those BAAs that are contributed significantly to EDAM transfers above and beyond their own import and export activity. These transmission systems

394 Direct Testimony of Adrien Marshall at Q&A 10 and CAISO Tariff section 33.26.2.

395 CAISO Tariff section 33.26.2.2.

supporting the significant volume of EDAM wheels, would receive this additional revenue component.

The EDAM transmission service provider will forecast their EDAM projected recoverable revenue shortfall on an annual basis.[396] Using the aggregate annual costs described above for each EDAM transmission owner, the CAISO will compute a $/MWh rate specific to each EDAM BAA.[397] The CAISO will assess the EDAM access charge to gross load (end-use customer demand (adjusted for distribution losses), including demand served by excess behind-the-meter production).[398] Each EDAM access charge will recover the projected recoverable revenue shortfalls for the EDAM BAs outside the BAA for that access charge, such that no EDAM BA will be assessed its own projected recoverable revenue shortfalls. Once collected through the EDAM access charges, CAISO will allocate revenues collected to EDAM entities on behalf of each EDAM transmission owner located in its BA, in proportion to each EDAM transmission service provider's share of EDAM projected recoverable revenue shortfalls.[399] There is a true-up to recover any delta, positive or negative, between the actual revenue shortfall and the amount of revenue received with the difference being added to or subtracted from the next years' revenue requirement.[400]

The mechanism the CAISO uses to process lost revenue estimates is addressed in the CAISO tariff. With respect to how the Companies may flow through the EDAM access charge in a future change to the NV Energy OATT, this is discussed in Section 9, below.

b. Markets+

Markets+ transmission service providers are eligible for compensation for potential lost revenues associated with transmission capacity used in the market. SPP will calculate, collect, and distribute the Market Transmission Use ("MTU") charge.[401] The MTU will be assessed based on total MWh of generation and load, including imports and exports, cleared in the day-ahead market activities, and to market participants with generation, load, import, and export MWh settled through real-time balancing market activities.[402]

The MTU charge works by estimating the share of short-term firm and non-firm transmission service on a particular Markets+ transmission service providers' system, adjusting for the lost

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396 *Id.* at section 33.26.1.

397 To form the numerator of the rate, the CAISO will divide each EDAM transmission owner's revenue shortfall to the EDAM BAAs associated with the other EDAM transmission owners by (a) the EDAM transmission service provider's gross load divided by (b) the total EDAM area gross load minus gross load of the EDAM transmission service provider. Accounting for the EDAM transmission service provider's gross load in relation to the overall EDAM gross load helps ensure EDAM access charges do not allocate costs beyond potential benefits, because the EDAM transmission owner's impact on the EDAM access charge will be proportional to its own share of gross load in the EDAM area. CAISO tariff section 33.26.1.1.

398 Direct Testimony of Anna McKenna at Q&A 41. ("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").

399 CAISO Tariff section 33.26.3.

400 *Id.* at section 33.26.1.2.

401 SPP Markets+ Protocols at section 7.1.

402 *Id.*

revenues, scaling to the current annual transmission revenue requirement, aggregating all the Markets+ transmission service provider to produce a market charge, and truing up collections.[403]

Annually, SPP will determine the MTU rate for each rate year as described in Attachment A, Appendix 2 of the Markets+ Tariff. The Markets+ transmission service provider qualified revenue amount is based on the amount of short-term firm and non-firm point-to-point revenues as an average of the last three-year period prior to the transmission service provider joining Markets+. The qualified revenue ratio is determined for the Markets+ transmission service provider by dividing the qualified revenue amount by the transmission providers annual transmission revenue requirement. This ratio remains fixed for that Markets+ transmission service provider for purposes of calculating the MTU Charge and is applied to the transmission service providers annual transmission revenue requirement for the current year in order to estimate what portion would be funded by short-term firm and non-firm transmission sales.[404] The use of a ratio allows for consideration of new transmission facilities. The estimated revenue from short-term firm and non-firm transmission sales for the current year is then multiplied by a scaling factor to determine the total estimated recovery amount for the Markets+ transmission service provider, representing the revenue expected to be displaced by Markets+ Due to a lack of historical data, the initial scaling factor will be set to 50 percent for all transmission service providers.[405]

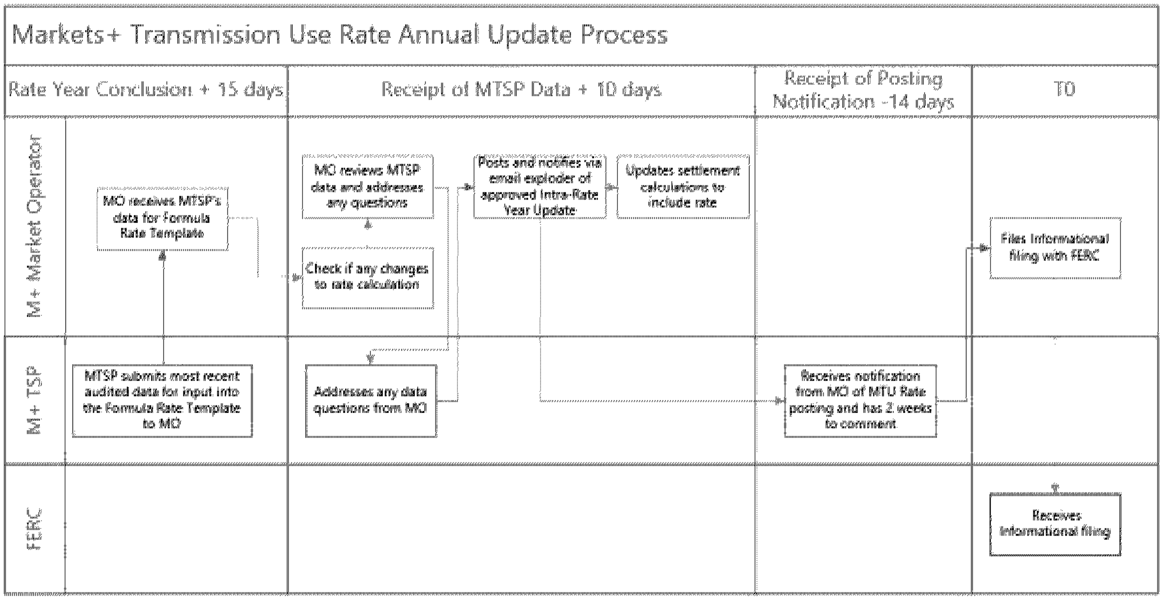
The Market Operator will distribute revenues it collects for MTU Charges to each Markets+ transmission service provider whose revenue recovery amounts included in the approved region-wide revenue recovery amount for the MTU charge as described in Attachment A, Appendix 2 of the Markets+ Tariff in proportion to the Markets+ transmission service providers' respective share of the overall revenue recovery amount.

In calculating the current rate year's revenue recovery amount, the transmission provider will net the under or over recovery of the prior year's MTU revenue, compared to the prior year's Markets+ transmission service provider's revenue recovery amount. The true-up would not be negative. Any balance would carry over to the next calendar year. The MTU process is summarized in Figure 38.

403 Markets+ Acceptance Order at P 321.
404 *Id.*
405 *Id.* at P 323.

Figure 38

Exhibit 7-1: Transmission Use Rate Annual Update Process



c. NV Energy Evaluation

For the potential revenue loss associated with short-term firm and non-form point-to-point service, both DAM designs include a transmission revenue recovery mechanism. FERC has referred to SPP's MTU charge as "generally similar to the EDAM's access charge."[406] Pending actual experience with the proposals, NV Energy finds the two approaches to be comparable.[407]

D. Congestion Revenue

Congestion is a characteristic of the transmission system produced by a binding transmission constraint. LMPs in nodal electricity markets differ by location due to transmission constraints that may arise on a transmission system. The revenue resulting from the difference between what a generator is paid and what a load is charged for the provision of electricity, based on their respective locations on the system and congestion due to transmission constraints, is called congestion revenue.[408] Depending on the direction of particular schedules in relation to congestion patterns, transmission customers may either receive or be charged for congestion.

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406 Markets+ Acceptance Order at P 328.
407 Direct Testimony of Adrien Marshall at Q&A 14.
408 Due to transmission limitations on the system, overall the total amounts paid to suppliers will be less than the total amounts paid by load on the system. Aside from accounting for marginal losses, the remaining amounts are congestion revenues to be allocated back to market participants.

1. EDAM

As proposed in the August 22, 2023, EDAM Filing and as accepted by FERC,[409] CAISO would allocate all EDAM congestion revenue to the EDAM BAA where the transmission constraint arose.[410] This congestion allocation method recognizes that the BAA where the internal transmission constraint is located bears the effects of that congestion and the reliability impacts associated with the constraint.[411] This is the same congestion revenue allocation method that is in effect in the WEIM today.[412] In addition, the CAISO Tariff requires the EDAM Entity for a participating BAA to ensure that congestion revenue it receives from the CAISO is sub-allocated among transmission customers in that BAA in accordance with the applicable OATT.[413]

Intervenors in the PacifiCorp and Portland General Electric EDAM OATT dockets raised questions concerning one aspect of the approved congestion allocation design – potential exposure to congestion associated with parallel flows. On June 26, 2025, CAISO filed a tariff amendment in FERC Docket No. ER25-2637 to address the parallel flow congestion allocation issue,[414] at least for initial EDAM operations.

Under the revised approach, congestion revenue associated with parallel flows resulting from balanced self-schedules would stay with the BAA where the congestion revenue was collected, which would allow the EDAM Entity to sub-allocate the additional revenue under the terms of its OATT and provide a more complete congestion hedge for transmission customers exercising their transmission rights, when coupled with congestion revenue accrued associated with congestion effects internal to the BAA as a result of an internal transmission constraint. As modified, there are three categories of congestion:

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409 EDAM Acceptance Order at PP 434 to 440.

410 *See* CAISO Tariff sections 33.11.1.2 and 33.11.3.9.3 as approved in the EDAM Acceptance Order. No party requested rehearing of the EDAM Acceptance Order where FERC accepted these congestion revenue allocation provisions.

411 Congestion revenue in EDAM will be separate from transfer revenue, which results when a scheduling limit between BAAs binds. EDAM continues to reflect the EIM approach of a 50:50 sharing of transfer revenues accruing at the interfaces between participating BAAs, including the CAISO. CAISO Filing Letter in ER23-2686 at 5 and 21. *See also*, Direct Testimony of Anna McKenna at Q&As 35-37.

412 FERC found, "CAISO proposes to appropriately assign congestion revenues entirely within the BAA where the constraint is modeled, thus adhering to cost causation principles," and "[a]s congestion revenues only account for congestion within each BAA, this methodology accurately assigns the revenue to the BAA where the congestion arose." EDAM Acceptance Order at P 435.

413 Two current WEIM participants have made filings with FERC to revise their OATTs to enable their participation in EDAM: PacifiCorp filed in FERC Docket No. ER25-951, and Portland General Electric in FERC Docket No. ER25-1868. Both PacifiCorp and Portland General Electric propose to sub-allocate congestion revenue allocated using a two-step process: in step one, the congestion revenue will be sub-allocated to balanced self-schedules submitted to EDAM associated with firm monthly and longer-term point-to-point and network OATT transmission service rights, and in step two any congestion revenue amount left over after step one will be sub-allocated to Measured Demand (i.e., load and exports). On August 29, 2025, FERC issued orders accepting the two step process. *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025) at P 84 (We find that Portland's proposed two-step sub-allocation of congestion revenues is just and reasonable and not unduly discriminatory or preferential and consistent with or superior to the Commission's *pro forma* OATT). See also, *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 147-P152.

414 In markets such as EDAM that span multiple BAA, parallel flow of electricity across the market area can mean a transmission constraint in one BAA impacts the cost of congestion—and thus the LMP—in another BAA. Parallel flow is also known as "parallel path flow," "loop flow," or "unscheduled flow."

- Congestion revenue not associated with parallel flow – this is internal congestion revenue arising from a binding transmission constraint within an EDAM BAA. CAISO will continue to allocate this congestion revenue to the affected BAA, the methodology approved in the EDAM Acceptance Order.

- Congestion revenue associated with parallel flow but associated with load participating in the market and not self-scheduling on firm OATT transmission service rights. CAISO will continue to allocate this congestion revenue to the affected BAA, the methodology approved in the EDAM Acceptance Order.

- With respect to eligible firm transmission service rights[415] utilized through submission of a balanced day-ahead self-schedule using a pre-assigned contract reference number, CAISO will allocate congestion revenue associated with parallel flow accruing within an EDAM BAA due to a binding transmission constraint within another EDAM BAA to the EDAM BAA where the congestion revenue accrued (rather than the BAA where the transmission constraint arose).

The modified approach allows better management of the congestion cost exposure for transmission customers exercising their firm OATT transmission service rights and minimize congestion cost shifts between EDAM BAAs and support EDAM entity mechanisms for sub-allocating congestion revenues. It mitigates the potential cost shift from the historical practice whereby transmission customers in neighboring BAAs have not borne the costs of any congestion their schedules cause in other BAAs. For example, today, NV Energy's transmission customers take service for a fixed access charge price.[416] While actions on NV Energy's transmission system may have effects on neighboring systems and vice versa, those flows are managed without passing through costs to customers.

The enhancement in FEERC Docket No. ER25-2637 is intended for "day one" EDAM implementation on May 1, 2026, as a transitional measure while the CAISO and its stakeholders consider and develop further enhancements to achieve the ultimate goal of developing a long-term framework for congestion revenue allocation.[417] On August 29, 2025, FERC issued an Order on accepting the proposed interim enhancement.[418] FERC found:

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415 CAISO Tariff section 33.11.1.2.1 defines eligible rights as long-term firm and monthly firm point-to-point and network integration transmission service rights, including conditional firm, as defined under the EDAM transmission service provider tariff (with shorter-term rights being ineligible for this treatment).

416 *See* NV Energy's OATT at Schedules 7, 8 and Attachment H. The monthly delivery rate is \$2.47/kW of reserved capacity per month.

417 CAISO June 26, 2025, Filing Letter in Docket No. ER25-2637 at 1. To that end, the CAISO commits to re-engage with stakeholders in working groups later in 2025, continue the engagement through EDAM go-live in 2026 as information becomes available from market simulation and parallel operations, and do the same thereafter as operational information becomes available. This engagement will consider both near-term and long-term EDAM design enhancements. The near-term discussions will focus on: (1) incentives to self-schedule identifying potential enhancements which incent economic bidding and mitigate or eliminate self-scheduling incentives; and (2) developing a treatment for congestion revenue allocation within the CAISO BAA that is comparable to the treatment afforded to OATT transmission service rights in other EDAM BAAs. The CAISO aims to implement a near-term enhancement in 2027, assuming an enhancement to the methodology meeting these needs is developed through the stakeholder process and approved. *Id.* at 9

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

> that CAISO's proposed Tariff revisions are just and reasonable and not unduly discriminatory or preferential because they will allocate a portion of certain congestion revenues associated with a binding constraint to the EDAM BAA where market participants paid congestion costs associated with the constraint, rather than to the EDAM BAA where the constraint occurs. As a result, these revisions ensure that eligible firm transmission customers have the opportunity to hedge against day-ahead congestion charges in EDAM by submitting balanced self-schedules.[419]

Transfer revenues accrue when scheduling limits are reached at transfer locations (interties) between participating BAAs. 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 location marginal prices between the two BAAs.[420]

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.[421] With the implementation of EDAM, CAISO will separate settlement of congestion and transfer revenue into two distinct charge codes and processes. Transfer revenue, once EDAM is implemented, will be allocated by CAISO equally, on a 50/50 basis, between the two BAAs at which interties the transfer revenue accrues. This allocation method recognizes that both EDAM balancing areas make transmission available to support mutually beneficial market energy transfers.[422]

2. Markets+

Firm point-to-point transmission service, NITS and other legacy transmission service of a month or longer duration will be eligible for congestion revenues (referred to as congestion rents). SPP will calculate congestion rents on a constraint-by-constraint basis and allocate the revenues to the holders of the rights to transfer energy over each constraint. When the flow-based capability made available for Markets+ use exceeds the eligible rights of individual market participants, SPP will allocate any excess to the Markets+ transmission service provider, for further allocation in accordance with its individual OATT or equivalent document.[423]

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419 *Id.* at P 32. FERC stated,

> We disagree with arguments that CAISO should allocate congestion revenue directly to transmission customers and/or based on their transmission rights and that CAISO should allow transmission customers to opt their transmission service rights out of EDAM. The Commission has already accepted in the EDAM Order CAISO's allocation of congestion revenue to EDAM Entities, who in turn sub-allocate the congestion revenue as provided for in their OATTs. *Id* at P 36.

420 Direct Testimony of Anna McKenna at Q&A 36.

421 *Id.* at Q&A 35.

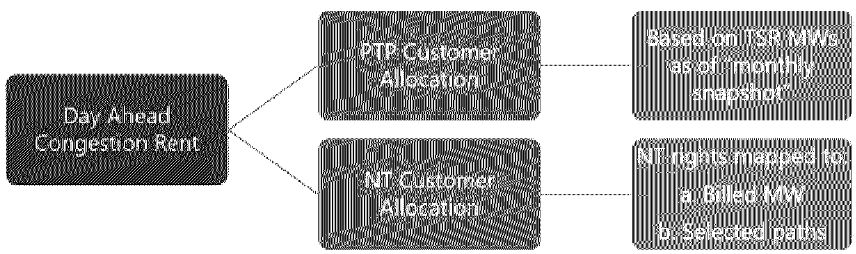
422 *Id.* at Q&As 35 and 36.

423 SPP Markets+ Filing Letter in Docket No. E24-1658 at 10.

Revenue collected by SPP resulting from binding transmission constraints in the day-ahead market will be allocated to Congestion Rent Eligible Transmission Service Reservation ("CRETSR") Holders and Markets+ Transmission Service Providers. A CRETSR is the quantity of firm point-to-point transmission service, conditional firm point-to-point transmission service, NITS, and/or legacy transmission service of a month or longer service increment that spans the full applicable calendar month, that has not been opted-out, and is available for use by Markets+.[424]

The Markets+ congestion rent allocation works through two processes, as shown in Figure 39 below. First, SPP will calculate the availability of congestion rent on a constraint-by-constraint basis, with the amount for each constraint calculated by multiplying the shadow price of the constraint by the market flow as described in Attachment A, Section 9.2.13 of the Markets+ Tariff. The shadow price is the redispatch cost to relieve congestion on the constraint by 1 MW.[425] Second, SPP will determine the MW quantity of transmission rights that are considered when distributing congestion rents to CRETSR holders.[426]

Figure 39[427]



CRETSR Holders may receive a portion of congestion rent prioritized using CRETSR Holder's OATT rights. The point-to-point service congestion rent distribution cap is equal to the eligible reserved MW quantity.[428] For CRETSRs associated with NITS, the injection/withdrawal combination is not specifically defined in the transmission service agreement, so SPP must determine which possible pairings of designated network resources ("DNRs") to the network load that will be considered and to what extent. SPP will begin with the NITS information to determine the possible pairings from the customer's DNRs to its network load,[429] and create a merit order

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424 Markets+ Tariff Definition of Congestion Rent Eligible Transmission Service Reservation.

425 SPP Markets+ Filing Letter in Docket No. E24-1658 at 29.

426 CRETSRs include transmission service made available for use in Markets+ of a month or longer service increment of the following types: Firm Point-To-Point Transmission Service, Conditional Firm Point-To-Point Transmission Service, Network Integration Transmission Service, and/or Legacy Transmission Service, including service contributed by a Markets+ Transmission Service Contributor on a non-participating transmission service provider's system, and also transmission rights held by Markets+ Market Participants on Markets+ Transmission Service Providers' systems.

427 Figure 39 is taken from the SPP Filing Letter in FERC Docket No. ER24-1658 at 30.

428 Markets+ Tariff Part I, Definition of Point-to-Point Distribution Cap.

429 Markets+ Tariff, Attachment A, Section 7.16(7). SPP in collaboration with Markets+ Transmission Service Providers and CRETSR Holders within the Markets+ Footprint, will retrieve and verify each CRETSR Holder's Congestion Rent Eligible Transmission Service Reservations from the applicable transmission service provider's Open Access Same-time Information System (OASIS), including relevant Designated Network Resources (DNRs) and

stack by sorting available DNRs from least to highest offer cost.[430] SPP will start this stack ordering with supply from DNRs with self-commit status or reliability must run resources, followed by DNRs in order of increasing offer cost, and ending with all or parts of unavailable DNRs in the highest cost portion of the stack. SPP will use this stack to identify a portion of the NITS customer's DNR capacity that will be mapped to the corresponding network loads, which will then be considered when determining the CRETSR impact to a binding constraint by selecting DNR capacity from least to highest cost up to the NITS distribution cap.[431] The NITS distribution cap amount is equal to the load amount used for NITS billing for the applicable congestion rent allocation month by each respective Markets+ transmission service provider.[432] This method allows for the point-of-receipt/point-of-delivery combinations most likely to be used by the CRETSR Holder to be selected first, maximizing the value to the CRETSR Holder.

Distribution of congestion rent for a particular binding constraint is determined by a congestion rent allocation factor based on a flowgate rights model. This factor is calculated by the ratio of the CRETSR Holder's positive MW impact in the binding flow direction on that binding transmission constraint to the total of the lesser of all the CRETSR Holder's positive MW impact in the binding flow direction on that same binding transmission constraint or the Day-Ahead Market flows.[433] The MW impact is the transmission service request reserved MW quantity multiplied by the shift factor impact in the binding flow direction on the binding constraint, calculated as part of the day-ahead market solution, for that CRETSR Holder's CRETSR.[434]

3. NV Energy Evaluation

The allocation and distribution of congestion revenues is an important example of how the proposed DAMs layer the organized markets' dispatch and use of LMP pricing onto the OATT platform of participating transmission providers. NV Energy's evaluation of the DAM proposals is based on two key principles with respect to allocation of congestion revenues: (1) the allocation should provide a means of holding OATT customers harmless to the extent possible from any

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Network Loads associated with Network Integration Transmission Service (NITS), pursuant to the Markets+ Protocols. Markets+ Tariff, Attachment A, Section 7.16(1).

430 *Id.* at Attachment A, Section 7.16(7)(b)(i).

431 Markets+ Tariff, Attachment A, Section 7.16(7)(b). "Network Service Distribution CAP is defined as" [t]he monthly maximum MW for which a CRETSR Holder is eligible to receive Congestion Rent associated with its Network Integration Transmission Service. The MW cap is equal to a monthly load used for Network Integration Transmission Service billing for the applicable Congestion Rent allocation month by each respective Markets+ Transmission Service Provider." Markets+ Tariff Part I, Definition of Network Service Distribution Cap.

432 "The monthly maximum MW for which a CRETSR Holder is eligible to receive Congestion Rent associated with its Network Integration Transmission Service. The MW cap is equal to a monthly load used for Network Integration Transmission Service billing for the applicable Congestion Rent allocation month by each respective Markets+ Transmission Service Provider." Markets+ Tariff, Part I, Section 1 (Definition of Network Services Distribution Cap). Under NV Energy's OATT section 34.2, "[t]he Network Customer's Monthly Network Load is its hourly actual load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak." The transmission provider's "Monthly Transmission System Load is "the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers." NV Energy OATT section 34.3

433 Markets+ Tariff, Attachment A, Section 9.2.14(1)(b).

434 *Id.* at Attachment A, Section 9.2.14(1)(d).

financial consequences ***from the actual use*** of their firm transmission rights;[435] and (2) firm OATT customers should be treated equally – there should be no winners and losers.

As NV Energy stated in comments to CAISO submitted on August 16, 2022,

> While other stakeholders have sought payment directly to the customer, NV Energy supports the proposed treatment of congestion revenue as a means of ensuring that all OATT customers are treated equally. After any OATT customers with firm transmission rights are protected from congestion costs resulting from intra-day changes to their transmission schedules as permitted by the OATT, congestion shortfalls or surpluses would be allocated on a load ratio share.[436]

Based on these criteria, EDAM has a clearly superior congestion allocation methodology. The EDAM congestion design, as enhanced by the tariff amendment in FERC Docket No. ER25-2637, in conjunction with the approved sub-allocation approaches of the PacifiCorp and Portland General Electric OATTs better protects customers' actual use of their OATT rights. As FERC explained:

> We find that PacifiCorp's proposed two-step sub-allocation of congestion revenues is just and reasonable and not unduly discriminatory or preferential, and consistent with or superior to the Commission's *pro forma* OATT. PacifiCorp's Step One allocation of congestion revenue, which reverses day-ahead congestion price differentials associated with balanced self-schedules of firm point-to-point and network transmission customers, will insulate balanced self-scheduled transmission use from EDAM's congestion exposure up to the congestion revenue that CAISO allocates to the PacifiCorp BAAs. Additionally, we find that PacifiCorp's Step Two allocation of congestion revenue will mitigate the congestion costs borne by entities that economically bid into EDAM.[437]

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[435] There will be no conversion of OATT physical rights to financial rights. OATT customers will continue to have the right to make intra-day schedule changes. In addition, there will be imbalances due to load and generation changes from the day-ahead schedule. Today, OATT customers can modify their schedules down to 57 minutes before real time without financial consequences. *See* NV Energy's OATT at Attachment P, section 4.2.4.5.2. These intra-day changes can cause redispatch and corresponding congestion.

[436] The comments can be found at: https://stakeholdercenter.caiso.com/Comments/AllComments/403bc91b-8c28-456d-bb1e-5ea1a95a8b7d#org-a3113bf2-0692-45bc-9903-29f4010e7487. The one exception to allocation of transfer and congestion revenue to the BA acting as the transmission provider is with respect to "Bucket 2" transmission. OATT transmission customers with firm point-to-point rights of a month or longer can elect to provide the transmission capacity to the market on a daily basis in exchange for a percentage of transfer or congestion revenue. A number of factors justify the limitation to firm point-to-point reservations of a month of longer including: (1) network customers cannot assign transmission capacity; (2) normally, CAISO as an independent system operator, would not be an eligible customer under an OATT. This "assignment" is a special exception designed to facilitate market activities, and the limitation does not take away any transmission customer's right to reassign transmission to other eligible customers on other days; and (3) especially at the start of a new market, it may be important not to create an incentive for customers with short term transmission reservations (hourly or daily) to remove valuable transmission capacity from the bilateral market which would limit the ability of load serving entities to engage in short term bilateral procurement to meet the resource sufficiency evaluation requirements.

[437] *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 147.

While both the EDAM and Markets+ congestion allocation methodologies are novel designs, untested by actual system operations, NV Energy has significant structural concerns with the Markets+ approach. First, Markets+ allocates congestion based on the total OATT reservations for point-to-point and NITS coincident peak usage. These reservations are based on the total transfer capabilities of the lines – there is no simultaneous feasibility test that RTOs use to determine the quantity of financial rights that can be awarded for purposes of providing a congestion hedge.[438] In other words, for sold-out paths, there is a significant risk of customers experiencing a shortfall in their congestion hedge.

As explained by Dr. Scott Harvey of the CAISO Market Surveillance Committee, "[w]hile ISO/RTOs take existing firm transmission service whose term has not yet expired into account in awarding CRR/FTRs, they do not automatically award financial rights for all prior firm transmission service," and "[a]ny transition to a CRR/FTR design would require a process that reviews past and current firm transmission service sales in combination with native load transmission entitlements and enforces some form of a simultaneous feasibility test to limit the award of CRR/FTRs."[439]

Second, there are several aspects of the Markets+ design which exacerbate the potential for revenue shortfalls for customers utilizing firm rights:

- the allocation is based on reserved capacity not actual usage. If Markets+ starts with the potential shortfall and then allocates a pro rata capacity share to customers who did not use their rights, this can exacerbate any under-recovery by customers who actually schedule and incur congestion, and

- The potential for a shortfall of a hedge against incurred congestion costs is compounded in Markets+ by the inclusion of conditional firm transmission reservations in the denominator for allocation of rights, even during the period where the condition is in effect.

For example, NV Energy has had two conditional firm reservations in recent years: (1) in FERC Docket No. ER22-1026, NV Energy filed a two-year conditional firm point-to-point transmission agreement with Powerex from Midpoint 345 kV to Mead 230 kV for 100 MW that was curtailable 8,000 hours/year; and (2) in FERC Docket No. ER24-1902, NV Energy filed a one-year,

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438 *See, for example*, CAISO Tariff section 36.4.2. describing the simultaneous feasibility test for release of congestion revenue rights. SPP's RTO Tariff at Attachment AE sections 7.2.3 and 7.2.3. *See also*, PJM Manual 06: Financial Transmission Rights, at 9-10, 19-37 (Sept. 25, 2024), available at https://www.pjm.com/-/media/DotCom/documents/manuals/m06.pdf at 28 ("If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis").

439 CAISO's Motion for Leave to File Answer and Answer filed in FERC Docket No. ER25-951 on March 7, 2025, at Attachment B, Statement of Dr. Scott Harvey at 2. Dr, Harvey explains,

> For example, in NYISO the grandfathered rights and existing transmission entitlements for native load, called ETCNL in the NYISO tariff, are subjected to a simultaneous feasibility test, and reduction, each time a capability period auction is settled as described in section 19.8.2 of attachment M of the NYISO OATT. This reduction process is necessary because the transfer capability needed to support existing firm transmission service and native load entitlements exceeded the actual transfer capability of the transmission system.

Id. at 5.

conditional firm point-to-point transmission agreement with Powerex from Hilltop 345 kV to Mead 230 KV for 25 MW that was curtailable 8,000 hours/year. The service agreement in ER 24-1902 noted that the path was "fully subscribed" and that "[t]he Transmission Customer has indicated it understands that it may be curtailed on a frequent basis since the path is fully subscribed, however would like to pay for the capacity to have a higher priority than non-firm." Markets+ would include this conditional firm reservation in the allocation of congestion revenue, whether the customer had scheduled on its rights and whether the congestion allocation would result in a shortfall for the customers who had first-in-time firm, non-conditional rights to the capacity.

The Markets+ congestion allocation methodology has the potential to create winners and losers. For example, NV Energy is currently developing the Greenlink transmission project. In his direct testimony Charles Pottey explains the significant increase in import capacity from this upgrade.[440] In the Markets+ design, a firm point-to-point customer with a reservation of a month or longer will get all of the congestion revenue in proportion of the capacity amount of the reservation, even if they have not scheduled on that reservation and incurred a congestion cost to offset. In accordance with FERC's transmission pricing policy, that same customer will only pay a system average rolled-in access charge rate for the reservation.[441] However, since the line is new and has a lower than average depreciation, the remaining revenue requirements associated with Greenlink will be paid for by other NV Energy customers, mostly NITS customers, including native load. In other words, these customers are supporting the revenue requirement associated with the generation of the congestion revenue but are not seeing any corresponding benefit. It is one thing to give congestion rent to point-to-point when they schedule as it preserves current OATT paradigm of paying the transmission provides rate and getting to move power from POR to POD without incurring additional congestion costs. It is quite another to give a windfall to customers based on reservation when doing so may lead to a shortfall in congestion revenue so that those who scheduled are given insufficient hedge.[442]

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440 Direct Testimony of Charles Pottey at Q&A 15.

441 FERC's policy is that "when facilities are integrated and thus provide system-wide benefits, facilities' costs are generally rolled-in and charged to all customers served." *Pinnacle West Capital Corp.*, 131 FERC ¶ 61,143, at P 42, *reh'g denied*, 133 FERC ¶ 61,034 (2010); *see also Sierra Pacific Power Co. v. FERC*, 793 F.2d 1086, 1088 (9th Cir. 1986) ("FERC favors rolled-in cost allocation when a system is integrated.") In making that determination, "a showing of any degree of integration is sufficient." *Northeast Texas Electric Coop., Inc.*, Opinion No. 474, 108 FERC ¶ 61,084, at P 48 (2004), *order denying reh'g*, Opinion No. 474-A, 111 FERC ¶ 61,189 (2005). Where customers "enjoy the benefits of reliable service by their association with [an] integrated system," the Commission has found that they "should share the cost of the entire transmission system." *Niagara Mohawk Power Corp.*, Opinion No. 296, 42 FERC ¶ 61,143, at 61,531 (1988). The Commission has explained that to justify a single, rolled-in rate, a utility "must demonstrate that all of its facilities function as a single, integrated transmission system that is used to serve [its] customers." *Pinnacle West*, 131 FERC ¶ 61,143 at P 43. Further, the Commission has determined that "[d]ue to the integrated nature of the transmission network, network facilities benefit all network users," even if "the facilities were installed to meet a particular customer's request for service." *Northeast Texas*, 108 FERC ¶ 61,084 at P 47. Indeed, "[t]here is no need to identify further actual benefits in order to include the costs of network transmission facilities in transmission rates." *City of Anaheim, Cal.*, 113 FERC ¶ 61,091, at P 58 (2005), *reh'g denied*, 114 FERC ¶ 61,311 (2006).

442 NV Energy strongly disagrees with statements of Arizona Public Service that the Markets+ congestion allocation approach "more accurately reflects the value of firm transmission rights held by customers, including both physical and financial firmness." Motion for Leave to Intervene and Comments of Arizona Public Service dated July 17, 2025, in FERC Docket No. ER25-2637 at 4-5.

A similar concern arises with respect to network customers. Markets+ will allocate congestion revenues based on the coincident peak as noted above. This can lead to over-recovery as there may be many hours where the usage is less than the coincident peak as well as potential under-recovery if NITS customer experiences non-coincident peak hours. For NV Energy, SPP's statement that, "[u]nder Markets+, congestion revenues are allocated to those who have invested in the transmission system, including native load and firm point-to-point customers, and on the paths where the congestion occurs"[443] fails to withstand scrutiny.

NV Energy's concern about firm customers not being sufficiently hedged is consistent with SPP's statement in the SPP Markets+ filing letter that, "Market Participants with firm transmission service should receive some offset, even if not a perfect offset, for the redispatch costs they will incur as a result of their contribution of transmission rights for use in Markets+ that benefits the broader market."[444] It remains to be seen how much protection "some offset" will provide customers, including native load's network rights.

SPP speaks of congestion payments being used to, "incent the purchase of longer-term transmission rights in sufficient firmness and duration to support investment in the transmission system."[445] NV Energy disagrees in the context of the establishment of a DAM. The primary drivers of transmission development have been the needs of LSEs to secure access to capacity procured to meet planning reserve margins in accordance with resource adequacy requirements. In the absence of unified BAAs in an RTO, both DAMs continue to require a demonstration of firm transmission rights in the resource sufficient programs.[446] Providing payments based on reservations provides a windfall to certain OATT customers at the potential expense of payment shortfalls to other customers for their actual use of the system.

In addition to the potential for under-recovery, NV Energy is concerned about the relation between the ability of transmission customers to opt their transmission capacity out of the market when they want to engage in physical deliveries and not be exposed to potential under-recovery of congestion costs and then opt it back in whey they are not using it to gain any additional revenue. For example, a customer could opt-out capacity for the summer season and then return it to the market for the remainder of the year. This can diminish the amount of capacity available for the market optimization.

NV Energy recognizes that CAISO's proposal is interim.[447] The Companies view the CAISO's response to the interventions in the PacifiCorp and Portland General Electric dockets as a sign of

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443 https://southwestpowerpool.s3.amazonaws.com/Brattle-white-paper-statement-20241010.pdf at 3.
444 March 29, 2024, Markets+ Tariff Transmittal letter at 29.
445 SPP Filing Letter in Docket No. ER24-1658 at 30.
446 *See,* CAISO Tariff Section 33.18.2.1 ("An EDAM Transfer from the source Balancing Authority Area to the sink Balancing Authority Area to support the EDAM Resource Sufficiency Evaluation for the sink Balancing Authority Area must be supported by firm or conditional firm point-to-point transmission service or network integration transmission service across an EDAM Internal Intertie"), and WRAP Tariff Section 16.3.1 ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load").
447 *Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025) at P. 37 ("We disagree with protesters that a deadline for further deliberation should be mandated as we find that CAISO's current allocation methodology for

responsiveness. As noted by the American Clean Power Association, Interwest Energy Alliance, and Renewable Northwest, "CAISO should be commended for its rapid response to these concerns and for its efforts to incorporate stakeholder feedback on its proposals and, ultimately, develop a reasonable solution to a complex topic on a very short timeline."[448] NV Energy also agrees with the statements of the Natural Resource Defense Council and Western Resource Advocates,

> CAISO's proposal reflects a strong commitment to addressing the long-term needs of EDAM entities and their customers. We support the initiation of a targeted stakeholder process aimed at developing a long-term solution. We also support efforts at CAISO to monitor and study relevant market design elements, such as binding transmission constraints, parallel flows, self-scheduling activity, and congestion revenue allocation, both prior to EDAM startup and once it is operational, as insights from initial EDAM operations will be crucial in informing further design refinements.[449]

While CAISO's congestion allocation methodology has garnered significant recent attention, the approach is more consistent with NV Energy's objectives of maintaining the financial certainty and equality for all customers using their firm transmission rights. NV Energy has supported the 50/50 distribution of transfer revenues. The challenges noted with the Markets+ design, may be based on specific factors related to NV Energy's system, but that is the concern the Companies have – if these problems surfaced under Markets+ would they be addressed or would the advantaged parties seek to maintain that outcome.

E. Virtual Bidding

Virtual bidding also known as convergence bidding, enables market participants to hedge their market positions and manage exposure to differences between the day-ahead and real-time prices by submitting purely financial bids which, if cleared in the day-ahead market, are automatically liquidated with the opposite buy/sell position at the real-time price. One of the main expected benefits of virtual bidding is a reduction in the difference between day-ahead and real-time prices.[450] Virtual bids are financially settled transactions without the bidder taking title to the physical product. This enables market participants that do not own generation assets or serve load to directly participate in the wholesale market for electricity. While virtual bids do not affect the physical side of the market, they are a key factor in energy market price determination. Although virtual bidding has benefits, it also has resulted in some of FERC's most significant enforcement actions for market manipulation.[451]

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congestion revenue is just and reasonable. Moreover, we will not direct CAISO to delay the go-live date of a market expansion that the Commission has already found to be just and reasonable").

448 July 17, 2025, Comments of American Clean Power Association, Interwest Energy Alliance, and Renewable Northwest in FERC Docket No. ER25-2637 at 3.

449 July 17, 2025, Comments Natural Resources Defense Council and Western Resource Advocates in FERC Docket No. ER25-2637 at 4.

450 *See, e.g., Cal. Indep. Sys. Operator Corp.*, 130 FERC ¶ 61,122, at P 35 (2010).

451 *See, e.g., Barclays Bank PLC*, 161 FERC ¶ 61,147 (2017). As stated by the SPP Market Monitoring Unit, "Cross-product market manipulation has been a concern in other RTO/ISO markets, and extensive monitoring is in place to detect potential cases in the SPP market. For example, a market participant may submit a money-losing virtual transaction intended to create congestion that benefits a transmission congestion right position for an overall net gain."

Virtual bidding in the CAISO market was implemented on February 1, 2011, at both internal nodes and the interties. To mitigate the potential for unintended consequences, CAISO proposed and the FERC accepted position limits on virtual bids. FERC recognized that CAISO could not identify all potential unintended consequences that virtual bidding could have on its market or demonstrate that they are necessary to protect against market manipulation, the exercise of market power or reliability problems. Although efforts had been taken in the design phase to ensure that convergence bidding would not lead to additional problems, the position limits acted as an additional safeguard against unforeseen problems.[452] Despite these protections, problems with virtual bidding at the interties were so severe that the CAISO filed a tariff amendment on September 21, 2011, to discontinue virtual bidding at the interties, due to the potential for market manipulation. In an order issued on September 25, 2015, FERC found that virtual bidders would "have the incentive to take advantage of the structural differences between congestion prices in the day-ahead and 15-minute market to the detriment of market efficiency" and therefore, the "CAISO's tariff provisions reinstating [virtual] bidding at the interties are unjust and unreasonable"[453] FERC noted that "the overall impact of implementing the previously accepted tariff provisions establishing [virtual] bidding at the interties would result in decreased economic efficiency, and, therefore, would fail to provide the desired benefits of both price convergence and improved market efficiency."[454]

In addition to terminating virtual bidding on the interties, CAISO has had to suspend its internal virtual bidding under stressed system conditions because, "when the system is as tight as it was during [the August 2020] heat wave, [virtual] bids can allow for a day-ahead market that is not supportable by actual available resources and system conditions."[455] The CAISO found that the presence of virtual bids contributed to supporting schedules that could not ultimately be honored in the real-time market. The CAISO determined that preventing the virtual bids from facilitating schedules that were not reliable provided the operators with fewer challenges in an already significantly constrained environment. The CAISO concluded it was better that the neighboring BAAs know in advance instead of being in a challenging condition in real-time to serve their load having relied on unsupported exports, rather than first allowing the Day-Ahead Market to schedule their export and then have to curtail it after it had been scheduled.[456]

The CAISO is not the only RTO that has experienced challenges with virtual bidding during stressed system conditions.[457] In its 2022 State of the Market Report, the SPP Market Monitoring

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Annual State of the Market Report for 2024 at 60. The report can be found at https://www.spp.org/documents/73953/2024_annual_state_of_the_market_report.pdf.

[452] *California. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,070 at P 18 (2011).

[453] *California. Indep. Sys. Operator Corp.*, 152 FERC ¶ 61,234 at P 41 and P 42 (2015).

[454] *Id.* at P 43.

[455] https://www.caiso.com/Documents/Aug14-15-StakeholderQandA.pdf.

[456] NV Energy notes that during the September 2022 heat wave, market participants were paid over $36 million in net revenues from virtual demand which represents nearly 93 percent of net revenues for virtual demand in all of 2022. See the Department of Market Monitoring Annual Report for 2022 at 2 and 74. The report can be found at: https://www.caiso.com/documents/2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf, 2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf (caiso.com).

[457] PJM has warned about potential adverse effects associated with convergence bidding:

> Notwithstanding the compelling theoretical efficiency value associated with financial trading, certain types of transactions can extract money from the market without adding commensurate benefit, skew transmissions flows and congestion patterns such that they are inconsistent with

Unit ("MMU") stated: The combination of large price spreads and an inability to displace more expensive generation during scarcity events lends to extremely high profit per megawatt values with little to no impact on price or market convergence. Where virtual transactions did create positive impacts, their high cost and profits largely outweighed their benefits. In light of these findings, the MMU made the recommendation to suspend virtual trading during scarcity events, particularly when day-ahead prices exceed the $1,000/MWh offer cap.[458]

Accordingly, while NV Energy understands the potential benefits of virtual bidding, the Companies want to proceed cautiously to limit potentially significant uplift costs that do not enhance market efficiency. NV Energy highlighted these concerns and advocated this go-slow approach to virtual bidding in both the EDAM and Markets+ stakeholder processes.

1. EDAM

CAISO's day-ahead market currently enables virtual bidding, except at the interties as noted above. Based on stakeholder input, the CAISO allows EDAM transmission service providers to enable virtual bidding in their BAAs at the onset of their participation in EDAM but does not mandate it.[459] Once EDAM participation begins, the CAISO will begin a stakeholder process to determine a permanent virtual bidding design for the EDAM and CAISO footprint. The optional transition period will give EDAM transmission service providers, their customers and market participants, and their local regulators experience and comfort with two-day markets before potentially enabling virtual bidding.[460] The CAISO and the Department of Market Monitoring will continue to monitor and evaluate EDAM's performance with or without virtual bidding in BAAs to help inform the evolution of the future design and address any unintended consequences of an optional virtual bidding design at the onset of EDAM.[461]

> system topology and load levels and, in large volumes, can significantly degrade the performance of the Day-Ahead Market. Refining the market rules that govern virtual transactions can eliminate a significant amount of the negative aspects of virtual trading while preserving their reasonably expected benefits.

Virtual Transactions in the PJM Energy Markets, PJM Interconnection October 12, 2015, at page 10. A copy was included as Attachment C to the PJM filing in Docket No ER18-88 on October 17, 2017. In PJM Interconnection, L.L.C., 162 FERC ¶ 61,139 (2018) (Docket No. ER18-88-000), the Commission accepted PJM's proposal to reduce the number of bidding points at which virtual transactions may be submitted by market participants. PJM's argument was that "when used in certain ways, virtual transactions can enable market participants to profit from the market without adding commensurate benefit, skew transmission flows and congestion patterns in a manner inconsistent with real-time system operations, and, in large volumes, can significantly degrade the performance of the day-ahead market." *Id.* at P. 4.

[458] 2022 Annual State of the Market report, Chapter 7 Recommendations, Consider limitations on virtual trading during emergency conditions. The report can be found at: https://spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf. The MMU further recommended that analysis should be done to determine what price levels, price spreads, and virtual volume to load ratios at which virtual transactions are no longer a cost-effective tool for aiding price and market convergence. The SPP MMU continues to support these recommendations. See 2024 State of the Market Report at section 2022.1. The report can be found at: https://www.spp.org/documents/73953/2024_annual_state_of_the_market_report.pdf.

[459] *See* CAISO Filing Fetter in Docket No. ER23-2686 at 154 citing CAISO Tariff section 33.30.7.

[460] *Id.*

[461] *Id.* at 155.

If virtual bidding is implemented in EDAM, CAISO would retain its authority to suspend or limit the practice.[462] Each EDAM Entity may recommend that the CAISO suspend convergence bidding in its BAA, provided that the CAISO will make the ultimate determination as to such recommendation.[463] NV Energy notes that the CAISO's existing tariff provision only allows suspension to address system reliability and grid operations.[464] NV Energy hopes that the future stakeholder process on the issue of EDAM virtual bidding would include an enhancement to permit suspension if there were economic consequences not consistent with reasonable market expectations.

2. Markets+

SPP proposes to delay implementation of virtual transactions until at least six months after the market go-live date, allow SPP and market participants to gain experience with the market before adding the potential complications involved with virtual transactions,[465] and proposes to provide notice to the FERC 60 days beforehand. [466] SPP will determine when to begin virtual transactions by reviewing the level of price convergence between the day-ahead and real-time markets, among other things, and will not implement virtual trading in the summer season due to concerns about physical generation being displaced in the day-ahead market during times of high load.[467]

After virtual bidding is implemented, SPP may suspend virtual transactions at its sole discretion.[468] In exercising this authority, SPP will consider whether virtual transactions remain a cost-effective tool aiding price convergence. The SPP MMU will monitor divergence between day-ahead and real-time market prices, and if the SPP Market Monitor identifies excessive price divergence caused by market participants through virtual transactions,[469] it will recommend SPP impose mitigation measures that restrict the responsible market participants from submitting virtual transactions at the settlement locations where the market participants caused the divergence.[470] If this occurs, SPP proposes that "additional analysis is required,"[471] but also that the market monitor will recommend that virtual transactions can be suspended by the market operator.[472] Under the proposal, virtual transactions can be suspended as long as necessary at the market participant level, at individual locations or groups of locations, or market-wide to identify and resolve the underlying

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462 CAISO Tariff section 7.9.

463 Section 33.30.7.3 ("The CAISO has the authority to suspend or limit convergence bidding pursuant to Section 7.9. Each EDAM Entity may recommend that the CAISO suspend convergence bidding in its BAA, provided that the CAISO will make the ultimate determination as to such recommendation.").

464 *See* CAISO Tariff section 7.9.

465 Markets+ Acceptance Order at P 263.

466 *Id.*

467 *Id.*

468 SPP, Proposed Markets+ Tariff, attach. A, § 5.4 (Virtual Transactions Implementation, Suspension, and Mitigation) (0.0.0).

469 SPP defines excessive price divergence as being a difference between day-ahead and real-time prices of plus or minus 10%. *Id.* attach. C, § 4 (Market Monitoring) (0.0.0), § 4.6.3 (Metric and Threshold Specifications).

470 *Id.* § 4.6.2; *see id.* attach. A, § 5.4 (Virtual Transactions Implementation, Suspension, and Mitigation) (0.0.0).

471 *Id.* attach. C, § 4 (Market Monitoring) (0.0.0), § 4.6.3 (Metric and Threshold Specifications).

472 *Id.* § 4.6.2 (Monitoring for Virtual Energy Bids and Virtual Energy Offers).

cause.[473] Finally, SPP proposes that it may restrict virtual transactions to physical Settlement Locations only.[474]

2. NV Energy Evaluation

NV Energy appreciates that both CAISO and SPP in their respective DAM designs have taken steps to recognize the challenges and risks of implementing virtual bidding as part of a novel market design. While virtual bidding can enhance market efficiency, there have been enough examples of this product causing significant uplifts without commensurate benefits to warrant a cautious approach to implementation. While both DAMs have provisions to curtail virtual bidding if it becomes problematic, NV Energy finds that the CAISO approach is more reasoned than SPP's mandatory implementation at six months.

During the EDAM stakeholder process the issue of virtual bidding was discussed extensively. The final proposal approved by the WEM Governing Body and the CAISO Board of Governors provided:

> Under the final proposal, in the lead-up to the two-year anniversary of EDAM operation – as a year-two enhancement – the [CA]ISO will conduct a stakeholder process to derive a more permanent EDAM [virtual] bidding policy informed by operational experience and stakeholder input. The proposed optionality enables interested EDAM entities to implement [virtual] bidding functionality in their balancing area at the onset of their participation in EDAM. It also allows entities that are not yet ready for enabling [virtual] bidding in their balancing area at the start of their EDAM participation to gain experience with the market and implement [virtual] bidding at a later time. The first two years of EDAM operation will allow the [CA]ISO and EDAM participants to develop valuable operational experience in the EDAM and evolve the design based on that experience. A future stakeholder process will evaluate a holistic implementation of [virtual] bidding, including a formal transition to convergence bidding for participating EDAM entities, the necessity for any interim bidding requirements, and design enhancements based on EDAM operational experience.[475]

NV Energy was one of the parties who raised concerns with the potential of virtual bidding to cause significant uplifts that could lead to unjust prices and harm anticipated EDAM benefits.[476]

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[473] *Id.* attach. A, § 5.4 (Virtual Transactions Implementation, Suspension, and Mitigation) (0.0.0). SPP will be required to publicly post notice of the suspension "and the underlying cause." *Id.*

[474] SPP, Proposed Markets+ Tariff, attach. A, § 5.4 (Virtual Transactions Implementation, Suspension, and Mitigation) (0.0.0).

[475] December 7, 2022, EDAM Final Proposal at 88.

[476] *See, for example,* NV Energy September 26, 2022, Comments on the Revised Straw Proposal, ("NV Energy maintains that whether to support convergence bidding should be an optional choice for the potential EDAM Entity. As an alternative, NV Energy could support initiating a stakeholder process to consider the specific issue of convergence bidding in the EDAM after two years of EDAM operation. That real-work experience and pricing data could better inform consideration of the issue rather than an unsupported assumption that it will be a benefit in a hybrid market with different footprints for day-ahead and real-time with the continuation of the EIM.). https://stakeholdercenter.caiso.com/Comments/AllComments/40ca9fe4-9c92-4296-87ea-9108886f0e73#org-4340739e-5595-4b4b-b757-24bb58ba8914. *See also*, NV Energy November 21, 2022, comments on the Draft Final

NV Energy noted certain of the justifications for convergence bidding that exist in an RTO might not be present in the EDAM structure. The resource sufficiency evaluation provides an incentive not to under-schedule load. The direct allocation of transfer and congestion revenues to the BA acting as the transmission provider to sub allocate to OATT customers addresses the need to use offsetting virtual supply and demand bids to hedge congestion costs.

Accordingly, NV Energy supported an approach whereby, after there is operational experience with the EDAM, CAISO would initiate a stakeholder process that considers whether the potential benefits of convergence bidding in the EDAM outweigh the potential for degraded market efficiency and significant uplift charges to loads such that convergence bidding be required for all BAAs participating in the new market. Based on actual EDAM operations, stakeholders could better assess whether structural issues are so significant as to warrant not proceeding with convergence bidding similar to the restrictions on the CAISO interties today or whether introductory measures are needed such as position limits and location restrictions to enable this product.

NV Energy understands that both DAM options have recognized both the potential for virtual bidding to harm efficient market operations and result in unnecessary uplifts. Overall, the Companies have more confidence in the CAISO's approach that does not mandate implementation by a certain date.

F. Price Formation – Fast Start Pricing

Price formation in DAMs establish market clearing prices for energy and ramping products. There are multiple components to price formation, including market power mitigation and how prices are set during conditions of scarcity. Appropriate compensation for generators must be balanced by protecting load from unjust and unreasonable prices. NV Energy discusses market power mitigation in section 5(I) of this Narrative. This section focuses on pricing for "fast start" resources, which are units that are able to start quickly to meet system needs of an RTO, but are often dispatched to their inflexible economic minimum or maximum operating limits.[477]

Fast-start pricing allows an RTO's software algorithms to incorporate the offers of fast-start resources into the market prices for energy and ancillary services, typically by treating fast-start resources as flexible (fully dispatchable from zero to their economic maximum operating limits) during a pricing run that is performed separately from the dispatch run. Additionally, fast-start pricing allows a fast-start resource to include its commitment costs (its start-up and no-load costs) in prices, thereby allowing a fast-start resource to recover a portion of its commitment costs through the market rather than through out-of-market uplift payments. Correspondingly, fast start pricing increases the LMP providing additional revenue for all infra-marginal generators and increased costs for loads.

Proposal at: https://stakeholdercenter.caiso.com/Comments/AllComments/d6824007-f3a8-4d3a-8309-9d9af4729ccf#org-fd4962eb-ba3d-4a0e-b531-602879903c93.

[477] Many fast-start resources have limited or no dispatch range because their economic minimum operating limits are equal to (or are relatively close to) their economic maximum operating limits. A resource that is operating inflexibly at its economic minimum operating limit or economic maximum operating limit is not dispatchable to serve an additional increment or decrement of load and thus is not eligible to set the LMP unless fast-start pricing logic is applied.

FERC examined fast-start pricing as part of a broader price formation initiative.[478] On December 15, 2016, FERC issued a notice of proposed rulemaking ("NOPR") that preliminarily found that certain RTO fast-start pricing practices, or lack of fast-start pricing practices, may not result in rates that are just and reasonable.[479] As a result, FERC proposed establishing several requirements regarding the pricing of fast-start resources and sought comment on those proposed requirements and the need for reform discussed in the NOPR.[480] Based on comments received, FERC withdrew the NOPR, stating it was persuaded to not require a uniform set of fast-start pricing requirements.[481] Instead, FERC initiated targeted section 206 investigations focusing on the fast-start pricing practices in the New York Independent System Operator, PJM, and SPP.[482] As a result of these proceedings, all of the RTOs, other than CAISO, have adopted a form of fast start pricing.[483]

1. EDAM

In response to that FERC NOPR, CAISO filed comments expressing concern that the proposed rule would promote the wrong incentives and undermine the CAISO's efforts to address the current operational challenges in its markets, including the need for more flexible resources in real-time.[484] Specifically, CAISO argued that relaxing the economic minimum operating limit of a fast-start resource to zero could create infeasible dispatches and potentially undermine accurate price signals arising from how the flexible ramping product dispatches and compensates resources to address ramping requirements between two successive real-time market intervals.[485]

While CAISO still has the concerns regarding the efficacy of fast start pricing, CAISO "remains open to the possibility that fast start pricing could result in prices that more accurately reflect

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478 FERC initiated the price formation proceeding in June 2014 in Docket No. AD14-14-000. *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice, Docket No. AD14-14-000 (June 19, 2014). During the initial stages of the price formation proceeding, FERC held a series of public workshops, received comments, and directed the RTOs/ISOs to file reports on several price formation topics, including fast-start pricing. *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221, at P 1 (2015).

479 *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61, 213, at PP 3, 36-37 (2016) (NOPR).

480 *Id.* at PP 3, 44.

481 *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 161 FERC ¶ 61,293 (2017).

482 *N.Y. Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,294 (2017); *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,295 (2017); December 2017 Order, *Southwest Power Pool, Inc*, 161 FERC ¶ 61,296 (2017).

483 The Importance of Fast Start Pricing in Market Design: Including the Cost of Starting and Operating Natural Gas Peaking Units in Wholesale Market Prices, prepared by Powerex and the Public Power Council dated June 2022 at 4. The document can be found at: https://powerex.com/sites/default/files/2022-06/The%20Importance%20of%20Fast%20Start%20Pricing%20In%20Market%20Design%20-%20June%202022.pdf. .

484 CAISO Comments dated February 28, 2017, filed in RM17-3; *see also* CAISO Supplemental Comments dated August 17, 2017. The comments can be found at: https://www.caiso.com/documents/feb28_2017_comments-fast-startpricingnopr_rm17-3.pdf and https://www.caiso.com/documents/aug18_2017_supplementalcomments-fast-startpricingnopr_rm17-3.pdf.

485 February 28, 2017, Comments in RM17-3 at 8-12.

system marginal costs in a regional market context."[486] Accordingly, CAISO has instituted a stakeholder process to continue to look at what pricing enhancements it can make to best reflect marginal costs and meet the operational needs of the system.[487]

2. Markets+

The Markets+ Tariff defines "Fast Start Resource" as

> A Resource with the following submitted offer parameters for a Day-Ahead Market or Real-Time Balancing Market interval: (1) a start-up Time offer of ten (10) minutes or less; and (2) a Minimum Run Time offer of sixty (60) minutes or less. Market Storage Resources (MSR) must also have a Minimum Discharge Time offer of sixty (60) minutes or less to qualify as a Fast-Start Resource. Multi-Configuration Resources (MCR) must also have a Group Minimum Run Time offer of sixty (60) minutes or less to qualify as a Fast-Start Resource.[488]

Markets+ will use separate dispatch and pricing runs to reflect the cost of fast-start resources in the LMP, a cost-minimizing dispatch run is followed by a pricing run. The pricing run entails logic to incorporate the commitment costs of the fast start resources.[489]

3. NV Energy Evaluation

The issue before the Companies and the Commission is not the justness and reasonableness of the CAISO market without fast start pricing.[490] Rather the question is how EDAM without (or potential with) fast start pricing compares to Markets+ with fast start pricing.

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486 *See* Price Formation Enhancements Issue Paper dated July 5, 2022, at 13. The paper can be found at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements.

487 Information on the stakeholder process can be found at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements.

488 Markets+ Tariff Part I Section 1 Definitions.

489 SPP's Filing Letter in Docket No. ER24-1658 at n. 63.

490 In a January 10, 2025, to the Body of State Regulators, Eric Hildebrandt of the CAISO Department of Market Monitoring identified the agreements for and against fast start pricing as follows:

Proponents	Opponents

• FSP results in "improved" price signal (i.e., higher prices when fast start peakers needed to meet demand)
• Increased efficiency from increased offers from importers and other resources (not already offering) in real-time market.
• Decrease bid cost recovery
• Support investment in new supply and ramping capacity
• Higher prices can increase demand response?
• Decrease emissions by reducing use of peakers?
• Higher prices create more incentive to deliver scheduled energy?
• Other ISOs have FSP – so the WEIM should also
	• FSP does not change how units are actually committed or dispatched by the market software
	• Any benefits from increased efficiency, imports or reduced emissions are based on assumption "that bids and offers respond to improved [higher] price signal"
	• FSP creates inconsistency between LMPs and the bid prices of supply and demand
	    o LMPs higher than the marginal cost (or bids) than supply that is not scheduled to operate
	    o LMPs higher than the bid price of some load/exports that clear the market

The major beneficiaries of fast start pricing are the low-cost units that benefit from the higher LMPs. The primary example is a hydro exporter. In contrast, NV Energy's gas-peaking fleets might set higher LMPs during periods when fast start pricing applied, but at the same time Nevada's loads would be exposed to corresponding price increases.[491] Without fast start pricing, NV Energy's peakers are eligible for bid cost recovery payments. In a Markets+ footprint with Arizona and limited connectivity with the Northwest, it is unlikely that fast start pricing will significantly benefit Nevada. Arguments about "fairer" pricing in sales to California though market-to-market seams discussions are speculative. Accordingly, the issue of fast start pricing was not a primary factor in the Companies DAM decision.

G. GHG

Two states, California and Washington, have adopted GHG pricing and capping mechanisms, while others, including Nevada, have adopted GHG reduction requirements and goals. In the DAM GHG stakeholder processes, NV Energy advocated based on four criteria:

(1) To the maximum extent possible, market design should be consistent with state policy objectives;

(2) Willing sellers to the GHG pricing states should be able to recover their compliance costs; however, the compliance cost of a state's policies should not impact the price for demand outside of a GHG regulation area;

(3) The design should reduce secondary dispatch; and[492]

(4) Renewable and non-emitting resources outside of jurisdictions with greenhouse gas policies should not be unfairly disadvantaged compared to renewable and non-emitting resources inside jurisdictions with greenhouse gas programs.

Nevada's Renewable Portfolio Standard ("RPS"), NRS 704.7801, was first adopted by the Legislature in 1997. The RPS sets the percentage of electricity sold each year by providers of electric service to Nevada customers that must come from renewable energy (biomass, geothermal energy, solar energy, waterpower, and wind) or energy efficiency measures. In 2019, Senate

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	• Decrease bid cost recovery from FSP likely to be very limited • Increase in LMP due to FSP not enough to incentivize any more demand response or investment in new supply

https://www.caiso.com/documents/presentation-wem-body-of-state-regulators-fast-start-pricing-dmm-jan-09-2025.pdf.

491 At the April 3, 2024, Commission Workshop in Docket No. 23-10019, Jack Moore of E3 testified that the inclusion of fast start pricing in Market+ and not EDAM had a "minimal impact" on the modeling. Transcript at page 145, line 3. Later he noted that fast stat pricing increased the price during certain hours when NV Energy was in Markets+. Transcript at page 157-158.

492 "Secondary dispatch" occurs when resources outside of a GHG regulation area attributed to serve demand within a GHG regulation area are backfilled by higher emitting resources.

Bill 358 modified the RPS by increasing the percentage of electricity sold each year to Nevadans that must come from renewable energy or energy efficiency measures. The 2019 Nevada Legislature also declared it is the policy of the state of Nevada to:

- Encourage and accelerate the development of new renewable energy projects for the economic, health and environmental benefits provided to Nevadans;
- Become a leading producer and consumer of clean and renewable energy, with a goal of achieving by 2050 an amount of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in Nevada; and
- Ensure that the benefits of the increased use of portfolio energy systems and energy efficiency measures are received by the Nevada residents. Such benefits include, without limitation, improved air quality, reduced water use, a more diverse portfolio of resources for generating electricity, reduced fossil fuel consumption and more stable rates for retail customers of electric services.

The percentage of renewable energy required by the RPS (NRS 704.7821) will increase at a scheduled rate until it reaches 50 percent in 2030. The rate is 34 percent in 2024 through 2026; 42 percent in 2027 through 2029; and 50 percent in 2030 and each year thereafter. The percentage that can be met by demand side management is phased out by 2025. Compliance, under Nevada Administrative Code section 704.8879, is measured by:

(1) The capacity of each renewable energy system owned, operated or controlled by the provider, the total number of kilowatt-hours generated by each such system during the most recently completed compliance year and the percentage of that total amount which was generated directly from renewable energy.

(2) Whether, during the most recently completed compliance year, the provider began construction on, acquired or placed into operation any renewable energy system and, if so, the date of any such event.

(3) The total number of kilowatt-hours sold by the provider to its retail customers in this State during the most recently completed compliance year.

In addition, SB 254 establishes climate targets consisting of an economy-wide GHG Reduction of 28 percent below 2005 by 2025, 45 percent below 2005 by 2030, and net-zero by 2050 (compared to a 2005 GHG emissions baseline). The statute requires the Nevada Department of Environmental Protection to develop an annual GHG inventory, project future emissions and catalog of climate policy options.

1. EDAM

EDAM accounts for GHG emissions by adopting the WEIM resource-specific design to identify which resources serve demand in a state the has policies that price carbon (a "GHG Regulation

Area") with several enhancements.[493] EDAM will introduce a special market run in the day-ahead market, the GHG reference pass, that will use energy bids to optimize dispatch to serve the demand and create a reference schedule that informs the value of a GHG transfer that the market may attribute to a resource.[494] In addition, CAISO will include a GHG net export constraint to reduce the potential for secondary dispatch, preventing the attribution of GHG transfers to resources in BAAs that are net importers and reducing the potential for secondary dispatch.[495]

Under this constraint, attributions of GHG transfers to EDAM resources located in an EDAM BAA outside of a GHG regulation area may not exceed the net exports from that EDAM BAA. If an EDAM BAA is a net importer during any hour, no EDAM resource located within the EDAM BAA may receive an attribution of a GHG transfer during that hour. Although this constraint will restrict attributions in EDAM, it will not apply to "committed capacity" located outside a specific GHG regulation area that is obligated to serve demand within that GHG regulation area, so long as the scheduling coordinator registers that capacity with the CAISO.[496]

When offering bids to serve demand in a state with carbon pricing policies, scheduling coordinators for resources located in BAAs outside submit a two-part bid adder consisting of a GHG bid capacity (MW) quantity and a GHG price ($/MWh).[497] The bid adder reflects the

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[493] CAISO Tariff section 33.32.1.2 describes GHG Regulation Areas. These will reflect the pricing nodes of the CAISO BAA or an EDAM Entity BAA within a state jurisdiction that has priced GHG emissions as part of a state GHG reporting and reduction program. Resources pseudo-tied or dynamically scheduled into a GHG Regulation Area will be considered to be located within that area.

[494] Direct Testimony of Anna McKenna at Q&A 42. CAISO proposes to conduct an optimized GHG counterfactual based on submitted bids after the day-ahead resource sufficiency evaluation but prior to running the integrated forward market. CAISO Tariff section 33.32.2.3. In this process, the CAISO will 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. In the integrated forward market, EDAM would limit an attribution to the lower of: (i) the GHG bid capacity, (ii) the positive difference between a resource's upper economic limit and its GHG reference pass, or (iii) the optimal energy schedule. CAISO Tariff section 33.32.2.2. The CAISO proposes to rely on the EDAM resource's day-ahead schedule to limit the MW value of a real-time GHG transfer. In real-time, this limit will reflect the lower of: (i) the MW value of the GHG bid adder, (ii) the resource's upper economic bid minus the day-ahead energy schedule, plus the resource's total day-ahead attribution to serve demand in a GHG regulation area, or (iii) the resource's real-time market energy schedule. CAISO Tariff section 29.32(b)(2). The difference between the day-ahead energy schedule and the day-ahead attribution reflects the MW value associated with serving load outside the GHG regulation area and is analogous to a base schedule in the WEIM. These rules seek to improve the accuracy of the CAISO's GHG attributions to generation actually dispatched to serve demand in a GHG regulation area. They also address concerns with the potential for secondary dispatch by reducing GHG attributions to resources that would have generated even without demand in the GHG regulation area, as reflected in the EDAM resources' integrated forward market schedules or WEIM resources' base schedules.

[495] CAISO's August 22, 2023, Filing Letter in Docket No. ER23-2686 at 5. *See also,* CAISO Tariff sections 29.32.1 and 33.32.5.

[496] CAISO Tariff sections 29.32.1 and 33.32.5. Committed capacity refers to contracted capacity. This allows capacity owned or contracted to serve demand in a GHG regulation area to receive a full attribution to serve that demand consistent with ownership or contractual entitlements.

[497] CAISO Tariff section 33.32.1.1 describes the use of these bid adders as specific to the current states that price carbon, Washington and California. The CAISO will calculate a maximum GHG bid adder price for each resource located outside each GHG regulation area on a daily basis. This calculation reflects a resource's highest average heat rate on its heat rate curve, the applicable GHG allowance price derived from published indices, and the resource's applicable emission rate. The CAISO also provides an option for resources to negotiate a maximum GHG bid adder

willingness of the resource's scheduling coordinator to make the resource's output available to serve demand within a state with carbon pricing policies, and reflects the cost of compliance with those carbon pricing policies. The market optimization considers the GHG bid adder in addition to the energy bid to determine efficient dispatch and identify which resources serve demand in a state with carbon pricing policies. If a resource does not submit a GHG bid adder, the market does not consider or attribute the resource to serve a state with carbon pricing policies.[498]

CAISO will calculate a separate marginal GHG cost for each GHG regulation area in both the day-ahead and real-time markets. This will create an additional payment above the marginal energy cost, called Greenhouse Gas Emission Cost Revenue, for resources located outside of a specific GHG regulation area that receive an attribution to serve demand in that GHG regulation area. The applicable marginal GHG cost for a GHG regulation area will reflect the GHG bid adder of the marginal resource selected through the market optimization to serve demand in that GHG regulation area.[499] In the day-ahead market, GHG payments to resource scheduling coordinators will reflect the product of the obligation to serve demand in a specific GHG regulation area and the marginal GHG cost from the integrated forward market for the respective GHG regulation area. EDAM will collect these payments through locational marginal prices paid by load in the GHG regulation areas.[500]

For resources located in California and for resources located in EDAM BAAs, the CAISO will notify scheduling coordinators of their reference pass schedules and their market results reflecting the MW quantity of any energy supporting transfers that served a particular GHG regulation area. The CAISO also will have the authority to disclose information regarding GHG transfers to a governmental authority only so long as the information does not disclose confidential information of any market participant. The CAISO intends to disclose such information to governmental authorities involved in overseeing state GHG policies. The CAISO proposes parallel obligations related to GHG transfers in the WEIM. These tariff provisions will ensure market participants have access to the data needed to meet their compliance obligations, and state agencies can review aggregated data relevant to their programs.[501] The CAISO also will establish offset accounts in the day-ahead market and real-time market for marginal GHG costs associated with a specific GHG Regulation Area to ensure there is a balance between amounts collected from demand in a GHG

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for each regulation area. Bid adders will be not less than $0/MWh and not greater than 110 percent of the resource's maximum GHG bid adder price GHG maximum compliance cost. *See,* CAISO Tariff at section 33.32.1.3.

498 CAISO's August 22, 2023, Filing Letter in Docket No. ER23-2686 at 19.

499 *Id.* at 173.

500 *Id.* These rules help ensure resources that offer their supply and receive an attribution through the day-ahead market to serve demand in a GHG regulation area receive compensation for the compliance obligations they will face as electricity importers into a GHG regulation area. In addition, the rules ensure demand within the GHG regulation area bears the cost of that payment. Locational marginal prices for supply serving demand outside of a GHG regulation area will not reflect these costs. Real-time market settlements of GHG payments reflect deviations or imbalances from day-ahead market settlements. A resource's fifteen-minute market settlement for GHG payments associated with an attribution to serve demand in a specific GHG regulation area reflects any imbalance from the resource's day-ahead attribution for that GHG regulation area. A resource's real-time dispatch GHG settlement for a specific GHG regulation area reflects any imbalance from the resource's fifteen-minute market GHG attribution for that GHG regulation area. This is similar to how the WEIM works today.

501 CAISO August 22,2023, Filing Letter in FERC Docket No. ER23-2686 at 176.

regulation area and payments made to compensate resources that receive an attribution to serve that demand.[502]

CAISO has an ongoing stakeholder process examining GHG accounting and reporting approaches that can be used in states that have reporting obligations but do not price carbon or for regulators or entities that want additional data associated with energy and emissions used to serve load.[503]

2. Markets+

Under the Markets+ GHG framework, states with GHG pricing and capping programs will be designated as GHG Pricing Zones. Energy from Resources internal and external to a GHG Pricing Zone may be attributed to serve load in the Zone. Market Participants will utilize a GHG adder in their Resource Offers to reflect the costs of compliance within the GHG Pricing Zone.[504] Under Markets+ there are three types of energy that can be attributed to a GHG Pricing Zone:

- Type 1A is energy from a specified resource with a commitment to supply load in a GHG Pricing Zone.[505] Type 1A Energy will be considered in the market clearing engine using the sum of its Energy offer price and Specified GHG Adder.[506] If a Specified Source Resource is economic and receives a market dispatch, its Type 1A Energy will be attributed to the GHG Pricing Zone where the load it is contracted to serve is located.[507] While Type 1A Energy Offers, like all Offers, may set the LMP for Markets+, Type 1A Energy will only be dispatched, and the underlying Offers will only set LMP, if it is economic compared to all Energy Offers. The Type 1A Energy offer must not exceed the projected load to which the Type 1A Energy is contracted.[508] A Market Participant offering a Specified Source Resource as Type 1A Energy must have transmission service, or be able to demonstrate the ability to procure transmission service, to the load to which the Type 1A Energy is committed.[509]

- Type 1B also is Energy from a Specified Source Resource with an agreement to supply load within a GHG Pricing Zone.[510] Type 1B Energy differs from Type 1A Energy in that Type 1B Energy may be available to a GHG Pricing Zone or to an area outside of a GHG Pricing Zone.[511] The market clearing engine will evaluate whether the GHG Pricing Zone requires additional Energy and, if needed, will consider the Type 1B Energy for attribution

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502 CAISO Tariff sections 33.11.3.9.2 and 11.5.4.1.4.
503 Direct Testimony of Anna McKenna at Q&A 43. The CAISO has an ongoing stakeholder initiative focused on: (1) a review of market operations and GHG design; (2) coordination with state air regulators on climate policies; (3) discussion of data needs for emissions tracking and accounting and (4.) re-examination of how the market could reflect climate policies that do not explicitly price carbon. This effort includes assessing how EDAM and WEIM may provide a means for utilities to assess which resources operated to support load in regions that do not price GHG as well as insight into the residual emissions intensity when that utility is a net importer.
504 SPP March 29, Filing Letter in FERC Docket No. ER24-1658 at 11.
505 Markets+ Tariff, Part I, Section 1 (Definition of Type 1A Energy).
506 *Id.* at Attachment K, section 3.2.2.
507 *Id.*
508 *Id* at section 2.1.
509 *Id.* at section 2.2.
510 *Id.* at Part I, Section 1 (Definition of Type 1B Energy).
511 *Id.* at Attachment K, section 3.1.

to the GHG Pricing Zone. The Specified GHG Adder will only be included in the cost of Type 1B Energy if it is attributed to the GHG Pricing Zone.[512]

- Type 2 energy is not owned or contracted to load within a GHG Pricing Zone. Type 2 Energy is Energy from a Specified Source Resource that is in excess of the Specified Source Resource's "Surplus Threshold," which is the quantity of Energy that must be exceeded for the GHG Pricing Zone to have access to that Resource's excess Energy.[513] A Market Participant must include a Specified GHG Adder in its Resource Offer when offering Type 2 Energy. Type 2 Energy is available to be attributed to a GHG Pricing Zone or to an area outside of a GHG Pricing Zone. A Surplus Threshold may be submitted by a Market Participant or calculated via a merit order process.[514]

Figure 40[515]

Type	Must Include a Specified GHG Adder	GHG Adder Included in the Cost of Dispatch	Available to Serve a GHG Pricing Zone	Available to Serve the Area Outside of a GHG Pricing Zone	Has an underlying agreement to Serve Load in a GHG Pricing Zone	Has a Surplus Threshold
Type 1A	Yes	Yes	Yes	No	Yes	No
Type 1B	Yes	Only if attributed to Zone	Yes	Yes	Yes	No
Type 2	Yes	Only if attributed to Zone	Yes	Yes	No	Yes

With respect to GHG reporting Markets+ is working on an accounting approach.[516] The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load.

3. NV Energy Evaluation

Both DAMs have programs to facilitate compliance with California and Washington GHG pricing programs. An important element of the design is that these states should not export the cost of GHG compliance onto customers in other states. NV Energy supports the extension of the EIM approach.[517] The Commission has accepted this methodology as a just and reasonable means to accommodate GHG policies without imposing unwarranted costs on customers in other states and without discriminating against non-California renewable resources. The EDAM tariff represents an enhancement to the program that has been working for the EIM.

512 *Id.* at Attachment K, section 3.2.5
513 *Id.* at section I (Definition of Surplus Threshold).
514 Markets+ Tariff Attachment K, Sections 3.4, 3.6.
515 SPP March 29, Filing Letter in FERC Docket No. ER24-1658 at 41.
516 *See,* SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).
517 Direct testimony of Lindsey Schlekeway at Q&A 29.

CAISO has proposed to implement a net export constraint as a measure to limit the secondary dispatch. Secondary dispatch has been identified as a phenomenon that could occur where higher-emitting resources may backfill to serve load in BAAs located outside of California when lower emitting resources are attributed to serving California. The Companies support the use of this constraint to limit the secondary dispatch and supports the proposal to remove the constraint with a resource sufficiency failure.[518] Market constraints that are utilized for emission accounting or attribution should not have an impact on reliability. In principle, market designs to support state GHG policies should not have a negative impact to reliability or harm the economic benefits for participants located outside that GHG region.

As explained in the Direct Testimony of Lindsey Schlekeway, the Companies have concerns that the Markets+ program and the specifications regarding Type 1A resources.[519] Specifically, if Type 1A is not dispatched to its full contractual amount, then it still is unavailable to the non-GHG market footprint even if it were an economic option. This essentially withholds the capacity that is available to serve part of the market footprint from serving the remaining part of the footprint.[520] In a second scenario, the Type 1A resource may be a marginal setting prices within the Markets+ footprint or being dispatched above the load that it serves in the GHG zone resulting in an uneconomic outcome for the non-GHG zone in which it would bear the compliance costs.[521]

H. Demand Response and Distributed Energy Resource Participation

Federal Power Act ("FPA") section 201 authorizes FERC to regulate the transmission of electric energy in interstate commerce and the wholesale sale of electric energy in interstate commerce, as well as all facilities used for such transmission or sale of electric energy.[522] FPA sections 205[523] and 206[524] provide FERC with jurisdiction over all rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to FERC's jurisdiction. Those sections also provide FERC with jurisdiction over all rules, regulations, practices, or contracts affecting jurisdictional rates, charges, or classifications.

In *FERC v. Electric Power Supply Ass'n.*, the U.S. Supreme Court interpreted the FPA as providing FERC with jurisdiction over the participation in RTO/ISO markets of demand response resources: a type of non-traditional resource that, by definition, is located behind a customer meter and generally is located on the distribution system.[525] Similarly, FERC's authority to issue regulations pertaining to distributed energy resource aggregations stems from both FERC's jurisdiction over the wholesale sales by distributed energy resource aggregators into RTO/ISO markets and from its

518 *Id.*
519 Direct Testimony of Lindsey Schlekeway at Q&A 31.
520 *Id.*
521 *Id.*
522 16 U.S.C. 824.
523 16 U.S.C. 824d.
524 16 U.S.C. 824e
525 *FERC v. Electric Power Supply Ass'n*, 136 S. Ct. 760, 776 (2016) (EPSA)). First, the Court found that FERC's regulation of demand response participation in wholesale markets met the "affecting" standard in FPA sections 205 and 206 "with room to spare." EPSA, 136 S. Ct. at 774 (referring to the Commission's jurisdiction under FPA sections 205 and 206 to regulate practices affecting jurisdictional rates). Second, the Court found that the Commission's regulation of demand response resources did not regulate retail sales in violation of FPA section 201(b). *Id.* at 784.

jurisdiction over practices affecting wholesale rates.[526] FERC Orders Nos. 719,[527] 745,[528] and 2222[529] have set the minimum requirements for treatment of demand response and distributed energy resources participating in RTO and ISO markets.

In 2008, FERC issued Order No. 719, which made several reforms to further eliminate barriers to demand response participation in organized energy markets. These reforms sought to ensure that demand response is treated comparably to other resources. In 2011, FERC addressed compensation for demand response participation in Order No. 745. FERC required each RTO and ISO to pay a demand response resource the market price for energy (locational marginal price or LMP) when the demand response resource can balance supply and demand as an alternative to a generation resource and dispatch of the demand response resource is cost-effective. In 2016, the Supreme Court upheld Order No. 745 in *FERC v. Electric Power Supply Ass'n.*

FERC's Order No. 2222 required RTOs/ISOs to revise the Tariff to facilitate participation by distributed energy resource aggregators.

> For each RTO/ISO, the tariff provisions addressing distributed energy resource aggregations must (1) allow distributed energy resource aggregations to participate directly in RTO/ISO markets and establish distributed energy resource aggregators as a type of market participant; (2) allow distributed energy resource aggregators to register distributed energy resource aggregations under one or more participation models that accommodate the physical and operational characteristics of the distributed energy resource aggregations; (3) establish a minimum size requirement for distributed energy resource aggregations that does not exceed 100 kW; (4) address locational requirements for distributed energy resource aggregations; (5) address distribution factors and bidding parameters for distributed energy resource aggregations; (6) address information and data requirements for distributed energy resource aggregations; (7) address metering and telemetry requirements for distributed energy resource aggregations; (8) address coordination between the RTO/ISO, the distributed energy resource aggregator, the distribution utility, and the relevant electric retail regulatory authorities; (9) address modifications to the list of resources in a distributed energy resource aggregation; and (10) address market participation agreements for distributed energy resource aggregators.[530]

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[526] *See Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 964 F.3d at 1186 ("FERC bears the responsibility of regulating the wholesale market, which encompasses 'both wholesale rates and the panoply of rules and practices affecting them.") (quoting *FERC v. Electric Power Supply Ass'n*, 136 S. Ct. at 773).

[527] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g, Order No. 719-A, F*ERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g,* Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[528] *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Order No. 745, 134 FERC ¶ 61,187, *order on reh'g & clarification,* Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied,* Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n v. FERC,* 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. FERC v. Elec. Power Supply Ass'n,* 136 S.Ct. 760 (2016).

[529] *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators,* Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g,* Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g,* Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[530] *Order No. 2222* at P 8.

Additionally, Order No. 2222 required that each RTO/ISO must accept bids from a distributed energy resource aggregator if its aggregation includes distributed energy resources that are customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year.[531]

There is one important distinction between demand response and distributed resource participation. With regard to demand response, the participation must be in accordance with the requirements of the state commission. This "opt-out/opt-in" provision was established in FERC Order Nos. 719 and 719-A.[532] and refers to the prohibition on demand response resources from participating in a distributed energy resource aggregation in an RTO market if the relevant electric retail regulatory authority does not opt into permitting demand response participation. Specifically, the Code of Federal Regulations at 18 CFR 35.28(g)(1)(iii)). provides:

> ***Aggregation of retail customers.*** Each [FERC]-approved independent system operator and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, ***where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers***. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers. (emphasis added).

FERC declined to include a similar state commission opt out provision for distributed energy resources[533] finding "that the benefits of allowing distributed energy resource aggregators broader access to the wholesale market outweigh the policy considerations in favor of an opt-out."[534]

1. EDAM

The EDAM design accounts for emergency or load modification programs. The CAISO's two demand response models that allow load modification programs to participate in the market as load curtailment will be available in EDAM. As shown in Figure 41, these models allow supply

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531 *Id.*

532 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008) at PP 154-155, *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). EPSA, 136 S. Ct. at 779 (describing the opt-out as a "notable solicitude toward the States," in recognition of "the linkage between wholesale and retail markets and the States' role in overseeing retail sales.")

533 Order No. 2222 at PP 56-67.

534 *Id.* at P. 60.

side demand response to offer supply bids into the market as either price responsive or reliability triggered load curtailment, and they include metering and telemetry requirements.

Figure 41

Design	Service	Market Dispatch	Description
Proxy Demand Resource (PDR)[535]	Energy, spinning and non-spinning reserves, and residual unit commitment	Economic day-ahead and real-rime	Bids into CAISO markets as supply
Reliability Demand Response Resource[536]	Energy	Economic day-ahead and reliability real-time	Bids into CAISO markets as supply; used for reliability purposes

In recognition that EDAM Entities may have their own demand response programs that may not align with these existing CAISO market models, EDAM allows EDAM BAAs to represent load modification programs, or supply types that can only be utilized during real time emergencies, through a demand forecast adjustment similar to that used in the WEIM;[537] these modifications can be utilized in both the EDAM RSE and the RUC process.[538]

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535 CAISO Tariff Section 30.6.1 Bidding and Scheduling of PDRs Unless otherwise specified in the CAISO Tariff and applicable Business Practice Manuals, and subject to Section 30.6.3, the CAISO will treat Bids for Energy and Ancillary Services on behalf of Proxy Demand Resources like Bids for Energy and Ancillary Services on behalf of other types of supply resources. The CAISO will only accept the following types of Bids from Proxy Demand Resources: (i) Economic Bids for Energy or Ancillary Services; (ii) submissions to Self-Provide Ancillary Services; (iii) submissions of Energy Self-Schedules from Proxy Demand Resources that have provided Submissions to Self-Provide Ancillary Services; (iv) submissions of Energy Self-Schedules in the Real-Time Market up to the Proxy Demand Resource's Day-Ahead Market Schedule in the same Trading Hour; (v) RUC Availability Bids; and (vi) Imbalance Reserves Bids. A Scheduling Coordinator for a Demand Response Provider representing a Proxy Demand Resource may Self-Provide Ancillary Services for which it is certified. The Demand Response Provider's Demand Response Services for Proxy Demand Resources will be bid separately and independently from the LSE's underlying Demand Bid.

536 CAISO Tariff Section 30.6.2 Bidding and Scheduling of RDRRs Unless otherwise specified in the CAISO Tariff and applicable Business Practice Manuals, and subject to Section 30.6.3, the CAISO will treat Bids for Energy on behalf of Reliability Demand Response Resources like Bids for Energy on behalf of other types of supply resources. The CAISO will only accept Economic Bids for Energy from Reliability Demand Response Resources. A Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource may submit Economic Energy Bids for the Reliability Demand Response Resource only in the Day-Ahead Market and in the Real-Time Market, but may not submit Energy Self-Schedules for the Reliability Demand Response Resource, may not Self-Provide Ancillary Services from the Reliability Demand Response Resource, and may not submit RUC Availability Bids, Ancillary Service Bids for the Reliability Demand Response Resource, or Imbalance Reserves Bids. The Demand Response Provider's Demand Response Services for Reliability Demand Response Resources will be bid separately and independently from the LSE's underlying Demand Bid.

537 NV Energy is not directly participating in the WEIM, but provides load impact forecast information for demand response event to CAISO. The load shape submitted to CAISO accounts for the projected demand response event impacts in the current WEIM scenario. Direct Testimony of Michael Brown at Q&A 12.

538 EDAM Final Proposal at 69. *See also*, CAISO Tariff at section 33.31.4.1 Load Modification/Demand Response Programs:

> An EDAM Entity may elect to adjust its Demand Forecast to account for demand response programs administered in its BAA that do not qualify as EDAM Resource Facilities in accordance with

The demand forecast adjustment represents an expectation and a commitment the EDAM BAA will utilize these programs in real time if forecasted conditions materialize; effectively these programs become a part of the EDAM BAA's day-ahead plan. CAISO will review load modifications made to the EDAM RSE requirement against demand response utilization in real-time to ensure this functionality is not being used to pass the EDAM RSE erroneously.[539]

On June 17, 2022, the FERC issued an order accepting CAISO's Order No. 2222 compliance filing, subject to a further compliance filing,[540] CAISO made the required compliance filing on August 15, 2022, and submitted an amendment on January 10, 2023. FERC accepted the compliance filing on May 18, 2023.[541] CAISO's Order No. 2222 tariff changes went into effect on November 1, 2024.[542] CAISO Tariff section 4.17 outlines the requirements for distributed energy resource aggregations.

Participation of distributed energy resources ("DER") and demand side resources ("DSR") in the markets is still growing and evolving. There are ongoing workshops to address gaps and barriers to effective participation of DERs and DSRs in the markets.[543] CAISO established a series of Demand and Distributed Energy Market Integration ("DDEMI") working group meetings in order to collaborative work with stakeholders to improve participation models and market rules in the day-ahead and real time markets. Stakeholders have identified a series of discussion topics, including: (1) performance evaluation methodologies, (2) economic-based demand response participation model, (3) reliability-based demand response participation, (4) DER participation, (5) expansion of demand side bidding options; and (6) enhancing demand flexibility market options.[544]

2. Markets+

Market participants may register demand-side resources as Dispatchable Demand Response ("DDR") Resources. A DDR Resource is a special type of Resource created to model demand reduction associated with controllable load and/or a behind-the-meter generator that is dispatchable on a 5-minute basis. DDR Resources must meet all application, registration and

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procedures set forth in the Business Practice Manual for the Extended Day-Ahead Market. When enabled, the EDAM Entity will enable or deploy the demand response corresponding to the adjustment consistent with the applicable requirements for such demand response programs. If the EDAM RSE for the CAISO BAA is adjusted to reflect demand response resources participating in demand response programs administered in its BAA that do not qualify as RSE-eligible EDAM Resource Facilities, then the CAISO may adjust RUC participation to correspond to such adjustment in accordance with the procedures set forth in the Business Practice Manual for the Extended Day-Ahead Market. If such an adjustment is made, the CAISO will enable or deploy the demand response corresponding to the adjustment consistent with the applicable requirements for such demand response programs. Adjustments made pursuant to this Section 33.31.4.1 are subject to audit and monitoring as provided in Section 33.38.

539 EDAM Final Proposal at 69.

540 *Cal. Indep. Sys. Operator Corp.*, 179 FERC ¶ 61,197, *order on reh'g*, 181 FERC ¶ 61,035 (2022).

541 *Cal. Indep. Sys. Operator Corp.*, 183 FERC ¶ 61,119 (2023).

542 *See* CAISO's November 5, 2024, informational filing in FERC Docket No. ER21-2455.

543 Direct Testimony of Michael Brown at Q&A 9.

544 *Id.* at Q&A 10.

technical requirements applicable to other resources offering imbalance energy in Markets+.[545] End-use customers aggregated into a single resource must be located at the same electrically equivalent withdrawal point from the transmission system and must be served by the same retail provider, and all end-use customers in an aggregation must be specifically identified.[546]

Coordination with the BA and confirmation that the resources are not already claimed by another entity is required. A market participant planning to offer Demand Response Load in the form of a demand response Resource in Markets+ must include in its application and registration a certification that participation in Markets+ by its demand response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority.[547]

With respect to distributed energy resources, the Markets+ filing in FERC Docket No. ER24-1658 did not mention compliance with FERC Order No. 2222. Public Service Company of Colorado has noted that FERC Order 2222 applies to regional grid operators, and because SPP will not be operating Markets+ in its capacity as an RTO, the order does not apply to Markets +.[548]

3. NV Energy Evaluation

NV Energy currently has a Demand Side Management ("DSM") Program Portfolio. Within this portfolio, NV Energy 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.[549] 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 Sierra'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 120 MW. NV Energy gives customers an energy market rebate for the energy they use.[550]

NV Energy 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.[551] NV Energy is currently replacing its existing Demand Response Management System ("DRMS") with a more integrated and functional Distributed Energy Resource Management System ("DERMS") that has been specified to support market integration. The upgrade is being implemented in a multistage upgrade process.[552]

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545 Markets+ Tariff, Attachment A, Section, 6.2(8).
546 *Id.*
547 *Id.* at Attachment A, Sections 6.1, 6.2(8).
548 *See* Exhibit No. 101, Direct Testimony and Attachments of Joseph C. Taylor filed with the Colorado Public Utilities Commission on February 14, 2025, in Proceeding No. 25A-0075E at 34.
549 Direct Testimony of Michael Brown at Q&A 12.
550 *Id.*
551 *Id.*
552 *Id.* at Q&A 11.

- Phase 1a (completed), improved the security of device communications for the existing DRMS. The DERMS team has finalized the design of phase 1b, which is scheduled to go live in the second quarter of 2026. This phase will replace the existing DRMS software.

- Phase 2 of the 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. Phase 2 of this upgrade process, when completed, will help NV Energy to improve automation and decision making regarding optimal economic dispatch of DERs. As such NV Energy is closely monitoring the requirement definitions. These phases will likely be completed before NV Energy enters EDAM and therefore the design and requirements should keep EDAM in focus so that NV Energy can participate with these enhanced functionalities in the EDAM market. NV Energy is expecting DERMS phase 2 to go live in 2028.[553]

While both EDAM and Markets+ have provisions to facilitate participation by demand response providers, only EDAM appears to accommodate biding by aggregators of distributed energy resources. NV Energy understands that CAISO's Order No. 2222 compliance filing has been accepted and implemented.[554] In contrast, even in the SPT RTO compliance with Order No. 2222 is not expected until 2030.[555] Moreover, SPP and certain Markets+ participants appear to be taking a view that Order No. 2222 only applies to RTO and ISO markets and since Markets+ is a separate service offering the requirement to facilitate participation by distributed energy resource aggregators is inapplicable.[556]

As noted by Michael Brown in his Direct Testimony, NV Energy needs to evaluate: (1) current program utilization and characterization; (2) how existing contracts would process curtailments; (3) whether the Companies tariffs and associated contracts could be updated to have more market-oriented definitions and approaches; and (4) metering and telemetry for existing programs.[557] NV Energy must consider how these properties relate to the market registration rules.[558] As Mr. Brown also recommends:

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553 *Id.*

554 Direct Testimony of Anna Mckenna at Q&A 44.

555 *See,* SPP's December 13, 2024, Order No. 2222 Compliance Filing in Response to March 2024 Order filing in FERC Docket No. ER22-1697 at 51 ("Given the practical impossibility of implementing a multi-nodal aggregation by the third quarter of 2025, SPP proposes a new implementation date of the second quarter of 2030, assuming that the Commission issues an order approving the instant compliance filing by March 1, 2025"). NV Energy understands that FERC has not issued an order at yet.

556 Exhibit No. 101, Direct Testimony and Attachments of Joseph C. Taylor filed with the Colorado Public Utilities Commission on February 14, 2025, in Proceeding No. 25A-0075E at 34 ("FERC Order 2222 applies to regional grid operators, and because SPP will not be operating Markets+ in its capacity as an RTO, the order does not apply to Markets +.)".

557 Direct Testimony of Michael Brown at Q&A 11.

558 *Id.*

> If NV Energy's request to join EDAM is granted as requested, the Companies would propose the Commission conduct a workshop (or potentially several workshops) to examine how best to approach Nevada DERs and DSRs with respect to the CAISO market. This could include indirect participation through NV Energy programs leveraging GSRs tied to market outcomes as well as requirements for direct DER and DSR participation. It could also explore potential additional changes needed to the Companies' Open Access Transmission Tariff ("OATT") to accommodate Nevada DERs and DSRs. The Companies do not anticipate commencing EDAM participation until the Fall of 2028. So, there is time for stakeholders to discuss and develop appropriate participation and coordination methods. Given the technological advances in this area, as well as continued improvements in CAISO's own DER and DSR market designs, it will be important to provide regular check-ins with the Commission and stakeholders regarding participation methods that should benefit customers and ratepayers.[559]

I. Market Monitoring and Market Power Mitigation

In Order No. 2000, FERC recognized that:

> Market monitoring is an important tool for ensuring that markets within the region covered by an RTO do not result in wholesale transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power. In addition, market monitoring will provide information regarding opportunities for efficiency improvements.[560]

In a 2005 Policy statement, FERC noted that market monitoring units, "perform an important role in assisting [FERC] in enhancing the competitiveness of ISO/RTO markets" and " identify ineffective market rules and tariff provisions, identify potential anticompetitive behavior by market participants, and provide the comprehensive market analysis critical for informed policy decision making."[561] FERC recognized that "RTO markets are operationally complex" and found that market monitoring units "should have access to data and other resources to evaluate participant behavior and responses in these markets."[562] FERC noted, "[i]t is critical that the MMU provide the ISO/RTO and [FERC] with its perspective and expertise in the development of market rules and tariff provisions," and [i]t is also essential that the MMU work proactively in identifying market design flaws, and provide assistance to the ISO/RTO in developing appropriate rule changes that will promote reliable and efficient operation of the wholesale markets."[563]

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559 *Id.* at Q&A 16.

560 *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, 1996–2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 90 FERC ¶ 61,201, 1996– 2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *petitions for review dismissed sub nom.* Pub. Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001). Regional at page 462. Order No. 2000 can be found at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-000.pdf.

561 *Market Monitoring Units in Regional Transmission Organizations and Independent System Operators*, 111 FERC ¶ 61,267 (2005).

562 *Id.* at P 3.

563 *Id.* at P. 4

In 2008, FERC issued Order No. 719 establishing the requirements for the market monitoring unit's core functions: evaluating market rules, tariff provisions and market design elements for their effectiveness and proposing recommended changes, reviewing and reporting on the performance of the wholesale markets and referring suspected wrongdoing to FERC. Additionally, Order No. 719 requires that the market monitor "report to the RTO or ISO board of directors, with management representatives on the board excluded from this oversight function."[564]

1. EDAM

CAISO's Department of Market Monitoring's ("DMM") mission is to "provide independent oversight and analysis of the CAISO [m]arkets 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."[565] The DMM is structured as an internal business unit of CAISO, but is fully independent of CAISO management and reports directly to the CAISO Board. The DMM may rely on CAISO for legal support, provided there is no potential for a conflict of interest, but can also use outside legal counsel. The DMM has direct access to the full Board, and each individual Board member at any time, as it deems necessary. The DMM Oversight Committee consists of two CAISO Board members and a WEM Governing Body member as an observer.

In addition to the DMM, CAISO established the Market Surveillance Committee ("MSC") to provide independent external expertise and recommendations to the CAISO Chief Executive Officer and CAISO Board of Governors.[566] The MSC is separate and independent from the DMM and market participants. A minimum of three outside experts are nominated by CAISO's Chief Executive Officer and approved by the Board of Governors and the WEM Governing Body for staggered 3-year terms. Their expertise is in economics, operational aspects of generation and transmission, antitrust or competition law in regulated industries, and energy and commodities trading financial expertise. The MSC serves to provide independent review of market performance and market power problems, develop a record of structural problems and propose corrective action, and review rule changes, penalties, and sanctions. The MSC may also review and comment on DMM analyses and reports.

The WEM Governing Body receives its own independent market analysis through the Governing Body Market Expert. This individual reports only to the WEM Governing Body and is tasked with providing comprehensive explanations and technical opinions, as requested. The position came from a Governance Review Committee recommendation and was jointly approved by the WEM Governing Body and CAISO Board of Governors in the fall of 2021. This position is expressly not a market monitoring function, but rather advises the WEM Governing Body on the fairness and efficacy of market rules, business practices, and market design alternatives consistent with their mission to promote the success of WEIM and EDAM for all market participants.

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[564] Removing the MMU from reporting to management gives it the separation needed to foster independence. Order No. 719. 73 FR 61,400 (Oct. 28, 2008), FERC Stats. & Regs. at 339.

[565] CAISO Tariff, Appendix P, section 1.2.

[566] CAISO Tariff Appendix O, section 1.1. The MSC presents to both the WEM Governing Body and the Board as well as conducting regular public meetings with stakeholders. Information on the MSC can be found on the CAISO website at: https://www.caiso.com/meetings-events/topics/market-surveillance-committee.

Separate from but related to the market monitoring function is the manner the DAMs identify and mitigate market power. For EDAM, CAISO will extend its BAA-level market power mitigation currently used in the WEIM to EDAM BAA. CAISO deems the marginal energy price in the CAISO BAA as competitive and then applies a dynamic competitive price assessment ("DCPA") when an EDAM BAA's marginal energy cost is greater than the CAISO's marginal energy cost.[567] The DCPA tests if three or fewer generators can provide pivotal supply (counter flow) to a binding transmission constraint and affect prices. The binding constraint is considered uncompetitive if supply counter flow from the three largest pivotal suppliers is required to satisfy it. In this case, energy bids for resources that provide counter-flow are subject to mitigation.[568] CAISO mitigates energy bids for these resources above the competitive LMP to the lower of their submitted bid or the respective CAISO generated default energy bid ("DEB").[569] In the day-ahead, CAISO runs two market passes. The first is the market power mitigation pass that uses unadjusted bids, and the second is the IFM pass that uses mitigated bids.

In the context of the WEIM, CAISO performs a DCPA to test if the supply in an individual WEIM BAA can meet the demand competitively or provide counter-flow on congested transmission constraints within the BAA. Where the binding constraint is the BAA power balance constraint, then all supply resources provide supply counter-flow. The CAISO only performs the DCPA when there are binding transfer limits in the import direction to that BAA that restrict external resources from meeting internal demand. When this test fails, the energy bids of all supply resources in the respective WEIM BAA are mitigated. [570]

In addition, the CAISO market design allows resources to submit separate bid components for their market bid for energy above minimum load, minimum load costs, start-up costs and, for multi-stage resources, their transitions from one configuration to another. Minimum load, start-up, and transition costs are collectively referred to as "commitment costs." CAISO protects the market against market power exercise through commitment cost bidding by validating resource submitted commitment cost bids against a threshold value, the default commitment cost calculation. The commitment cost multiplier applied to this calculation provides a range above the cost-based calculation within which resource submitted values are validated.[571] Resource submitted values in excess of the threshold are capped at the resource-specific default commitment cost value.

2. Markets+

The market monitoring plan for Markets+ is set forth in Attachment C to the Markets+ Tariff. The SPP Market Monitor, also referred to as the Market Monitoring Unit or "MMU", is an organization within SPP that reports to the Board of Directors and has a wide range of authority to investigate

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567 CAISO October 11, 2023, Answer in Docket No. ER23-2686 at 131.

568 EDAM Final Proposal dated December 7, 2022, at 87.

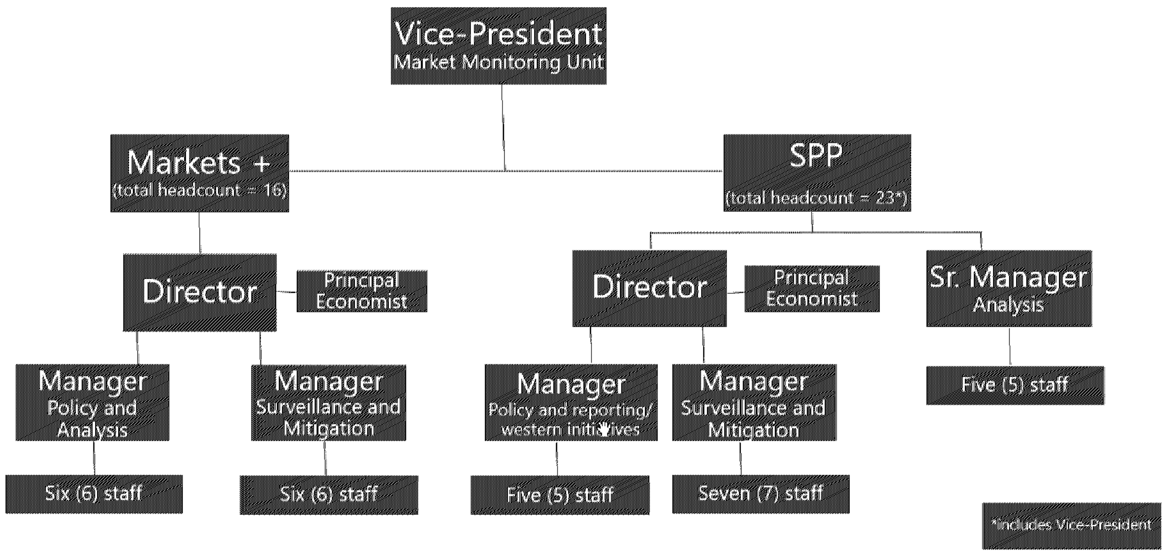
569 DEBs represent an approximation of the resource's nominal marginal cost, and they can include fuel costs, opportunity costs, and other costs. The competitive LMP is the LMP at the resource location as calculated in the MPM run, excluding marginal congestion contributions from uncompetitive constraints.

570 EDAM Final Proposal dated December 7, 2022, at 87. *See also,* CAISO Tariff section 29.39(a).

571 Under the current design, the ISO calculates daily "reference levels" for each natural gas generator that are based on published natural gas price indices. Commitment cost bids are capped at reference levels determined by 125 percent of the ISO-calculated costs. The ISO sets reference levels for energy above minimum load at 110 percent of its calculation of each resource's costs. These energy reference levels are referred to as "default energy bids.

and report on market activities.[572] The mission of the MMU is to: (1) monitor and report on possible abuses of market power and gaming; (2) identify market design flaws and recommend changes in design; and (3) monitor compliance with market rules.[573] Additionally, the MMU focused on development and maintenance of surveillance screens and tools, screening for market power and mitigation issues; works with market participants to understand individual issues impacting their participation in the market; and investigates and refer potential issues where warranted.[574] Figure 42, depicts the MMU organization.

Figure 42



For Markets+, the SPP Market Monitor will conduct a market power test, a conduct test, and a market impact test on market offers to detect the potential exercise of market power.[575] First, the market power test is designed to identify whether a selling participant can significantly affect prices and consists of three criteria to determine whether a resource has market power: (1) whether the resource is necessary to relieve congestion;[576] (2) whether the resource is committed as a reliability must run resource; and (3) within its reserve zone, whether the resource is owned by a pivotal supplier.[577] Second, the conduct test examines whether a resource's market offer exceeds a certain price threshold beyond the resource's mitigated offer. SPP proposes to set the conduct

572 Markets+ Tariff, Attachment C, Section 3.1.
573 *Id.* at Attachment C, Section 1.3.1
574 *See* Markets+ Participants Executive Committee Meeting Materials for August 5, 2025 at Item 11 External Market Advisor Scope, at slide 6. The document can be found at: https://spp.org/spp-documents-filings/?id=370747.
575 Markets+ Transmittal Letter in FERC Docket No. ER24-1658 at 72; *see* Markets+ Tariff Attachment B, section 3.1 (Market Power Test); section 3.3 (Mitigation Measures for Energy Offer Curves); section 3.4 (Mitigation Measures for Start-Up Offers and No-Load Offers); section 3.5 (Mitigation Measures for Flexibility Reserve Product Offers); section 3.6 (Validation of Mitigated Resource Offers); section 3.7 (Additional Mitigation Measures for Resource Offer Parameters); and section 3.8 (Market Impact Test).
576 Markets+ Tariff Attachment B, section § 2 and 2.2.
577 *Id.* at section 3.1 (Market Power Test). SPP proposes to define a Reserve Zone as a zone, containing a specific group of Pnodes, for which minimum and maximum flexibility reserve product requirements are calculated. *Id.*, part I, section 1.R (Definitions).

threshold for a resource's market energy offer to 10 percent above its mitigated offer.[578] Third, the market impact test evaluates whether applying mitigation measures to a resource found to have market power would result in a more competitive market outcome. A resource's offer would fail the market impact test when one of the following conditions is met: (1) aa LMP or Market Clearing Price at a settlement location exceeds the corresponding price from the market solution with mitigation measures applied by the applicable impact test threshold; or (2) a make-whole payment for any resource exceeds the corresponding make-whole payment from the market solution with mitigation measures applied by the make-whole payment impact test threshold.[579] For market offers that fail all three tests, SPP will systematically replace the market offer with a mitigated, or cost-based, offer.[580] Finally, SPP proposes thresholds for screening for withholding transmission facilities.[581]

3. NV Energy Evaluation

Core functions of independent market monitors include: (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; (3) notify FERC Office of Enforcement when a market participant or the ISO has engaged in conduct that may require investigation; and (4) perform functions related to inputs for market power mitigation. Both the CAISO and SPP Market Monitors meet the FERC standard.

NV Energy appreciates the outreach efforts CAISO's DMM has made to discuss ongoing WEIM operations and NVE's perspectives on issues under consideration. With respect to market oversight, EDAM includes the added perspectives provided by the Market Surveillance Committee and the WEM Governing Body Market Expert. NV Energy does not have the same level of experience with SPP's market monitor, but the Companies have appreciated the issues raised by SPP's market monitoring unit during the development of the Markets+

With respect to the market power mitigation approaches, NV Energy understands that SPP's conduct and impact threshold could give the Resource Optimization additional biding flexibility that could assist with intra-day gas management, a particular concern given NV Energy's lack of gas storage capability. On the other hand, as an LSE, NV Energy would be exposed to that same ability to take advantage of the higher thresholds by other suppliers. Given the more limited transmission associated with the Markets+ footprint, NV Energy has a heightened concern that prices could reflect the exercise of market power or limited liquidity before being mitigated. These higher prices could significantly reduce any potential participation benefit.

In the Markets+ Acceptance Order, FERC found,

> that the conduct test will appropriately determine whether a resource's market offer falls within the appropriate price level of 10% above the resource's mitigated offer,

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578 Markets+ Tariff, Attachment B, section 3.3 (Mitigation Measures for Energy Offer Curves).
579 *Id.* at section 3.8 (Market Impact Test).
580 SPP Transmittal Letter in FERC Docket No. ER24-1658 at 72.
581 Markets+ Tariff, Attachment C, section 4 4.6.4.2 (Thresholds for Screening Potential Physical Withholding of Transmission Facilities).

> which is more stringent than the Integrated Marketplace conduct thresholds of 17.5% and 25% for resources located inside and outside of frequently constrained areas, respectively. As the SPP Market Monitor explains, Markets+ participants may be located in areas that are not geographically contiguous and the limited transmission between areas in the Markets+ footprint may cause all balancing authorities to be frequently constrained areas. Therefore, we find that the more stringent conduct thresholds for energy and flexibility reserve products, as well as the lack of distinct thresholds for resources located in frequently constrained areas, are reasonable given the potential fragmented footprint and currently unknown participants of Markets+.[582]

While the use of a tighter impact threshold could help mitigate the exercise of market power, the limited transmission in Markets+ is a reoccurring theme, resulting in each non-contiguous zone being a "frequently constrained area."

CAISO has an ongoing stakeholder process that should result in design improvements to facilitate participation by entities such as NV Energy with significant gas fleets but limited storage capabilities. In sum, NV Energy has greater confidence in the EDAM market power mitigation approach to minimize the exercise of market power.

J. Data Reporting and Transparency

Among the criteria in the July 9, 2024, Order in Docket No. 23-10019, were several related the transparency of the DAM market data including: (1) the type and location of the data currently available; (2) the type and location of the data that will be available after NV Energy joins; (3) how the Commission can access that data; and (4) the frequency with which the data is/will be available to the Commission. While significant data would be available to NV Energy individually as a market participant, this section focuses on publicly available information and the Commission's ability to request additional analytics or data from the market monitor.

1. EDAM

As an extension of CAISO's existing day-ahead market, EDAM will be part of the extensive reporting processes that have been established by CAISO. Data transparency starts with the CAISO website: https://www.caiso.com. Significant sources of information include:

- The Department of Market Monitoring annual, quarterly, and special reports. These can be found at: https://www.caiso.com/market-operations/market-monitoring.
- The Market Surveillance Committee Reports can be found at: https://www.caiso.com/meetings-events/topics/market-surveillance-committee.
- WEM Governing Body Market Expert opinions and briefings can be found at: https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

582 Markets+ Acceptance Order at P 260.

- WEM Governing Body meeting materials can be found at: https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

- CAISO Board of Governors Meeting materials can be found at: https://www.caiso.com/about/governance-committees

- CAISO stakeholder center located at: https://stakeholdercenter.caiso.com/StakeholderInitiatives?_gl=1*c4qju7*_ga*MTI5NDU3NjQ4My4xNzM3ODU0NzA5*_ga_NDS4B4M2WP*czE3NTE0OTA1NjUkbzI5MCRnMSR0MTc1MTQ5MDc3OSRqNTckbDAkaDA

- Information on Quarterly Financial Reports, debt financing, audit reports, and the budget and grid management charge can be found at: https://www.caiso.com/about/financials.[583]

CAISO also posts market reports (https://www.caiso.com/library/market-reports) covering a number of topics, including:

- Market performance reports
  - Weekly market performance reports
  - Day-ahead daily market watch and summer reports
  - Monthly renewable performance report
  - Real-time daily market watch report
  - Monthly market performance reports
  - Daily energy storage reports.
  - Current day wind and solar curtailment report
  - Daily renewable reports
  - Daily wind and solar curtailment reports
  - Wind and solar daily market watch reports
- Greenhouse gas emissions tracking reports
- Average Emissions Rate Reports
- Exceptional dispatch reports
- Demand response net benefits test results
- Resource adequacy evaluation reports
- Curtailed and non-operational generator reports
- Non-resource adequacy capacity reports
- Capacity procurement mechanism reports
- Weekly price correction reports
- Market disruption reports

[583] One of the criteria in the July 9, 2024, Order in Docket No. 23-10019, as a discussion of the overall financial health of the organization that owns the DAM, as well as the financial statements of that organization. In addition to the financial statements identified above, a discussion of CAISO's financial health can be found in the Direct Testimony of April Gordon at Q&A 8.

Another significant source of data is CAISO's OASIS.[584] A description of the public data available on the OASIS site can be found in the CAISO's Business Practice for Market Instruments.[585] CAISO provides the following reports groups through OASIS listed by the Tab name as they appear on the CAISO OASIS web site: (1) prices,[586] (2) transmission,[587] (3) system demand,[588] (4) energy,[589] (5) ancillary services, (6) congestion revenue rights, (7) public bids, and (8) Atlas.[590]

In Order No. 719,[591] FERC expanded information sharing between market monitoring units ("MMUs") supporting the ability for state commissions to "make tailored requests for information from the MMUs, so long as the request is limited to information regarding general market trends and the performance of the wholesale market."[592] Consistent with FERC's requirements, the CAISO Tariff Attachment P, section 8 provides:

- Tailored Requests for Information from a State Commission to DMM - DMM shall consider requests from a State Commission for specifically identified information or data

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584 The CAISO's OASIS can be found at: https://oasis.caiso.com/mrioasis/logon.do.

585 https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments.

586 Pricing information includes locational marginal prices, EIM Green House Gas Shadow Prices, ancillary service prices, intertie constraint prices, fuel prices by fuel region, reference prices associated with virtual bidding nodes, flexible ramp constraint results, and greenhouse gas allowance prices.

587 Transmission data includes the transmission interface usage, market available transfer capacity. Transmission outages, Net WEIM transfer limits, EIM transfer, and ATC for priority wheeling requests.

588 System demand data includes the CAISO peak demand forecast. The CAISO demand forecast, the Wind and solar forecast, and load adjustments.

589 The Energy reports contain: System Load and Resource Schedules, expected energy, reliability must run, wind and solar summary, schedule reductions, RUC under supply infeasibility and enforced constraint report, market power mitigation status, exceptional dispatch, marginal losses, Day-Ahead Market Summary Report, Aggregated Generation Outages, Operator-Initiated Commitment, Transmission Loss, Excess Behind the Meter Production, Convergence Bidding Aggregate Awards, Net Cleared Convergence Bidding Awards, Convergence Bidding Nodal MW Limits. EIM BAA Hourly Base net schedule interchange, EIM Transfer Limits, EIM Transfer, EIM BAA Dynamic net schedule interchange, EIM BAA Base net schedule interchange net schedule interchange, EIM Transfer Limits By Tie, EIM Transfer By Tie, Flexible Ramp Requirements Input and Outputs, EIM RSE Capacity Test Data, Flexible Ramp Test Result Groups, Flexible Ramping Forecasts, Flexible Ramp Requirement Thresholds, Flexible Ramp Requirement Input Polynomials, Flexible Ramp Requirements Input Uncertainty Histograms, Flexible Ramp Surplus Demand Curves, Flexible Ramp Aggregated Awards, Uncertainty Movement by Category. Flexible Ramp Requirements, Zonal uplift, Resource-Specific Uplift.

590 The Atlas report lists all pricing locations, including PNode IDs and effective dates of operation. For Virtual Bidding purposes, the report also displays an indicator of whether or not the PNode is eligible for Virtual Bidding, the maximum MW Limit associated with each PNode as well as the effective start and end date for the limit. Additional information includes Load Distribution Factors; a listing of Load Aggregation Points, a list of Market Resources, including Generating Unit ID, PNode, aggregation type, resource type, effective dates; Trading Hub Listing; Ancillary Service Region; RUC Zone; TAC Area; Intertie Constraint Mapping; Transmission Interface Listing; Peak/Off-Peak Definition; OASIS Publication Schedule; System Operating Messages: Price Correction Messages; Price Correction Summary; Scheduling Point Definition; BAA and Tie Definition; Scheduling Point and Tie Definition: Intertie Constraint and Scheduling Point Mapping; Intertie Scheduling Limit and Tie Mapping ; and Constraint Relaxation Thresholds.

591 *See Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), as amended, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *reh'g denied,* Order No. 719-B, 129 FERC ¶ 61,252 (2009).

592 Order No. 719 at P 446. FERC found this "limitation is needed in light of the limited resources of the MMUs, whose first order of business is evaluating market design, monitoring the markets, and referring suspected wrongdoing to the[FERC]," and "[i]f this limitation were not imposed, the MMU could rapidly become an unpaid consultant for the states, and would be unable to perform its core functions." *Id.*

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 as defined in Section 5 of this Appendix P. For the avoidance of doubt, this Section 8.1 of Appendix P shall not apply to otherwise enforceable subpoenas, court orders, or any other form of compulsory process issued by, or on behalf of, a State Commission.

- DMM may agree to provide information about general market trends or performance. If DMM determines, in its sole discretion, that this information either is market sensitive or identifies an individual Market Participant, then the information may be shared only if the State Commission with which the information will be shared agrees in writing with the CAISO that the information will not be disclosed unless the State Commission has been directed to do so by a court of competent jurisdiction. The written agreement also must specify that if a State Commission is so directed to disclose such information, the State Commission will notify the CAISO before such information is disclosed. Once the CAISO receives such notification, the CAISO must notify the affected Market Participant promptly.

- DMM may agree to release to a State Commission raw CAISO data, but only after the information is redacted to satisfy any concerns that DMM may have about the need to maintain confidentiality. If DMM agrees to provide a State Commission with raw data that pertains to a specific Market Participant, DMM shall notify the affected Market Participant and give it the opportunity to contest the accuracy of the data. The affected Market Participant may provide to DMM a written statement providing context to the data. So long as the process of providing such a written statement does not unduly delay release of the data to the State Commission, DMM shall provide an unedited copy of such written statement to the State Commission concurrently with DMM's submission of the data to the State Commission. If the affected Market Participant asserts that the data to be provided is commercially sensitive, DMM shall share such sensitive information or data only if the State Commission with which the information will be shared agrees in writing with the CAISO that the information shared will not be disclosed unless the State Commission has been directed to do so by a court of competent jurisdiction. The written agreement also must specify that if a State Commission is so directed to disclose such information, the State Commission will notify the CAISO before such information is disclosed. Once the CAISO receives such notification, the CAISO must notify the affected Market Participant promptly. DMM shall not provide any requested information or data that is designed to aid an enforcement action by an instrumentality or political subdivision of any state of the United States of America

Anna McKenna notes that 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, the CAISO will publish quarterly EDAM benefits reports as it does today.[593] In addition, FERC ordered CAISO is to provide to FERC reports on the congestion allocation every six months starting with parallel operations and ending after a long-term design for congestion revenue allocation is developed.[594]

2. Markets+

SPP provides significant amounts of information on its website at the Markets+ page.[595] Under "Related Documents" are the Markets+ service offering, tariff, and protocols. Clicking on the Related Documents Groups Markets+ icon accesses information on the stakeholder groups[596] as well as the Funding Agreement. With respect to the RTO, significant data related to the Integrated Marketplace can be found at: https://portal.spp.org/groups/integrated-marketplace. It is not clear, however, if a comparable level of information will be provided publicly with respect to Markets+.

Attachment C, section 7.1.1 of the Markets+ Tariff requires the market monitor to publish annual and quarterly reports on the state of the market.[597] Additionally, Attachment C, section 8.1, the market monitor is to provide confidential information to Interested Government Agencies[598] consistent with Attachment A, Section 11. Section 8.4 further provides,

> [a]ny data created by the Market Monitor, including any reconfiguration of Data and Information under this section, will remain within the Market Monitor's exclusive control. Such data may be shared at the Market Monitor's sole discretion and on a non-discriminatory basis, subject to the confidentiality provisions specified in this Attachment C and Attachment A, Section 11.

Attachment A, section 11.4.1 of the Markets+ Tariff provides that the Market Operator or Market Monitor will only disclose Confidential Information to an Authorized Requestor under the following conditions:

- The Authorized Requestor[599] has executed the Non-Disclosure Agreement in Attachment F with the Market Operator; and

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593 Direct Testimony of Anna McKenna at Q&A 47. The CAISO also hosts a series of stakeholder forums to share market information, which will in the future include EDAM related information. For example, the CAISO hosts a bi-weekly market update stakeholder call to discuss market results data and market trends. On a quarterly cadence, the CAISO hosts a market planning and performance forum where CAISO staff discuss more broadly market trends and performance, market activities, which will also include EDAM related trends and information. *Id.*

594 *Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025) at P 38.

595 https://www.spp.org/western-services/marketsplus/.

596 https://www.spp.org/western-services-documents/?id=371697.

597 Pursuant to Attachment C, section 7.2.2, "[t]hose Market Monitor reports are made available on the Market Operator's website."

598 Markets+ Tariff Attachment C, section 2.3 defines "Interested Government Agencies" as "FERC and any state regulatory commission or agency with relevant regulatory oversight responsibilities."

599 An "authorized Requestor" is an individual who has executed the Non-Disclosure Agreement found in Attachment F and Attachment A, Section 11 and is authorized by an Authorized Agency to receive and discuss Confidential Information.

- The Market Operator is able to verify that the Authorized Agency[600] employing or retaining the Authorized Requestor has provided the Market Operator with the following information pursuant to Attachment F, Section 2.2:
    - A list of authority (including statutory) specifying the particular Authorized Agency's duty, responsibility, or authority in fulfillment of which it will make requests to the Market Operator or the Market Monitor under this section for information, including, but not limited to, that enumerated and described as available to the Market Monitor in Attachment C; or, in the case of a regional state committee, a FERC order prohibiting the release of Confidential Information by the regional state committee, except in accordance with the terms of the Non-Disclosure Agreement;
    - A statement notifying and identifying to the Market Operator that the Authorized Agency has practices or procedures in place adequate to protect against the unauthorized release of Confidential Information; and
    - Confirmation in writing that the Authorized Requestor is authorized by the Authorized Agency to enter into the Non-Disclosure Agreement and to receive Confidential Information under Attachment A.

Under Attachment A, section 11.4.2, the Authorized Requestor will use the Confidential Information for the purpose of assisting an Authorized Agency in discharging its duty, responsibility, or authority in fulfillment of which it authorizes Authorized Requestors to make requests for Confidential Information and for no other purpose. Again, consistent with FERC Order No. 719, the Markets+ Tariff at Attachment A, section 11.4.3(7) states, "Market Monitor may respond to tailored requests for information from state commissions regarding general market trends and the performance of the wholesale market, but not for information designed to aid state enforcement actions. Granting or refusing such requests will be at the Market Monitor's discretion."

In addition, FERC's Order accepting the Markets+ Tariff required SPP and the Market Monitor to file joint informational progress reports every six months on the ongoing development of the market during the implementation period defined as the period beginning January 16, 2025, and ending three years after Markets+ begins full operation.[601] Specifically, SPP is to report on the "number of participants and the daily amount of resources offered into and load served by Markets+, transmission availability, modifications to transmission availability through intra-day changes and the opt-out provision, market prices, and other relevant issues."[602]

In response to the Markets+ Tariff filing, the Colorado Consumer Advocate suggested that the market monitor be required to directly communicate with state consumer advocates, provide unrestricted access of data and reports, and guarantee access to transmission expansion modeling

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[600] An "Authorized Agency" is a state public utility commission that regulates, within the Markets+ Footprint, the distribution or supply of electricity to retail customers or is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers; (ii) the Markets+ State Committee or any successor organization formed to act as a regional state committee within Markets+; or (iii) a state agency that has both access to documents in the possession of a state public utilities commission pursuant to state statute and the ability to protect those documents in accordance with Attachment F and Attachment A, Section 11.

[601] Markets+ Acceptance Order 190 FERC ¶ 61,030 (2025) at P 44.

[602] *Id.*

and other key analyses.[603] The market monitor disagreed in order to maintain its independence.[604] FERC "disagree[d] with Colorado Consumer Advocate's arguments that consumer advocate groups should have unrestricted access to data and reports of the SPP Market Monitor" and determined "that nonpublic analyses, data, and reports must be kept confidential because the information therein may be commercially sensitive."[605]

3. NV Energy Evaluation

NE Energy understands that both CAISO and the SPP RTO make significant amounts of market data available to the public. The Companies are less sure about the public release of Markets+ data as it is a separate service offering. Both EDAM and Markets+ provided for the release of the market monitor's annual and quarterly reports. EDAM will also make available special reports from DMM as well as the reports from the MSC and the WEM Governing Body Market Expert. Both the CAISO and Markets+ tariffs contain provisions permitting the Commission to make information requests. Whether it is a matter of experience or site design, the NV Energy team has found the CAISO website easier and quicker to navigate. The Companies would rate EDAM, as an extension of CAISO's existing market reporting processes, slightly higher with respect to data availability.

K. Settlements and Dispute Resolution

Both of the DAMs proposed to use their established settlement timelines and dispute resolution processes. CAISO will continue the approach that has been used in WEIM with the addition of the new EDAM charge codes. Markets+ adopts the methodology employed in the SPP RTO, again with the addition of certain DAM-specific charge codes.

1. EDAM

NV Energy understands that EDAM will require 53 new and updated settlement charges: 43 applicable to the EDAM Entity (the transmission department) and 31 applicable to the EDAM merchant scheduling coordinator (Resource Optimization).[606] Certain of the charge codes overlap and apply to both. These are illustrated in Figure 43.

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603 Markets+ Acceptance Order at P 254.
604 *Id.* at P 256.
605 *Id.* at P 262.
606 A matrix of the EDAM charge codes can be found at: https://www.westerneim.com/Pages/ExtendedDayAheadMarketImplementation.aspx.

Figure 43
EDAM 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		6404	Day Ahead Energy Offset - System
X		6704	Day Ahead Congestion Offset
X		6800	Day Ahead RUC Reliability Capacity Up Settlement
X	?	6806	Day Ahead Reliability Capacity Up Tier 1 Allocation
X	?	6807	Day Ahead Reliability Capacity Up Tier 2 Allocation
X		6810	Day Ahead RUC Reliability Capacity Down Settlement
X	?	6816	Day Ahead Reliability Capacity Down Tier 1 Allocation
X	?	6817	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***

CAISO issues the initial settlement statement nine business days after the trading day (T+9B) and issues the second settlement statement after 70 business days (T+70B). All of the recalculation settlement statements after the T+70B, namely the T+11M, T+21M, and T+24M recalculation settlement statements are optional.[607] They are issued only when necessary to adjust settlements.[608]

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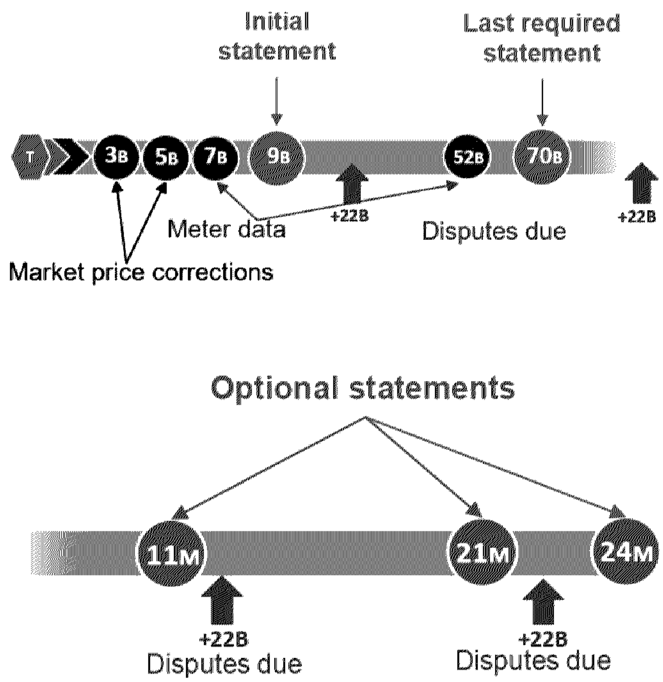
[607] CAISO Tariff section 11.29.7.1

[608] Interest is applied to any incremental changes between Initial Settlement Statement T+9B and Recalculation Settlement Statement T+70B, and thereafter to any incremental changes between each subsequent Recalculation Settlement Statement through Recalculation Settlement Statement T+24M. Interest is calculated on a daily basis and will apply from the Payment Date for the Invoice of Payment Advice to the Payment Date for the next Recalculation

The T+24M is not subject to dispute unless directed by CAISO Governing Board or FERC.[609] The CAISO settlements timelines are illustrated in Figure 44.

Figure 44
CAISO Settlement Timeline



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 CAISO Tariff section 11.29.8 and managed through the CAISO's customer inquiry, dispute, and information system.[610] Unresolved settlement issues and other disputes must also follow the dispute resolution procedures in CAISO Tariff section 13.[611] CAISO and Market Participants (party or parties) are to make good-faith efforts to negotiate and resolve any dispute prior to invoking the CAISO alternative dispute resolution procedure. In the event a dispute is not resolved through negotiations, any one of the parties may submit a statement of claim, in writing, to each other disputing party, and the CAISO ADR Coordinator. After submission of the statements of claim, the parties may request mediation.[612] If the parties do not agree to mediate or if mediation is not successful, a party

Settlement Statement. The rate of interest is in accordance with FERC's requirements at 18 C.F.R. Section 35.19a. CAISO Tariff section 11.29.7.2.

609 CAISO Tariff section 11.29.7.3.2.

610 Direct Testimony of Anna McKenna at Q&A 48.

611 *See* Standard Procedure for Resolution of Disputes dated October 24, 2024. The document can be found at: https://www.caiso.com/documents/disputeresolutionprocedure.pdf.

612 If the parties agree to mediate, the CAISO ADR Coordinator shall distribute to the parties by facsimile or other electronic means a list containing the names of at least seven prospective mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as he or she shall deem appropriate to the dispute. The parties shall have seven days from receipt of the CAISO ADR Coordinator's list of prospective

may commence the arbitration process. The arbitrator shall have the discretion to grant the relief sought by a party, or determine such other remedy as is appropriate, unless the parties agree to conduct the arbitration "baseball" style in which case the arbitrator will select one of the offers. A party may apply to the FERC or any court of competent jurisdiction to hear an appeal of an arbitration award only upon the grounds that the award is contrary to or beyond the scope of the relevant CAISO Documents, United States federal law, including, without limitation, the FPA, and any FERC regulations and decisions, or state law.

2. Markets+

In general, for both the day-ahead and real-time markets, SPP will calculate energy and flexibility reserve products, settlement quantities at each settlement location, calculate charges and payments associated with these products, and render invoices detailing net charges or payments. Similar processes are established for congestion rent allocation, market transmission use charges, and all other market charge types. A list of the day-ahead and real-time charges and payments for Markets+ consists of the following:

- Day-Ahead Market Settlements
    - Day-Ahead Energy Amount
    - Day-Ahead Short-Term Flex Up Amount
    - Day-Ahead Short-Term Flex Down Amount
    - Day-Ahead Mid-Term Flex Up Amount
    - Day-Ahead Short-Term Flex Up Distribution Amount
    - Day-Ahead Short-Term Flex Down Distribution Amount
    - Day-Ahead Mid-Term Flex Up Distribution Amount
    - Day-Ahead Make Whole Payment Amount
    - Day-Ahead Make Whole Payment Distribution Amount
    - Day-Ahead Demand Reduction Amount
    - Day-Ahead Demand Reduction Distribution Amount
    - Day-Ahead Congestion Rent Available for Allocation Amount
    - Day-Ahead CRETSR Holder Congestion Rent Allocation Distribution Amount
    - Day-Ahead Excess Congestion Rent Allocation Distribution Amount
    - Day-Ahead Must Offer Penalty Charge Amount
    - Day-Ahead Must Offer Penalty Distribution Amount
    - Day-Ahead Self- Committed Incremental Energy Make Whole Payment Amount
    - Day-Ahead Combined Interest Resource Adjustment Amount
    - Day-Ahead GHG Injection Amount
    - Day-Ahead GHG Unspecified Source Import Amount
    - Day-Ahead GHG Load Amount

mediators to agree upon a mediator from the list provided or from any alternative source, unless the time is extended by mutual agreement. If the parties cannot agree on a mediator, any party may request from the American Arbitration Association a list of at least seven mediators with technical or business experience in the electric power industry, or both. The parties will alternate in striking names from the list with the last name on the list becoming the mediator.

- Real-Time Balancing Market Settlements
    - Real-Time Energy Amount
    - Billable Metered Load
    - Real-Time Base Obligation Short-Term Flex Up Amount
    - Real-Time Increased Obligation Short-Term Flex Up Amount
    - Real-Time Short-Term Flex Down Amount
    - Real-Time Base Obligation Mid-Term Flex Up Amount
    - Real-Time Increased Obligation Mid-Term Flex Up Amount
    - Real-Time Base Obligation Short-Term Flex Up Distribution Amount
    - Real-Time Increased Obligation Short-Term Flex Up Distribution Amount
    - Real-Time Short-Term Flex Down Distribution Amount
    - Real-Time Base Obligation Mid-Term Flex Up Distribution Amount
    - Real-Time Increased Obligation Mid-Term Flex Up Distribution Amount
    - Real-Time Short Term Flexibility Reserve Products Non-Performance Amount
    - Real-Time Short-Term Flexibility Reserve Products Non-Performance Distribution Amount
    - Real-Time Mid-Term Flex Up Non-Performance Amount
    - Real-Time Mid-Term Flex Up Non-Performance Distribution Amount
    - Reliability Unit Commitment Make Whole Payment Amount
    - Reliability Unit Commitment Make Whole Payment Distribution Amount
    - Real-Time Out-of-Merit Amount
    - Real-Time Out-of-Merit Distribution Amount
    - Real-Time Demand Reduction Amount
    - Real-Time Demand Reduction Distribution Amount
    - Real-Time Combined Interest Resource Adjustment Amount
    - Real-Time Uninstructed Resource Deviation Amount
    - Real-Time Uninstructed Resource Deviation Exemptions
    - Real-Time Uninstructed Resource Deviation Distribution Amount
    - Real-Time Must Offer Penalty Charge Amount
    - Real-Time Must Offer Penalty Distribution Amount
    - Real-Time Incremental Energy Make Whole Payment Amount
    - Reliability Unit Commitment Self-Committed Incremental Energy Make Whole Payment Amount
    - Real-Time GHG Injection Amount
    - Real-Time GHG Unspecified Source Import Amount
    - Real-Time GHG Load Amount
    - Real-Time GHG Overcollection Amount

- Revenue Neutrality Uplift Distribution Amount

- Market Transmission Use Amount

- Market Transmission Use Distribution Amount

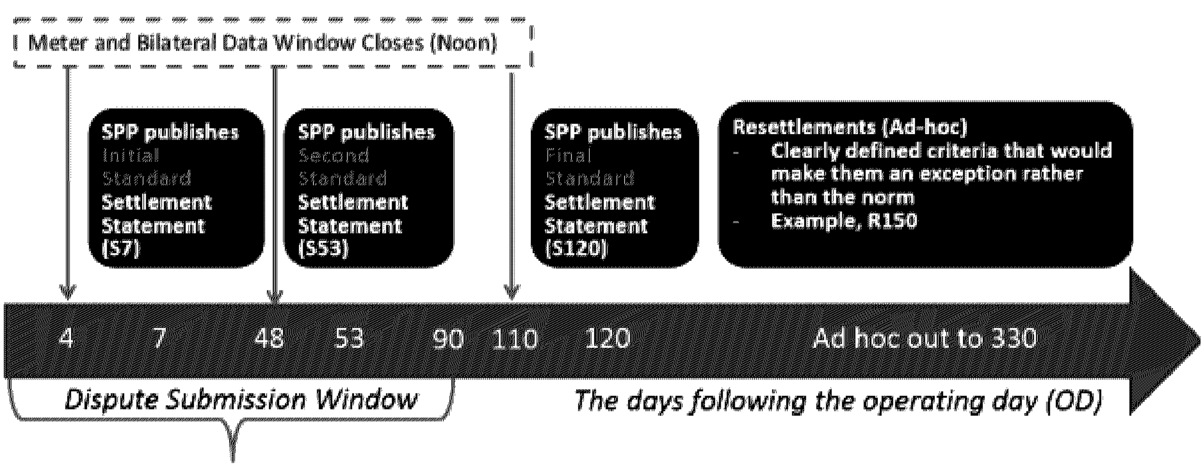
- Market Administration Services Amount

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. The Markets+ settlements timeline is shorter, utilizing a 12-month settlement process.

In accordance with Markets+ Tariff Attachment A, Section 10.1, SPP will issue a first scheduled settlement statement no later than seven calendar days following the applicable operating day unless the seventh is not a business day, in which case, the preliminary settlement statement will be issued on the first business day thereafter. SPP will issue a second scheduled settlement statement no later than fifty-three calendar days following the applicable operating day (or the first weekday thereafter). SPP will issue a final Scheduled settlement statement no later than one hundred and twenty calendar days following the applicable operating day (or the first weekday thereafter). The SPP timeline is illustrated in Figure 45.

A Market Participant may dispute the settlement beginning with the posting of the S7 scheduled settlement statement and through the 90th calendar day after the applicable operating day. In the case of the S120 scheduled settlement and any resettlement statements, a market participant may only dispute material incremental changes. A dispute relating to an S120 scheduled settlement or resettlement statement must be filed within 30 calendar days.

Figure 45
Markets+ Settlement Timeline



SPP will schedule resettlements as needed to correct a previously posted settlement statement for an operating day. Resettlements will be limited to (1) the correction of data resulting from an SPP software error or an SPP data error per the discretion of the transmission provider in accordance with the rules specified under the tariff; (2) a granted dispute; (3) FERC or court orders. Settlement associated with a specific operating day are considered final at the end of the 365th calendar day following the applicable operating day.[613]

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[613] Markets+ Tariff Attachment A, section 10.1(4).

Markets+ Tariff Part 1, section 5.1 provides that:

> Any dispute between a Market Participant(s) and the Market Operator involving service under the Markets+ Tariff (excluding applications for rate changes or other changes to the Markets+ Tariff, or to any Market Participant Agreement entered into under the Markets+ Tariff, which will be presented directly to FERC for resolution) will be referred to a designated senior representative of the Market Operator and a senior representative of the Market Participant for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the parties may agree upon) , such dispute may be submitted to arbitration by mutual agreement and resolved in accordance with the arbitration procedures set forth below.

The arbitration process is outlined in Part 1, section 1.5.2. Under section 5.3, the decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms, and conditions of service or facilities. Any arbitration initiated under the Markets+ Tariff will be conducted before a single neutral arbitrator appointed by the parties.

3. NV Energy Evaluation

The settlements and dispute resolution processes were not major drivers of the Companies' DAM recommendation. While EDAM and WEIM together have a larger number of charge codes than Markets+, the new EDAM codes will be mostly incremental to the existing WEIM settlement process; whereas Markets+ will introduce new settlements for both day-ahead and real-time markets. The overall shorter settlement timeline in Markets+ could mean statements become final sooner, absent disputes brought before FERC through a potential complaint process. Both the settlement correction methodology and the dispute resolution approaches are comparable.

L. Seams and Intertie Biding

The National Regulatory Research Institute ("NRRI") provides that: "Seams issues are trading barriers between adjoining wholesale electricity markets resulting from the use of different rules and procedures by the neighboring markets.[614] There has been and certainly will continue to be substantial discussion in the West between EDAM and the potential Markets+ footprint regarding the issue of market seams. Based on the announced preferences, the potential for market seams would occur no matter what DAM option Nevada chooses. In Markets+, NV Energy would be surrounded by the PacifiCorp East, Idaho Power, CAISO, LADWP, and potentially the WAPA

[614] National Regulatory Research Institute, Electric Transmission Seams: A Primer White Paper, p. iv (Feb. 2015). The document can be found at: https://pubs.naruc.org/pub/FA86CD9B-D618-6291-D377-F1EFE9650C73.

Desert Southwest BAAs. In EDAM, NV Energy would have market borders with the Arizona Public Service at Meade and BPA over Path 76.[615]

In a January 2024 presentation, Gridwell Consulting noted the DAMs in the West are "fundamentally different" than the RTOs in the East and identified five distinct categories of seams: economic seams, transmission availability, contracting barriers, GHG accounting and dispatch, and market power mitigation.[616] NV Energy agrees with BPA's statements, "having two day-ahead markets may create inefficiencies and will be challenging to resolve" and "[t]hese seams include commercial and operational seams and congestion."[617] FERC has stated, "[w]e recognize that myriad seams issues will need to be addressed by CAISO, SPP, and the participating BAAs, and that some of these issues may require the development of agreements such as joint operating agreements and tailored operational procedures."[618]

Related to the discussion of seams is whether the DAM participate could, should, or must enable external bidding at their external interties. The CAISO Tariff, as approved by FERC provides the EDAM Entity BA the choice of whether or not to enable external bidding.[619] FERC, "agree[d] with CAISO that certain limitations on non-source specific external resources is a reasonable accommodation to mitigate risk that non-source specific supply that is not deliverable could displace internal generation" and that requiring external bidding, "could introduce operational risk that the supply may not be deliverable, may displace other supply, and may force the BA to replace the supply in real-time."[620] This optionality was reaffirmed by FERC in consideration of the PacifiCorp and Portland General OATTs.[621] In contrast, Markets+ mandates participating BAs to

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615 Direct Testimony of Charles Pottey at Q&A 10-12. By point of comparison, BPA has 18 adjacent BAAs and 15 adjacent Transmission Service Providers, several of which are located within its BAA, that it must coordinate with on a day-to-day basis. BPA Record of Decision at 129.

616 The presentation can be found at: https://www.wptf.org/files/Western_Day-Ahead_Seams_Exploration_FINAL_240116.pdf. BPA notes,

> The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection. In eastern RTOs, /ISOs, they are vertically aligned among roles as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

BPA Day-Ahead Market Policy dated May 9, 2025, at 84.

617 BPA Record of Decision at 129.

618 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 251.

619 CAISO Tariff at section 33.30.3 Resources located outside of an EDAM BAA may fully participate in the day-ahead market if they are pseudo-tied or dynamically scheduled into an EDAM BAA or are a designated network resource to serve load in an EDAM BAA.

620 EDAM Acceptance Order at P 239.

621 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 331 ("We find that PacifiCorp's decision to not enable economic bidding on external interties is just and reasonable and not unduly discriminatory or preferential. Further, we find that PacifiCorp's proposal is consistent with the CAISO tariff's EDAM provisions"). *See also, Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025) at P 61 ("[i]n its Answer, Portland explains that it needs to gain experience with EDAM to ensure that all of the core functions work as intended and that introducing external intertie bidding at launch would introduce complexities in implementation. As previously noted, CAISO's tariff defers the decision on whether to enable economic bids at external interties to the EDAM Entity where the external intertie is located, and we find that it is reasonable to expect that there might be additional complexities involved").

participate in external bidding.[622] A feature of Markets" is the requirement that the import bidder must have an associated transmission service reservation from the external interface to the sink location identified in the e-Tag within the Markets+ footprint.[623] In other words, unlike the common practice of a sale taking place at the border and then the LSE uses their NITS transmission to deliver it to load with no additional cost to the supplier, external entities bidding into Markets+ will need to buy additional point-to-point service from a Markets+ participating transmission owner to deliver to an internal location. Thus, it is less intertie bidding and more internal delivery. Additionally, if the supplier uses short term point-to-point there may be exposure to unhedgeable congestion charges.

NV Energy prefers the optionality provided by the EDAM Tariff. NV Energy did not authorize intertie bidding for the WEIM as an incentive for other BAAs to join EDAM, in other words, to bear both the burdens as well as the benefits of market participation. The WEIM market has expanded so that at this time all of the Companies' interties are with other WEIM participants.

Even if NV Energy determines to limit intertie bidding at the outset of EDAM participation, this limitation does not apply to external resources that are Designated Network Resources for NV Energy's Network Integration Transmission Service customers with load inside the NV Energy BAA. Beyond those already-established exceptions, it may be important for NV Energy to stand up the EDAM design and ensure all of the core functions work as intended to support efficient and reliable operations. In EDAM, NV Energy retains its BA responsibilities for Nevada. Intertie bidding at go-live could introduce complexities in implementation that may not be adequately addressed until further experience with EDAM functioning is obtained.

SECTION 6 – BRATTLE ANALYSIS

The Report adopted in the June 21, 2024, Order in Docket No. 23-10019 specified that the Companies were to provide,

> [a]ll cost-benefit analyses that demonstrate the value of the DAM versus other options, including any viable, alternate DAMs and the "status quo" that examines, at a minimum, the following information: (a) [i]mpact of transfers between markets and balancing areas; (b) [a]nalysis of resource procurements; (c) [a]ny costs related to solar curtailment; (d) [u]se of the most recently available Nevada-specific inputs; (e) [i]mpact on transmission development and investments currently proposed or in progress for Nevada by NV Energy and other developers; and (f) [i]mpact on generation development currently approved or proposed by NV Energy.

The Companies discussed the work performed by E3 as part of the WMEG effort in section 3(C) of the Narrative. At the April 3, 2024, Workshop in Docket No. 23-10019, the Companies also had John Tsoukalis of the Brattle Group discuss the detailed modeling they had performed. The Companies engaged Brattle to perform a benefits study that compared potential participation in either EDAM or Markets+ compared to remaining in WEIM.

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622 Markets+ tariff at Attachment A, section 4.3.1 (1) ("Market Participants may submit offers to sell Energy into the Day-Ahead Market, RTBM, or both, delivered from a source located outside of the Markets+ Footprint").
623 Markets+ Tariff at Appendix A, section4.3.1(3).

During the Workshop held in Docket No. 23-10019 on April 3, 2024, Brattle presented the results of its Summer 2023 NV Energy EDAM Benefits Study, Fall 2023 Markets+ Benefits Study and January 2024 EDAM/Markets+ Footprint Scenarios (Figure 46).[624] As shown in Figure 47, Brattle projected EDAM benefits ranged across the scenarios from $62 million to $149 million annually.[625] In contrast, Markets+ projected benefits ranged from ***negative*** $17 million to $16 million annually.[626] Moreover, NV Energy's greatest benefits were seen in market consisting of CAISO, LADWP, BANC, PacifiCorp, Portland General Electric, Idaho Power, NV Energy, and Seattle City Light, which contained 46 percent of WECC load but 80 percent of solar generation, 70 percent of storage capacity, and 68 percent of wind generation.[627]

Figure 46

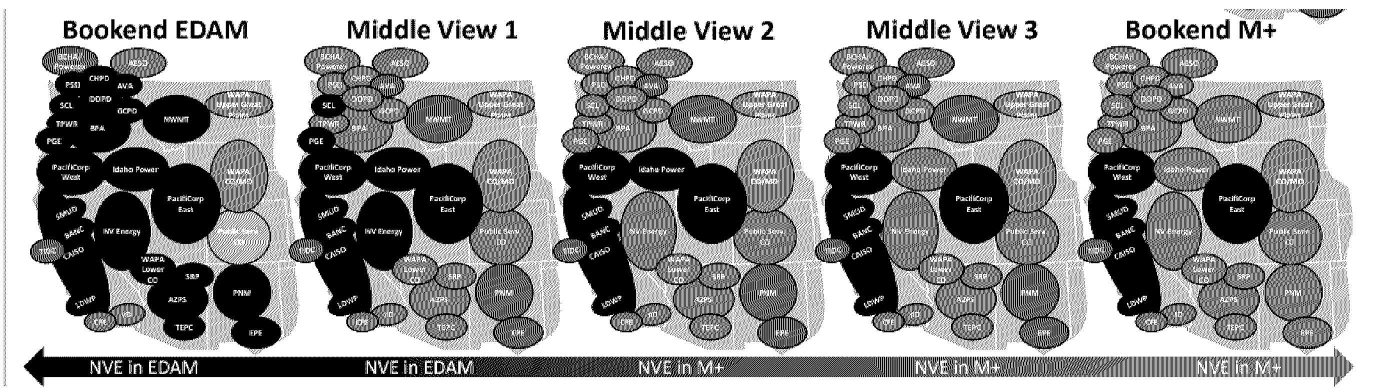

Figure 47

Nevada Energy System Cost by Case ($ Millions)

		BAU	Bookend EDAM	Middle View 1	Middle View 2	Middle View 3	Bookend Markets+
Market Membership	**Metric**	**EIM Only**	**EDAM**	**EDAM**	**Markets+**	**Markets+**	**Markets+**
Adjusted Production Cost	Cost	$485.5	$420.1	$357.0	$425.4	$420.8	$415.4
Wheeling Revenues	Revenue	$15.4	$0.0	$14.9	$0.5	$0.3	$0.4
Trading Revenues:							
Bilateral	Revenue	$72.2	$0.0	$10.2	$4.9	$4.0	$4.2
WEIM	Revenue	$33.2	$30.1	$19.0			
WEIS/Mk+ RT Market	Revenue				$9.3	$11.5	$11.2
EDAM	Revenue		$88.3	$98.0			
Markets+	Revenue				$30.0	$50.3	$52.2
Total System Cost		**$364.7**	**$301.6**	**$214.8**	**$380.6**	**$354.8**	**$347.3**
Benefit to BAU			**$63.1**	**$149.9**	**-$15.9**	**$9.9**	**$17.4**

As explained by John Tsoukalis, Brattle evaluated adjusted production costs, impacts on wheeling revenues, potential loss of bilateral trading profits and congestion and transfer revenue. Brattle modeled the EDAM and Markets+ GHG structures and simulated the existing and prospective real-time markets.

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[624] Docket No. 23-10019, April 3, 2024, *NV Energy Day-Ahead Market Benefits Studies* (The Brattle Group), submitted on April 17, 2024, as Attachment 1

[625] *Id.* at slide 2.

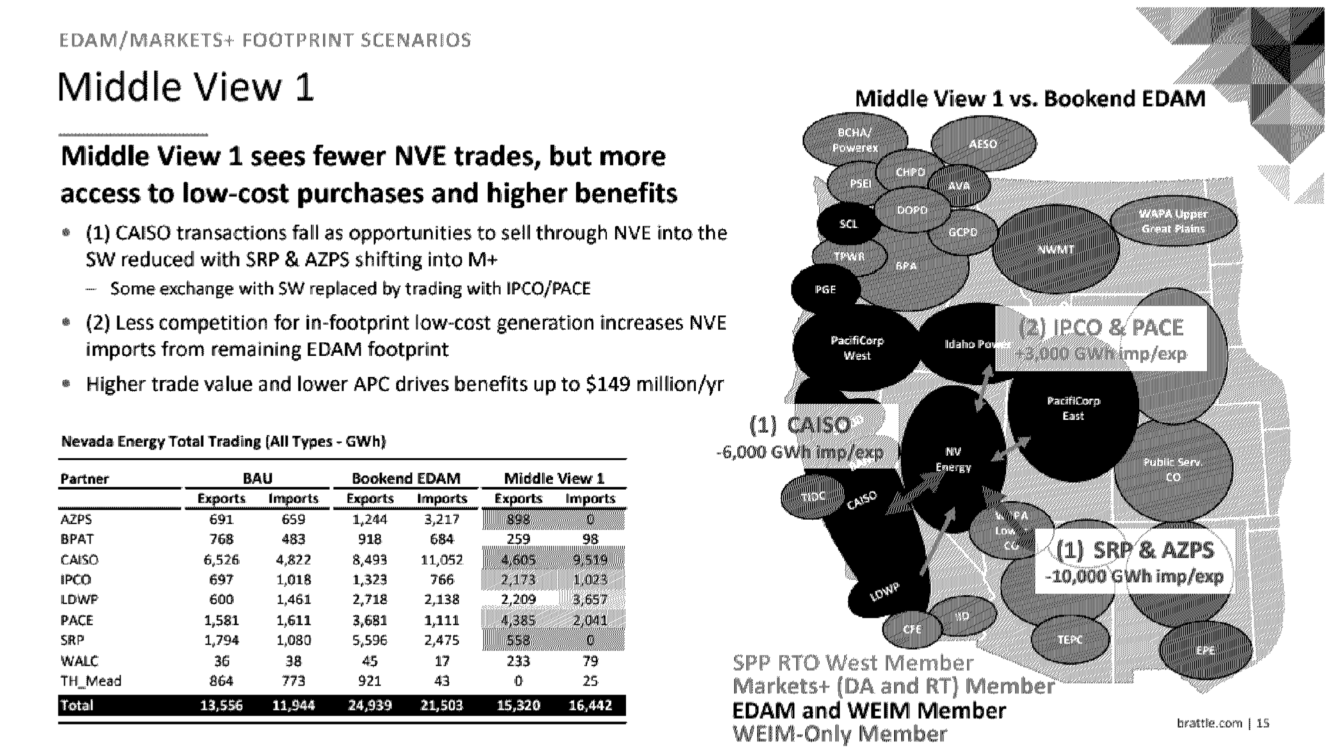
[626] *Id.*

[627] *Id.* at slide 17.

The study year was 2032, which aimed to reflect the first decade of markets operations, representing an intermediate year that captures known changes in resource mix and transmission infrastructure.[628] The model also included two extreme weather events modeled as single weeks with increased loads and gas prices.[629] Brattle used an average hydro year based on 2009 data for hydro generation.[630] As explained by Mr. Tsoukalis, the projected benefits are likely understated, especially by overstating the efficiency of the base case trading.[631]

Figure 48, taken from slide 15 presented at the Aprile 3, 2024, Workshop provides additional detail regarding the Middle View 1 ("MV1") footprint. MV1 shows the highest benefits for Nevada (higher even than Bookend EDAM) due increased availability of low-cost purchases MV1's EDAM contains the largest solar, wind, and battery storage entities in the WECC, containing 46 percent of WECC load but 80 percent of solar generation, 70 percent of storage capacity, and 68 percent of wind generation. In contrast Bookend EDAM contains 74 percent of WECC load, but 97 percent of solar generation, 97 percent of storage capacity, and 83 percent of wind generation.

Figure 48



Partner	BAU		Bookend EDAM		Middle View 1	
	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	691	659	1,244	3,217	898	0
BPAT	768	483	918	684	259	98
CAISO	6,526	4,822	8,493	11,052	4,605	9,519
IPCO	697	1,018	1,323	766	2,173	1,023
LDWP	600	1,461	2,718	2,138	2,209	3,657
PACE	1,581	1,611	3,681	1,111	4,385	2,041
SRP	1,794	1,080	5,596	2,475	558	0
WALC	36	38	45	17	233	79
TH_Mead	864	773	921	43	0	25
Total	13,556	11,944	24,939	21,503	15,320	16,442

One of the criteria identified in the report approved in the July 9, 2024, Order in Docket No. 23-10019 was a study that incorporated, "[u]se of the most recently available applicable to Nevada-specific inputs." Accordingly, NV Energy retained Brattle to "refresh" its early work based on the

628 *Id.* at slide 4.
629 *Id.*
630 *Id.*
631 *Id.* at slide 5.

most recent data available. As discussed in the Direct Testimony of John Tsoukalis, Brattle updated fuel prices, resource mix data, load projections and new transmission rights and projects including:

- NV Energy's system assumptions were updated by the NV Energy transmission and resource 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 CAISO, Arizona Public Service, the Salt River Project and other entities via both public integrated resource plan announcements and other data;

- Public Service New Mexico, Idaho Power, PacifiCorp, El Paso Electric, Turlock Irrigation, and Seattle City and Light have all completed studies with Brattle since the prior NV Energy work that lead to significant changes to their systems' modeling assumptions; and

- Other updates include, breaking out Black Hills Power & Cheyenne Light Fuel and Power from the WACM BAA, making them their own BAA, 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 Council, and adjusting transmission limits on SWIP North and Greenlink in consultation with the NV Energy transmission team.[632]

The 2025 study analyzed the potential benefits for NV Energy in joining either CAISO's EDAM, SPP's Markets+, or remaining in the existing WEIM (the Business as Usual ("BAU") case) using 2032 as the study year. In all three cases, the market participation assumptions for all the other utilities in the WECC remain the same to isolate the impact of NV Energy's market participation.[633]

- The EDAM footprint included CAISO, the Los Angeles Department of Water and Power, Portland General Electric, the Balancing Authority of Northern California and the Sacramento Municipal Utility District, Public Service Company of New Mexico, PacifiCorp (modeled as their two separate BAAs, PAC-East and PAC-West, the Imperial Irrigation District, the Turlock Irrigation District, the Idaho Power Company, and Seattle City & Light.

- The Markets+ footprint included BPA, Tacoma Power, Powerex, Puget Sound Energy, Chelan County Public Utility District, Grant County Public Utility District, Arizona Public Service, the Salt River Project, Tucson Electric Power, El Paso Electric, and the Public Service Company of Colorado.

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632 Technical Appendix 1, Brattle NV Energy Day-Ahead Market Study 2025 Updated Cases October 2025 at 3.

633 Direct Testimony of John Tsoukalis at Q&A 7.

- The WEIM footprint contained utilities that that have not announced a decision, leaning, or preference for either day-ahead market, including Avista Power, Black Hills (which includes Black Hills Power and Cheyenne Light Fuel & Power, who have announced their intention to join the WEIM), Northwestern Energy, and the WAPA Lower Colorado BAA.[634]

Brattle used a model developed by Polaris Systems Optimization, Inc. and run in the Enelytix modeling environment. [635] 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.[636]

Data inputs were 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. [637] Brattle worked with the NV Energy transmission team to refine the assumptions used in the model for transfer capability between NV Energy and its neighbors, and between NV Energy's northern and southern systems.[638]

For other BAAs in the WECC, Brattle used the data either directly from the utility if they have been part of a study (PacifiCorp, the Balancing Authority of Northern California, the Los Angeles Department of Water and Power, Idaho Power, Portland General Electric, Public Service Company of New Mexico, Turlock Irrigation, El Paso Electric, and Seattle City Light) for from the most recent integrated resource plan. [639]

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634 *Id.*
635 *Id.* at Q&A 23.
636 *Id.*
637 *Id.* at Q&A 24.
638 *Id.*
639 *Id.*

Brattle examined: (1) adjusted production cost ("APC") savings,[640] (2) short-term wheeling revenues,[641] (3) market congestion revenues,[642] and (4) bilateral trading margins.[643] Brattle did not attempt to quantify potential reliability or environmental benefits.

As shown in Figure 49, the study determined that NV Energy's net system costs are reduced by $93.1 million by joining EDAM but increase by $7.3 million moving from WEIM to Markets+. EDAM produces net benefits in APC, surplus market congestion revenues, and short-term wheeling revenues.

Figure 49

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.

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640 APC Savings is 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. Brattle analyzed each of those three components separately – production costs, sales revenue, and purchased power costs and summed 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.

641 Short-Term Wheeling Revenues account 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.

642 Market Congestion Revenues 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's generation resources will be paid their LMP and that all NV Energy load will pay their LMP, 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.

643 Bilateral Trading Margins account 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.

As noted by Brattle,

> 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.[644]

In contrast,

> 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.[645]

In EDAM, NV Energy customers see a net APC cost reduction of $34.1 million per year 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.[646]

The Companies see 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.[647]

As shown in Figure 50 Brattle found that that participation in either market would reduce NV Energy's system curtailments, with the decrease being greater in Markets+. On the other hand, joining Markets+ would increase NV Energy's gas dispatch while EDAM is decreasing it.

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644 Direct Testimony of John Tsoukalis at Q&A 15.
645 *Id.* at Q&A 12.
646 *Id.* at Q&A 13.
647 *Id.*

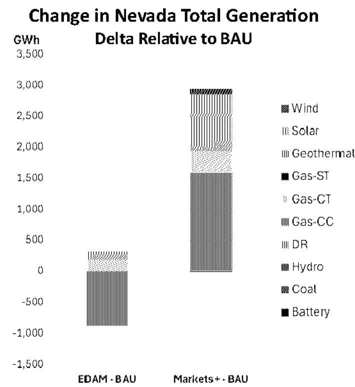
Figure 50

DETAILED MODELING RESULTS

Generation and Dispatch Results

NVE's generation is decreasing in EDAM, mostly from gas, and increasing in Markets+

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



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As shown in Figure 51, the Companies' trading volume is higher in EDAM with transactions totaling more than 33 TWh, while in Markets+ transactions with other markets are less than 19 TWh.

Figure 51

DETAILED MODELING RESULTS

Market Trading Dynamics

Total NVE trade volume is highest in EDAM, with EDAM transactions totaling more than 33 TWh, while in Markets+ transactions with other Markets+ entities total just ~19 TWh

- **EDAM** offers more variety in trading partners and total transfer capability than Markets+
  - NVE can trade with California entities without paying the high California export charges and can make some sales without payi ng GHG, given EDAM allows for unit-specific pricing
  - NVE also can trade with PacifiCorp and Idaho Power, who have very different resource mixes compared to NVE
  - NVE can thus access cheap hydro, wind, and gas from PAC/Idaho, solar from California, and make sales to a wide variety of counterparties
- **In Markets+,** NVE's resource mix is extremely similar to the desert southwest entities which are also solar and gas heavy balancing authorities, offering less diversity
  - NVE's connection to Bonneville Power in the Northwest is also small, only about 200 – 300 MW, reducing the potential value of Pacific Northwest resource diversity
  - Thus, even in Markets+, NVE trades considerably with EDAM entities as it is able

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

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Brattle explains that the benefit calculation is likely to be conservative as it: (1) overstates the efficiency of bilateral markets, (2) uses weather-normalized loads which reduce the market benefits seen in scarcity events; (3) does not fully reflect the limited liquidity of the bilateral market during challenging system conditions, and (4) does not account for sub-hourly trading benefits in the organized markets.[648] In one respect, however, the Markets+ benefits may be overstated as Brattle's study assumed that the resources and loads in the portion of the SPP's RTO West were co-optimized with the Markets+ footprint.[649] NV Energy is unaware of any current plan to combine Markets+ and RTO West in a single optimization.

SECTION 7 – GOVERNANCE

FERC noted in Order No. 2000 that independent governance is the "bedrock" upon which the organized market must be built.[650] Market participants, their customers, and their regulators must have confidence in the overall fairness of the governance process. No one state and no one sector can have control or undue influence over market design. The governance structure should be independent "in both reality and perception."[651] FERC noted in Order No. 719 that governance should be responsive to the needs of customers and other stakeholders[652] and meet four criteria: (i) inclusiveness; (ii) fairness in balancing diverse interests; (iii) representation of minority positions; and (iv) ongoing responsiveness.[653]

In the following sections, the Companies discuss the EDAM and Markets+ governance structures consisting of: (1) oversight of the markets and the process for amending the tariffs; (2) the stakeholder process, including the ability of stakeholders and the market operator to react quickly to issues when necessary, and (3) opportunities for the Commission and the Bureau of Consumer Protection to engage in the stakeholder process. Following this review, NV Energy identifies the aspects of the different approaches that lead the Companies to favor the EDAM governance structure as enhanced by the Pathways Initiative.

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648 Direct Testimony of John Tsoukalis at Q&A 10.

649 *Id.* at Q&A 7.

650 *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

651 Order No. 2000 at pp. 194, 205; *id.* at p. 65 ("perceptions of undue discrimination can also impede the development of efficient and competitive electric markets"); *id.* at p. 69 ("perceptions of discrimination are significant impediments to competitive markets.") Order No. 2000 can be found at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

652 Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 477.

653 *Id* at P 502. With respect to these criteria, FERC held that the business practices and procedures of each RTO must ensure that any customer or other stakeholder affected by the operation of the RTO, or its representative, is permitted to communicate its views to the RTO's board of directors. FERC also held that the interests of customers or other stakeholders must be equitably considered, and that deliberation and consideration of RTO issues must not be dominated by any single stakeholder category. FERC found that, in instances where stakeholders are not in total agreement on a particular issue, minority positions must be communicated to the RTO's board of directors at the same time as majority positions. In addition, FERC stated that stakeholders must have input into the RTO's decisions with mechanisms available to provide RTO feedback to stakeholders to ensure that information exchange and communication continue over time.

A. Market Oversight

1. EDAM

Since 2001, the CAISO Board has consisted of five members who are appointed by the Governor of California and subject to confirmation by the state Senate.[654] CAISO Tariff Section 15 specifies that, before a proposed tariff amendment may be filed with the Commission, the Board must approve it in accordance with the corporate bylaws. In 2015, CAISO established the five-member WEM Governing Body,[655] which is selected by stakeholder sectors and comprised of individuals who are independent from market participants.[656] The WEM Governing Body's rules of operation and the process for selecting members are established in corporate governance documents, including the corporate bylaws, the Charter for WEIM and EDAM Governance and the Selection Process for the WEM Governing Body.[657]

WEM Governing Body members serve three-year terms. The WEM Governing Body acts by majority vote of the members with each member having one vote.[658] Meetings are conducted in accordance with the CAISO's Open Meeting Policy,[659] 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 the [CA]ISO's real-time and day-ahead markets, including both participants transacting in the [CA]ISO's balancing authority area and participants transacting in WEIM/EDAM balancing authority areas (meaning the balancing authority areas of WEIM/EDAM entities, collectively).[660]

The WEM Governing Body is to make decisions and recommendations that will:

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654 The California State Legislature passed AB 5x on January 18, 2001, authorizing the replacement of the then-existing stakeholder board with a five-member board to be appointed by the Governor of California and confirmed by the state senate. CAL. PUB. UTIL. CODE § 337(a) (Deering 2005) ("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.").

655 *See* generally the September 11, 2015, decisional memo for the CAISO Board, available at https://www.caiso.com/documents/decision_eim_governanceproposal-memo-sep2015.pdf.

656 Members of the WEM Governing Body must comply with FERC's regulation that prohibits non-stakeholder directors from having a financial interest in any market participant, 18 C.F.R. 35.34(j)(1)(i), and the CAISO's Code of Conduct and Ethical Principles, which includes the same rule.

657 The relevant governing documents as originally adopted are available at https://www.caiso.com/library/board-of-governors-meeting-dec-17-18-2015-board-6. The currently effective versions are available at https://www.westerneim.com/Pages/Governance/default.aspx.

658 WEM Charter at 4.5

659 The Open Meeting Policy can be found at: https://www.caiso.com/Documents/CaliforniaISOOpenMeetingPolicy.pdf.

660 WEM Charter at 2.1 The Charter can be found at: https://www.westerneim.com/Documents/Charter-for-WEIM-and-EDAM-Governance.pdf.

- Preserve the benefits of existing market offerings and expand them across as broad a footprint as possible;

- Make the most efficient use of available energy resources;

- Reduce, to the extent possible, overall economic cost to customers within the market footprint;

- Maximize availability of existing electric generation resources necessary to promote reliability and meet the needs of all affected electricity customers;

- Help control costs to participate, and in internal operations, so as to ensure that favorable cost/benefit ratios are maintained for the benefit of market participants;

- Protect the CAISO market, including the WEIM and EDAM, its participants, and consumers against the exercise of market power or manipulation and otherwise further just and reasonable market outcomes;

- Facilitate and maintain compliance with other applicable legal requirements, including but not limited to environmental regulations and states' renewable energy goals;

- Respect state and local authority to set procurement, environmental, reliability, and other public interest policies;

- Allow WEIM/EDAM Entities to withdraw from the WEIM/EDAM prior to any action that would cause or create an exit fee; and

- Allow options to expand the functionality of the CAISO market to provide additional services.[661]

One of the WEM Governing Body members serves as a non-voting participant at the DMM Oversight Committee of the CAISO Board of Governors. In addition, the CAISO Board of Governors will not approve the nomination of any person to the Market Surveillance Committee unless the WEM Governing Body has also jointly approved the nomination.

West-Wide Governance Pathways Initiative

In July 2023, a group of state regulators from Arizona, California, New Mexico, Oregon, and Washington sent a letter to the Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation, advancing a proposal "for ensuring that the benefits of wholesale

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[661] *Id.*

electricity markets are maximized for customers across the entire Western U.S."[662] The regulators contemplated creation of a new nonprofit regional entity to "serve as a means of delivering a market that includes all states in the Western Interconnection, including California, with independent governance." Their vision included the eventual assumption by the new entity of the WEIM and EDAM, "avoiding a duplication of the investments and expenses of the market infrastructure that has already been created, and avoiding a deterioration of the benefits of those programs [...]." A 26-member group comprising a diverse set of utilities, consumer advocates, public power, generators and power marketers, public interest organizations, labor representatives, and others established a Launch Committee to implement this vision.[663]

The Launch Committee developed a range of potential market design options along with evaluation criteria, obtained legal expertise, and began to identify potential solutions to the associated legal and technical questions related to independent governance for the existing and developing markets. After several months of discussion and stakeholder input, the Launch Committee coalesced around a 3-step process:

- Step 1: Early success. Demonstrate early commitment to the vision of independent governance by elevating the authority of the WEM Governing Body from "joint authority" with the CAISO Board of Governors to "primary authority" over initiatives that "apply to" the WEIM and EDAM.[664] These changes expand independent oversight of WEIM and EDAM to the maximum extent allowed under California law, prior to the passage of AB 825, while continuing to develop paths towards greater independence.

- Step 2: Durable, independent governance of markets and other potential services. This step required a legislative change and consists of forming a new, fully independent Regional Organization that would have sole authority over WEIM and EDAM market rules. Step 2 would create a suite of voluntary wholesale electricity market services as stakeholders and participants desire, without relying on the actions of any one state or BA.

- Step 3: Beyond the Pathways Initiative. As Step 2 matures, the Regional Organization may evaluate expanding the scope of regionalized functions and services. Proposing a particular

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662 The letter is available at: https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

663 A complete list of the launch committee Members and Alternates is available at Pathways-Initiative-Launch-Committee-Roster_Nov-17-2023.pdf. NV Energy had a representative on the committee. CAISO did not have a Launce Committee member but provided significant support and expertise to facilitate the discussions.

664 As revised Section 2.2. of the Charter for WEIM and EDAM Governance now provides,

> The WEM Governing Body will have primary to 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 the CAISO balancing authority area or to the CAISO-controlled grid.

The charter can be found at: https://www.westerneim.com/Documents/Charter-for-WEIM-and-EDAM-Governance.pdf.

design for these subsequent incremental stages was beyond the scope of the Launch Committee's work, but Steps 1 and 2 were developed with an expectation of voluntary future services beyond the scope of existing day-ahead and real time energy markets.

In April 2024, the Launch Committee released a Phase 1 Straw Proposal[665] Based on stakeholder feedback, the Launch Committee refined Step 1 and adopted a final recommendation at a public meeting on May 31, 2024. The Launch Committee presented the Step 1 proposal to the CAISO Board of Governors and WEM Governing Body in June 2024. Following CAISO's additional stakeholder process, the Board of Governors and WEM Governing Body unanimously adopted the Step 1 recommendation on August 13, 2024. On November 7, 2024, the two bodies further approved the tariff provision and the additional changes to the CAISO's Bylaws and Charter for WEIM and EDAM Governance necessary to effectuate Step 1. As approved by the Launch Committee, the CAISO Board of Governors and WEM Governing Body, Pathways Step 1 has three elements:

1. **Elevate WEM Governing Body Decision-making from Joint Authority to Primary Authority**. Under this approach, a market-related proposal comes to the WEM Governing Body first for review and approval, and if approved (by majority vote) is placed on a consent agenda for the Board of Governors. The Board would then have the option to simply approve the consent agenda item or remove the matter from the consent agenda for a full discussion of the proposal. If the Board takes a contrary action to the WEM Governing Body, it triggers the dispute resolution process.

2. **Element Two: Modify the current dispute resolution process to include a dual filing option**. The governance documents detail a multi-step dispute resolution process the CAISO staff would follow if there were an instance when one body votes in favor of a proposal within their shared authority and the other body votes against it – a situation that has not arisen to date. This process requires that the initiative be remanded back to CAISO staff for additional public stakeholder proceedings to develop a revised proposal. The revised proposal would then come back to the two bodies for review and approval. If the revised proposal is not approved by both bodies, it could not move forward for filing at FERC, except in one limited circumstance.[666] The Pathways Step 1 proposal retains this process, including the Board's "exigent circumstances" authority, but adds a "dual filing" option as a second means for moving forward when the Board and Governing Body are unable to agree on a single proposal for FERC to consider. Only after an initial proposal is not approved and CAISO staff conducts a stakeholder process to review possible alternatives, the two bodies could each approve a different proposal which would be filed at FERC as "co-equal" proposals in a single document. FERC could then approve either proposal, or potentially adopt elements of each proposal.[667] The dual filing concept is based

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[665] https://www.westernenergyboard.org/wp-content/uploads/Phase-1-Straw-Proposal.pdf.

[666] Specifically, the Board may authorize a filing with FERC if it finds by unanimous vote "that exigent circumstances exist such that a tariff amendment is critical to preserve reliability or to protect market integrity."

[667] FERC would not be required to consider whether the then-existing filed rate is unlawful, and may adopt any or all of either body's proposal as it finds, in its discretion, to be just and reasonable and preferable, subject only to any limitations the bodies place on choosing elements from each proposal. CAISO management will work with the Chairs of the Board of Governors and the WEM Governing Body, or the two bodies in full, to ensure that the

on a model previously approved by the FERC[668] and removes the veto of CAISO's Board of Governors over new market rules.

3. **Element Three: Augmenting language in the governing documents regarding consideration of the public interest**. The Launch Committee proposed expanding the list of factors that the WEM Governing Body would consider when evaluating proposals to reinforce the importance of considering the interests of consumers across the WEIM and EDAM footprint and respecting state and local regulatory authority.[669]

Elements 1 and 3 were addressed in revisions to the CAISO Bylaws and the Charter for WEIM and EDAM Governance. In addition to being reflected in the Charter, Element 2 required a targeted change to the CAISO Tariff. CAISO submitted the filing to FERC in Docket No. ER25-542 on November 25, 2024, and it was approved on April 2, 2025.[670]

Pathways Step 1 was "triggered" after a specific threshold was met. Specifically, it required: (1) execution of EDAM Implementation Agreements by utilities representing non-CAISO BAA load that is equal to or greater than 70 percent of CAISO BAA load; and (2) geographic diversity among the non-CAISO participants beyond PacifiCorp, BANC and LADWP, such that it includes at least one additional non-California entity each from the Northwest and the Southwest.[671] With the execution of EDAM Implementation Agreements by PacifiCorp, Portland General Electric, the

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explanation of each body's proposal is reflected accurately and that the two proposals are presented as co-equals with no preference indicated.

668 *See,* ISO New England Participants Agreement § 11.1.5, available at https://www.iso-ne.com/static-assets/documents/2015/10/parts_agree.pdf. ISO New England refers to its filings that contain two proposals as "jump ball" filings. See, e.g., *ISO New England Inc. and ISO New England Power Pool*, 152 FERC ¶61,190 (2015), n.2.

669 Section 2.1 of the Charter for WEIM and EDAM Governance has been revised as indicated in the blackline: The WEM Governing Body shall make decisions and recommendations that will:

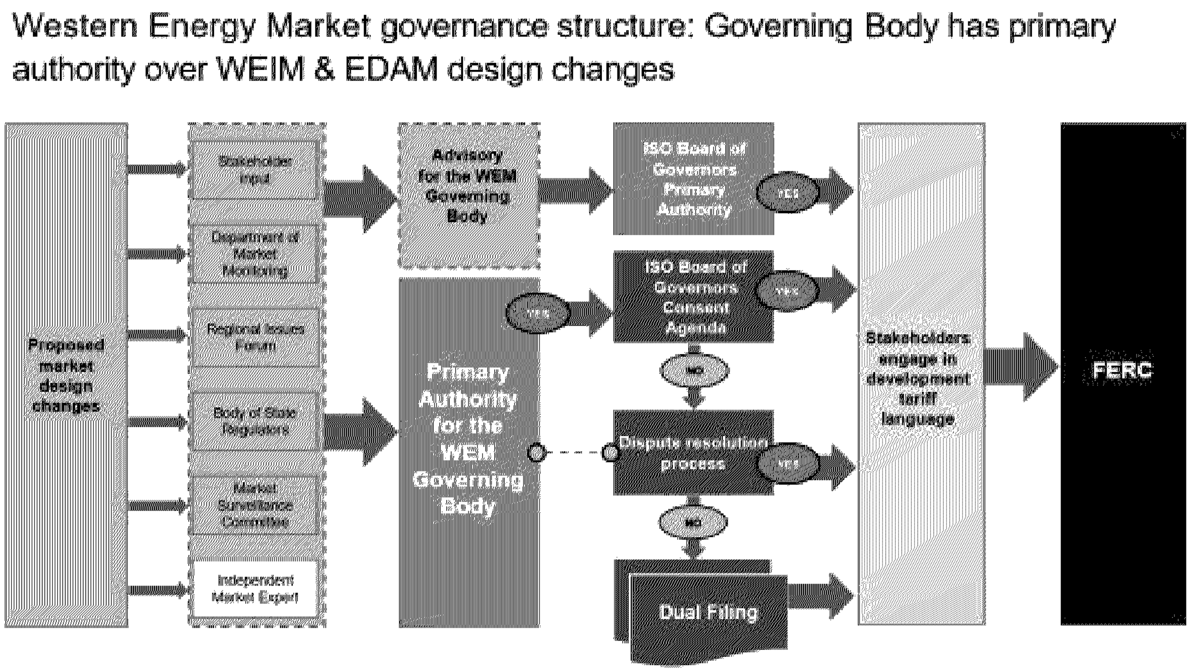
- **Preserve the benefits of existing market offerings and expand them across as broad a footprint as possible;**
- **Make the most efficient use of available energy resources;**
- **Reduce, to the extent possible, overall economic cost to customers within the market footprint;**
- **Maximize availability of existing electric generation resources necessary to promote reliability and meet the needs of all affected electricity customers**;
- Help control costs **to participate, and in internal operations, so** as to ensure that favorable cost/benefit ratios are maintained for the benefit of market participants;
- Protect the ISO market, including the WEIM and EDAM, its participants, and consumers against the exercise of market power or manipulation and otherwise further just and reasonable market outcomes;
- Facilitate and maintain compliance with other applicable legal requirements, including but not limited to environmental regulations and states' renewable energy goals;
- **Respect state and local authority to set procurement, environmental, reliability, and other public interest policies;**
- Allow WEIM/EDAM Entities to withdraw from the WEIM/EDAM prior to any action that would cause or create an exit fee; and
- Allow options to expand the functionality of the ISO market to provide additional services.

670 *Cal. Indep. Sys. Operator Corp.*, 191 FERC ¶ 61,009 (2025).

671 The full Pathways Step 1 proposal, available at https://www.caiso.com/documents/attachment-1-west-wide-governance-pathways-initiative-step-1- recommendation-final-draft-proposal-may-2024.pdf and the decisional memorandum to the CAISO Board and WEM Governing Body dated August 6, 2024, available at https://www.caiso.com/documents/decision-on-west-wide-governance-pathways-step-1-proposalmemo-aug-13-2024.pdf.

Balancing Area of Northern California, the Los Angeles Department of Water and Power, Imperial Irrigation District, Turlock Irrigation District and Public Service Company of New Mexico, the criteria has been met. Accordingly, CAISO announced the implementation of the Pathways Step 1 structure effective July 1, 2025.[672] With the implementation of Step 1, Figure 52 is an illustration of the current EDAM and WEIM process.

Figure 52



With the passage of AB 825 by the California legislature, Pathways Step 2 will transition market oversight further from primary authority to sole authority under the auspices of a new Regional Organization (the "RO"). Market operations would continue to be performed and overseen on a day-to-day basis by the CAISO within the scope of its existing corporate authority, with oversight from the RO. The RO would have audit rights and responsibilities to ensure the CAISO as market operator is following the tariff and business practices. At least initially, the RO and CAISO rules will remain in a single integrated tariff The CAISO's existing financial responsibility, liability, and compliance responsibilities related to the market would not migrate to the RO immediately, reducing the time and cost required for RO start up, and CAISO will remain the counterparty to existing market contracts, such as Participating Generator Agreements and Scheduling Coordinator Agreements. Market operator staff will retain emergency operational authority under FERC oversight, during actual emergency conditions in the market, as it does today. In the Step 2 Proposal, the Launch Committee noted that the RO will have limited staffing at the outset with an estimated initial annual cost of $1.25 to $1.5 million, which could increase to $10 to $14 million over time as the organization develops.[673]

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672 *See* CAISO's July 1, 2025, Informational Filing in FERC Docket No. ER25-542 at 1.

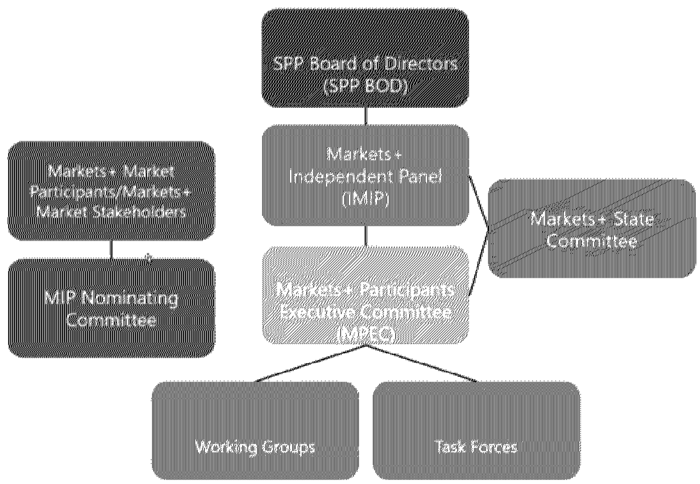
673 Pathways Step 2 Proposal at 35 and 37. The document can be found at: https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf. ("For

Accordingly, at least in this initial iteration, Pathways Step 2 is very similar in most respects to what the WEM Governing Body is today as a policy-setting board with the change of assuming sole authority over market rules. Over time and if economically feasible, the RO could take on more responsibility and convert CAISO into the role of a vendor under a service contract.

2. Markets+

The Markets+ Governance structure is illustrated in Figure 53. It consists of a hierarchical committee structure in which initiatives are reviewed in certain working groups and task forces before being brought before the Markets+ Participants Executive Committee ("MPEC") for a vote. Based on the outcome of the MPEC vote and any challenges, the matter goes to the MIP. Finally, SPP Board of Directors approval is needed for any FERC filing.

Figure 53[674]



The SPP Board of Directors consists of nine independent directors plus the SPP Chief Executive Officer[675] and provides the ultimate oversight of SPP's administration of Markets+. The Board is to give significant recognition and deference to the MIP decision-making role.[676] The Board is selected through the SPP RTO Tariff governance process and operates by a majority vote. The SPP Board will review and consider:

example, the cost to market participants of the current WEM GB today is about $640,000 annually, including compensation paid to GB members. For a governing board with two additional members, more responsibilities, and one to two dedicated support staff, we estimate an annual cost of $1.25 to $1.5 million.") More extensive RO executive staffing with an estimated annual cost of roughly $25 million; the additional RO staff will enable the RO to meet its increased oversight responsibilities with respect to the markets. The feasibility study will examine, among other cost factors, the extent to which these RO cost increases would be offset by increases in expanded market products and participants and/or decreases in the administrative payments to CAISO. Pathways Step 2 Proposal at 14.

674 *See* Figure JCT-D-6 Hearing Exhibit No. 101, Direct Testimony and Attachments of Joseph C. Taylor filed with the Colorado Public Utilities Commission on February 14, 2025, in Proceeding No. 25A-0075E at 58.

675 https://spp.org/about-us/leadership/.

676 Markets+ Tariff, Attachment O, Section 4.1.

1. Decisions of the MIP, after completion of the applicable Markets+ stakeholder process, that have a material adverse effect on SPP, including:
   a. Material agreements and material changes to those agreements between SPP and Markets+ Market Participants or SPP and Markets+ Market Stakeholders.
   b. Issues or concerns raised by the Market Monitor related to any FERC filing, rule or process within the scope of the Market Monitor's authority as established by FERC that has been previously raised to the MIP.
   c. Legal and/or litigation disputes or actions involving SPP or the implementation of Markets+; and
   d. Financial ramifications or corporate risk to SPP.
2. Markets+ budgets, any debt obligations related to Markets+, or material changes to SPP's staffing requirements; and
3. Appeals of MIP decisions made by any member of the MIP (including the Board of Director member).[677]

The MIP is the primary level of authority for decisions related to Markets+.[678] It will consist of five individuals, one of whom will be an SPP board member, with others resulting from an independent nationwide executive search conducted by the Markets+ Nominating and Governance Committee. MIP members will be independent of any Markets+ party.[679] The MIP currently exists in an interim form (the "IMIP") and consists of three SPP Board members. The nominating

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677 *Id.* at Attachment O, Section 4.1.

678 In accordance with Attachment O, Section 4.2.1 of the Markets+ Tariff, the MIP will

- Provide a forum for the entities that have executed a Markets+ Market Participant Agreement or a Markets+ Stakeholder Agreement with SPP, the MSC, and Markets+ Non-Voting Stakeholders to discuss issues related to the ongoing administration and advancement of Markets+ development in the Western Interconnection. The MIP has the authority to set priorities and direct the MPEC to investigate potential market design and tariff revisions.
- Approve or reject proposed amendments to the Markets+ Tariff made by the MPEC or the MSC before the filing of such amendments at FERC. If the MSC proposes a tariff amendment(s) to the MIP, the MPEC will be provided the opportunity to review and comment on the proposed changes.
- Consider, approve or reject market rules if such rules solely apply to the administration of the Markets+ market and have no application to the SPP Integrated Marketplace or any other service provided by SPP. To the extent such rules apply to the SPP Integrated Marketplace or any other service provided by SPP, the MIP will be afforded the opportunity to provide input to any other applicable SPP organizational group and the SPP Board of Directors.
- Collaborate with SPP Staff on the development of Markets+ tariff provisions, market protocols, business practices and interregional agreements to promote transparency and efficiency in the operation of the Markets+ market.
- Evaluate and provide consultation to SPP on the Markets+ market administration budget to the MSC, Markets+ Market Participants and Markets+ Market Stakeholders, including modifications or adjustments of the Markets+ market administration rate, in accordance with the Markets+ Tariff.
- Review, consider and decide whether to approve market design system or process enhancement proposals recommended by SPP, the MSC, the MPEC or any designated working group, committee, or task force established by the MPEC. Recommendations to enhance systems or processes materially impacting SPP's administration of the Markets+ market or the Markets+ market administration budget must be approved by the MIP before beginning implementation of the enhancement.
- Resolve any disputes regarding the establishment of a working group or task force and the staffing of that working group or task force.

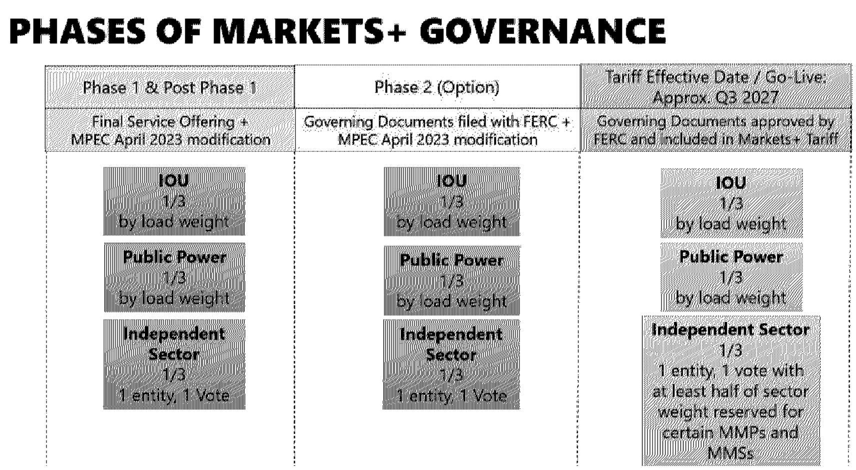
679 Markets+ Tariff, Attachment O, Section 4.2.2.

committee will commence the process of vetting MIP candidates prior to market start.[680] Meetings of the MIP are open to all interested parties; however, the MIP may limit attendance during specific portions of a meeting by an affirmative vote of the MIP. Matters for consideration in closed or limited sessions should be limited to personnel, legal, proprietary, confidential or security sensitive information.[681] Decisions of the MIP will be by simple majority vote of the members participating.[682]

The MPEC is a stakeholder representation committee. Each stakeholder that has executed a market participant or stakeholder agreement has an opportunity to appoint one voting representative.[683] The MPEC will review system or process enhancement proposals recommended by SPP, the Markets+ States Committee ("MSC"), Markets+ Market Participants, Markets+ Market Stakeholders, Markets+ Non-Voting Stakeholders or any designated working group, committee or task force established by the MPEC.

Each member of Markets+ is assigned to one of three membership sectors: Investor-Owned Utilities, Public Power, or Independent. Each of the sectors represents 33 1/3 percent of the vote. An action is approved by the MPEC if the average of these percentages is at least 67 percent.[684] The voting structure is illustrated in Figure 54.

Figure 54[685]



680 *Id.* at Attachment O, Section 4.2.4.
681 *Id.* at Attachment O, Section 4.2.3.4.
682 *Id.* at Attachment O, Section 4.2.3.45.
683 Markets+ Tariff, Attachment O, Section 4.3.1.1. Market participants that own generation or otherwise participate in the market will participate and have voting rights at the MPEC. Similarly, any stakeholder that executes a Markets+ Stakeholder Agreement and either pays an annual fee of $5,000 or has the fee waived (for eligible nonprofit organizations) also has voting rights at the MPEC. Any other stakeholder interested in participating in the Markets+ process may do so at any time, as all SPP stakeholder meetings are open to the public upon registration.
684 Markets+ Tariff, Attachment O, Section 4.3.1.4
685 May 21, 2025, Webinar: https://www.spp.org/documents/73921/phase%20two%20governance%20and%20readiness%20webinar%2020250521.pdf.

B. Stakeholder Process

FERC has noted that. "[s]takeholder processes are the primary ways that RTOs and ISOs develop, modify, and propose market rules," and [e]ach of the RTO stakeholder processes have unique structures that influence how the RTO operates in the market-rule development process."[686] Active participation in the stakeholder process requires a significant commitment of time and resources. However, it is the primary means to ensure consideration of how the market design affects the Companies' operations and customers.

1. EDAM

CAISO's stakeholder model does not rely on formal committees. Rather, initiatives are issue specific and discussions are open to all stakeholders, including market participants, public interest organizations, and regulators. CAISO staff guides the process; though more recently, especially with respect to complex topics, stakeholder-led workshops have been incorporated into the deliberations. The CAISO staff provides independence and expertise distinct from the perspectives of individual market participants and other stakeholders. Staff utilizes stakeholder input to inform issue development, and direction and to create balanced solutions that fit within the construct of the market operations. Stated another way, stakeholders represent their individual position and staff represent the market as a whole. Under the CAISO approach, anyone can qualify as a stakeholder and submit comments. In January 26, 2023, comments, the Body of State Regulators ("BOSR"), found:

> the current level of engagement from stakeholders not just sufficient, but significant, and contends the CAISO policy initiative process is open and transparent. The BOSR supports the GRC's recommendation of using working groups when the complexity and impact of a policy initiative merit the extra work and understands the benefit to using working groups in these scenarios. The BOSR also supports the proposed process for developing the policy roadmap.[687]

The annual catalog and roadmap process develops the policy initiatives the CAISO will undertake in the following three years. CAISO policy initiatives originate from a variety of sources including: (1) FERC Orders, (2) recommendations of DMM or the Market Surveillance Committee, (3) observations of day-to-day market operations, and (4) stakeholder proposals.[688]

Stakeholders may propose potential discretionary policy initiatives in January and February. Following a stakeholder-led prioritization process in the spring, the CAISO publishes the catalog,[689] which is a list of potential discretionary policy initiatives. The catalog helps inform the

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686 https://www.ferc.gov/opp/energy-markets.

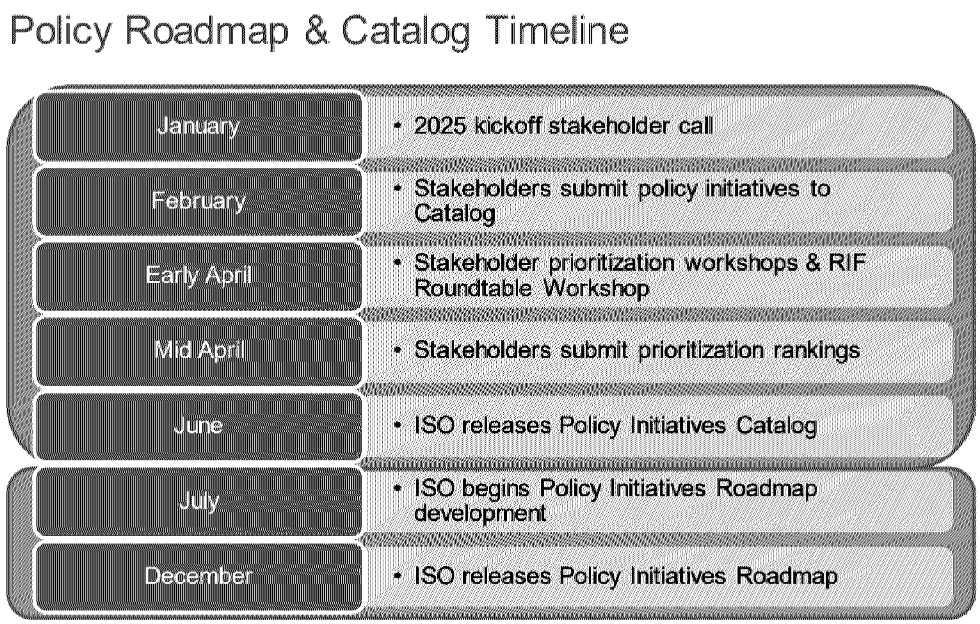
687 Advice from the Western Energy Imbalance Market Body of State Regulators to the Western Energy Imbalance Market Governing Body on the Extended Day-Ahead Market Final Proposal and the Governance Review Committee's Phase Three EDAM Governance Final Proposal dated January 26, 2023, at 8. https://www.westernenergyboard.org/wp-content/uploads/BOSR-Advice-to-WEIM-Governing-Body-on-EDAM-Market-Design-and-Governance.pdf.

688 Direct Testimony of Stacy Crowley, CAISO's Vice President External Affairs, at Q&A 21.

689 The current catalog can be found at:

development of the "Roadmap," published at the end of the year. Following the compilation of potential initiatives in the catalog, the Regional Issues Forum ("RIF") hosts a roundtable discussion about priorities within the set of possible discretionary initiatives. Figure 55 summarizes CAISO's initiative development process.

Figure 55



In addition to discretionary initiatives, CAISO considers management priorities, comments from the Department of Market Monitoring, the Market Surveillance Committee, and stakeholders regarding high-priority issues related to market operations and FERC mandates in developing the Roadmap. There are also recurring items such as the evaluation of the CAISO's administrative costs recovered under the Grid Management Charge or the development of the annual transmission plan. Figure 56 illustrates the current CAISO Policy Roadmap. Not surprisingly, a significant amount of attention is directed at EDAM implementation.

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https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Annual-policy-initiatives-roadmap-process-2025.

Figure 56
CAISO Policy Roadmap[690]

Revised 2025 policy roadmap

2025					
		Q1	Q2	Q3	Q4
Congestion Revenue Rights		**Scoping working groups**		**Policy development**	
Demand and Distributed Energy Market Integration		**Scoping working groups**			**Policy Development**
EDAM Congestion Revenue Allocation			**Policy Development & Decision**		
Gas Resource Management		**Proposal working groups**	**Straw proposal**	**Policy development**	**Decision**
Greenhouse Gas Coordination					
	Topic 1: WEIM/EDAM GHG design	**Scoping working groups**		**Postponed**	
	Topic 2: Non-priced approaches for GHG reduction	**Policy development**	**Straw proposal**	**Policy development**	**Decision**
	Topic 3: Additional GHG-related metrics	**Addressed & closed out**			

[690] These slides are from the May 21, 2025, Briefing on Annual Policy Roadmap Process before the Join CAISO Board of Governors and WEM Governing Body Meeting and can be found at: https://www.westerneim.com/Documents/Briefing-on-Policy-Roadmap-Process-May-2025.pdf.

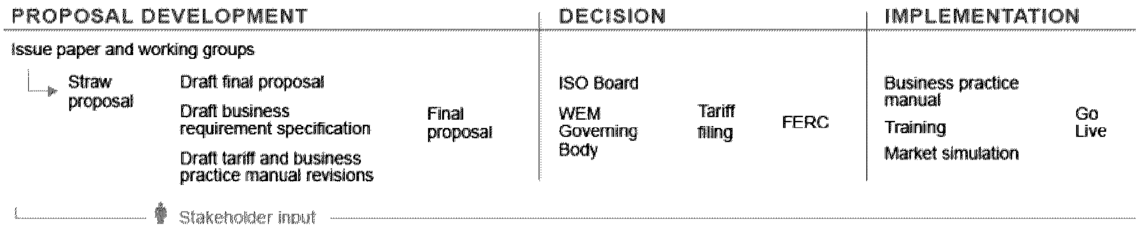
2025					
		Q1	Q2	Q3	Q4
Price Formation Enhancements					
	Scarcity pricing & market power mitigation	Proposal working groups	Straw proposal	Policy development	
	Fast start pricing	Postponed			
Resource Adequacy Modeling and Program Design					
	Track 1: Modeling, Defaults, and Accreditation	Policy development			Decision (Default Counting Rules/PRM)
	Track 2: Outage & substitution and availability and incentive mechanisms	Policy development			
	Track 3a: RA status visibility	Policy development			
	Track 3b: Backstop reform and long-term EDAM RSE solutions		Postponed		Policy development

		2025			
		Q1	Q2	Q3	Q4
Storage Design and Modeling		Scoping working groups Issue papers & straw proposals		Policy development	
WEIM Resource Sufficiency Evaluation Enhancements		Postponed			
WEIM Assistance Energy Transfer			Policy development	Decision	

In the typical initiative process, the CAISO releases an Issue Paper followed by a straw proposal, a Draft Final Straw Proposal, and a Final Straw Proposal that is presented to the WEM Governing Body and the Board of Directors for approval. During the iterative proposal development process, stakeholders are able to comment and provide feedback on each revision of a proposal. Once final, tariff changes are proposed and submitted for FERC approval. These stages are illustrated in Figure 57. The extensive use of written comments provides transparent documentation of stakeholder positions, facilitating further deliberations and review by the Department of Market Monitoring, the Market Surveillance Committee, and the WEM Governing Body.[691]

[691] Direct Testimony of David Rubin at Q&A 21.

Figure 57



In NV Energy's experience, the CAISO stakeholder process has evolved. In response to criticisms that the staff had too dominant a role, the CAISO has: (1) adopted the use of stakeholder-led workshops for complex initiatives and (2) used workgroups to help define the scope of initiatives prior to issuing a straw proposal.

In addition to the initiative development process, the RIF provides an additional avenue for stakeholder education and involvement. The RIF is organized by 12-sector selected liaisons that facilitate input and participation from their respective sectors on relevant topics.[692] The forums, held approximately three times a year, allow stakeholders to discuss broad issues related to the Western Energy Markets including the WEIM and EDAM. The forums are open to the public. The RIF may produce documents or opinions for consideration by the WEM Governing Body and CAISO.

2. Markets+

Markets+ utilizes a hierarchical standing committee structure to review revisions to the tariff and business practices with various work groups and task forces reporting to the MPEC which is overseen by the MIP and the SPP Board of Directors. The MPEC may establish working groups to assist with its mission. Several working groups were formed to develop the Markets+ tariff and protocols. These are illustrated in Figure 58. Each working group has a charter and is intended to have a balance of voting members between the investor-owned, public power, and independent sectors. The Markets+ State Committee may also assign a member as a non-voting member of the working group. Working group and task force votes are based on the majority of member votes with a proxy requirement.

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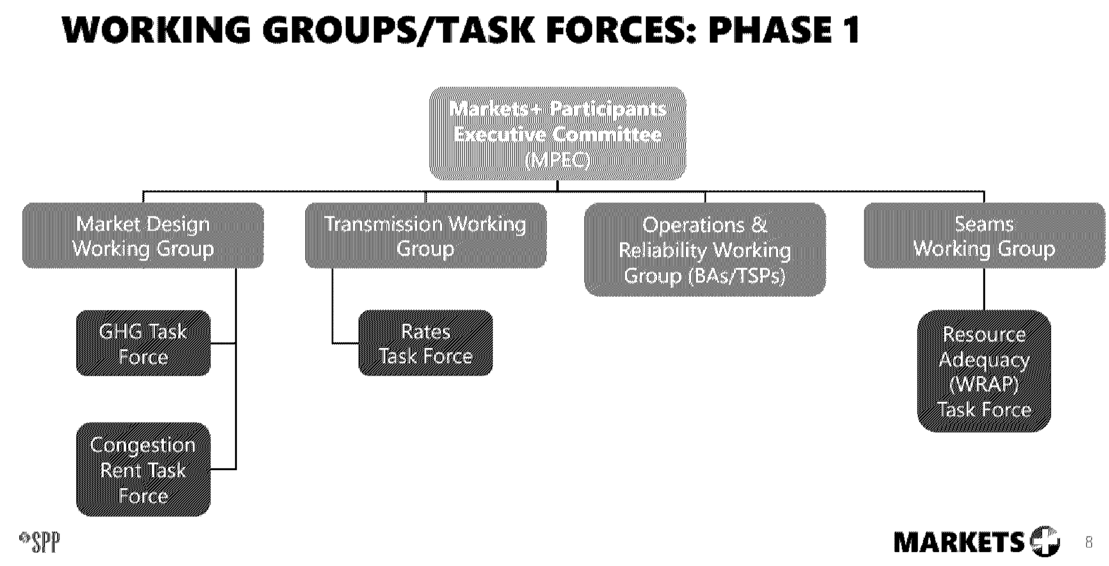
692 The RIF sector liaisons are self-selected. There are two liaisons from: (1) WEIM entities, (2) CAISO participating transmission owners, (3) Consumer-owned utilities located within a WEIM BAA that are not included in another sector; (4) public interest groups and consumer advocate groups that are actively involved in energy issues within the WEIM footprint; and (5) Independent power producers and marketers who engage in transactions within the WEIM footprint. In addition, federal power marketing administrations may select one liaison. EDAM Entities may also select one liaison.

Figure 58



The following is a brief description of the work scope of these working groups and task forces:

- The Markets+ Design Working Group ("MDWG")[693] develops the policies and procedures related to the tariff and protocols, including energy, flexibility reserves, congestion rent allocation, greenhouse gas policy, congestion management, demand response, market power mitigation, and settlements.

- The Markets+ Seams Working Group ("MSWG")[694] identifies seams coordination issues between Markets+ and adjacent transmission providers and markets. It also provides direction and solutions on inter-operability policies with the WRAP.

- The Markets+ Transmission Working Group ("MTWG")[695] provides policy recommendations around transmission usage and capability.

- The Markets+ Greenhouse Gas Task Force ("MGHGTF"):[696] reports to the MDWG and is responsible for the development of policies and procedures to incorporate GHG into the market for GHG pricing states such as Washington, and to develop accounting and tracking

693 https://spp.org/documents/69073/design%20working%20group_mdwg_scope.pdf.

694 https://spp.org/documents/69070/operations%20and%20reliability%20working%20group_morwg_scope.pdf.

695 https://spp.org/documents/69071/greenhouse%20gas%20task%20force%20mghgtf%20scope.pdf.

696 https://spp.org/documents/69071/greenhouse%20gas%20task%20force%20mghgtf%20scope.pdf.

requirements for GHG reduction states such as Colorado.[697] The MGHGTF also included state representatives as voting members.

- The Markets+ Congestion Rent Task Force ("MCRTF")[698] reports to the MDWG and establishes tariff and protocol language to address the distribution of congestion rents from the day-ahead market.

- The Markets+ Resource Adequacy Task Force ("MRATF") reports to the MDWG and is responsible for incorporating policies and procedures to the Tariff and protocols to ensure inter-operability between Markets+ and the WPP WRAP.

- The Markets+ Rates Task Force ("MRTF")[699] reporting to the MTWG and develops the determination, collection and distribution of the Market Transmission Use ("MTU") charge, including tariff and protocol documents needed to implement the MTU.

- The Markets+ Interim Governance Task Force ("MIGTF")[700] is responsible for reviewing and processing issues related to Markets+ governance past Phase 1 and during Phase 2 development.

In addition, the Markets+ Change User Forum ("MCUF") is open to all Markets+ stakeholders and participants and coordinates for operator system changes affecting Markets+ participants. The MCUF facilitates meetings and disseminates information concerning the implementation of participant-facing and participant-impacting projects and provides a forum for participants to give feedback about projects, including project timelines, testing windows and impacts.

SPP staff only provides facilitation and technical support, as determined is available. MPEC and Markets+ workgroup meetings are open to the public. Any participant can raise issues, suggest policy proposals and engage in discussions. Entities that are not market participants are able to join and participate as Markets+ Market Stakeholders for $5,000 fee, which may be waived for non-profit organizations and state-chartered consumer advocate offices.[701]

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[697] The GHGTF has the unique characteristic of having four sectors represented in its voting structure: investor-owned utilities, public power, independent, and the MSC.

[698] https://spp.org/documents/69263/congestion%20rent%20task%20force_mcrtf_scope.pdf.

[699] https://spp.org/documents/69069/rates%20task%20force_mrtf_scope.pdf.

[700] Information on the MIGTF can be found at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fspp.org%2Fdocuments%2F72025%2Fmigtf%2520scope%2520document%252020240430.docx&wdOrigin=BROWSELINk.

[701] Markets+ Tariff at Attachment O, section 2 definition of Markets+ Stakeholder. A stakeholder that has executed the Markets+ Stakeholder Agreement and pays an annual fee of $5,000. A Markets+ Stakeholder has voting rights at the Markets+ Participants Executive Committee, and is eligible for a voting seat, if appointed, on the Markets+ Nominating and Governance Committee, working groups and task forces. The annual fee may be waived for eligible entities that are nonprofit organizations under the Internal Revenue Code, or a governmental entity designated by state statutes to represent the interests of end-use customers before a state's regulatory agencies).

C. PUCN and BCP Participation

One of the criteria in the July 9, 2024, Order in Docket No. 23-10019, was:

> Governance of the DAM and the overall organization of the entity that owns the DAM, including the process by which changes to the FERC-approved DAM tariff occur, to include any opportunities for the Commission to participate in the DAM change process prior to a filing at FERC;

This section focuses on the DAM's state committee and additional opportunities for the PUCN to participate in the stakeholder process.

In addition, to PUCN participation, NV Energy understands that as the Companies increase their organized market participation, in accordance with the directives in SB 448, the Bureau of Consumer Protection also will want to enhance its ability to monitor and comment in the ongoing initiative processes. This could be done either individually or in cooperation with other state consumer advocate offices.

1. EDAM

Similar to the options in WEIM today, the PUCN could participate in the EDAM stakeholder process either on its own or through its membership on the Body of State Regulators ("BOSR"), which was established in 2015.[702] The BOSR includes one commissioner from each of the state commissions in which a LSE participates in the WEIM.[703] Additionally, liaisons who represent three other sectors -- consumer-owned utilities, public-owned utilities, and federal power marketing administrations also participate in BOSR discussions.[704] BOSR is self-governing and has a voting member on the WEM Governing Body nominating committee.[705] Through its meetings, the BOSR, with assistance from CAISO staff, informs regulators about the WEIM, EDAM, the WEM Governing Body and related CAISO developments. BOSR also provides advice to the WEM Governing Body and stakeholders. BOSR also may, as necessary, provide its opinions to FERC regarding any proposed tariff amendment.[706] BOSR has provided comments on a number of issues including:

- Western EIM Body of State Regulators Comments on Proposed Revisions to EIM Governance Documents dated December 18, 2017;[707]

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702 The CAISO Board of Governors authorized the creation of the BOSR at its September 17, 2015, meeting. The BOSR Body has been formed by state utility regulatory commissioners and is not a committee or sub-committee of or established by the CAISO Board of Governors or the WEM Governing Body. https://www.westernenergyboard.org/wp-content/uploads/04-30-21-EIM-BOSR-Amended-Charter.pdf.

703 When necessary, a state commission may select a representative who is not a commissioner.

704 Direct Testimony of Stacey Crowley at Q&A 10.

705 Charter at 6.1.2. https://www.westerneim.com/Documents/Charter-for-WEIM-and-EDAM-Governance.pdf.

706 *Id.* at 6.1.2.2 and 6.1.2.3.

707 https://www.westernenergyboard.org/wp-content/uploads/2017/12/12-18-17-EIM-BOSR-Comments-on-Governance-Revisions-FINAL-1.pdf.

- Comments of the Western Energy Imbalance Market Body of State Regulators on the California Independent System Operator EIM Greenhouse Gas Enhancements Initiative 3rd Revised Draft Final Proposal dated June 21, 2018;[708]
- Comments of the Western Energy Imbalance Market Body of State Regulators on the Energy Imbalance Market Governing Body's EIM Governance Review dated January 18, 2019;[709]
- Western EIM Body of State Regulators April 10, 2019, Draft Principles to Guide EIM BOSR Membership;[710]
- Comments of the Western Energy Imbalance Market Body of State Regulators on the Energy Imbalance Market Governance Review dated June 14, 2019;[711]
- Comments of the Western Energy Imbalance Market Body of State Regulators on the Extending the Day-Ahead Market to EIM Entities Issue Paper dated November 22, 2019;[712]
- Comments of the Western Energy Imbalance Market Body of State Regulators on the EIM Governance Review Committee's Scoping Paper dated February 21, 2020;[713]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the EIM Governance Review Committee's Draft Straw Proposal dated August 27, 2020;[714]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the EIM Governance Review Committee's Revised Straw Proposal dated January 29, 2021;[715]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the CAISO's Market Enhancements for Summer 2021 Readiness Initiative dated March 1, 2021;[716]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the EIM Governance Review Committee's Key Aspects of the Delegation of Authority dated June 9, 2021;[717]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the CAISO's EIM Resource Sufficiency Evaluation Enhancement Initiative dated January 10, 2022;[718]
- Western Energy Imbalance Market Body of State Regulators Comments on the California ISO Extended Day-Ahead Market Straw Proposal dated June 20, 2022;[719]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the Western Energy Imbalance Market Governance Review Committee's Phase Three Straw Proposal dated August 15, 2022;[720]

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708 https://www.westernenergyboard.org/wp-content/uploads/06-221-18-eim-bosr-comments-on-caiso-eim-ghg-enhancement-initiative-3rd-rev-final.pdf.

709 https://www.westernenergyboard.org/wp-content/uploads/01-18-19-EIM-BOSR-Comments-on-Western-EIM-Governance-Review-Final.pdf.

710 https://www.westernenergyboard.org/wp-content/uploads/2019/04/04-10-19EIM-BOSR-Governance-Principles-final-draft-1.pdf.

711 https://www.westernenergyboard.org/wp-content/uploads/2019/09/06-14-19-EIM-BOSR-Comments-Governance-Review-Committee-and-Charter-formation-1.pdf.

712 https://www.westernenergyboard.org/wp-content/uploads/BOSR-comments_EDAM_IP_Nov-22-2019_final.pdf.

713 https://www.westernenergyboard.org/wp-content/uploads/2020/02/02-21-20-BOSR-Comments-GRC-Scoping-Paper-FINAL-1.pdf.

714 https://www.westernenergyboard.org/wp-content/uploads/08-27-20-BOSR-Comments-GRC-Draft-Straw-Proposal.pdf.

715 https://www.westernenergyboard.org/wp-content/uploads/01-29-2021-bosr-comments-grc-revised-straw-proposal-b.pdf.

716 https://www.westernenergyboard.org/wp-content/uploads/03-01-2021-bosr-comments-eim-market-enhancements-summer-readiness-initiative.pdf.

717 https://www.westernenergyboard.org/wp-content/uploads/06-09-21-BOSR-Comments-GRC-Phase-2-Straw-Proposal.pdf.

718 https://www.westernenergyboard.org/wp-content/uploads/BOSR-Comments-EIM-RSE-Enhancement-Revised-Draft-Final-Proposal-Submitted.pdf.

719 https://www.westernenergyboard.org/wp-content/uploads/WEIM-BOSR-Written-Comments-CAISO-EDAM-Straw-Proposal.pdf.

720 https://www.westernenergyboard.org/wp-content/uploads/WEIM-BOSR-Comments-on-EDAM-Governance-Straw-Proposal_081522.pdf.

- Comments of the Western Energy Imbalance Market Body of State Regulators on the Extended Day-Ahead Market Revised Straw Proposal dated September 26, 2022;[721]
- Comments of the Western Energy Imbalance Market Body of State Regulators on the Extended Day-Ahead Market Draft Final Proposal dated November 22, 2022;[722]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the Western Energy Imbalance Market Governance Review Committee's Phase Three Revised Proposal dated November 29, 2022
- Advice from the Western Energy Imbalance Market Body of State Regulators to the Western Energy Imbalance Market Governing Body on the Extended Day-Ahead Market Final Proposal and the Governance Review Committee's Phase Three EDAM Governance Final Proposal dated January 26, 2023;[723]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the California ISO on the Final 2023-2025 Policy Initiatives Roadmap and Final 2023 Policy Initiatives Catalog dated April 27, 2023;[724]
- Comments on the West-Wide Governance Pathways Initiative Step 1 Proposal dated July 25, 2024;[725]
- Comments of the Western Energy Imbalance Market Body of State Regulators to the California ISO on the 2024 Policy Initiatives Roadmap Process dated March 6, 2024;[726] and
- Comments of the Western Energy Markets Body of State Regulators to the Western Energy Markets Governing Body on Track 1 of the Storage Bid Cost Recovery and Default Energy

CAISO provides staff liaison support to the BOSR.[727] However, the BOSR recognized the need for additional assistance in performing its functions. On January 15, 2021, WIEB and the BOSR approved a memorandum of understanding that established an agreement for WIEB to provide the EIM-BOSR the technical expertise, staff resources, and office space necessary to support the BOSR activities in the WEIM.[728] WEIB entered into agreements with each of the state regulated WEIM participants to fund WIEB's work. NV Energy executed its agreement on February 5, 2021.

WIEB prepares an annual business plan and budget which is reviewed by BOSR and the state regulated market participants. The BOSR funding assessment is allocated to State-Regulated

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721 https://www.westernenergyboard.org/wp-content/uploads/WEIM-BOSR-Comments-on-EDAM-Revised-Straw-Proposal-09262022.pdf.

722 https://www.westernenergyboard.org/wp-content/uploads/WEIM-BOSR-Comments-on-EDAM-Draft-Final-Proposal-November-2022.pdf.

723 https://www.westernenergyboard.org/wp-content/uploads/BOSR-Advice-to-WEIM-Governing-Body-on-EDAM-Market-Design-and-Governance.pdf.

724 https://www.westernenergyboard.org/wp-content/uploads/BOSR-Comments-on-Final-2023-Policy-Catalog-and-Roadmap.pdf.

725 https://www.westernenergyboard.org/wp-content/uploads/BOSR-Comments-on-West-Wide-Governance-Pathways-Step-1.pdf.

726 https://www.westernenergyboard.org/wp-content/uploads/Comments-on-2024-Policy-Initiatives-Roadmap-Process.pdf.

727 Direct Testimony of Stacey Crowley at Q&A 11.

728 WIEB was formed in 1970 pursuant to the Western Interstate Nuclear Compact, P.L. 91-461. WIEB provides the instruments and framework for developing energy policy cooperatively among member states and provinces and the federal government to enhance the economy of the West. WIEB currently shares staff resources and office space with the Western Interconnection Regional Advisory Body (WIRAB). WIRAB was created by FERC in 2006 upon petition of the western governors. WIEB also provides staff support to the WRAP Committee of State Representatives ("COSR") and the Markets+ States Committee ("MSC"). The COSR is an organization comprised of one representative from each state with a utility participating in the WRAP. The MSC is an organization of representatives from any of the states or provinces with entities that may plausibly choose to participate in the ultimate Markets+ day-ahead market structure of SPP. WIEB, WIRAB, BOSR, COSR, and MSC are independent sister organizations that share staff and office resources but maintain independent governance and decision-making. The following chart illustrates the relationships between the organizations.

Market Participants ("SRMPs") using a two-tier allocation methodology.[729] The funding assessment is first allocated to each state. Those states with small amounts of electric load participating in the WEIM receive a discount. Second, each SRMP within a state is allocated a funding amount based on its percentage share of the electric load within the state. The proposed budget for 2025 was $456,865 based upon employment of 2.2 full-time equivalent employees. NV Energy's share of the BOSR budget has generally been between $40,000 and $50,000 annually.[730]

Currently, the CAISO Tariff does not provide funding for state sponsored consumer advocates such as Nevada's BCP. As noted above, CAISO's stakeholder processes are open to all parties, without an entrance fee, so there are no restrictions on BCP's potential participation.

The Pathways' Launch Committee was sensitive to the role of the consumer advocates authorized by state law in advancing the public interest in their respective states and recognized that "some Western ratepayer advocates have identified barriers to their participation, including being overall under-resourced, difficulties assigning those limited resources to regional processes that are unpredictable in timing, and potential restrictions for individual offices to use their own resources to coordinate with other Western state consumer advocates."[731] To address these concerns and to be sure that consumers will be fully represented, the Launch Committee recommended a formally structured Consumer Advocate Organization ("CAO") with modest tariff-based funding to facilitate its participation be part of the Step 2 design.[732] AB 825 as enacted by the California Legislature supports this objective and requires,

> The independent regional organization makes funding available for a consumer advocate organization that represents the interests of one or more consumer advocate offices authorized in state law, including the Public Advocate's Office of

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[729] Each state with less than 10,000,000 megawatt-hours of annual load participating in the WEIM is designated as a small load state; all other states will be designated large load states. Each small load state is allocated a funding amount equal to the total funding amount divided by the number of states represented on the EIM-BOSR multiplied by 50 percent. Each large load state is allocated a funding amount equal to the remaining funding balance divided by the number of large load states. Each state regulated market participant within a state will be allocated a funding amount by multiplying the state funding amount by the state regulated market participants' percentage share of the total state regulated market participant load in the state.

[730] Direct Testimony of David Rubin at Q&A 25.

[731] Pathways Step 2 Final Proposal at 69, available at https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf.

[732] *Id.* The Launch Committee recommended that the consumer advocates take the lead on developing the CAO and its governance structure. The CAO would be a new 501(c)(3) organization similar to the Consumer Advocates of PJM States, with membership by the state-designated utility consumer advocate for each state with a load-serving utility participating in any RO-governed market. The CAO would serve as a liaison between individual state-designated consumer advocates and the RO, monitor RO initiatives and identify work of interest and priority to the consumer advocates, convene and coordinate the consumer advocate members, as well as assist with general information sharing and support for advancing their collective positions.
An example of such an entity is the Consumer Advocates of the PJM States, Inc. (CAPS). FERC approved the ongoing funding of CAPS via the PJM budget in 154 FERC ¶ 61,147 (2016). The organization attends PJM stakeholder meetings and regularly informs its member state Consumer Advocates of the RTO's activities. While the internal organization of a CAPS-equivalent for the West should be determined by the Consumer Advocates themselves, the availability of dedicated funding and an established voice is imperative, as the existing state Consumer Advocate offices in the West, individually and collectively, are not resourced to participate in new regional forums.

the Public Utilities Commission, and facilitates engagement by those offices with the independent regional organization.[733]

2. Markets+

The Markets+ State Committee ("MSC") was established in April 2023 in accordance with the governance structure of Markets+.[734] The MSC is composed of one member from each state in which a Markets+ market participant has generation or load participating in the market, although initial membership has been broader given the uncertainty about which states will ultimately participate.[735] State members are appointed to the MSC by the head of each respective state public utility commission and may include a member from other state agencies such as state energy offices, state environmental offices, or state consumer advocates. Each state member has one vote and actions by the MSC require the affirmative vote of a majority of its members.

The purpose of the MSC is to effectively engage state members in the development and operation of Markets+ and to provide direction and input to the MIP, MPEC, and any working group or task force on all matters deemed pertinent by the MSC and its members, including but not limited to initiative prioritization, market operations, and policy issues.[736] Additionally, MSC members and other state officials are eligible for appointment to Markets+ task forces. The Markets+ Nominating and Governance Committee must have one member of the MSC. Individual MSC members have the right to appeal decisions to the MIP. The MSC operates in a public setting and welcomes other regional stakeholders to attend committee meetings to better foster engagement and collaboration.[737]

Similar to the BOSR, the MSC employs WIEB to provide independent staff support.[738] Annually, the MSC submits a proposed budget to the MIP for approval. Before approval, the MIP shall seek comment from the MPEC. The approved MSC budget costs will be allocated to the Markets+ Market Participants.[739] During Phase 2 and prior to market start, the MSC budget will be incorporated into SPP's Phase 2 budget. WEIM presented its 2025 Business Plan and Budget to the IMIP on May 15, 2025. The MSC proposed budget for 2025 is $428,680. The budget is based upon the employment of one full-time equivalent employee consisting of five WIEB staff in 2025 and retention of the MSC consultants, currently through AESL Consulting, through Markets+ Phase 2 to continue supporting the MSC engagement in the Markets+ development process.

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[733] AB 825 at Section 4 (4) amending California Public Utilities Code section 345.6(a)(4). The bill can be found at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260AB825.

[734] The MSC has been incorporated into the Markets+ Tariff Markets+ Tariff at Attachment O, section 4.3.2.

[735] *See* Charter of the Markets+ State Committee. Initial membership may include representatives from any of the states or provinces with entities that may plausibly choose to participate in the ultimate Markets+ day-ahead market structure, to the extent the states or provinces wish to participate. A copy of the Charter can be found as Attachment A to the April 29, 2024, Comments of the Markets+ State Committee filed in FERC Docket No. ER24-1658.

[736] https://www.westernenergyboard.org/wp-content/uploads/MSC-Charter_050323.pdf. See also, April 29, 2024, Comments of the Markets+ State Committee filed in FERC Docket No. ER24-1658 at 1.

[737] *Id.* at 2.

[738] *Id.*

[739] Markets+ Tariff, Attachment O, Section 4.3.2.3.

With respect to state sponsored consumer advocates, the Markets+ Tariff does not include special provisions regarding funding. BCP could register as a "Markets+ Market Stakeholder" defined as:

> A stakeholder that has executed the Markets+ Stakeholder Agreement and pays an annual fee of $5,000. An MMS has voting rights at the Markets+ Participants Executive Committee, and is eligible for a voting seat, if appointed, on the Markets+ Nominating and Governance Committee, working groups and task forces. The annual fee may be waived for eligible entities that are nonprofit organizations under the Internal Revenue Code, or a governmental entity designated by state statutes to represent the interests of end-use customers before a state's regulatory agencies.

Alternatively, BCP could simply be a "Markets+ Non-Voting Stakeholder who provides input at all stakeholder meetings but do not have voting rights on working groups and task forces.

D. NV Energy's Governance Evaluation

In comparison with Markets+ governance structure for market oversight consideration of new initiatives and implementation of the stakeholder process, NV Energy prefers the EDAM/WEIM approach, as ***substantially*** enhanced by the Pathways effort. NV Energy has consistently advocated for governance of the WEIM and EDAM should, "seek to achieve the maximum independence for oversight of the market, consistent with existing California law."[740] Pathways Step 1 achieves this important objective.[741]

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[740] *See, for example*, NV Energy's January 18, 2019, and February 21, 2020, Comments to the EIM Governance Review Committee. The January 18, 2019 comments can be found at: https://www.westerneim.com/Documents/NVEnergyComments-EIMGovernanceReviewIssuePaperandStrawProposal.pdf and the February 21, 2020 comments can be found at: https://www.westerneim.com/Documents/NVEnergyComments-ScopingPaper.pdf. NV Energy notes that on February 22, 2020, all of the current EIM Entities: Arizona Public Service Company, Avista Corporation, Balancing Authority of Northern California, BPA, Idaho Power Company, the City of Los Angeles, Department of Water and Power, NV Energy; PacifiCorp, Portland General Electric Company; Powerex, Public Service Company of New Mexico, Puget Sound Energy, Inc., Salt River Project, the City of Seattle, acting by and through its City Light Department, the City of Tacoma, Department of Public Utilities, Light Division, Turlock Irrigation District; and NorthWestern Corporation d/b/a NorthWestern Energy stated, "for the external Balancing Authorities ("BAs"), stakeholders, and regulators to have confidence in the successful operation of the EDAM, all parties will work to achieve the maximum level of independence possible under current policies with respect to governance of the EDAM." https://www.westerneim.com/Documents/EIMEntitiesComments-ScopingPaper.pdf. Pathways Step 1 achieves this objective.

[741] The Launch Committee retained Perkins Coie to examine the extent to which current California law permitted the range of options under consideration. In their response to the Launch Committee.

> Based on this legal analysis, the Launch Committee concludes that the option proposed as "Step 1" (Option 0) in the accompanying Straw Proposal presents little, if any, legal risk under current state law; it thus substantively increases independent governance of the WEIM and Extended Day-Ahead Market (EDAM) while retaining sufficient CAISO authority to enable it to meet its ongoing statutory and corporate governance requirements. The analysis recognizes that the proposed options that would effectuate "Step 2" (Option 2 and 2.5) push independent governance further, increasing legal risk under current state law. The Launch Committee believes, based on the analysis, that the increased risk in these specific designs could be materially mitigated through targeted legislation that reshapes the CAISO's role in energy market management.

Pathways Step 1 recognizes the success and widespread acceptance of WEM Governing Body. By attracting highly qualified individuals and the manner in which these WEM Governing Body members have undertaken their responsibilities, the WEM Governing Body has garnered trust and respect from market participants, other stakeholders, and regulators throughout the West. The WEM Governing Body members have been diligent in reviewing both the CAISO's proposals and stakeholder comments and questioning both CAISO staff and stakeholder positions. They have been accessible to existing and potential EDAM and EIM Entities, regulators, and market participants. In addition, they have been strong advocates and ambassadors for the EDAM and EIM in a variety of meetings and conferences. Step 1 expanded the authority of the WEM Governing Body over market rules from joint authority to primary authority. While the Governor-appointed Board of Governors can remove an initiative from the consent agenda and institute a dispute resolution process, Pathways Step 1 removed the Board of Governors' veto over market changes.[742] If there is continued disagreement between the Board of Governors and the WEM Governing Body, Pathways Step 1 provides for both positions to be reflected in Section 205 filings with FERC allowing FERC to determine the better option.[743]

NV Energy strongly supported the modification of the dispute resolution process to include a dual section 205 ("jump ball") filing as a critical element of the Step 1 proposal. First, it is important to recognize that this dual filing would only come into play after an extensive effort to resolve the issue through remand to the stakeholder process consistent with section 2.2 of the current Charter for WEIM and EDAM Governance. Second, the mere existence of the dual filing option provides greater parity in the negotiations as there is no veto right on the part of the Board of Governors. Moreover, the dual filing approach, as demonstrated by the limited applications in ISO New England, resolves the burden of proof issue that would otherwise be present. Accordingly, the most important part of the dual filing is not the expectation it will be used, but rather the mere fact that its existence places the EIM Governing Body in a position to have an independent voice at FERC with its own section 205 rights.[744] With the adoption of AB 825, Pathways Step 2 would

The legal analysis can be found at: https://www.westernenergyboard.org/wp-content/uploads/Legal-Analysis.pdf.

742 The proposed tariff amendment authorizing dual section 205 filings was a critical component of Pathways Step 1. Under the joint authority approach, the CAISO Board of Governors had a veto over potential market rules. While market participants could file complaints, Section 206 of the Federal Power Act has a very different burden of proof. *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 13 (D.C. Cir. 2021) (explaining that section 206 "mandates a two–step procedure" whereby the [FERC], on the first step, must make an explicit finding that the existing rate is unlawful and then, on the second step, must set a new rate. (Quotation omitted)). The dual filing amendment promoted independence by removing the veto and allows consideration of competing proposals on an equal basis.

743 Under FERC's precedent, a utility filing under section 205 of the Federal Power Act need only show that its proposal is "just and reasonable." *See, e.g., New Eng. Power Co.*, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd sub nom. Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (proposed rate design need not be perfect, it merely needs to be just and reasonable); *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (finding that, when determining whether a proposed rate was "just and reasonable" as required by the FPA, FERC properly did not consider "whether a proposed rate schedule is more or less reasonable than the alternative rate designs.") It does not have to prove the provision to be the best or superior to any proffered options. *Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282, at P 29 (2006) (the just and reasonable standard under the FPA is not so rigid as to limit rates to a "best rate" or "most efficient rate" standard, but rather a range of different approaches often may be just and reasonable). By giving the WEM Governing Body equal section 205 rights to the Board of Governors, FERC has the authority, consistent with the revised CAISO tariff, to choose which approach FERC deemed to be the better option.

744 NV Energy also supported the additional emphasis on public interest safeguards in Phase 1. Courts have found that that the Federal Power Act is a consumer protection statute. For example, *Pa. Water & Power Co. v. FPC*,

transition market oversight further from primary authority to sole authority under the auspices of a new Regional Organization.

In contrast to this demonstrated process, the relationship between the Markets+ Independent Pannel (the "MIP") and the SPP Board of Directors is a work in progress. While Attachment O of the Markets+ Tariff indicates that the SPP Board of Directors will give "significant recognition and deference to the MIP decision-making role," the list of items that remain subject to the review of the SPP Board of Directors is substantial, including "Decisions of the MIP... that have a material adverse effect on SPP" including items it deems have financial ramifications or corporate risk to SPP. The SPP Board may be "independently" appointed, but it is directed to serve the interests of the RTO membership, with a fiduciary duty to those members. The SPP Bylaws specify: "[t]he Board of Directors shall at all times act in the best interest of SPP in its management, control, and direction of the general business of SPP."[745] The market footprints of the SPP RTO, RTO West, and Markets+ have a seam and it is not clear that the SPP Board does not have competing priorities in its oversight of the SPP RTO and Markets+. SPP "encourage[d] the Commission to continue to investigate how each market operator can negotiate fairly with neighboring market operators on behalf of Nevada customers and the customers of other market participants on an equitable basis."[746] The relationship between a fully formed MIP and the SPP Board is unproven. As Markets+ will not be optimized with the SPP RTO but will require a seams agreement between the two SPP-administered Markets+, there is room for disagreement between the MIP and the Board, without a similar jump ball filing process at FERC.

With respect to the stakeholder process, EDAM and Markets+ reflect the different approaches utilized by SPP and CAISO. Markets+ uses a stakeholder led process. SPP staff have a more passive role. In the CAISO process, stakeholders represent their interests, and CAISO staff performs a balancing function. NV Energy sees a number of advantages to the CAISO approach:

- Staff involvement helps protect minority interests that can get overruled by SPP's voting structure.

- Greater use of written comments in the CAISO process provides increased transparency and allows fuller definition of positions both internally and with other stakeholders. The written comments also facilitate earlier review by the Department of Market Monitoring, the Market Surveillance Committee, the WEM Governing Body's Market Expert and as well as the WEM Governing Body members who cannot attend all the stakeholder meetings.

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343 U.S. 414, 418 (1952) stating that, "[a] major purpose of the whole [Federal Power] Act is to protect power consumers against excessive prices," or *Pub. Sys. v. FERC*, 606 F.2d 973, 979 n.27 (D.C. Cir. 1979) providing that "the Federal Power Act aim[s] to protect consumers from exorbitant prices and unfair business practices." Markets exist to provide reliable service at just and reasonable rates. Public interest is a foundational element to market design.

[745] Southwest Power Pool—Governing Documents Tariff—Bylaws, First Revised Volume No. 4.—Bylaws 4.1 Board of Directors., available at: https://www.spp.org/documents/13272/current%20bylaws%20and%20membership%20agreement%20tariff.pdf.

[746] SPP Comments in Response to Procedural Order No. 3 in Docket no. 23-10019 filed on May 31, 2024, at 4.

- The CAISO's initiative-specific process is less bureaucratic than SPP's formal committee structure and can react more quickly to emerging events.[747] Moreover, the SPP Committee chairs and co-chairs can have significant influence over the presentation of issues, while at the same time reflecting the specific interests of their entity. CAISO better balances the staff-led process with presentations and proposals from individual participants.

- Pathways work has promoted further improvements to the CAISO process including greater use of indicative voting and additional involvement in determining which issues to stakeholder. Pathways Step 2 also proposes a defined source of funding for state consumer advocates, including the Nevad Bureau of Consumer Protection.

As a WEIM participant, NV Energy has seen its stakeholder recommendations on critical initiatives such as the Assistance Energy Product and Order No. 831 move from proposal to tariff implementation.[748] For EDAM, the congestion rent allocation and approach to virtual bidding incorporate the Companies priorities and concerns.[749] In contrast, NV Energy's votes against the Markets+ proposals for congestion rent allocation, greenhouse gas compliance, and resource adequacy illustrate the challenges of having specific concerns in a majority-based decisional process.[750] Additionally, NV Energy expressed concern during the Markets+ Phase 1 process that the definition of "affiliate" in the Markets+ tariff would means that NV Energy, and potentially PacifiCorp, if the companies were in the same market, would be limited to a single vote for the selection of MIP members, while significantly smaller utilities would retain their individual votes. The issue was not addressed. This is not in any way to suggest that NV Energy has agreed with every decision approved by the WEM Governing Body or CAISO Board of Governors.[751] Rather in its overall evaluation of the DAMs, NV Energy has greater confidence in its ability to represent the interests of Nevada customers through the CAISO process.

NV Energy is cognizant that the CAISO wears multiple hats, including market operator, Reliability Coordinator, BA, and transmission provider, and that a number of Western entities have expressed

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747 Experience has shown that emergent operational or market issues may require prompt action by stakeholders and the Market Operator to bring proposes changes to FERC. For example,

- Docket No. ER22-2881 – to address an issue CAISO's Department of Market Monitoring identified resulting in significant uplift costs associated with bid-cost recovery for certain storage resources;
- Docket No. ER22-869 – to address the needs of a potential EIM participant by allowing for sub-Balancing Authority direct participation;
- Docket No. ER1902497 – to address an issue with the reasonableness of the real-time market neutrality settlement;
- Docket No. ER16-1649 – to address the issues associated with the leak at the Aliso Canyon gas storage facility; and
- Docket No. ER25-2637 – to enhance the methodology for EDAM congestion revenue allocation.

CAISO has shown the ability to amend its Roadmap process to quickly address these concerns. NV Energy questions whether the Stakeholder led process in Markets+ could act with similar speed, especially if an issue may involve potential disagreements among stakeholders.

748 Direct Testimony of David Rubin at Q&A 27.

749 *Id.*

750 *Id.*

751 Markets+ Tariff Attachment O at 2 (Definition of Affiliate as subsidiaries of the same company) and 4.2.3.2 ("For purposes of electing or removing members of the MIP only, each group of Markets+ Market Participants that are Affiliates will be considered a single Markets+ Market Participant.").

a preference for the Markets+ governance approach. Both DAMs have inclusive but resource-intensive stakeholder processes and provide opportunities for PUCN and BCP participation in initiative development. There are significant equivalencies between the BOSR and MSC, including valuable support from WEIB. If implemented, Pathways Step 2 would provide a similar level of support for state sponsored consumer advocates.

Based on a decade of experience in the WEIM and participation in both DAM's stakeholder processes; however, NV Energy has a strong preference for the CAISO/Pathways governance design. Factors supporting the Companies view include:

- Giving the WEM Governing Body primary authority over market rules is a significant advancement in the independence of EDAM and WEIM oversight. Moreover, the inclusion of a dual 205 filing right between the WEM Governing Body and the CAISO Board of Directors places the WEM Governing Body in a stronger position in a dispute with the CAISO Board of Governors versus the MIP who will always lose in a dispute with the SPP RTO Board.

- Implementation of Pathways Step 2, as authorized by AB 825, will further enhance independent oversight of the EDAM and WEIM and provide a platform for expanded service offerings.

- The CAISO initiative-specific stakeholder approach can address emergent issues more expeditiously and efficiently. Moreover, the staff-led process can help balance stakeholder interests and protect minority rights. Conversely, NV Energy's experience in Markets+ Phase 1 highlighted concerns with block voting by similarly situated parties.

- The CAISO approach with its greater reliance on written comments provides additional transparency regarding stakeholder positions and can help identify and support important minority views.

- CAISO's expanded market oversight includes not only the market monitoring unit, but also the Market Surveillance Committee and the WEM Governing Body Market Expert and provides significant oversight and independent perspectives on market performance and new initiatives.

SECTION 8 – IMPLEMENTATION COSTS, TIMING, AND EXIT FEES

In this section, NV Energy reviews: (1) the costs of NV Energy's participation in the DAM, (2) the applicable timeline for the DAM and NV Energy joining, (3) and the process, timeline, and costs to exit the DAM. In addition, the Companies identify the implementation-related agreements and where these *pro forma* documents can be found on the DAMs' websites.

A. EDAM

1. Implementation Agreement and CAISO Costs

The EDAM *pro forma* Implementation Agreement ("IA") was accepted by FERC in Docket No. ER23-2686 as Appendix B31 of the CAISO Tariff.[752] The agreement commits CAISO to make the system changes necessary to enable participation by the new EDAM Entity. The scope of work includes planning and project management, full network modeling of resources, system integration and testing, metering and settlements, and operations readiness and training. The IA requires an initial deposit and commits the EDAM Entity to pay the actual costs of implementation. Copies of the EDAM IAs for PacifiCorp, Portland General Electric, the Balancing Area of Northern California, the Los Angeles Department of Water and Power, Turlock Irrigation District and Public Service Company of New Mexico are available on the WEM Governing Body website.[753]

If the deposit exceeds the actual cost incurred, CAISO will refund the excess amount including any interest accrued on the remaining deposit.[754] If the actual cost exceeds the deposit, additional deposits in $300,000 increments will be required.[755] An EDAM Entity may terminate the IA with 30 days' notice.[756] With the exception of any incurred implementation costs, CAISO would not levy an exit fee or other charges.[757]

2. NV Energy Projected Implementation Costs

NV Energy's estimated EDAM project costs are displayed in Figure 59 which is taken from Table 2 of the Utilicast Gap Assessment.[758] The costs are estimated for the NV Energy labor, vendor services, purchased services (including consulting and external legal support), hardware and software acquisitions, licenses and subscriptions and external fees and includes a contingency. The cost elements are further broken down into (1) capital and (2) operation, maintenance, administrative and general ("OMAG"). To account for uncertainty, a 20 percent contingency was included.

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752 The agreement can be found at https://www.caiso.com/documents/appendixb31-edam-entityimplementationagreement-asof-dec21-2023.pdf.
753 These agreements can be accessed at: https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx.
754 *See* the IA at section 2.2.
755 Direct Testimony of April Gordon at Q&A 5.
756 IA at section 3.3.
757 *Id.* at Section 3.3.
758 Technical Appendix 2.

Figure 59

	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**

Note the $16.15 million projection in Figure 59, includes an estimated $1.5 million payment to CAISO for CAISO's implementation costs,

3. EDAM O&M Costs

In the Gap Assessment, Utilicast estimated the incremental OMAG costs that would be incurred from the Companies' potential EDAM participation. There were three categories of expenses: (1) additional CAISO Grid Management Charge ("GMC") costs above the amounts paid in WEIM today, reflecting the additional day-ahead services; (2) the costs of the additional NV Energy hires to support EDAM activities; and (3) increased vendor costs for PCI and OATI systems support.

Participation in EDAM will increase the GMC assessed by CAISO to recover their administrative costs. The GMC comprises three cost categories,[759] four administrative fees, and a fixed charge for transmission ownership rights holders. There is a load volume discount for BAs joining EDAM in the first five years.[760] The WEIM charge will no longer be assessed when NV Energy joins

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[759] These cost categories are as follows:

(1) The market services category consists of costs related to implementing and operating the markets and is charged based on each scheduling coordinator's gross absolute value of awarded megawatt hours of energy and megawatts per hour of ancillary services in the day-ahead and real-time markets;

(2) The system operations category consists of costs associated with reliably operating the grid by balancing supply and demand and is charged based on each scheduling coordinator's gross absolute value of real-time energy flows for generation, load, imports and exports; and

(3) The congestion revenue rights (CRRs) category consists of costs related to the CRR function and is charged based on each scheduling coordinator's total megawatt CRR holdings applicable to each hour.

[760] CAISO Tariff section 33.11.6.1. The EDAM Administrative Charge assessed to Scheduling Coordinators' demand-related charge codes will be assessed on an incremental percentage at the outset of EDAM. Each incremental percentage will apply to the calendar year, January to December, such that the CAISO would assess the incremental percentage to an EDAM Entity joining after January to the remaining part of the calendar year only. The first year EDAM is available for participation, the CAISO will assess five percent of the MWh of each EDAM Scheduling Coordinator's metered demand to apply the EDAM Administrative Charge. In the second year, the CAISO will assess twenty-five percent. In the third year, the CAISO will assess fifty percent. In the fourth year and thereafter, the CAISO

EDAM. CAISO's GMC estimate is also predicated on the number and size of BAs joining EDAM, and when. The GMC cost could increase in these years if some entities delay their implementation schedules. After year 5, the discount will end, and the full GMC will be levied. NV Energy's BAA level annual GMC cost attributed to EDAM is estimated at approximately $15.5 million beginning in year 5 of EDAM's operations.[761] This GMC is separate from the CAISO implementation charge, which is captured in the EDAM project implementation costs.

The CAISO has a defined and transparent process for updating its GMC. As specified in the CAISO Tariff Appendix F, schedule 1,

> Every three (3) years, the CAISO will conduct an updated cost-of-service study, in consultation with stakeholders and using costs from the previous year. In conducting each cost-of-service study, the CAISO will recalculate the service charge percentages and the rates for the fees and charges that constitute the Grid Management Charge as set forth in Section 11.22. In addition, the cost-of-service study results will be used to update the RC Funding Percentage used to calculate the annual RC Funding Requirement, as well as the real-time percentages of the Market Services Charge. If, based on the cost-of-service study results, the service category revenue requirement allocation percentages or the level of fees and charges have changed, the CAISO will submit tariff amendments to reflect such changes pursuant to Section 205 of the FPA.[762]

Section 11.22.2.5 of the CAISO Tariff delineates a cap on GMC costs. The cap is $245 million in 2025 and $250 million in 2026 and thereafter, unless the CAISO submits a tariff amendment to FERC.

The EDAM implementation will increase NV Energy's internal business processes and require additional staff. Utilicast recommended the addition of eight full-time equivalent ("FTE") employees:

- Transmission Business Service
  - 1 FTE would be responsible for supporting a more complex representation of NV E OATT transmission service as part of daily EDAM operations.

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will assess seventy-five percent. In the fifth year and thereafter, the CAISO will assess one hundred percent. The foregoing does not apply to EDAM Scheduling Coordinators' MWh of Energy or Supply: The CAISO will assess one hundred percent of the MWh of each EDAM Scheduling Coordinator's Energy to apply the EDAM Administrative Charge at the outset of EDAM and thereafter.

761 Direct Testimony of April Gordon at Q&A 7.

762 The CAISO's last Cost-of-Service study was done in 2023 for the 2024 through 2026 period. https://www.caiso.com/documents/revised-draft-final-2023-cost-of-service-study-and-2024-2026-grid-management-charge-update.pdf. The study's results are used to update the Grid Management Charge Revenue Requirement percentage allocations to the Market Services, System Operations, and Congestion Revenue Rights Services cost categories. The study results are also used to update the WEIM cost category percentages and the Reliability Coordinator funding percentage. Finally, the study is used to analyze the costs to support supplemental services such as, the Transmission Ownership Rights services, and set the charges, fees, and rates for these supplemental services accordingly. The study was filed at FERC in Docket No. ER23-974 and approved without protest by letter order on December 21, 2023.

- Resource Optimization
  - 1 FTE would be responsible for supporting increased day-ahead activities and supporting the real-time operations during off hours.
  - 1 FTE would focus 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.
- Transmission System Operations:
  - 1 WEIM/BA Engineer to support more complex transmission models, system operation changes, and ongoing needs related to the D3, D2, and D1 advisory processes.
  - 1 FTE operations resource to manage ongoing processes to support DA Advisory Run processes and modify market inputs.
  - 1 FTE operations resource to lead day-to-day, engineering, and EESC settlements team.
  - 1 FTE 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:
  - 1 FTE 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.

Figure 60 is the summary of these incremental OMAG expenses attributable to EDAM participation.

Figure 60
Summary of Ongoing Costs[763]

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

The difference between the $14.82 million GMC projection from Utilicast in Figure 60 and the $15.5 million as estimated by Ms. Gordon is because Utilicast is identifying the incremental

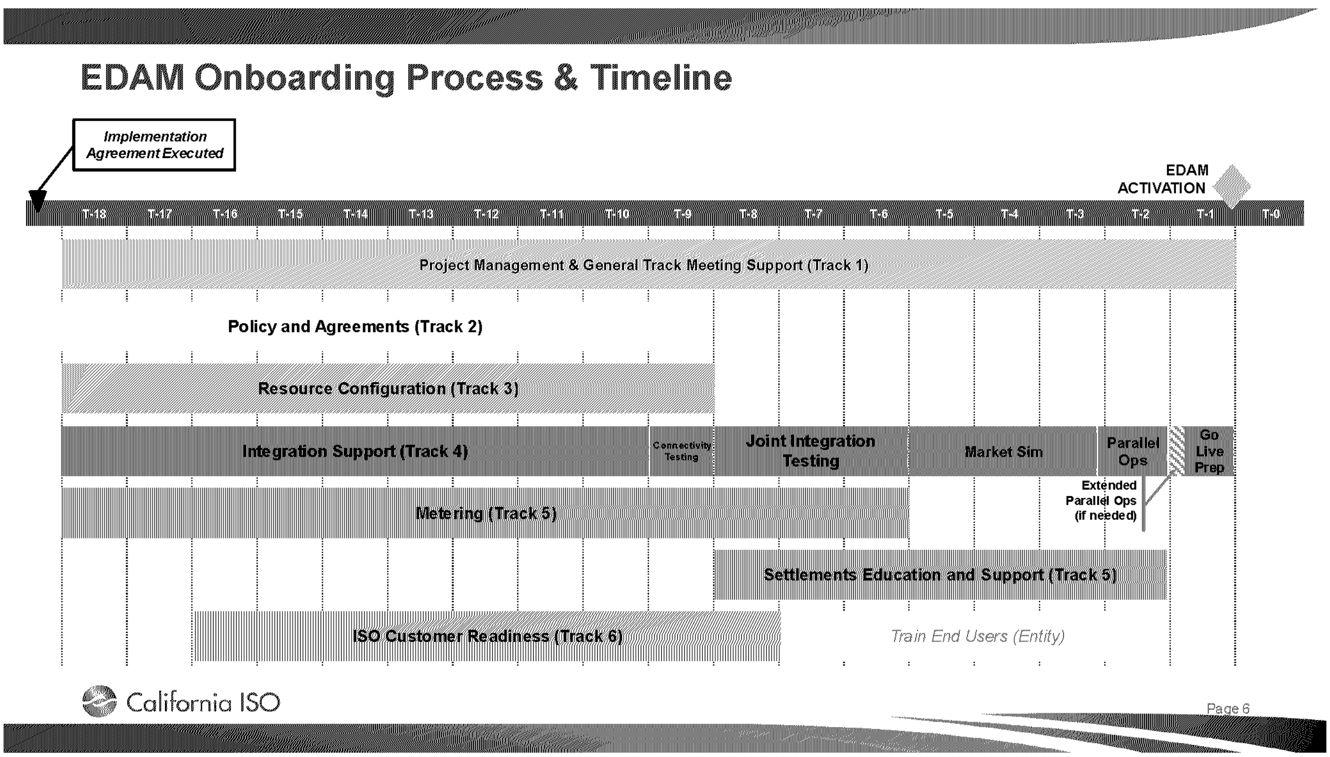
763 *See* Technical Appendix 2 at 15.

amount above what NV Energy pays currently in the WEIM, while Ms. Gordon is providing an estimate of the total projected GMC costs.

4. Timing

The CAISO has divided the EDAM onboarding process into six separate tracks with their own scope, deliverables, milestones, meeting structures, and workshops: (1) planning and project management; (2) policy, legal, contracts, and access; (3) resource configuration; (4) systems integration and testing; (5) metering and settlements, and (6) training and readiness.[764] These tracks, which can run in parallel over an anticipated 18-month timeframe are illustrated in Figure 61.

Figure 61



Project management activities commence once the EDAM Implementation Agreement is executed. Planning is a joint effort between CAISO and the EDAM Entity project management teams, who meet regularly to review the progress of all onboarding tracks, discuss project risks and issues, and determine mitigation plans.[765] The primary objective of Track 2 is to ensure all

[764] Direct Testimony of Stacey Crowley at Q&A 25. *See also*, https://www.westerneim.com/Documents/edam-onboarding-overview.pdf.

[765] EDAM Onboarding Overview dated January 2, 2025. The document can be found at: https://www.westerneim.com/Documents/edam-onboarding-overview.pdf.

required agreements[766] are executed in accordance with the schedule laid out in the "Agreement Plan" and to support the onboarding entity in provisioning access to all necessary individuals and applications for EDAM testing in the multiple environments, MAP Stage, Stage, and Production. Each EDAM transmission service provider customer with firm point-to-point or network transmission service rights will need to be represented by a scheduling coordinator.

The primary objective in Track 3 is to ensure that all resources are accurately defined and configured in CAISO's Master File and network model. Proper resource configuration is required before beginning joint integration testing. Track 3 also includes configuration required for load and variable energy resources forecasting. The objective of Track 4 is to ensure all integration points between the CAISO and the EDAM Entity are clearly understood and successfully validated.

Once a scheduling coordinator ID has been assigned to the new the EDAM Entity and the necessary scheduling coordinator agreements have been executed, the CAISO issues security certificates, and the EDAM Entity can begin providing access to their testing users to conduct initial connectivity testing by pinging each CAISO system and verifying that an appropriate response is received. Joint integration testing is the first opportunity to verify the integration points between the CAISO and the EDAM Entity and their vendors, where applicable and is primarily an EDAM Entity responsibility that begins approximately eight months before go-live. The Market Simulation phase of the testing process provides an environment for all of the EDAM Entities' customers to test their systems and procedures before new features are implemented. During market simulation, the CAISO and the EDAM Entity execute specific, pre-defined scenarios to ensure that current and new system and market functionality continue to work as designed.

Beginning two months before EDAM activation, CAISO will open a parallel operation environment to practice production grade systems integration, as well as market processes and operating procedures in preparation for new EDAM Entity activation. The transition to Parallel Operations acts as a dry run of the transition to production. Figure 62 provides a summary of the EDAM onboarding testing program.

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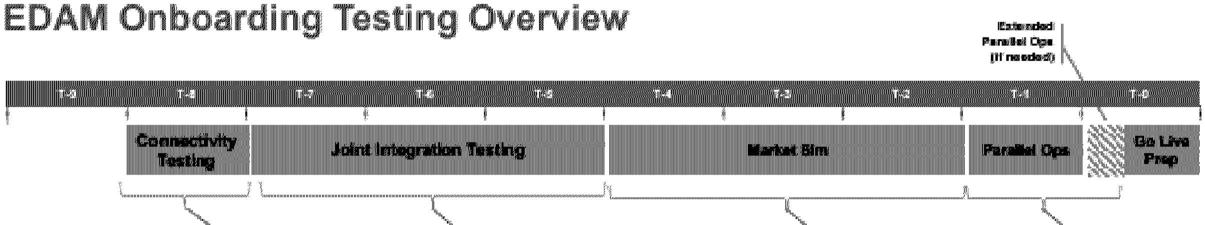
[766] These include the Scheduling Coordinator Agreement; EDAM Load Serving Entity Agreement; EDAM Transmission Service Provider Agreement; EDAM Addendum to EIM Entity Agreement; EDAM Addendum to EIM Participating Resource Scheduling Coordinator Agreement; EDAM Addendum to EIM Participating Resource Agreement; EDAM Addendum to EIM Entity Scheduling Coordinator Agreement. Copies of these pro forma agreements can be found in Appendix B of the CAISO Tariff; https://www.caiso.com/legal-regulatory/tariff.

Figure 62[767]

EDAM Onboarding Testing Overview



	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

As to Track 5 Metering and settlements, all resources entering the EDAM market must be able to submit the meter data in 5 or 15-minute intervals. Any resource that does not meet this requirement will need to self-schedule in the market.[768] A new EDAM Entity will be required to add a number of new and changed charge codes to ensure settlement accuracy in the new market. Track 6 is the training plan that runs in support of these implementation readiness activities.

Appendix B of the Utilicast Gap Assessment provides a seven-page description of the tasks that will be necessary for the Companies to enter EDAM. Based on the interrelationship of these workstreams and the projected durations, NV Energy is proposing to target EDAM implementation in Fall 2028. NV Energy understands that CAISO is transitioning from a Spring onboarding release to a Fall implementation date for new entities to avoid joining just prior to the summer peak season.

CAISO's EDAM framework will included readiness criteria in the EDAM implementation process paralleling the similar criteria in the WEIM to ensure CAISO and participants are prepared for day-ahead market operation in each BAA.[769] The CAISO Tariff also includes transitional measures similar to those in the WEIM to insulate participants from adverse reliability or market outcomes

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767 Direct Testimony of Stacey Crowley at Q&A 25.

768 CAISO proposes to accommodate any legacy generating units in the EDAM area that have not updated to modern metering systems by allowing an exception to its metering granularity requirement. Scheduling coordinators for EDAM resources that cannot meter an EDAM resource facility's energy every 15 minutes or faster may not submit economic bids to provide ancillary services and must submit self-schedules in the day-ahead and real-time markets. This allows legacy units to participate in the day-ahead market without requiring expensive upgrades and will protect against inaccurate price signals and settlement data. CAISO Tariff, section 33.10.2.

769 CAISO EDAM Transmittal Letter in Docket No. ER23-2686 at 13.

during the implementation and initial participation process.[770] CAISO has committed to monitor and issue public reports on the performance of the EDAM design and work with stakeholders to refine the design.[771]

5. Exit Notice and Fee

A prospective EDAM entity may terminate the Implementation Agreement, without penalty, by giving at least 30 days' written notice to the CAISO. In the event of termination, CAISO will make every effort to halt work and related costs on the implementation as soon as practical and refund any payments provided by the prospective EDAM entity in excess of costs already incurred by CAISO.[772]

Any BA that seeks to participate in EDAM must enter into a *pro forma* EDAM Addendum to its EIM Entity Agreement with the CAISO. The prospective EDAM entity must execute the addendum no later than 90 days before its designated implementation date.[773] Participation in the EDAM is voluntary and can be terminated with 180 days months' notice without paying any exit fees.[774]

B. Markets+

1. Markets+ Funding Agreement and Participation Paths

Markets+ Phase 2 covers the period beginning June 30, 2025,[775] to the start of Market+. To finance these activities, SPP filed the Phase 2 Funding Agreement with FERC on February 21, 2025, in Docket No. ER25-1372. Under the agreement, the "Funding Participants" will provide the collateral backstop for the $150 million in third-party financing that SPP will obtain in order to develop the systems, processes, and operations necessary to implement Markets+.[776] During Phase 2, "SPP will set up the hardware, software, and systems to implement Markets+; hire and train the staff that will operate Markets+; and lead negotiations for any necessary seams agreements with neighboring Balancing Authorities or markets."[777]

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770 CAISO Tariff section 33.27.1

771 EDAM Acceptance Order at P 11.

772 CAISO EDAM Filing, Transmittal Letter at 113-114.

773 CAISO Filing Letter in FERC Docket No. ER23-2686 at 118. This addendum incorporates new CAISO Tariff section 33 into the underlying WEIM Entity Agreement, thereby allowing a WEIM Entity also to participate as an EDAM Entity in the day-ahead market.

774 CAISO Filing Letter in FERC Docket No. ER23-2686 at 104 and 118.

775 On June 30, 2025, SPP announced it had reached agreement with Simmons Bank for the $150 million funding. https://www.spp.org/news-list/marketsplus-phase-two-development-begins-with-secured-financing/.

776 *See* SPP's Filing Letter in FERC Docket ER25-1372 at 1 and note 9. A breakdown of the $150 million responsibility can be found at: https://www.spp.org/documents/73296/markets%20plus%20phase%202%20exhibit%201%20funding%20agreement.pdf.

777 SPP's Filing Letter in FERC Docket ER25-1372 at 7. https://www.spp.org/documents/73326/20250221_spp%20markets%20plus%20phase%202%20funding%20agreement_er25-1372-000.pdf.

SPP notes that the Phase 2 implementation costs will include the cost of sharing resources with the SPP RTO, including facilities and office expenses, and costs such as administrative, human resources, information technology, legal, accounting, and insurance. According to SPP, the Funding Agreement provides for these expenses to be included in the Markets+ implementation costs in order to ensure that the SPP RTO members are not subsidizing the implementation of Markets+.[778]

The Funding Agreement obligates each Funding Participant to provide an amount of collateral in the form of cash or a letter of credit based on the funding participant's Phase 2 pro rata share of the Markets+ total cost less the funding participant's Phase 1 payments and post-Phase 1 payments.[779] The financing will be repaid after the start of Markets+, ultimately resulting in release of collateral and expiration of the Funding Agreement.[780] The Phase 2 Implementation Costs will be incorporated into the rates charged to all Markets+ market participants through Schedule 1-B under the Markets+ Tariff.[781] As these costs are recovered under Schedule 1-B, SPP will repay the financing, and the lender will authorize the release of excess collateral on an annual basis.

FERC accepted the Markets+ Funding Agreement on April 22, 2025.[782] At this time, nine entities: Arizona Public Service, BPA, Chelan County PUD, Grant County PUD, Powerex, Puget Sound Energy, Salt River Project, Tacoma Power, and Tucson Electric Power have executed the Phase 2 Funding Agreement. On June 30, 2025, SPP announced that Simmons Bank has agreed to provide the funding.[783]

As illustrated in Figure 63, Markets+ offers several participation paths, each with its own registration requirements. Markets+ Registration types include: (1) BAs and transmission service providers, (2) LSEs, (3) Market Participant and (4) Stakeholders. BA transmission service providers and LSEs must execute the Funding Agreement.

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778 SPP's Filing Letter in FERC Docket ER25-1372 at 4. "The February 17, 2025 Resolution of the SPP Board of Directors . . . provides that the Financing was authorized by the Board of Directors on August 6, 2024 on the condition that the Financing must: "(a) be non-recourse to the SPP RTO . . . and (c) be repaid by the Market+ participants, who will serve as the backstop for cost recovery[.]" Motion for Leave to Answer and Answer filed by SPP in FERC Docket No. 25-1372 on March 31, 2025 at 5.

779 SPP's Filing Letter in FERC Docket ER25-1372 at 6.

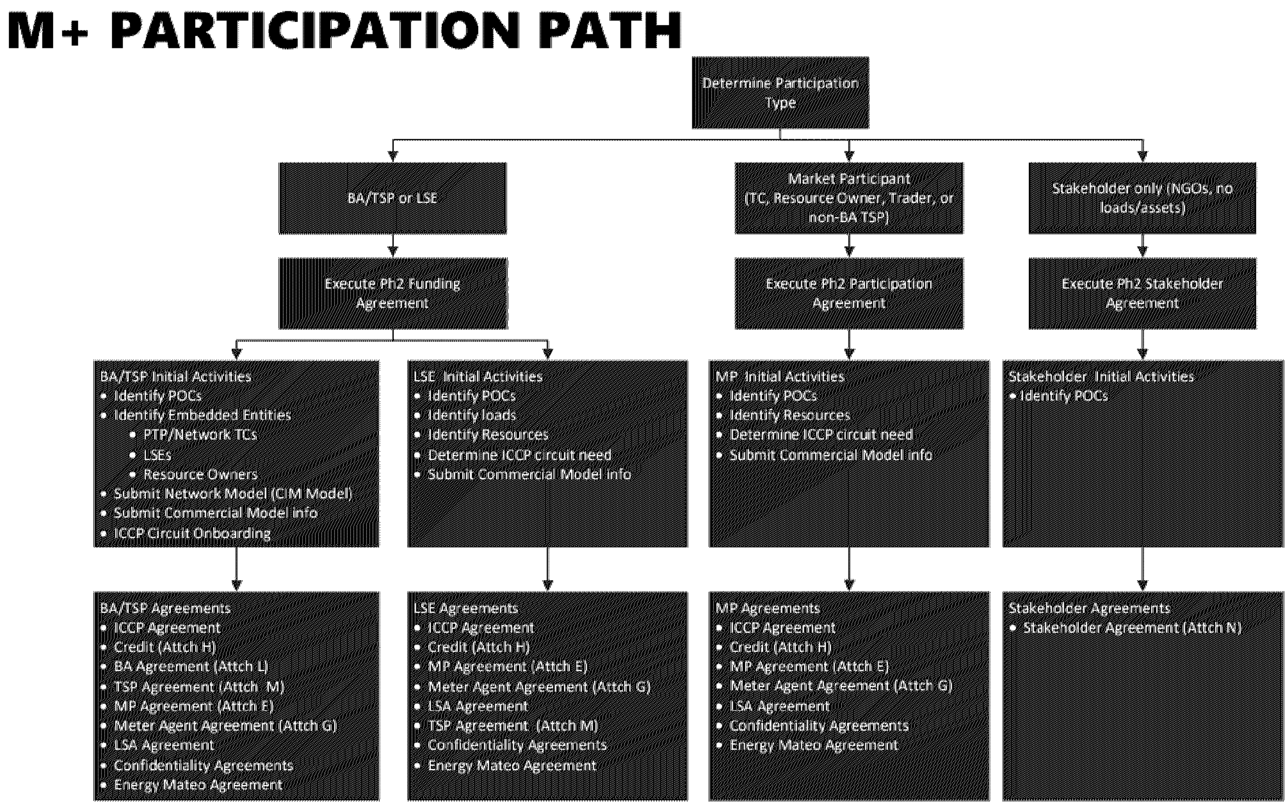
780 *Id.* at 5, 7-8.

781 Under Schedule 1-B of the Markets+ Tariff, Markets+ market participants must purchase administration services from SPP as the Market Operator. Markets+ administration service consists of those Market Operator functions necessary to support the administration of the Markets+ Tariff, including market policy and design, information technology support, and market operations. SPP, Markets+ Tariff, Schedule 1-B, Schedule 1-B Tariff Administration Service (0.0.0).

782 *Sw. Power Pool, Inc.*, 191 FERC ¶ 61,071 (2025).

783 On June 30, 2025, SPP announced it had reached agreement with Simmons Bank for the $150 million funding. https://www.spp.org/news-list/marketsplus-phase-two-development-begins-with-secured-financing/.

Figure 63[784]



BAs and transmission service providers must execute the following agreements, most of which are *pro forma* versions in the Markets+ Tariff:

- The Inter-Control Center Communications Protocol (ICCP) Agreement
- Appendix A – Credit Application
- Appendix B – Credit and Security Agreement
- Appendix C – Form of Irrevocable Standby Letter of Credit
- Appendix D – Guaranty Agreement
- Appendix E – Annual Minimum Market Participation Criteria and Risk Management Certification Form
- Appendix F – Surety Bond
- Attachment L Form of Agreement for Participating Balancing Authorities in Markets+
- Attachment M Form of Agreement for Transmission Service Provider in Markets+
- Attachment N Markets+ Stakeholder Agreement

LSEs must execute:

- ICCP Agreement
- Appendix A – Credit Application

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[784] https://spp.org/spp-documents-filings/?id=518832; May 7, 2025, MCUF Meeting Materials Item 9 Registration Overview.

- Appendix B – Credit and Security Agreement
- Appendix C – Form of Irrevocable Standby Letter of Credit
- Appendix D – Guaranty Agreement
- Appendix E – Annual Minimum Market Participation Criteria and Risk Management Certification Form
- Appendix F – Surety Bond
- Attachment E – Market Participation Agreement
- Attachment G – Meter Agent Agreement
- Local Security Administrator (person at the company who can add, edit and delete users. Assign roles)

Market Participant (resource owner, trader, non-BA transmission service provider must execute:
- ICCP Agreement
- Appendix A – Credit Application
- Appendix B – Credit and Security Agreement
- Appendix C – Form of Irrevocable Standby Letter of Credit
- Appendix D – Guaranty Agreement
- Appendix E – Annual Minimum Market Participation Criteria and Risk Management Certification Form
- Appendix F – Surety Bond
- Attachment E – Market Participation Agreement
- Attachment G – Meter Agent Agreement
- Local Security Administrator

To be a Markets+ Stakeholder requires execution of the Stakeholder Agreement which is Attachment N of the Markets+ Tariff.

SPP has identified the following registration deadlines to go live by October 2027:[785]
- BA – September 1, 2025,
- Non- BA transmission service provider - October 1, 2025, and
- Market Participants – December 1, 2025.

2. NV Energy Projected Implementation Costs

NV Energy has not made a detailed assessment of the costs necessary to participate in Markets+. These would include expenses to adopt the SPP systems and communication protocols and upload the information on Nevada-based resources and the Companies transmission system into the SPP detailed model. As noted above, BPA has estimated the implementation costs associated with switching markets are "approximately double the costs of a potential EDAM implementation."[786]

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[785] https://spp.org/spp-documents-filings/?id=518832; May 30, 2025, MCUF Meeting Materials Item 8 Onboarding First Steps.

[786] BPA Day Ahead Market Policy dated May 9, 2025, at 39- 40. The document can be found at: https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/20250509-dam-final-policy.pdf. While BPA estimates internal costs to implement Markets+ will be $53.7-$74.2 million. *Id.* at 39.

3. Markets+ O&M Costs

Markets+ will have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. In testimony before the Commission at the April 10, 2024, Workshop in Docket No. 23-10019 , Antoine Lucas, who became SPP's Chief Operating Officer in January 2025, stated SPP's ongoing operations costs were estimated at $70 to $75 million per year.[787] NV Energy has not seen a breakdown of the $70 to $75 million per year estimate; nor is there a process identified in the Markets+ tariff for updating the administrative charge. NV Energy was approximately 10 percent of the load allocated Markets+ Phase 1 implementation costs. The Companies are not sure if the anticipated allocation of the Markets+ administrative fees would be higher.[788]

Under Schedule 1-B of the Markets+ Tariff, SPP is to recover "100 percent of its costs for the fiscal year in which services are provided, including an adjustment for over or under recovery for prior fiscal years, as described herein." These service are all of the market operator functions necessary to support the administration of Markets+: (1) market clearing and settlements, (2) market monitoring functions, (3) market operations, (4) market policy and design, (5) market support and analysis, (6) customer training, (7) credit evaluation and risk management, (8) information technology support, (9) customer service, and (10) Markets+ counterparty role for transactions. Costs include all direct costs associated with providing these services including: salaries, benefits, and taxes; system and facilities maintenance; network and communications; outside services; travel and meeting expenses, administrative expenses, other operating expenses; and capital costs and applicable debt service obligations In addition to those direct costs, Schedule 1-B1 includes corporate overhead, including human resources, facilities management, legal, regulatory, accounting, and other support services.

The Schedule 1-B1 billing determinants as expressed in MWh are: (1) all real-time energy cleared by Markets+; (2) all import and export interchange transactions cleared by Markets+ in real-time; and (3) all cleared virtual energy bids and all cleared virtual energy offers in the Markets+ day-ahead market.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10[78] :

Table 10 | Internal Implementation Costs ($M)

Market	Non-Labor	Incremental Labor	Total Cost (Non-Labor + Incremental Labor)
EDAM	$11.6M - $19.7M	$18.3M	$29.9M - $38M
Markets+	$26.8M - $47.3M	$26.9M	$53.7M - $74.2M

787 Testimony of Antoine Lucas at page 444 lines 17-25, Docket No. 23-10019 Workshop Volume 3 April 10, 2024.

788 BPA contacted SPP to request a forecast of BPA's anticipated portion of these annual operating expenses. SPP estimated that BPA's expense could be between $13 and $15 million annually. BPA Market Policy at 38. Public Service Company of Colorado has estimated their share of SPP's ongoing administrative costs as being approximately 13.3% or $10 million per year. Exhibit No. 101, Direct Testimony and Attachments of Joseph C. Taylor filed with the Colorado Public Utilities Commission on February 14, 2025, in Proceeding No. 25A-0075E at 84.

The Companies have not performed a separate Gap Assessment of what the incremental costs would be to participate in Markets+. In addition to amortization of the higher implementation costs, NV Energy would need to include: the annual Markets+ administration fees, the costs of the cash collateral needed under the Phase 2 Funding Agreement, the incremental staffing costs and any additional vendor costs.

4. Timing

SPP has released its plan supporting a go live date of October 1, 2027. As presented at the April 2025 MPEC Meeting, BAs are to declare their intention to join by September 1, 2025.[789] As noted above, Arizona Public Service Company, Salt River Project, Tucson Electric Power, Powerex and Public Service Company of Colorado have expressed an intention to go live in Markets+ in October 2027. SPP's initial milestones are indicated in Figure 64.

Figure 64[790]
SPP Markets+ Implementation Milestones

INITIAL SHARED MILESTONES

Milestone	Target Complete Date	Comment
Establishing Readiness Metrics	TBD	
Network and Commercial Model Ready for SPP Integration Testing	5/30/2026	
ICCP Onboarding	9/30/2026	
Connectivity Testing	10/30/2026	
Data Exchange Testing	1/31/2027	
Market Trials (Bid-to-Bill Testing)	5/31/2027	
Parallel Operations	8/31/2026	
Stakeholder Training	5/31/2027	
Go/No Go Decision	8/31/2027	
Cutover Activities	9/30/2027	
Go Live	10/1/2027	

NV Energy has not seen any implementation plan of schedule for BAs to join after this initial class. It may be that future onboarding will take less than the 25-month period between September 1, 2025, and October 1, 2027.

5. Exit Notice and Fee

Under Attachment L, of the Markets+ tariff is the *pro forma* Agreement for Participating Balancing Authorities. Under Section 20, the BA may terminate the agreement by providing 180 days' notice.

Entry into Markets+ requires execution of the Phase 2 Funding Agreement. Under that agreement, beginning on the start date of Markets+, expected in 2027, all market transactions will pay a proportional share of SPP's market administration fee. This fee will include repayment of the

789 The MPEC documents can be found at: https://www.spp.org/western-services-documents/?id=370747. Under the April 15, 2025, Meeting Materials, *see* Item 11 – Phase 2 Timeline and Overview.

790 The MPEC documents can be found at: https://www.spp.org/western-services-documents/?id=370747. Under the April 15, 2025, Meeting Materials, *see* Item 11 – Phase 2 Timeline and Overview.

principal and interest for a period of five years. After this five-year period there are no exit fees to exit Markets+. Should Markets+ be terminated, or should a participating BA terminate its participation in Markets+, prior to the expiration of the five-year period for repayment of the loan obligation, the BA's exit fee would be the remaining balance of its share of the Phase 2 funding.[791]

C. NV Energy Evaluation

An important factor in the Commission's authorization of the Company's joining WEIM participation was that participation was voluntary, and termination did not require an exit fee.[792] EDAM contains the same exit provisions as WEIM: (1) six months' notice and no exit fee. Markets+ has a similar provision once the liability for the Phase 2 financing has been paid off.

While SPP officials have testified that the market operator charges are projected to be lower, the tariff simply obligates participants to pay any and all expenses. Unlike EDAM and the CAISO GMC process, there is no transparency as to the basis for the projected costs, the process for updating the rate, and there is no FERC-specified cap. Both DAMs operate from the existing RTO systems. However, EDAM will move forward as an integral part of CAISO's day-ahead market while Markets+ is to be a separate service offering paid for by its western participants. New market programs and functionality will need to be supported by the Markets+ participants.

The Companies acknowledge future uncertainty with respect to Pathways Step 2 implementation. As discussed previously, the initial expectation is to set up a seven-person Board with limited staff support to replace the five-person WEM Governing Body.[793] Of course, Markets+ would come with the additional costs associated with WRAP participation as well as the significant penalty exposure.

In summary, NV Energy has greater confidence that EDAM will be established and operated consistent with the projected schedules and costs. While there certainly may be delays in the implementation dates of the first movers and any market is likely to require amendments to address initial operational issues, the viability of the EDAM footprint, defined process for onboarding new entities, and integration with the existing market processes and administrative framework offer increased confidence that the requested expenditures will result in benefits for customers.

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791 *See* SPP's February 21, 2025, Filing Letter in FERC Docket No. ER25-1372 at 6-7 citing the Phase 2 Funding Agreement Section 7(d)(ii) and 7(e)(ii).

792 August 29, 2014, Order in Docket No. 14-04024 at P 124.

793 Pathways Step 2 Proposal at 35 and 37. The document can be found at: https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf. ("For example, the cost to market participants of the current WEM GB today is about $640,000 annually, including compensation paid to GB members. For a governing board with two additional members, more responsibilities, and one to two dedicated support staff, we estimate an annual cost of $1.25 to $1.5 million.") More extensive RO executive staffing with an estimated annual cost of roughly $25 million; the additional RO staff will enable the RO to meet its increased oversight responsibilities with respect to the markets. The feasibility study will examine, among other cost factors, the extent to which these RO cost increases would be offset by increases in expanded market products and participants and/or decreases in the administrative payments to CAISO. Pathways Step 2 Proposal at 14.

SECTION 9 – OATT CUSTOMER IMPLEMENTATION

NV Energy has not yet prepared amendments to its OATT to facilitate EDAM implementation. The Companies anticipate undertaking a similar process to that used to prepare the WEIM OATT that consisted of the following stages:[794]

Figure 65

Activity	Date
Announcement of OATT Stakeholder Process	August 28, 2014
Overview Stakeholder Presentation	September 16, 2014
Initial Tariff Posting	September 22, 2014
Stakeholder Comments	September 22-October 1, 2024
Stakeholder Meeting	October 8 (Vegas) October 9 (Reno)
Second Tariff Posting	November 10, 2014
Stakeholder Comments	November 10-21, 2014
Stakeholder Meeting	December 2, 2014
FERC Filing	March 6, 2015

NV Energy was the second FERC-jurisdictional entity to enter the WEIM. If authorized by the Commission, the Companies expect to be the fourth FERC-jurisdictional entity to join EDAM. As noted above, PacifiCorp filed proposed changes to its OATT to implement EDAM in FERC Docket No. ER25-951, and Portland General Electric filed their EDAM OATT in FERC Docket No. ER25-1868. As noted above, FERC approved both the PacifiCorp and Portland General Electric filings on August 29, 2025.[795] Public Service Company of New Mexico is working to join EDAM in the Fall of 2027.

EDAM is to be compatible with the current OATT platform for physical transmission rights. The rules for EDAM participation within the NV Energy BAA will be embedded in the NV Energy OATT. Consistent with the WEIM, the EDAM components of the NV Energy OATT will be constructed to be compatible with the CAISO Tariff rules approved for EDAM participation. NV Energy will be an "EDAM Entity" just as it is an "EIM Entity" today. In that role, NV Energy implements its responsibilities as transmission provider and BA to implement the EDAM in its BAA. Most of the core aspects of the EDAM design are specified in the CAISO Tariff. As was the case with entry into the WEIM, there are a few design elements that are left with the NV Energy EDAM Entity to decide. As discussed previously, these include virtual bidding and intertie bidding. Consistent with WEIM participation, NV Energy would use a single load aggregation point for its BAA.[796] In addition, there are implementation requirements including registration of transmission rights and submission of data on resources.

794 Direct Testimony of David Rubin at Q&As 29 and 30.

795 *PacifiCorp*, 192 FERC ¶ 61,197 (2025); *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025).

796 As shown in the Department of Market Monitoring's Annual Report for 2024, there is extremely limited congestion into and from NV Energy. *See* Figures 2.5, 2.6, 5.1, 5.2, 5.5, and 5.6. The report can be found at: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf.

For the Companies' third-party OATT customers, EDAM presents a material difference from the WEIM today. In WEIM, transmission customers may be non-participating, except to follow their own balanced schedules. EDAM requires a higher level of participation because, in order for the market to work, all transmission schedules must be reflected in the market optimization and subject to market pricing.

NV Energy will propose to FERC a set of modifications to its OATT to permit EDAM participation. Most of the revisions will be to Attachment P. In addition, Schedule 1-A will be amended to sub-allocate the EDAM administrative charge. Schedules 4 and 9 will be amended to reflect the measurement of imbalances from the day-ahead market to real-time.

While NV Energy will undertake its own OATT analysis, the approved frameworks developed by PacifiCorp and Portland General provide meaningful visibility into what amendments NV Energy will propose. Moreover, there has been considerable pressure from LSEs and transmission customers for EDAM Entities to adopt consistent rules to ensure that there are no seams created within the EDAM or opportunities for undue arbitrage.[797] In evaluating the changes to the OATT for participation in any market, FERC uses a standard of review that considers whether the proposed changes are "consistent with or superior" to the *pro forma* OATT. In the context of various market developments over the years, including EIM, FERC has found this standard satisfied.[798]

A. Roles and Responsibilities Generally

To participate in the EDAM, a BA must already be a participant in the WEIM or join both markets simultaneously.[799] As described in Section 5(A)(1) above, there will be four main participant roles. (1) BA (EDAM Entity), (2) Resource Owner/Operator (EDAM Resource and EDAM Resource Facility), (3) Transmission Service Provider (EDAM Transmission Service Provider), and (4) LSE (EDAM Load-Serving Entity).[800] Each participant must be represented by a Scheduling Coordinator.

B. Ability to Act as One's Own Scheduling Coordinator for Load

One issue that has emerged throughout the EDAM stakeholder process is that many larger OATT customers that serve load expressed strong interest in participating in the EDAM through their own Scheduling Coordinator. This option creates direct contractual privity between that customer and the CAISO with regard to market settlements for load in the EDAM. NV Energy envisions that the NV Energy EDAM Entity will be the default Scheduling Coordinator for all load in the

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[797] *See, for example,* Protest of the Western Power Trading Forum and the Northwest and Intermountain Power producers Coalition in PacifiCorp FERC Docket No. ER25-951 dated February 18, 2025 at 27 encouraging "CAISO to work with EDAM Entities and stakeholders to adopt a *pro forma* implementation tariff to ensure consistency throughout the footprint while avoiding the "race to file" that is created by the current approach to EDAM implementation."

[798] *See e.g., Nw. Corp.*, 173 FERC ¶ 61,125 (2020); *Ariz. Pub. Serv. Co.*, 155 FERC ¶ 61,112, *order on reh'g,* 156 FERC ¶ 61,227 (2016); *Puget Sound Energy, Inc.*, 155 FERC ¶ 61,111 (2016); *Nevada Power Co.*, 151 FERC ¶ 61,131, *order on reh'g & clarification*, 153 FERC ¶ 61,306 (2015); *PacifiCorp*, 147 FERC ¶ 61,227 (2014).

[799] CAISO Tariff section 33.4(a)-(c).

[800] *Id.* at sections 33.4.1 - 33.4.6.

NV Energy BAA, much like in the EIM today. The Companies are also likely to require that EDAM Load-Serving Entities for whom the NV Energy EDAM Entity is acting as the Scheduling Coordinator may only self-schedule their load and may not engage in economic load bidding. Economic load bidding is the process of assigning an economic value to load as opposed to bidding solely as a price-taker. This rule would be implemented so that the NV Energy EDAM Entity is not directly involved in the market bids of third parties except where necessary. Alternatively, NV Energy anticipates that its tariff will permit a Nevada EDAM Load-Serving Entity to be represented by its own Scheduling Coordinator. This will require the EDAM Load-Serving Entity to satisfy various CAISO requirements for being a Scheduling Coordinator and coordinate with the NV Energy EDAM Entity on certain meter data issues. This ability to elect Scheduling Coordinator status for load should enhance participation in the market by third-party LSEs in the NV Energy BAA.

C. Resource Sufficiency Evaluation

Section 5(B)(1)(a) above describes the EDAM RSE. The basic purpose of the RSE is to ensure that 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. Before the first run of the day-ahead market, the RSE will assess each BAA's demand obligations and supply options to ensure there is enough supply to meet forecasted demand, imbalance reserve requirements, and ancillary service obligations. CAISO will provide the results to each BA as guidance to help them establish resource sufficiency before the final evaluation at around 10:00 a.m., just before the day-ahead market run. The RSE program will penalize BAAs that fail one of the several components of the RSE test and will allocate revenue collected under those surcharges to BAAs that passed the test for that period. The existence and operation of the RSE at the BAA level is a fixed component of the EDAM design.

Stated another way, the RSE test does not distinguish between individual OATT transmission customers and only looks at the entire BAA. The EDAM Entity must fashion its own approach, through the OATT, to allocate the RSE requirements of the BAA down to each OATT customer.[801] This allocation of responsibilities within the NV Energy BAA is important because when the BAA as a whole fails the RSE there are certain financial implications. The market design must not encourage one LSE to unduly lean on another when it comes to day-ahead resource sufficiency.

The EDAM Entity must first sub-allocate RSE responsibilities on the front end so that failures can be tracked accurately. This requires taking the CAISO-provided BAA-wide forecast (of load as well as the requirements for imbalance reserves and ancillary services) and allocating it to each LSE. PacifiCorp decided to sub-allocate the day-ahead demand forecast and imbalance reserve requirement to each LSE in the PacifiCorp BAA based on their historical loads. To account for the fact that some smaller LSEs own or contract with generating resources that are not technically capable of providing imbalance reserves, PacifiCorp will make energy and imbalance reserve bids

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[801] *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025) at P 240 ("[t[he EDAM framework necessarily delegates to the EDAM Entity the obligation to devise an internal BAA methodology to manage RSE…").

interchangeable for purposes of meeting the RSE.[802] PacifiCorp adopted a different treatment for ancillary services, by offering to maintain primary responsibility or providing sufficient ancillary services to the day-ahead RSE. OATT customers will contribute to this RSE element by satisfying their obligations to pay for or self-supply ancillary services under the existing OATT schedules. The RSE requirements would be made known to each LSE ahead of the EDAM bidding deadlines each day.

Once the RSE requirements have been allocated out to each LSE, performance of each LSE must be measured as well. PacifiCorp adopted its own snapshot of RSE requirements ahead of the day-ahead bidding deadlines to ensure that each customer is bidding sufficient resources. This process has been referred to as "internalizing" the RSE, through a financially binding snapshot at 9:15 a.m. to assess any failure penalties, regardless of the outcome of the CAISO-run RSE at 10:00 a.m. PacifiCorp argued that this RSE methodology will: (1) create a proper incentive structure to ensure the PacifiCorp BAA remains resource sufficient; (2) empower LSEs to control their own exposure to penalties by meeting their allocated RSE; and (3) protect against intra-BAA leaning between LSEs.[803] FERC determined that,

> PacifiCorp's intra-BAA RSE requirements and penalties are consistent with cost causation principles. Under PacifiCorp's proposal, an LSE's penalty is ultimately based only upon its individual performance relative to its individual RSE obligations. We find that it is reasonable to subject an LSE that fails PacifiCorp's intra-BAA RSE to penalties because such deficiency could result in the PacifiCorp BAAs failing CAISO's EDAM RSE and, consequently, incurring penalties. Moreover, we agree with Portland General that if the PacifiCorp BAAs pass the EDAM RSE despite one or more LSEs not meeting their assigned LSE RSE obligations, then that deficiency must have been made up by other LSEs within the PacifiCorp BAAs.[804]

D. Transmission Availability

Prior to the start of the day-ahead market, a participating BA will provide information to the CAISO regarding any applicable transfer constraints and the amount of transmission capacity available, thereby allowing the EDAM to utilize all transmission capacity available to it, including any unsold firm transmission capability, while honoring existing and legacy transmission rights. EDAM recognizes those existing and legacy transmission rights 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

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802 In Section 6.3.1.1.2 of Attachment P of its OATT, Portland General Electric proposed to have customers "bid or Self-Schedule sufficient resources to meet their respective EDAM LSE's Imbalance Reserve Up and Imbalance Reserve Down requirements."

803 Under PacifiCorp's proposal, all RSE penalty revenue collected from LSEs goes first to satisfy any penalty assessed by the CAISO on the PacifiCorp BAA. To the extent of any excess after satisfying the CAISO penalty, it will be returned to those LSEs that were sufficient and passed the RSE. And when no CAISO is assessed, the penalty revenue is distributed to all LSEs that were RSE-sufficient in that internal RSE run. *See*, PacifiCorp Motion for Leave to Answer and Answer dated March 12, 2025, in FERC Docket No. ER25-951 at 42.

804 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 312.

long-term firm transmission rights over an EDAM intertie 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.

Transmission customers with registered firm point-to-point transmission service rights with firm reservations of a month or longer across an "EDAM Internal Intertie" (defined as an interface between two BAAs that are both participating in the EDAM) will have the option to "release" those rights for use by the market in facilitating EDAM transfers between participating BAAs.[805] As explained in the CAISO tariff, "[t]he Scheduling Coordinator representing the transmission rights may determine, on a daily basis, whether to make the full amount or only a portion of its registered transmission service rights available for EDAM Transfers for that day only or a longer timeframe…."[806] In exchange for releasing transmission rights, transmission customers can receive a share of transfer revenues generated from price differences between EDAM balancing authority areas. Lastly, under the third pathway, the transmission customer retains rights for intra-day self-scheduling.

The EDAM Entity OATT must explains how transmission customers can take advantage this release program as well as the treatment of firm ATC. The NV Energy tariff will address the process for each transmission customer to make these elections. It will also have settlement language providing for the recovery and assignment of any EDAM-related charge codes.

E. Congestion Pricing - Return of Congestion Revenue

EDAM is an extension of the CAISO market, which is based on a system of locational marginal pricing. One of the biggest issues in any transition to LMP markets is the fact that congestion now has a direct and observable cost. Under the OATT traditionally, NV Energy's native load has born the costs of transmission congestion through generation redispatch of the Companies' resources. In a LMP market, the cost of congestion is calculated instantaneously at each market node, providing a direct and observable price signal. LSEs; however, will have mechanisms limit or

805 CAISO Tariff section 33.18.2.2.2,
The Scheduling Coordinator for a transmission customer of an EDAM Transmission Service Provider, EDAM Legacy Contract or EDAM Transmission Ownership Right must notify the CAISO and the EDAM Transmission Service Provider prior to 9:00 a.m. the morning of the Day-Ahead Market if it intends to release its long-term and monthly firm and conditional firm point-to-point registered transmission service rights across an EDAM Internal Intertie. The Scheduling Coordinator representing the transmission rights may determine, on a daily basis, whether to make the full amount or only a portion of its registered transmission service rights available for EDAM Transfers for that day only or a longer timeframe, provided such release is consistent with the registered transmission rights and the EDAM Transmission Service Provider tariff. Released transmission service rights cannot be reclaimed or scheduled for the duration of the trade date for which they have been released. The EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider will ensure that information on such released transmission service rights is communicated to the CAISO for association with an EDAM Transfer System Resource in accordance with the timelines and procedures in the Business Practice Manual for the Extended Day-Ahead Market. The released transmission capacity utilized by the Day-Ahead Market will be settled by the CAISO with the Scheduling Coordinator for the transmission rights.

806 CAISO EDAM Filing, Attachment A-2, CAISO Tariff section 33.18.2.2.2.

hedge their exposure to congestion charges. In the EDAM, this happens through a return of collected revenue from the CAISO to the EDAM Entity for sub-allocation to its OATT customers to help offset their congestion exposure in the market.

As discussed in Section 5.D.3 above, NV Energy has supported the distribution of congestion revenues from CAISO as the market operator to NV Energy as the transmission provider to provide equitable treatment to all firm customers.[807] The amount of congestion revenue that the NV Energy EDAM Entity will have returned is governed by the CAISO Tariff based on the amendment approved in FERC Docket No. ER25-2637.

What NV Energy will have to do is develop tariff provisions to govern the *allocation* of the those received congestion revenues. In *PacifiCorp* and *Portland General Electric, FERC* approved a two-step process for addressing the return of congestion revenue and the settlement of Charge Code 8704 (Day-Ahead Congestion Offset).[808] In the first step, the EDAM Entity seeks to reverse day-ahead congestion price differentials (positive or negative) arising from balanced self-schedules (point-to-point and Network customers) associated with firm monthly and longer-term OATT rights. This treatment is confined to monthly and long-term OATT firm rights, including conditional firm, because that is the class of customers who may have made reservations prior to the adoption of EDAM. Confining the treatment to balanced self-schedules aligns with the higher scheduling priority the CAISO will afford to balanced self-schedules that track with OATT-based transmission rights. To facilitate this reversal, the EDAM Entity will use any congestion price differential revenues and costs allocated to the EDAM Entity under Charge Code 8704 (Day-Ahead Congestion Offset). The end result of this reversal process should be to zero out day-ahead congestion exposure or congestion benefit associated with these qualifying schedules. In the unlikely event that revenues collected through Charge Code 8704 are insufficient to offset entirely the congestion exposure for qualifying self-schedules, the EDAM Entity will prorate any shortfall proportionally based on relative congestion exposure. In the second step, the amount remaining in Charge Code 8704 after the step one allocation (i.e. the amount remaining in that account for the

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807 *Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025) at P 36,

> We disagree with arguments that CAISO should allocate congestion revenue directly to transmission customers and/or based on their transmission rights and that CAISO should allow transmission customers to opt their transmission service rights out of EDAM. The Commission has already accepted in the EDAM Order CAISO's allocation of congestion revenue to EDAM Entities, who in turn sub-allocate the congestion revenue as provided for in their OATTs.

808 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) at P 147 – P 149 and *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025) at P 84,

> We find that Portland's proposed two-step sub-allocation of congestion revenues is just and reasonable and not unduly discriminatory or preferential and consistent with or superior to the Commission's *pro forma* OATT. Specifically, Portland's Step One allocation of congestion revenue, which reverses day-ahead congestion price differentials associated with self-schedules of firm point-to-point and network transmission customers, will insulate balanced self-scheduled transmission use from EDAM congestion exposure up to the congestion revenue that CAISO allocates to the Portland BAA. Additionally, we find that Portland's Step Two allocation of congestion revenue will mitigate the congestion costs borne by entities that economically bid into EDAM. Noting Portland's offer to revise the Step One suballocation to conform with any EDAM enhancements if directed to do so by the Commission in a compliance filing, we direct Portland to make this revision and incorporate additional revenues allocated by CAISO under Charge Code 8704 in the compliance filing ordered below within 30 days of the date of this order.

EDAM Entity to sub-allocate) will be allocated proportionally to load and exports for the applicable period not already included in the step one allocation. This second step is essentially the same as a "Measured Demand" allocation except that it was necessary to ensure that entities who received congestion revenue under step one did not receive further revenue in step two.

With respect to transfer revenues, the transmission customers that make their capacity available for EDAM transfers will be eligible to receive transfer revenues that need to be directly allocated to those customers. NV Energy anticipates that the remaining transfer revenue would be allocated to Measured Demand.

F. "Carve Out" of Transmission Capacity

Section 33.18.3.3 of the CAISO Tariff[809] expressly allows each individual EDAM transmission service provider an exclusive carve-out right under its own tariff. CAISO emphasized the narrow scope of this provision in its transmittal letter for its filing to implement the EDAM provisions of the CAISO Tariff, stating "CAISO expects the transmission service provider will request adjustment of available transmission only under narrow, limited, and specific circumstances as provided in the transmission service provider's tariff."[810] CAISO explained it expects such carve-outs will be rare, because the EDAM design depends heavily on making transmission capacity available to the market to reach efficient outcomes. More extensive carve-outs would create inefficiencies that would limit the benefits of EDAM to ratepayers because transmission not otherwise available for optimization reduces the opportunity to access lower-cost resources.[811]

Portland General Electric, "agrees with CAISO's position that hold backs should remain narrowly tailored and applied only in limited circumstances to protect market efficiency and integrity."[812] Similarly, PacifiCorp agrees any cave outs would be "rare".[813] NV Energy supports the position that any carve outs should be limited. A transmission service right is not akin to an ownership right that would support such unilateral authority on the part of a transmission customer, and permitting a wholesale conversion of transmission rights for use in a neighboring market design would vest a privilege in a transmission customer that exceeds their rights under current OATT design.[814]

As PacifiCorp has explained,

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809 *See* CAISO Tariff section 33.18.3.3 ("Transmission Not Available in the Day-Ahead Market"). If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.").

810 *See* CAISO Motion for Leave to File Answer and Answer to Comments and Protests, Docket No. ER25-1868-000, at 20 (filed May 19, 2025).

811 *Id.* at 20-21.

812 Portland General Electric June 30, 2025, Response to Deficiency Letter in FERC Docket No. ER25-1868 at 3.

813 PacifiCorp April 28, 2025, Response to Deficiency Letter in Docket no. ER25-951 at 7.

814 *Sw. Power Pool, Inc.*, 191 FERC ¶ 61,177 (2025) at P 15 (we grant Rehearing Parties' request for clarification and clarify that nothing in the January 16 Order purports to grant transmission customers an ownership right to the transmission capacity over which they take service, nor grants, waives, modifies or otherwise interprets any rights or

> The EDAM will also accept intra-day self-schedules by firm customers, even after the close of the Day-Ahead market. Specifically, through the EDAM, PacifiCorp OATT transmission customers will still be able to submit schedule changes after the 10:00 a.m. day-ahead timeframe until T-20 before the operating hour. Such changes will be accommodated "if practicable," which in EDAM will mean, as noted above, the market will afford such self-schedules a market scheduling priority that is equal to other real-time self-schedules and equal to day-ahead self-schedules. The market will redispatch to accommodate such intra-day schedules based on system conditions and the volume of economic bids. In the event of an infeasibility, as the [FERC] acknowledged, "CAISO will notify the EDAM Entity, which is then responsible for resolving the infeasibility through its OATT procedures." In other words, as PacifiCorp stated in its Answer, this market design is the manner by which the accommodation of intra-day schedules is made practicable, which is consistent with or superior to the pro forma OATT.[815]

CAISO has noted the detrimental impact of making the day-ahead market subservient to any exercise of OATT rights:

> Granting a higher priority for all intra-day schedule changes submitted after the 10:00 a.m. deadline, even when there is no basis in the EDAM transmission service tariff for such a higher priority, would degrade the confidence in EDAM transfers because the transfer could be unwound to accommodate the exercise of transmission customer rights in the real-time market. Unwinding transfers awarded based on transmission capability that becomes available when firm transmission service is not scheduled by 10:00 a.m. the day prior to operation would adversely affect other entities that depend on such market transfers, including other resource adequacy program participants, further eroding the confidence in transfers, reducing market efficiency, and possibly creating an inappropriate arbitrage opportunity.[816]

In its order approving the EDAM design, FERC found that "…CAISO's proposal strikes an appropriate balance between preserving a transmission customer's rights under an EDAM transmission service provider's OATT and ensuring that there is confidence that EDAM transfers will be delivered."[817]

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obligations under the OATT of a non-participating transmission service provider not before the [FERC} in this proceeding.). In the January 19, 2025, Order on the Markets+ tariff, FERC explained, "the Markets+ Tariff will not force changes in the operations of non-participating transmission service providers' systems" and that "Markets+ Transmission Contributors will be responsible for "coordinating transmission schedule changes, curtailments, and other operational concerns with the non-participating [transmission service provider] and non-participating [balancing authority], in accordance with the applicable governing documents and agreements, including applicable OATTs.". Markets+ Acceptance Order at P 153 and P 154.

[815] PacifiCorp April 28, 2025, Response to Deficiency Letter in FERC Docket No. ER25-951 at 6.

[816] CAISO EDAM Filing, Transmittal Letter in FERC Docket No. ER23-2868 at 136-137.

[817] EDAM Acceptance Order at P 307.

PacifiCorp and Portland General have created one exception whereby certain intra-day schedule changes will receive a "higher" CAISO market scheduling priority if associated with a WRAP forward showing obligation (or another Commission-accepted regional resource adequacy program).[818] NV Energy is not sure if it has any long term firm reservations that would be used for this purpose, but the Companies would be willing to include a similar provision.

G. EDAM Access Charge

As noted in Section 5(C)(2)(a) above, because the EDAM market design will make significant use of transmission capacity not scheduled in the day-ahead timeframe, an EDAM Transmission Service Provider may experience a degradation in its short-term, non-firm sales that currently provide a significant revenue credit to firm customers. To backfill any lost revenue from such forgone sales the CAISO EDAM design contains an element referred to as the "CAISO EDAM Access Charge."[819] To the extent the NV Energy BAA is assigned charges associated with lost revenue on other EDAM BAA systems, it will allocate those costs under the NV Energy OATT. To the extent the NV Energy EDAM Entity receives revenue associated with a request by a transmission provider within the NV Energy BAA, it will be allocated to each transmission provider that has submitted for EDAM Access Charge reimbursement.

With respect to how the Companies may flow-through the EDAM access charge in a future change to the NV Energy OATT, the current expectation is to assign charges associated with lost revenue on other EDAM BAA systems on a Measured Demand basis.[820] To the extent the NV Energy transmission function submits for and receives EDAM Access Charge revenue associated with lost revenue, FERC accepted the proposals of PacifiCorp and Portland General to treat these payments as a transmission revenue credit (consistent with the perspective that they replace the loss of short-term firm and non-firm service).[821] This matter will be addressed when the Companies file their EDAM-related OATT amendment after a separate stakeholder process.

H. Changes to Real-Time Participation

In addition to expanding participation in the CAISO Market to the day-ahead timeframe, the EDAM also will change the way NV Energy and its customers will participate in the real-time market. Under the WEIM today, CAISO is involved only in resolving real-time energy imbalances in the NV Energy BAA, measured as deviations from submitted base schedules. The EIM base schedule is submitted by each OATT customer illustrating their resource plans for meeting load. As noted above, under the WEIM, customers can designate their generating resources as "participating," meaning they are available to the WEIM for real-time dispatch based on bids and self-schedules, or "non-participating," which means the WEIM market cannot dispatch the unit up or down. By contrast, under the EDAM, all resources in the NV Energy BAAs will have to participate in the market. So, the distinction between "participating" and "non-participating"

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818 PacifiCorp's OATT at Attachment T, section 4.1.3.6.1. Portland General Electric OATT at Attachment P. section 6.1.2.2.3.

819 CAISO Tariff at sections 33.11.7 and 33.26.

820 The NV Energy OATT at section 1.25D defines "Measured Demand as including: (1) metered load volumes, including losses pursuant to Schedule 10, in NV Energy's BAA, plus (2) e-Tagged export volumes from the NV Energy BAA, including losses pursuant to Schedule 10 (excluding Dynamic Schedules that support EIM Transfers).

821 *See for example*, the Portland general OATT at Attachment P, section 8.1 (suballocation of charge code 8326).

resources goes away. In addition, there will be no day-ahead "base schedules" submitted by load-serving entities. CAISO's day-ahead market will produce the day-ahead schedule based on submitted bids and self-schedules and generate associated binding financial results. From a standpoint of tariff terminology, a significant amount of WEIM terminology is anticipated to remain in the NV Energy Tariff in order to align with the conventions adopted in the approved CAISO EDAM tariff. Because EDAM builds on the WEIM tariff platform, certain WEIM terminology still applies to the real-time aspects of the market.

I. Transmission for Generators not Affiliated with NITS or Point-to-Point Transmission.

Section 33.23 of the CAISO Tariff provides that if an EDAM Resource is not: (1) a DNR under a NITS, (2) included with a firm point-to-point transmission service of any duration or (3) associated with an EDAM Legacy Contract or an EDAM Transmission Ownership Right then it will be assessed "a transmission charge based on the transmission rate for the lowest duration of firm transmission service offered under its tariff, which may be a daily firm or hourly firm transmission service." If the EDAM Transmission Service Provider offers daily firm point-to-point transmission service as the lowest granularity of firm transmission service, the transmission service charge would be based on the single highest-hour Real-Time Dispatch of the resource across the day for the amount in excess of reserved transmission service. If the EDAM Transmission Service Provider offers hourly firm point-to-point transmission service as the lowest granularity of firm transmission service, the transmission service charge would be evaluated based on each individual hourly Real-Time Dispatch of the resource for the day.[822]

Under Section 13.1 of the NV Energy OATT, the minimum term of firm point-to-point service is one day. By comparison, the same provision of PacifiCorp's OATT provides for a minimum term of one hour. NV Energy does have an hourly non-firm rate under Schedule 8 of the OATT.[823] The Companies expect the situation where an in-state generation is not associated with a NITS or point-to-point reservation to be very rare, especially given the transmission requirements associated with resources qualifying under the EDAM RSE and WRAP.[824] An example might be a project with an expiring PPA for a period prior to obtaining a new off-taker. In other words, NV Energy does not expect projects to be built solely based on expected energy market payment streams. NV Energy would commit to working with CAISO to be able to use the hourly non-firm rate for in-state

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[822] Markets+ Protocols at Section 8.4 states that SPP will undertake a review to determine what, if any, cost shifts have occurred in the absence of a requirement for generators to purchase transmission service to conduct sales in Markets+, after the occurrence of either of the following: (1) two years of data needed to conduct the study are available; or (2) a Markets+ Transmission Service Provider requests such a review following a reduction of at least two percent of their long-term firm point-to-point revenues or 2% of their long-term firm point-to-point reservations on an annual basis for their transmission facilities as they existed when Markets+ began operations; or a request may be made by any Market Participant provided the required data is available.

[823] The current rate is $5.94/MWH On-Peak and $3.33/MWH Off-Peak.

[824] *See,* CAISO Tariff Section 33.18.2.1 ("An EDAM Transfer from the source Balancing Authority Area to the sink Balancing Authority Area to support the EDAM Resource Sufficiency Evaluation for the sink Balancing Authority Area must be supported by firm or conditional firm point-to-point transmission service or network integration transmission service across an EDAM Internal Intertie"), and WRAP Tariff Section 16.3.1 ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load").

generators not otherwise associated with a firm transmission reservation. Alternatively, the Companies could consider adding an hourly firm product to the OATT, when as part of the future FERC filing placing Greenlink West into transmission rates. These suppliers provided additional liquidity in the Nevada BAA, Assessing the hourly rate based on their market dispatches will provide a measure of contribution to the transmission revenue requirement.

SECTION 10 – EFFECT ON COMMISSION JURISDICTION

Being a participant in a DAM is not equivalent to membership in an RTO. As with WEIM participation today, the Companies will maintain control of their generation, purchase power, transmission and distribution assets. The Companies will also retain their BA obligations, including the reliability responsibility to maintain load-interchange-generation balance within the BAA, and support interconnection frequency in real time.

Joining a DAM does not change the Companies' transmission planning, transmission cost allocation, or pre-existing obligations under FERC Order Nos. 1000 and 1920 and under the FERC OATT. In EDAM, NV Energy's integrated resource planning process is unchanged. As discussed previously, Markets+ mandates participation in WRAP, which would set a minimum threshold for a planning reserve margin.

SECTION 11– PATHWAY TO AN RTO

NV Energy proposes participation in a DAM to capture additional customer benefits, beyond those currently being realized through the Companies' participation in the WEIM. How a potential DAM may serve as a pathway to the Companies joining an RTO is an important factor, but one that should be considered wholistically with the other criteria in determining a best-interest, least-regrets approach to capture benefits for the Companies' retail and transmission customers.

Senate Bill 448 (2021)[825] recognizes the potential for RTO participation to bring benefits to Nevada, if such participation is: (1) viable and (2) in the best interests of the Companies and their

[825] Senate Bill 448 (2021) is codified at NRS 704.79881-704.7989.

customers. The Companies understand that to be viable, the RTO must meet all of the identified statutory criteria,[826] including the requirement that governance be independent.[827]

Nevada law (specifically, NRS 704.798865) directs the Commission to require NV Energy to join an RTO on or before January 1, 2030; provided, however, NV Energy may seek to waive or delay this requirement by filing an application (pursuant to NRS 704. 79886(2)) with the Commission on or before January 1, 2027, requesting a waiver or delay of the filing requirement in NRS 04.79886(1).

Viability also includes interconnectivity – the Companies must have sufficient transmission interchange with a footprint of sufficient size and resource diversity to secure the potential benefits of coordinated dispatch. "Best interests" includes reliability, economic, and environmental regulatory compliance components. Consideration of joining an RTO would require extensive analysis of additional issues. These could include: (1) identification of additional market features and determination of projected additional economic benefits – for example though consolidation of BAAs or co-optimization of ancillary services; (2) transition of the interconnection queue and process from the NV Energy OATT to the market operator's tariff; (3) the process for converting existing transmission service agreements to the market operator's tariff; (4) the methodology for establishing transmission rates and review of transmission revenue issues and potential cost shifts; (5) the resource adequacy program and must offer requirements; (6) an overall cost/benefit analysis; (7) the changes in the governance structure beyond that for the day-ahead market; (8) the role of the Commission, especially over critical areas of resource adequacy and transmission cost allocation; and (9) conditions for entry and exit.

As explained in the testimony of Mr. Clausen, the Companies ***currently*** do not have a viable RTO option that is in the best interests of its customers.[828] The CAISO's Board of Governors, selected by the Governor of California, is not independent. The new regional organization provided for in

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[826] NRS 704.79882. These include:

- Approved by FERC;
- Separate control of transmission facilities from control of generation facilities;
- Implements policies/procedures to minimize pancaked transmission rates;
- Improves service reliability within Nevada;
- Achieves the objectives of an open and competitive wholesale electric generation marketplace, elimination of barriers to market entry and preclusion of control of bottleneck electric transmission facilities;
- Operates to substantially increase economical supply options for customers;
- Structure of governance or control that is independent of the users of the transmission facilities;
- Policies promote positive performance to satisfy electricity requirements of customers;
- Promotes and assists new economic development in Nevada; and
- Capable of maintaining real-time reliability of the transmission system, ensuring comparable and nondiscriminatory access and necessary service, minimizing system congestion and further addressing real or potential transmission constraints.

[827] NRS 704.79882(7) states" "Has a structure of governance or control that is independent of the users of the transmission facilities, and no member of its board of directors has an affiliation with a user or with an affiliate of a user during the member's tenure on the board so as to unduly affect the regional transmission organization's performance."

[828] Direct Testimony of Timothy Clausen at Q&A 36.

California Assembly Bill AB 825 is just being established. In addition, the Companies lack direct connectivity with the current SPP RTO and the expected footprint of RTO West.[829]

While SPP has claimed it "can provide a clear path forward to RTO membership,"[830] NV Energy is unaware of any plan to effectuate a transition form Markets+ to RTO West.[831] To the contrary, Markets+ will have a separate optimization,[832] a separate cost responsibility[833] and must prepare a seams agreement with RTO West.[834]

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[829] At this time entities expected to participate in RTO West include Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Platte River Power Authority, Tri-State Generation and Transmission Association, Western Area Power Administration (*Upper Great Plains-West region, Colorado River Storage Project, and Rocky Mountain region). RTO west is projected to commence operation in 2026.* The list can be found on SPP's RTO expansion page at: https://www.spp.org/western-services/rto-expansion/.

[830] SPP Comments in Response to Procedural Order No. 3 in Docket no. 23-10019 filed on May 31, 2024, at 7.

[831] In its May 9, 2025, Record of Decision, BPA states it will not sell power out of the Western Interconnection and provides further:

> It is important to clarify the footprint of Markets+ and the role of SPP. The Markets+ footprint will be entirely in the Western Interconnection, meaning all generation and load (energy demand) is located in the West. No energy will flow from the Pacific Northwest to Arkansas as a result of Markets+ optimization. The Western Interconnection is geographically separated from and not synchronously connected to other regions, meaning that there is no inadvertent flow out of the Western Interconnection. The footprint of Markets+ is limited to the Western Interconnection and does not include any generation or load in SPP's eastern RTO footprint or SPP's proposed RTO West footprint.
>
> SPP is the Markets+ market operator, meaning it will provide services and run the market solution algorithm based on data submitted by Western entities participating in Markets+. Neither SPP nor any participant in another SPP-operated market will have generation or load in Markets+. While SPP operates other markets, the Markets+ market run will not include co-optimization with SPP's eastern RTO footprint, its Western Energy Imbalance Service footprint, or its proposed RTO West footprint.

https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2025-rod/rod-20250509-day-ahead-market-policy.pdf at 140.

[832] As BPA notes, "RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint. May 9, 2025, Day-Ahead Market Policy at note 24. https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/20250509-dam-final-policy.pdf.

[833] *See* the Markets+ Phase Two Funding Agreement approved in FERC Docket No. ER25-1372, 191 FERC ¶ 61,071 (2025) at P 2 and P 4 ("SPP proposed the Markets+ Tariff as a separate, stand-alone tariff" and "t the purpose of the Funding Agreement is to enable SPP to begin the next phase (i.e., Phase 2) of bringing the benefits of Markets+ to entities in the Western Interconnection, while ensuring that it is funded only by entities that stand to benefit from Markets+").

[834] *See* FERC's Order approving the RTO West tariff, *Sw. Power Pool, Inc.*, 190 FERC ¶ 61,169 (2025) at P 92 ("we anticipate that seams between centrally cleared markets (e.g., RTO West, EDAM, and Markets+) and between markets and non-market areas will necessitate agreements between parties that will address issues such as data sharing, congestion management, and transmission rights and use."). Earlier in the Order, FERC quoted,

> SPP states that in response to Colorado Commission's, Black Hills', and PSCo's, concerns about potential future seams issues between SPP's RTO, Markets+, and other regions, SPP acknowledges the importance of addressing seams but believes it is premature to impose conditions related to seams management at this stage, given that the exact seams are still unknown. SPP states that it agrees that seams are a pressing issue that must be addressed and that failing to do so could have harmful consequences. However, SPP argues that more time is needed for the seams to become known so SPP and the affected entities can work through details and, if necessary, make future filings associated with Expansion Members' integration before it can effectively resolve seams

Similarly, even with the passage of AB 825, NV Energy recognizes that the West-Wide Governance Pathways Phase 2 initiative has many hurdles before it can serve as a platform for a Western RTO. In the interim, before there is more widespread agreement about the next steps to take with respect to full RTO participation, NV Energy will continue to explore options and, where possible, seek to capture incremental market-related benefits for customers. The Companies' request to move forward with EDAM is consistent with these objectives.

SECTION 12 – REQUEST FOR REGULATORY ASSET AND ASSESSMENT OF RATE IMPACT

A. Request for Regulatory Asset

In Docket No. 25-02016, Nevada Power General Rate Case ("GRC"), the Commission approved Nevada Power's request to establish a regulatory asset to record EDAM implementation costs.[835] While the Companies did not request a regulatory asset for Sierra in Docket No. 24-02026, the precedent set by the Commission's approval for Nevada Power provides a clear and consistent framework. The EDAM regulatory asset request in this Docket is also consistent with the Commission approval of the RTO regulatory asset for the Companies in Docket No. 22-09006.[836] Therefore, the Companies respectfully requests approval to establish a regulatory asset for Sierra, at this time, ensuring equitable treatment and regulatory consistency across both companies as they advance EDAM implementation.

The proposed regulatory asset will capture incremental and necessary costs to join EDAM, including the labor and materials needed to design, build, and test the software and hardware changes necessary for EDAM implementation. More specifically, the regulatory asset should include:

- Utilicast Gap Analysis,
- Business process changes,
- Build and configure the solution implementation changes,
- Solution Implementation or software/ hardware vendor solution costs.
- Initial solution testing,
- CAISO's implementation fee, and
- CAISO testing and Go – Live.[837]

issues. SPP states that the locations of seams and the relevant parties comprising the seams are currently unknown and will remain so for some time. SPP states that the Commission held in December 2023 that it would be premature to address Extended Day-Ahead Market (EDAM)-related seams, and SPP asked the Commission to make the same ruling with respect to Markets+ seams. *Id.* at P. 87.

835 September 16, 2025, Order at 93.

836 Third Amendment to the 2021 IRP, March 24, 2023, Order at 153-54.

837 These categories of costs replicate those identified in the rebuttal testimony of Michael Holland for Nevada Power's EDAM regulatory asset request in Docket No. 25-02016 (Ex. 193 at 3-4).

As explained in the Direct Testimony of Jenny Naughton, the Companies propose that the costs of the regulatory asset be allocated between Nevada Power and Sierra in the same manner as was ordered by the Commission for the RTO regulatory asset, thus 75 percent to Nevada Power and 25 percent to Sierra.[838] Costs associated with the EDAM implementation will be deferred into a regulatory asset as they are incurred until the implementation is completed in 2028. Once the implementation is complete in 2028 and the regulatory asset is moved into rates, the regulatory asset will begin amortizing and will continue amortizing in accordance with the applicable depreciation rates until all costs have been recovered.[839]

B. Assessment of Rate Impact

In the July 9, 2024, Order in Docket No. 23-10019, the Commission requested a "[f]orecast of rate and revenue impacts for the 5 and 10 years immediately after joining the DAM."[840] As described in the Direct Testimony of Jenny Naughton, with Brattle's estimate of an annual savings of $93.1 million through the deferred energy mechanism, overall, Nevada retail customers at both Nevada Power and Sierra are expected to save. This accounts for these savings being offset by the projected base tariff general rate ("BTGR") increase from annual ongoing OMAG and the amortization of the implementation regulatory asset. Although the Companies target joining EDAM in the Fall of 2028, the rate and revenue impact calculations conservatively account for savings starting in 2029. A summary is shown in Figure 66.

Figure 66

Retail Rate Impact			
	Nevada Power		Sierra
Year	Res	Non-Res	
2028	$ 0.00059	$ 0.00042	$ 0.00018
2029	$ 0.00011	$ (0.00161)	$ (0.00012)
2030	$ (0.00567)	$ (0.00391)	$ (0.00214)
2031	$ (0.00141)	$ (0.00266)	$ (0.00116)
2032	$ (0.00285)	$ (0.00271)	$ (0.00085)
2033	$ (0.00241)	$ (0.00256)	$ (0.00084)
2034	$ (0.00234)	$ (0.00084)	$ (0.00084)
2035	$ (0.00226)	$ (0.00377)	$ (0.00085)
2036	$ (0.00224)	$ (0.00246)	$ (0.00083)
2037	$ (0.00218)	$ (0.00249)	$ (0.00080)

838 Direct Testimony of Jenny Naughton at Q&A 7 referencing Docket No. 22-09006, March 24, 2023, Order at 153-54.
839 *Id.* at Q&A 8.
840 Order at Att. 1 at 10.

The rate impact calculation shows that, during the implementation period, there is a slight increase in rates ($0.00059 per kWh or 0.059 cents per kWh maximum increase for Nevada Power residential customers in 2028), the rate impact flips into savings beginning in 2029 and continuing throughout the forecasted period. The maximum projected savings shown are also for Nevada Power residential customers reaching $0.00567 per kWh or 0.567 cents per kWh in 2030.

Figure 67 below unsurprisingly demonstrates a similar trajectory for the revenue impact with costs initially rising in 2028 by $6.3 million for Nevada Power residential customers only to be eclipsed with $61.7 million in savings by 2030.

Figure 67

Revenue Impact (In Thousands)			
	Nevada Power		Sierra
Year	Res	Non-Res	
2028	$ 6,313	$ 5,165	$ 2,587
2029	$ 1,210	$ (20,053)	$ (1,757)
2030	$ (61,745)	$ (49,595)	$ (35,971)
2031	$ (15,547)	$ (34,308)	$ (21,612)
2032	$ (32,140)	$ (35,508)	$ (17,377)
2033	$ (27,686)	$ (33,930)	$ (17,428)
2034	$ (27,376)	$ (11,283)	$ (17,939)
2035	$ (26,924)	$ (51,575)	$ (18,581)
2036	$ (27,332)	$ (34,409)	$ (18,606)
2037	$ (27,209)	$ (35,464)	$ (18,403)
2038	$ (27,569)	$ (34,485)	$ (18,597)

SECTION 13 – SUMMARY OF SPECIFIC APPROVALS REQUESTED AND CHANGES IN ASSUMPTIONS OR DATA

NAC 704.9504(3)(a) requires that an amendment to an ESP include a section that identifies specific approvals requested by the utility. The ESP and its component elements, including the Power Procurement Plan, Gas Procurement Plan, Coal Supply Plan, and Risk Management Strategy, govern each Company's day-to-day operations and facilitate the provisioning of reliable electric service to customers at just and reasonable rates. The most recent ESP was approved pursuant to a Phase I Stipulation accepted in the October 2, 2024, Order in Docket No. 24-05041. The approved ESP covered the 2025-2027 period. As part of the request in this Joint Application and to facilitate the Companies' participation in EDAM, the Companies amended:

- The Power Fundamentals portion of the Market Fundamentals subsection (a component of the Market Fundamentals & Price Forecasts Section);[841] and

[841] Section 3.A.1.

- The Current Portfolio Optimization Procedures portion of the Power Portfolio and Optimization Procedures subsection (a component of the Power Procurement Plan Section) of the 2025-2027 ESP.[842]

The amended Power Fundamentals and Current Portfolio Optimization Procedures portions of the 2025-2027 ESP are provided as Attachment 1 to this narrative. The Companies request the Commission approve the 2025-2027 ESP as amended. The amended Power Fundamentals narrative updates its WEIM, EDAM and Regional Market Development discussion, including the Companies' intent to join EDAM in the Fall of 2028 if the Joint Application is granted. The amended Current Portfolio Optimization Procedures narrative adds EDAM-related procedures and discusses the interplay with the WEIM procedures. The Companies do not propose modifications of any other portion of the 2025-2027 ESP.

The Companies request that the Commission:

- Grant the Joint Application;
- Approve their participation in the EDAM beginning in the Fall of 2028; and
- Approve the 2025-2027 ESP with amendments to the Power Fundamentals and Current Portfolio Optimization Procedures portions of the Plan, as presented in Attachment 1, as prudent pursuant to NAC § 704.9494.

NAC 704.9504(3)(b) requires a section that specifies any changes in assumptions or data that have occurred since the utility's last resource plan was filed. As stated above, the last ESP was filed as part of the 2024 IRP in Docket No. 24-05041 on May 31, 2024. Since that time, and as discussed in the Direct Testimony of David Rubin[843] and throughout the narrative, a number of developments have occurred that have influenced the Companies' decision to file this ESP Amendment and seek approval to participate in the EDAM. These developments include:

- June 28, 2024, Portland General Electric executed an EDAM Implementation Agreement with CAISO.[844]
- November 7, 2024, the CAISO Board of Governors and Western Energy Markets (WEM) Governing Body jointly approved changes to the CAISO governance documents that implement the Step 1 recommendation of the Pathways Launch Committee. On November 22, 2024, CAISO submitted tariff revisions to FERC in Docket No. ER25-542 to implement the dual filing dispute resolution proposal.
- November 22, 2024, CAISO filed with FERC a development agreement with Great Basin Transmission for the construction of SWIP-North in Docket No. ER25-543. The agreement was accepted on January 21, 2025.[845]

842 Section 4.A.4.
843 Direct Testimony of David Rubin at Q&A 55.
844 https://www.westerneim.com/Documents/jun-28-2024-edam-entity-implementation-agreement-portland-general-electric.pdf.
845 *Cal. Indep. Sys. Operator Corp.*, 190 FERC ¶ 61,034 (2025).

- December 10, 2024, the Los Angeles Board of Water and Power Commissioners approved the Implementation Agreement with CAISO to participate in EDAM.[846]
- January 25, 2025, FERC accepted EDAM Implementation Agreement with the Balancing Area of Northern California.[847]
- April 2, 2025, FERC approved the tariff amendment to implement Pathways Step 1.[848]
- May 17, 2025, Turlock Irrigation District executed an EDAM Implementation Agreement.
- May 22, 2025, Imperial Irrigation District executed an EDAM Implementation Agreement.
- July 1, 2025, Public Service Company of New Mexico executed an EDAM Implementation Agreement.
- July 1, 2025, threshold trigger was met to implement Pathways Step 1 giving WEM Governing Body primary authority over market initiatives and dual jump ball filing rights.
- August 29, 2025, FERC approved the PacifiCorp (Docket No. ER25-951) and Portland General Electric (Docket No. ER25-1868) OATT filings to implement the EDAM design.[849]
- August 29, 2025, FERC's approved CAISO's interim congestion allocation methodology in Docket No. ER25-2637.[850]
- September 5, 2025, NV Energy filed its decision to leave WRAP with the Commission in Docket No. 25-08027.[851]
- September 5, 2025, Idaho Power submitted to FERC in Docket No. ER25-3372 a Participation and Joint Ownership Agreement with Great Basin Transmission involving SWIP-North.
- September 19, 2025, Governor Newsom signed AB 825 providing a means to move forward with Pathways Step 2.[852]
- September 23, 2025, CAISO filed in FERC Docket No. ER25-3491 to extend the assistance energy transfer product.

Changes in assumptions underlying the Brattle Study, Technical Appendix 1, are listed in Section 6 above.

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846 https://www.newsdata.com/california_energy_markets/markets/ladwp-board-approves-edam-implementation-agreement/article_e5bd44bc-bda7-11ef-96a1-0bc2dead05ca.html.

847 https://www.westerneim.com/Documents/FERC-Order-No-ER25-663-000.pdf.

848 *Cal. Indep. Sys. Operator Corp.*, 191 FERC ¶ 61,009 (2025).

849 *PacifiCorp*, 192 FERC ¶ 61,197 (2025) and *Portland General Electric Co.*, 192 FERC ¶ 61,195 (2025).

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

851 Docket No. 25-08027, 2025 ESP Update, Direct testimony of Lindsey Schlekeway.

852 https://www.caiso.com/about/news/gov-newsom-signs-landmark-legislation-for-independent-governance-of-western-electricity-markets.

ATTACHMENT 1

SECTION 3 – MARKET FUNDAMENTALS & PRICE FORECASTS

A. MARKET FUNDAMENTALS

1. POWER FUNDAMENTALS

Regional Profile. The Companies are members of the Western Electricity Coordinating Council ("WECC"). WECC is the Regional Entity ("RE") responsible for compliance, monitoring and enforcement, and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC bylaws. There are six REs given authority by the North American Electric Reliability Corporation ("NERC") and the Federal Energy Regulatory Commission ("FERC"). Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection ("WI"). WECC's footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.[11] Figure ESP-20 depicts the various NERC regions and sub-regions, including the WECC.

In order to conduct NERC reliability assessments, NERC further divides the REs into 20 assessment areas, also shown in Figure ESP-20 below. This level of granularity allows NERC to better evaluate resource adequacy and ensure deliverability constraints between and among assessment areas are accounted for.

The WECC assessment area is divided into five sub-regions: California/Mexico ("CA/MX"), Northwest ("NW"), Alberta ("AB"), British Columbia ("BC"), and the Southwest ("SW"). NW area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. The Companies reside in the NW sub-region. These subregional divisions are used for this assessment as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

[11] https://www.wecc.org/Pages/AboutWECC.aspx.

FIGURE ESP-20
NERC REGIONS AND SUB-REGIONS

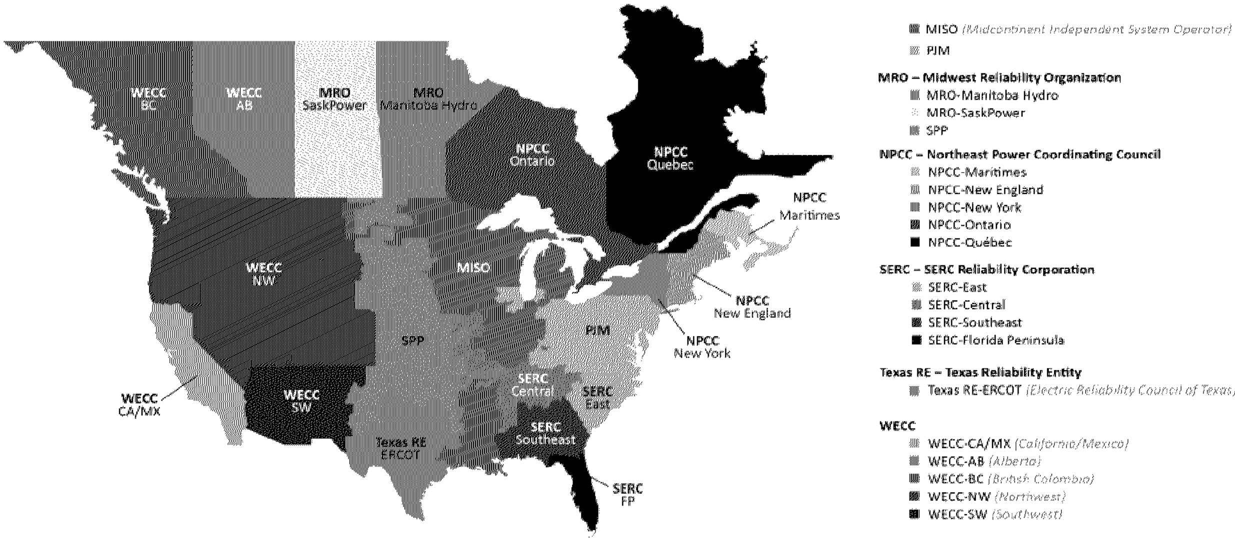


Figure ESP-21 shows the capacity composition in the NW sub-region and the prevalence of gas-fired and hydroelectric generation.[12]

FIGURE ESP-21
WECC-NW CAPACITY BY FUEL TYPE

WECC-NW Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,883	13,450	10,834	10,834	9,961	9,272	8,631	7,675	7,678	7,675
Petroleum	285	285	285	285	285	279	279	279	280	279
Natural Gas	31,882	31,882	31,634	31,457	31,053	30,862	30,519	30,388	30,144	29,414
Biomass	775	773	767	737	731	671	671	671	669	656
Solar	8,373	9,130	9,492	9,660	8,877	9,883	9,883	9,815	8,622	9,767
Wind	4,864	5,077	5,065	5,065	4,119	5,058	5,037	4,998	3,779	4,928
Geothermal	910	892	926	890	905	858	740	740	670	467
Conventional Hydro	22,220	22,216	22,119	22,111	19,768	22,090	22,090	22,083	19,116	22,081
Pumped Storage	448	448	448	448	434	448	448	448	402	448
Nuclear	1,097	1,097	1,097	1,097	1,081	1,095	1,095	1,095	1,091	1,095
Hybrid	1,293	1,293	1,293	1,293	1,394	1,430	1,430	1,430	1,117	1,157
Other	78	78	78	78	78	77	77	77	78	77
Battery	824	1,124	1,124	1,129	1,186	1,440	1,495	1,550	1,605	1,705
Total MW	86,933	87,745	85,161	85,084	79,872	83,464	82,395	81,249	75,250	79,749

[12] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Energy Imbalance Market ("EIM").

The California Independent System Operator's ("CAISO") EIM is a real-time energy market, the first of its kind in the western United States. The EIM's advanced market system automatically finds low-cost energy to serve real-time consumer demand across the west. Since its launch, the EIM has enhanced grid reliability and generated cost savings for its participants. In addition to its economic advantages, the EIM improves the integration of renewable energy, leading to a cleaner, "greener" grid.[13] The EIM began financially binding operation on November 1, 2014, by optimizing resources across the CAISO and PacifiCorp Balancing Authority Areas ("BAAs"). NV Energy began participating in December 2015. The EIM uses a sophisticated system to automatically balance demand every five minutes with the lowest cost energy available across the combined grid.

The first quarter 2025 EIM Benefits Report published by the CAISO estimates that the EIM has yielded more than $6.99 billion in total benefits for all participants since the market was launched in 2014. The measured benefits of participation in the EIM include cost savings, increased integration of renewable energy, and improved operational efficiencies including the reduction of the need for real-time flexible reserves. The estimated gross economic benefits for the Companies have been $81.71 million out of total $744.05 million in the first quarter of 2025.[14] Sharing resources across a larger geographic area reduces greenhouse gas emissions by utilizing renewable generation that otherwise would have been turned off. A map of the active and pending EIM participants is provided in Figure ESP-22.

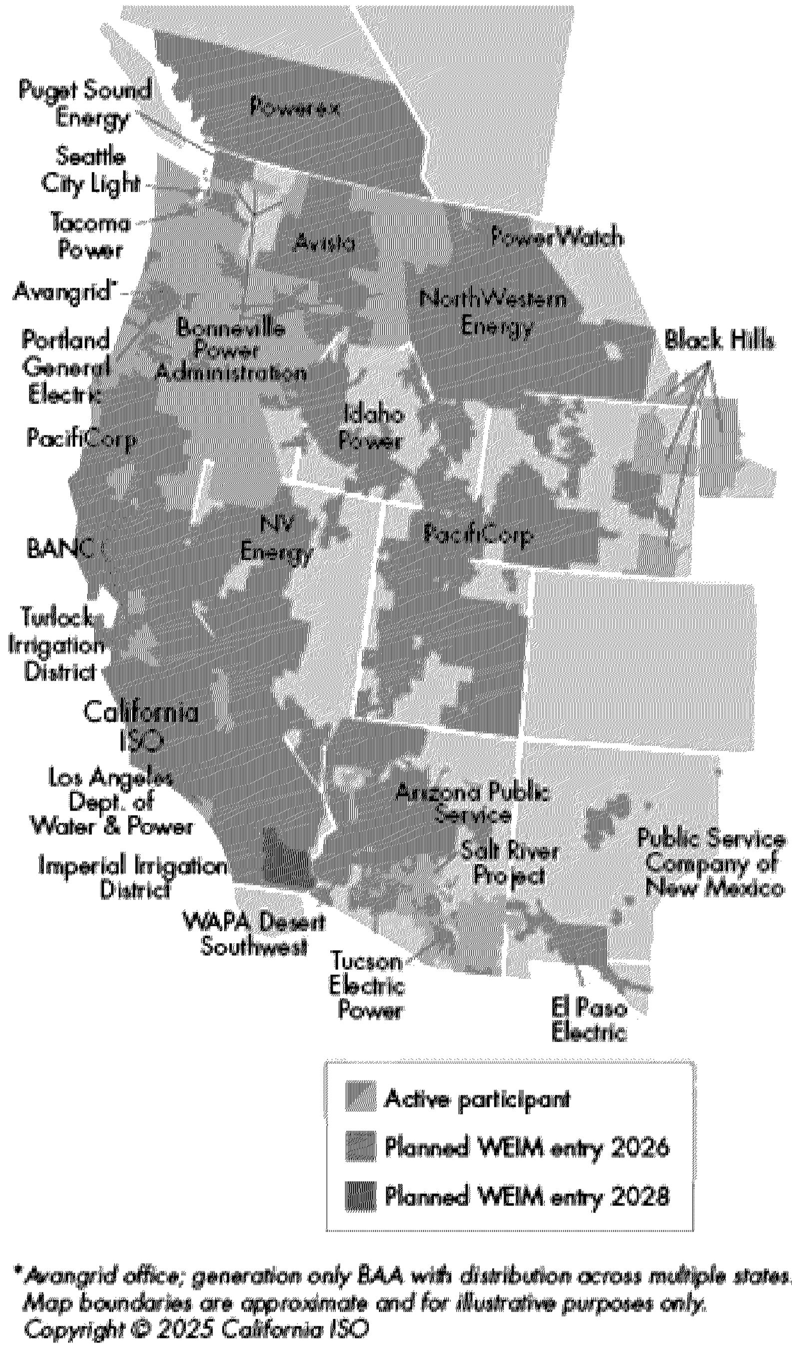
Participants

- Imperial Irrigation District – planned entry 2028
- Black Hills – planned entry 2026
- PowerWatch (formerly BHE Montana) – planned entry 2026
- Avangrid – entered 2023
- El Paso Electric – entered 2023
- WAPA Desert Southwest Region – entered 2023
- Bonneville Power Administration – entered 2022
- Tucson Electric Power – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021
- Public Service Company of New Mexico – entered 2021

[13] https://www.westerneim.com/Pages/About/default.aspx.
[14] https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q4-2023.pdf.

- Turlock Irrigation District – entered 2021
- Salt River Project – entered 2020
- Seattle City Light – entered 2020
- Balancing Authority of Northern California – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound – entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- California ISO – entered 2014

FIGURE ESP-22
WESTERN EIM ACTIVE PARTICIPANTS



Extended Day-Ahead Marke (EDAM)t

Based on the success of the EIM, the CAISO has worked with stakeholders and sought and received FERC approval to extend its day-ahead market to external Balancing Authorities. The participants in EDAM manage their electricity needs and supplies on a day-ahead and real-time basis. The market improves electricity transmission and resource use by finding the most efficient mix to meet demand, maintaining reserves for imbalances, and standardizing greenhouse gas emissions reporting. EDAM offers the potential for significant economic, reliability, and environmental advantages by reducing production costs, enhancing supply visibility, and promoting efficient use of renewable resources. Furthermore, it reduces operational risks and emergencies. The CAISO anticipates going live with the EDAM in 2026. PacifiCorp will be the first participating Balancing Authority and Portland General Electric anticipates joining later that year. Entities entering Implementation Agreements with CAISO to enter EDAM in 2027 include the Los Angeles Department of Water and Power, the Balancing Area of Northern California, and the Turlock Irrigation District and Public Service Company of New Mexico. The Imperial Irrigation District proposes to join EDAM in 2028.

The Companies seek approval to join EDAM no earlier than 2028. Participation in EDAM will require amendment to the Joint Dispatch Agreement as well as modifications to the Companies' Open Access Transmission Tariff ("OATT").

Resource Adequacy

To ensure reliability during the transition to greater reliance on renewable resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term resource adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy assured. To evaluate the projected resource adequacy (generation resource reserve margins), NERC prepares the Long-Term Reliability Assessment ("LTRA") - an annual assessment of anticipated resource reserve margins.

Planning Reserve Margins (Anticipated Reserve Margin or "ARM" [15] and Prospective Reserve Margin or "PRM" [16]) are calculated and reported for each of the WECC sub-regions and provide an indication of the ability of those sub-regions to meet their load requirements with internal generation and imports from other sub-regions or zones under the specified conditions. Planning Reserve Margins (anticipated or prospective) are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand.

[15] This is the amount of anticipated resources (includes only Tier 1 resources) less net internal demand calculated as a percentage of net internal demand.
[16] This is the amount of prospective resources (includes also Tier 2 resources) less net internal demand calculated as a percentage of net internal demand.

NERC assesses resource adequacy by evaluating each assessment area's planning reserve margins relative to its Reference Margin Level[17] ("RML") - a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load ("LOL") analysis.

The most recent forecast of these reserve margins from the NERC 2023 LTRA published in December of 2023 is shown in Figure ESP-23.[18]

FIGURE ESP-23
WECC-NW POWER SUPPLY ASSESSMENT

Demand, Resources, and Reserve Margins										
Quantity	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%

The NW sub-region is assessed as adequate by NERC until summer of 2031. The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.

The Companies' BAA is included in the NW sub-region within the WECC. The BAA is integrated with the other sub-regions by way of transmission interconnections within the electric grid. The Companies routinely engage in purchase and sales transactions with neighboring utilities belonging to other WECC sub-regions and reserve margins in those sub-regions have the ability to impact operations in Nevada. Consequently, reserve margins in BAAs located in the other subregions can affect operations and capacity availability in the system as well.

The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability that

[17] The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/ RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of the assessment period or may be different for the summer and winter seasons.

[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

result from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural gas-fired generation, unprecedented proportions of nonsynchronous resources, including renewables and battery storage, demand response, smart and micro-grids and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Therefore, WECC also performs energy-based probabilistic assessments ("ProbA") looking at all hours of the year. The difference between the LTRA and the ProbA results is that the ProbA captures the expected equivalent forced outage rate for baseload resources whereas the LTRA does not. Another difference is that the ProbA looks at all hours of the year, and the LTRA looks at the peak hour only. WECC uses the Multi-Area Variable Resource Integration Convolution model ("MAVRIC"). The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. LOLH and EUE are not anticipated in 2026 and 2027, and EUE is minimal in 2028. Results of the 2024 ProbA shown in Figure ESP-24 table below indicate negligible unserved energy and load-loss risk.

FIGURE ESP-24
WECC-NW SUMMARY OF ASSESSMENTS

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

Demand in WECC-NW. The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034. This represents nearly 18.7 percent load growth over the forecast horizon, with an average growth rate of 1.73 percent. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Generation in WECC-NW. Five GW of baseload resource retirements are anticipated between 2025 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage in WECC-NW. Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co- located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real- world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Transmission in WECC-NW. Twelve transmission projects with 500 kV and higher are planned.

Regional Market Development

FERC approved the Western Resource Adequacy Program[19] **(**"WRAP") tariff in February 2023. As discussed in the Companies' Update to the 2025-2027 ESP, the Companies decided to withdraw from WRAP and, consequently, not to go binding in the initial WRAP winter 2027/2028 season.[20]

Two day-ahead markets were under consideration by the Companies: CAISO's EDAM and Southwest Power Pool's ("SPP") Markets+. The decision to join a day-ahead market is a significant event, and while it is not impossible to exit a market, it is far better to get the decision correct the first time. It is for that reason the Companies have taken a methodical approach and performed due diligence on both day-ahead market options.

Based on a holistic view of these qualitative and quantitative factors, the Companies are requesting authorization from the Commission to participate in the CAISO's EDAM. As the second participant in the EIM, the Companies have experienced significant economic, reliability, and environmental benefits. Having developed a market that includes more than 80 percent of load in the WECC, NV Energy would hope to preserve as much of that size and diversity as possible while expanding the scope of the organized market services. Critical to NV Energy's decision is the expected EDAM footprint. The anticipated participation by CAISO, PacifiCorp, the Balancing Authority of Northern California, Los Angeles Department of Water and Power, Portland General Electric, Turlock and the Imperial Irrigation District, Idaho Power and Public Service Company of New Mexico provides a significant degree of interconnectivity and supports a diversity of resources. Moreover, the approval of the SWIP-North transmission by CAISO and Idaho Power

[19] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program
[20] *See, e.g.,* Docket No. 25-08027, 2025 Joint ESP Update at 50.

will only enhance the transfer capacity of the existing ON Line transmission line in Nevada, bringing even greater benefits to all EDAM participants.

If the Companies' Joint Application to amend the 2025-2027 ESP is granted by the Commission, NV Energy anticipates joining EDAM in the Fall of 2028.

4. CURRENT PORTFOLIO OPTIMIZATION PROCEDURES

The Companies' resource portfolio is adjusted continuously based upon many factors, including changes in expected load, changes in system conditions, system reliability needs, and changes in market conditions. The Companies continuously monitor the resources available to meet load obligations, recognizing the uncertainty not only in system conditions but also in regional energy markets organized across different commodities, locations, and trading timeframes. Forward prices are continuously monitored for comparison with the internal generation costs. As conditions change and new information becomes available, the Companies optimize their portfolio to account for changes in load, cost, volatility, reliability, and other commercial or technical factors.

Each month, the Companies assess their capacity and energy positions for the upcoming month by taking into account planned unit outages, available resources, forecasted system loads and forecasted reserve requirements. If the assessment shows that the Companies are expected to be short in terms of meeting system load and reserve requirements in the upcoming month, the Companies may purchase energy or capacity. The Companies utilize both RFP processes and direct negotiations with approved counterparties to fill short capacity and energy positions.

Short-term energy transactions may be made either for economic reasons or in order to maintain the reliability of the transmission grid. The circumstances in which adjustments may be made for reliability purposes include unexpected loss of generation due to forced outages or capacity constraints, imbalances between supply and demand of non-native load customers, actual loads being higher than the amount forecasted, and transmission constraints due to forced outages or other unanticipated contingencies impacting transmission facilities inside or outside the Companies' transmission network. In any of these circumstances, the transmission system may enter a condition under which, absent an adjustment to short-term transactions, one or more of the requirements of the applicable reliability standards will be violated. Operation in violation of the requirements of the applicable reliability standards poses undue risk to the reliable and secure operation of the bulk electric system and can also result in monetary sanctions for non-compliance. In addition to participation in the EIM as described above, the remedy for a negative imbalance between load and resources is the procurement of emergency resources to regain such balance and restore the required reserve margins.

The Companies also prepare day-ahead plans. On a daily basis, the Companies forecast their energy position and generation costs for the scheduling day using a production cost simulation model. Internal generation costs are compared to actual energy market prices to identify opportunities to sell into the market and mitigate customer costs. The Companies' traders determine actual energy market prices by communicating with other traders and by monitoring the Intercontinental Exchange ("ICE"), a trading platform for global commodity and financial products marketplaces, including electronic energy markets. Purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

In EDAM, all load in the NV Energy Balancing Authority Area will clear through the day-ahead and real-time markets. Since EDAM is an extension of the real-time market to the day-ahead timeframe, NV Energy will still participate in the real-time market as well. However, the use of "Base Schedules" will be discontinued and real-time deviations will be measured from the day-ahead position. EDAM incorporates the use of a resource sufficiency evaluation to ensure that each Balancing Authority Area must have economically bid or self-scheduled enough resources to meet the assigned energy, imbalance reserves, and ancillary service requirements for each hour of the following day, as estimated by the CAISO. EDAM's security-constrained, least-cost dispatch model will determine the most economic dispatch of resources, including bids and self-schedules from NV Energy to determine the most economic way of serving the load in the footprint.

On the day of delivery, the Companies continue to compare hourly generation costs to hourly energy market prices, monitor hourly weather patterns and actual generation and transmission availability and costs, and assess hourly energy market conditions in order to balance loads and resources across the day. The Companies' traders ascertain real-time market conditions by conducting market surveys through communications with other counterparties. Again, purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

In the delivery operating hour, the power portfolio is further optimized through participation in the EIM operated by CAISO. The EIM will continue to utilize a security constrained economic dispatch model to dispatch resources in five-minute intervals in the participating Balancing Authority Areas. Subject to state and federal regulatory approvals, the Companies began participating in the EIM on December 1, 2015. The Companies' traders determine which resources are available for participation in the EIM and voluntarily submit bids to the market operator for EIM purchases or sales. Participation in the EIM does not absolve the Companies from compliance with reliability standards or the obligation to meet customer demand.

APPLICATION EXHIBIT B

DRAFT NOTICE

PUBLIC UTILITIES COMMISSION OF NEVADA
DRAFT NOTICE
(Applications, Tariff Filings, Complaints, and Petitions)

Pursuant to Nevada Administrative Code ("NAC") 703.162, the Commission requires that a draft notice be included with all applications, tariff filings, complaints and petitions. Please complete and include **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(5)(a)):

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.

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(5)(b)):

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

A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(5)(c)):

The filing seeks approval of an amendment to the Joint Energy Supply Plan of Nevada Power Company and Sierra Pacific Power Company to reflect each Company's participation in the Extended Day-Ahead Market that is being established by the California Independent System Operator. Participation in the Extended Day-Ahead Market will enable the Companies to further optimize their power supply portfolios for the benefit of their customers.

A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1)[1] and NAC 703.162(2):

No. A consumer session is not required by NRS § 704.069.

If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

N/A

[1] **NRS 704.069(1) states in relevant part:**

> 1. [T]he Commission shall conduct a consumer session to solicit comments from the public in any matter pending before the Commission pursuant to NRS 704.061 to 704.110 inclusive, in which:
> (a) A public utility has filed a general rate application, an application to recover the increased cost of purchased fuel, purchased power, or natural gas purchased for resale or an application to clear its deferred accounts; and
> (b) The changes proposed in the application will result in an increase in annual gross operating revenue, as certified by the applicant, in an amount that will exceed $50,000 or 10 percent of the applicant's annual gross operating revenue, whichever is less.