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In accordance with NRS Chapter 719, this filing has been electronically signed and filed by: /s Connie Silveira

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This filing has been electronically filed and deemed to be signed by an authorized agent or representative of the signer(s) and

SPPC NPC
April 16, 2014

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

RE: Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of Amendments to their Energy Supply Plans to Reflect Participation in the Energy Imbalance Market

Dear Ms. Potter:

Enclosed for filing with the Commission please find the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of Amendments to their Energy Supply Plans to Reflect Participation in the Energy Imbalance Market that is being established by the California Independent System Operator.

The Joint Application is organized as follows:

1. Transmittal Letter
2. Joint Application
3. Draft Notice
4. Narrative
5. Testimony
   a. Shawn M. Elicegui
   b. Marc D. Reyes
   c. Brian J. Whalen
   d. Mark A. Rothleder
6. Technical Appendix
7. Certificate of Service
For ease of reference, the following table identifies each item contained in the technical appendix, provides a brief description of the item, and identifies the witnesses that sponsor the technical appendix items.

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Should you have any questions regarding this filing, please contact me at (775) 834-5696 or chilen@nvenergy.com.

Respectfully submitted,

/s/ Christopher A. Hilen
Christopher A. Hilen
Associate General Counsel
JOINT 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 Amendments to Their Energy Supply Plans to Reflect Participation in the Energy Imbalance Market Docket 14-04

JOINT APPLICATION FOR AMENDMENTS TO ENERGY SUPPLY PLANS

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” and individually the “Company”) respectfully file this Joint Application (the “Joint Application”) for approval of an amendment to each of their respective Energy Supply Plans (“ESP”) to reflect each Company’s participation in the energy imbalance market (“EIM”) that is being established by the California Independent System Operator (the “ISO”). Participation in the EIM 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 Section 704.741 of the Nevada Revised Statutes (“NRS”) and Section 704.9504.3 of the Nevada Administrative Code (“NAC”). In this Joint Application, the Companies request an amendment to the Portfolio Optimization Procedures of their respective ESPs for the respective action plan periods pursuant to NAC § 704.9482. For Nevada Power, the remaining action plan period is 2015. For Sierra, the remaining action plan period is 2015-2016.

The amendments to the respective ESPs that are requested through this Joint Application are based on the Narrative of the Companies’ Proposed Participation in the EIM that accompanies the Joint Application (the “Narrative”), prepared direct testimony filed in support
of the Joint Application, and the technical appendices to this Joint Application. 1

I. THE JOINT APPLICANTS

All correspondence related to this Joint Application (including all pleadings, notices, orders and discovery requests) should be served electronically at the following email address: regulatory@nvenergy.com. Hardecopy documents should be transmitted to the Companies’ counsel and Manager, Regulatory Services, whose names and addresses are set forth below:

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Nevada Power provides electric service to the public in portions of Clark and Nye Counties, Nevada, pursuant to Certificates of Public Convenience and Necessity issued by the Commission. Nevada Power’s primary business office is located at 6226 West Sahara in Las Vegas, Nevada.

Sierra provides electric service to the public in portions of fourteen Nevada counties, including the communities of Carson City, Minden and Gardnerville, Reno and Sparks, and Elko pursuant to Certificates of Public Convenience and Necessity issued by the Commission. Sierra’s primary business office is located at 6100 Neil Road in Reno, Nevada.

Nevada Power and Sierra are both Nevada corporations and wholly-owned subsidiaries of NV Energy, Inc., which is itself an indirect wholly-owned subsidiary of MidAmerican Energy Holding Company. Nevada Power and Sierra are public utilities within the meaning of NRS § 704.020 and, as such, are subject to the jurisdiction of the Commission.

II. THE JOINT APPLICATION

A. Introduction

In Commitment 13 of the stipulation resolving Docket No. 13-07021, the Companies committed to request the Commission’s authorization prior to participating in the EIM:

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.

In its order approving the stipulation in Docket No. 13-07021, including this part of Stipulation 13, the Commission stated:

Additionally, the 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. (Tr. at 145.)

NRS § 704.741 requires the Companies to submit to the Commission on or before July 1 of every third year, and in a manner specified by the Commission, a plan to increase its supply of electricity or decrease the demands made on its systems by customers. The Commission’s regulations obligate each Company to provide an annual update to its triennial ESP to address the second and third years of the period covered by the Action Plan from its last triennial ESP.

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2 Docket No. 13-07021, Order dated December 17, 2013, at paragraph 24 (emphasis in Order).
3 NRS § 704.741; see also NAC § 704.9208.
4 NAC § 704.9506(1).
The ESP and its component elements, including the Power Procurement Plan, the Gas Procurement Plan, the Coal Supply Plan, and the 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.

In Docket No. 13-07005, Application of Sierra Pacific Power Company d/b/a NV Energy for approval of its 2014-2033 triennial integrated resource plan and 2014-2016 energy supply plan, the Commission accepted and approved Sierra Pacific’s energy supply by adopting a stipulation of the parties.\(^5\)

In Docket No. 13-08024, Application of Nevada Power Company d/b/a NV Energy for approval of its energy supply plan update for 2014-2015, the Commission accepted and approved Nevada Power’s Update to its ESP for 2014-2015: “The Commission accepts and approves the following: the Power Procurement Plan and the constituent elements of the plan including the portfolio optimization plans . . . The Commission finds the elements of the ESP Update . . . are prudent pursuant to NAC § 704.949.3.”\(^6\)

NRS § 704.751.2(a) provides that for an amendment to an ESP, “the Commission shall issue an order accepting the amendment as filed or specifying any portions of the plan it deems to be inadequate” within 135 days after the filing.

B. The Amendment to Each Company’s Energy Supply Plan Is Narrow

The Companies in this Joint Application ask the Commission to approve an amendment to each of their respective ESPs as follows:

(1) Section IV.A.5 (“Current Portfolio Optimization Procedures”) of the Nevada Power ESP approved in Docket No. 12-06053 as updated in Docket No. 13-08024; and


(2) Section IV.A.4 ("Current Portfolio Optimization Procedures") of the Sierra Pacific ESP approved in Docket No. 13-07005.

The Portfolio Optimization Procedures are a component of the Power Procurement Plan of the ESP. It sets forth the Companies’ strategies for optimizing assets (such as generating units and gas transportation assets) for the benefit of customers.

The Companies ask that the Commission accept the amendment to each of their respective Portfolio Optimization Procedures and find that the ESP, as amended, is prudent pursuant to NAC § 704.9494.

The Companies do not, in this Joint Application, propose modifications of any other portion of their approved ESPs.

C. Elements of the Joint Application

This Joint Application is organized as follows:

1. Transmittal Letter
2. Joint Application
3. Draft Notice
4. Narrative
5. Testimony
   a. Shawn M. Elicegui
   b. Marc D. Reyes
   c. Brian J. Whalen
   d. Mark A Rothleder
6. Technical Appendices
7. Certificate of Service

NAC § 704.9504.3 requires that an amendment of the ESP 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 IRP was filed.

(c) As applicable, the information required by NAC § 704.9482. These provisions require inclusion with the ESP the following items: (1) Power procurement plan; (2) Fuel procurement plan; (3) Risk management strategy; and (4) a Technical appendix that conforms to NAC § 704.922.

With respect to the specific requirements of NAC §§ 704.9504.3, 704.9482 and 704.922, the Companies:

- Include in this Joint Application the specific approvals requested by the Companies (NAC § 704.9504.3(a)).

- Include, as part of the Narrative, changes in assumptions that have occurred since the Companies’ respective last IRPs were filed, that are germane to participation in the EIM, specifically, the development and establishment of the ISO EIM (NAC § 704.9504.3(b)).

- Include a technical appendix, which includes (1) The study of economic benefits that was performed by ABB Inc. (“ABB”) and Energy and Environmental Economics, Inc. (“E3”), in conjunction with the ISO, “NV Energy-ISO Energy Imbalance Market Economic Assessment” dated March 25, 2014 (the “Economic Analysis”); (2) the EIM Implementation Agreement between the ISO and the Companies; (3) the proposed amendment to the Current Portfolio Optimization Procedures of Nevada Power; and (4) the proposed amendment to the Current Portfolio Optimization Procedures of Sierra Pacific. (NAC § 704.922)

- Do not include any of the other elements of the Companies’ currently approved ESPs that are specified in NAC § 704.9482, because none of those elements of the ESPs are being modified in this Joint Application.
D. Prepared Direct Testimony on the Amendment to the Energy Supply Plans

The Companies have prepared and filed written testimony of several witnesses to support the Amendment to each Company’s ESP. The Companies are prepared to present their witnesses in their direct case at any hearing scheduled in this matter. Specifically, the Companies intend to call the following witnesses to sponsor prepared written testimony in their direct case:

1. **Shawn M. Elicegui, Vice President, Regulation.** As the overall policy witness, Mr. Elicegui explains why the Companies are requesting the Commission’s approval to participate in the EIM, explains why the Companies are seeking authorization through an amendment to their respective ESPs, discusses the interim governance structure that the ISO has developed for the EIM, and sponsors Section 1 and portions of Section 7 of the Narrative.

2. **Marc D. Reyes, Manager, Market Fundamentals.** Mr. Reyes explains the Companies’ role in the performance of the Economic Analysis, which is provided as Item 1 in the Technical Appendix. He describes how the modeling was conducted for the Economic Analysis, from the Companies’ perspective, the input assumptions the Companies provided for use in the Economic Analysis, the Companies’ review of the other input assumptions used in the Economic Analysis, and the Companies’ review of the results of the Economic Analysis. Mr. Reyes also describes the costs the Companies estimate they will incur to begin participating in the EIM and the on-going annual costs the Companies expect to incur related to participation in the EIM. Mr. Reyes sponsors portions of Sections 6 and 8 and portions of Section 4 of the Narrative.

3. **Brian J. Whalen, Director, Transmission Planning.** Mr. Whalen describes the NV Energy transmission system, planning studies and technical transmission data provided by the Companies for use in the Economic Analysis, explains the Companies’ proposed transmission policies related to their Open Access
Transmission Tariff with regard to EIM implementation, and sponsors the transmission portions of Sections 3, 4 and 5 of the Narrative.

4. **Mark A. Rothleder, Vice President of Market Quality and Renewable Integration, California Independent System Operator.** Mr. Rothleder describes the development and operation of the EIM and the Economic Analysis. He also sponsors Section 2 and portions of Sections 3 and 7 of the Narrative.

E. **Determination that the Amendment to Each Energy Supply Plan is Prudent**

Pursuant to NAC § 704.9508.2, the Commission reviews an update to an ESP under the same standards that apply to the Commission’s review of an ESP, specifically, NAC § 704.9494. Although the Commission’s regulations do not specify the standards that apply to the Commission’s review of an amendment to an ESP, the Companies assert that it is reasonable for the Commission to apply the same standards in the review of an amendment to an ESP that it applies to the review of an ESP.

The Companies ask that the Commission accept the amendment to their respective Portfolio Optimization Procedures and find that the each Company’s 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.
The Commission can make each of these findings. Importantly, as noted in Section II.A above, the Commission recently found that the Companies' respective existing ESPs are prudent. Through this Joint Application, the Companies are adding an additional portfolio optimization option – a new, short-term energy imbalance market – that will further reduce the cost of supply and increase the reliability of supply over the period of the ESPs.

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 EIM, discharging the Companies' obligation under Commitment 13 of the stipulation in Docket No. 13-07021 with respect to participation in the EIM.

III. REQUESTS FOR RELIEF

Nevada Power and Sierra respectfully request that the Commission proceed in the manner required by law and, in accordance with its regulations, that it:

1. Accept the amendment to each Company’s ESP.

2. Find, pursuant to NAC § 704.9494 that the decision of the Companies to add participation in the EIM to their respective Portfolio Optimization Procedures is prudent.

3. Find, pursuant to NAC § 704.9494:

   a. That the ESP of each Company, 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 each Company’s ESP.

   b. That the ESP of each Company, 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 each Company, 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.

4. Find that the Companies have discharged Commitment 13 of the stipulation in Docket No. 13-07021 as it relates to participation in the EIM, by requesting, and obtaining, the Commission’s authorization to participate in the EIM.

5. 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.

Respectfully submitted this 16th day of April, 2014.

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

By: /s/ Christopher A. Hilen
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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 Amendments to their Energy Supply Plans to Reflect Participation in the Energy Imbalance 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 by the Commission of an amendment to the respective energy supply plans of Nevada Power Company and Sierra Pacific Power Company to reflect each Company’s participation in the energy imbalance market that is being established by the California Independent System Operator. Participation in the energy imbalance 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)⁠:

**This amendment to the energy supply plan does not require a consumer session.**

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.

**Not applicable.**

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¹ NRS 704.069 states in pertinent part:

1. The 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.
NARRATIVE
Amendment to the Energy Supply Plans of
Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
To Reflect Their Participation in the Energy Imbalance Market

Narrative of the Companies’ Proposed Participation in
the Energy Imbalance Market
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SECTION 1 – EXECUTIVE SUMMARY

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” and individually the “Company”) are through this filing, requesting approval of the Public Utilities Commission of Nevada (the “Commission”) of an amendment to each Company’s Energy Supply Plans (“ESP”) to reflect the participation of the Companies in the Energy Imbalance Market (“EIM”) that is being established by the California Independent System Operator (the “ISO”). These amendments will enable the Companies to further optimize their power supply portfolios for the benefit of their customers.

The ISO EIM is a voluntary, five-minute balancing market that will cover the NV Energy, PacifiCorp West, PacifiCorp East, and ISO Balancing Authority Areas (“BAAs”). In late 2012, the Companies and the ISO embarked on a joint study to estimate and evaluate the costs and benefits for customers of the Companies as a result of participation in the EIM. ABB Inc. (“ABB”) and Energy and Environmental Economics, Inc. (“E3”) were retained to perform the analysis, which was finalized March 25, 2014, and titled “The NV Energy-ISO Energy Imbalance Market Economic Assessment” (“Economic Analysis”).

As described below, economic benefits were estimated using production cost modeling. The Companies and the ISO formed technical teams consisting of various members within each of the two organizations. The preliminary results of the analysis led NV Energy to announce in November 2013 that it intended to pursue participation in the EIM. The Companies made a decision to participate in the EIM after the Economic Analysis became final. The purpose of this filing is to receive approval from the Commission to participate in the ISO EIM. Specifically, the Companies request, pursuant to Nevada Administrative Code Section 704.9494 that the decision of the Companies to add participation in the EIM to their respective portfolio optimization procedures is prudent.

As concluded in the Economic Analysis, the potential benefits to NV Energy’s customers outweigh the costs and risks of participating in the EIM. Benefits to customers will include:

- Costs are reduced through the use of an automated system that matches demand with least-cost available resources within transmission constraints in real-time, by making available a larger pool of diverse generation resources from which to obtain power, and by making available an intrahour market in which Company resources can be used to earn incremental revenue.

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1 A balancing authority area (“BAA”) is the collection of generation, transmission, and loads within the metered boundaries of a BA. A balancing authority (“BA”) is an entity responsible for integrating resource plans in advance of real-time balancing needs, maintaining load-interchange-generation balance within a balancing authority area, and supporting interconnection frequency in real time.
- Reliability is enhanced by increasing visibility, situational awareness, coordination, and automated outage response across larger portions of the western U.S. energy network.

- Integration of renewable energy sources is improved due to load and resource diversity across the large EIM geographic footprint. In addition, the necessity to curtail renewable resources in situations of over-generation is reduced.

The EIM will allow the real time dispatch of power plants between the Companies’ BAA and other participating BAAs in the ISO EIM. Participation will also provide flexible reserves to follow variable generation such as wind and solar. Participating in the EIM is forecast to provide economic benefits to both NV Energy customers and other participating BAAs in three areas: 1) interregional dispatch savings, 2) reduced flexible reserves, and 3) reduced renewable energy curtailment. The combined potential annual gross benefits to NV Energy, ISO, and PacifiCorp BAAs, as found in the Economic Analysis, are estimated to range from $9.2 million to $18.2 million in 2017 growing to $15.0 million to $29.4 million in 2022. The potential annual gross benefits to NV Energy customers are estimated to range from $6.0 million to $9.5 million in 2017 growing to $7.7 million to $12.2 million in 2022.

The upfront capital investment by NV Energy to implement and integrate the NV Energy system into the ISO EIM is estimated to be $11.2 million. The ongoing operation and maintenance (“O&M”) cost of participating in the ISO EIM is estimated to be $2.6 million to $3.2 million. This O&M cost estimate range is based on assumptions about the staffing that will be required to participate in and analyze EIM results. Because the ISO EIM will be a new market, there is uncertainty inherent in estimating the staffing needs. Participation in the EIM is voluntary, and NV Energy may terminate its participation in the EIM with no exit fee in the event the estimated benefits do not materialize or for any other reason.

The ISO is in the process of establishing the EIM, which is scheduled to go live in October 2014, with PacifiCorp as the initial participant. In February 2013, PacifiCorp announced its plan to participate in the EIM and is actively working on the integration of the necessary systems and operations to effectuate its participation. NV Energy will have the benefit of PacifiCorp’s experience, which PacifiCorp has shared with NV Energy, and will use these lessons from the initial implementation to assure NV Energy efficiently captures benefits for its customers. An expanded EIM that includes NV Energy would allow EIM participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources between participating BAs.

On a parallel path to this ESP filing, on April 16, 2014, the ISO filed an Implementation Agreement with the Federal Energy Regulatory Commission (“FERC”) for approval. The Implementation Agreement, as further discussed below, defines the steps the Companies and the ISO will take to expand the ISO dispatch model to include NV Energy’s BAA. It also provides specific milestones and a payment schedule that is in
place to assure that key milestones are met before the Companies are required to make payments to the ISO.

It is important to note that the Companies’ participation in the EIM does not mean that they are joining the ISO as participating transmission owners or relinquishing control of any of their generation or transmission assets. The Companies will remain responsible, as they are today, for grid reliability and compliance with reliability standards. They will retain control of their generation, purchase power, transmission and distribution assets and will continue to use those to serve load and provide reliable service as they do today. Furthermore, participation in the EIM will not modify the Companies’ day-ahead and longer term responsibilities and operations.

The market design policies that are being established for the EIM are consistent with NV Energy’s responsibility to protect its customers while also obtaining benefits from the market. Finally, because the ISO is using its functioning market platform for the EIM, it offers less risk and lower costs than could be achieved by creating a new market design and infrastructure.

SECTION 2 – OVERVIEW OF THE INDEPENDENT SYSTEM OPERATOR

The ISO operates the largest wholesale transmission grid in the Western United States, providing open and non-discriminatory access supported by a competitive energy market and comprehensive planning efforts. The ISO opened its Northern and Southern California control centers in 1998 when the state restructured its wholesale electricity industry. While utilities still own transmission assets, the ISO acts as a traffic controller, maximizing the use of the transmission system and its generation resources, and supervising maintenance of the lines. The ISO matches buyers and sellers of electricity, facilitating over 28,000 market transactions each day to ensure enough power is on hand to meet demand.

In April 2009, the ISO implemented a major redesign of California’s wholesale energy markets. The redesign created an integrated forward market, improved congestion management, and introduction of locational prices for a more efficient use of resources, and a 5-minute real-time market. Every five minutes the ISO forecasts electrical demand, accounts for operating reserves and dispatches the lowest cost resources to meet demand while ensuring enough transmission capacity is available to deliver the power. This market has operated since 2009 and is the platform for the ISO’s EIM, which the ISO will operate and administer.

SECTION 3 – DESCRIPTION OF THE EIM

The ISO’s proposed EIM does not represent a new market. It is an expansion of one component of the ISO’s existing market. The ISO’s proposal takes advantage of its existing real-time market by adding new procedures to accommodate the voluntary participation of other BAs” within the current imbalance market structure. This provides other BAs with access to a real-time market based on a proven structure, which the ISO introduced five years ago.

ESP Amendments - EIM Narrative
The ISO’s proposed procedures accommodate BAs whose operations in advance of real-time operations (i.e., day-ahead and other forward operations) differ from the ISO’s day-ahead market. This allows BAs to participate in the EIM without altering other aspects of their operations and without having to transfer control of their transmission systems or generating units.

Each BA that chooses to participate in the EIM will remain responsible for the reliability of its BAA. This includes operating reserve and capacity requirements, scheduling and curtailment of the transmission facilities under its operational control, and manually dispatching resources out-of-market to maintain reliability. The proposed ISO tariff revisions for implementing the EIM recognize the retention of these responsibilities by participating BAs, as well as elements designed to ensure that each participating BA has sufficient resources to serve load while still realizing the benefits of increased resource diversity.

A. Development of the ISO EIM

In March 2012, the ISO provided the Public Utility Commission-EIM group, a group of 12 western state regulatory commissions, a conceptual proposal under which the ISO would provide energy imbalance services through its existing market platform to BAs that choose to participate. The ISO explained that, under its proposal, interested BAs would have the opportunity to participate voluntarily in the ISO’s existing real-time market with a low up-front cost, a proven design, and no exit fee. By using its functioning market platform, the ISO could offer less risk and lower costs than could be achieved by creating a new market design and infrastructure.

Because the ISO did not need to build a new platform for the regional EIM, its proposal offered BAs the opportunity to begin participating in the market when they are ready to do so under a “pay-as-you-go” design. Participants would pay a one-time up-front fee to cover the cost of ISO modeling, licensing, and other preparatory work. Once operational, they would pay ongoing fees based on their level of participation, consistent with the ISO’s grid management charge structure.

PacifiCorp expressed interest in the ISO proposal shortly after it was presented. In March 2013, the ISO Board of Governors (the “ISO Board”) approved moving forward with PacifiCorp in parallel with an ISO stakeholder process to develop the design of the EIM. On June 28, 2013, the FERC approved an implementation agreement between the ISO and PacifiCorp to account for PacifiCorp’s portion of the expansion of the ISO real-time model. ISO and PacifiCorp are in the process of integrating their two systems and are planning on going live with a fully functional EIM in October 2014.

B. EIM Stakeholder Processes

Development of the EIM has been an open and transparent process. In all, there have been three separate stakeholder processes led by the ISO. These included processes on market design, governance, and tariff design. With regard to market design, the ISO held five stakeholder meetings over the course of about six months, including meetings in
Phoenix and Portland to facilitate participation by stakeholders outside of California. In addition, the ISO held five technical workshops to discuss specific design elements of particular interest to stakeholders in more technical detail. All of these materials are available for reference on the ISO website.\textsuperscript{2} The ISO prepared detailed comment matrices throughout the stakeholder process, which addressed stakeholder concerns. NV Energy representatives participated throughout the stakeholder process. Broad stakeholder support was voiced in public comments and written submissions. The ISO Board approved the proposed design for the EIM on November 7, 2013.

A separate ISO stakeholder process addressed governance issues associated with the EIM. As part of this process, the ISO Board approved a charter in December 2013 for a transitional committee to advise it on matters relating to the EIM and to develop a proposal for an independent governance structure for the EIM. The ISO anticipates that this committee will engage in the consideration of future design features and enhancements.

A third ISO stakeholder process related to tariff changes necessary to implement the market design. A result of this process was the ISO’s February 28, 2014, filing with FERC of revisions to its tariff to implement the EIM (Docket ER14-1386). On March 31, 2014, the Companies intervened in that filing, in support of the ISO’s development of the EIM.

In addition to the ISO’s stakeholder processes, NV Energy has conducted three formal workshops in the first quarter 2014 with the Regulatory Operations Staff of the Commission (“Staff”), Commission Advisors, and the technical staff of the Attorney General’s Bureau of Consumer Protection (“BCP”). The purpose of the workshops was to inform the regulatory bodies of the plan, review the technical merits and economics, and seek input on the merits of NV Energy participating in the ISO EIM. Representatives from the ISO also attended the workshops. NV Energy appreciates the time that Staff, Commission Advisors and the BCP have dedicated to learning about the EIM and the thoughtful discussions that took place in these workshops.

Finally, the Companies will initiate a stakeholder process for their transmission customers and other stakeholders focused on the key elements of the ISO EIM, what steps customers will need to take in order to participate in the EIM, and review of changes to the Companies’ Open Access Transmission Tariff (“OATT”) that will be made for the Companies to participate in the EIM.

C. EIM Participation

Figure 1 below illustrates the ISO, PacifiCorp, and NV Energy BAAs and helps to show the regional nature of the EIM and the geographical diversity that enhances the benefits of the EIM.

\begin{footnotesize}
\footnotesize
\begin{enumerate}
\item \url{http://www.caiso.com/informed/pages/StakeholderProcesses/EnergyImbalanceMarket.aspx.}
\end{enumerate}
\end{footnotesize}
Participation in the EIM will be open to non-NV Energy generators within NV Energy’s BAA. Any party within NV Energy’s BAA wishing to participate would need to be an eligible customer under the NV Energy OATT, meet the EIM requirements of both the Market Operator (the ISO) and the EIM Entity (NV Energy). Similarly, generators within the NV Energy BAA may choose not to participate in the EIM.

The operation of the EIM will include the following types of entities or functional roles:

1. **EIM Entity**: The EIM Entity is a BA that elects to participate in the EIM. Proposed section 29.2 of the ISO tariff sets forth the process for becoming an EIM Entity, with the pre-market operation particulars and initial fee to cover the costs associated with including its BAA in the EIM to be included in an implementation agreement. As an EIM Market Participant, the EIM Entity is responsible (1) for identifying available transmission intertie capacity from participating transmission service providers in its BAA for use in the ISO’s real-time market and,
(2) for scheduling all load and resources in its BAA that do not participate in the real-time market (known as non-participating load and non-participating resources) and for paying EIM charges related to non-participating load and non-participating resources. NV Energy will be an EIM Entity.

2. **EIM Entity Scheduling Coordinator**: The EIM Entity Scheduling Coordinator is the entity through which the EIM Entity provides information to the real-time market. In order to prevent the inappropriate sharing of information regarding transmission and generation, an EIM Entity Scheduling Coordinator cannot be a scheduling coordinator for a supply resource unless it is a transmission provider subject to FERC standards of conduct in 18 C.F.R. § 358.

3. **EIM Participating Resources ("EPR"):** EPRs are the owners or operators of EIM resources that wish to bid supply into the real-time market. EPRs can be generating units, load, demand resource providers, or other resources qualified to deliver energy or similar services, such as non-generation resources. Each type of resource that is eligible to participate in the current ISO real-time market is eligible to participate through the EIM, but only if the EIM Entity supports participation by that type of resource and the resource meets the technical requirements for such participation.

4. **EIM Participating Resource Scheduling Coordinator**: The EIM Participating Resource Scheduling Coordinator is the entity through which the EIM Participating Resource participates in the real-time market. To prevent the inappropriate sharing of information regarding transmission and generation, an EIM Participating Resource Scheduling Coordinator cannot be an EIM Entity Scheduling Coordinator unless it is a transmission provider subject to FERC standards of conduct in 18 C.F.R. § 358.

5. **Market Operator**: The ISO will perform the role of the Market Operator. The Market Operator performs the following functions: 1) forecast expected imbalance energy requirements, 2) clear bid offers to meet expected imbalances, 3) produce prices used for settlement of imbalance energy, and 4) settle imbalance energy. The Market Operator settles imbalance energy with the EIM Participating Resource Scheduling Coordinator for all EIM Participating Resources and with the EIM Entity Scheduling Coordinator for all non-participating resources.
D. Operation of the EIM

The EIM Entity Scheduling Coordinator ensures and informs the Market Operator of the resource plan that balances EIM Entities’ forecast demand plus exports. This plan may be made of both resources inside the EIM Entity BAA or imports from other BAAAs.

The EIM Entity Scheduling Coordinator will submit the balanced BAA base schedule and resource plan to the Market Operator. Also, prior to the start of the EIM, the Market Operator will evaluate the BAA base schedule and provide advisory information back to the EIM Entity Scheduling Coordinator to provide an opportunity for the EIM Entity to ensure the BAA base schedule is balanced and feasible from a congestion perspective. Separately, an EIM Participating Resource Scheduling Coordinator will submit to the Market Operator bid offers for increased or decreased dispatch for EIM Participating Resources relative to their individual base schedules.

The Market Operator will optimize all real-time bid offers, using a security constrained economic commitment and dispatch process every 15 and 5 minute interval of each hour for which the EIM Participating Resource was offered for EIM dispatch. Since a resource may have some of its capacity committed to the BA for operating reserve or regulation the EIM Entity Scheduling Coordinator shall also inform the Market Operator of such committed resource capacity so that the Market Operator does not dispatch such committed resource capacity via the EIM.

The Market Operator will issue dispatch instructions and compensate EIM Participating Resources through the EIM Participating Resource Scheduling Coordinator. The Market Operator will settle and allocate imbalance and other associated costs that are attributable to the EIM BA to the EIM Entity Scheduling Coordinator. The EIM Entity will allocate such costs to its customers pursuant to its OATT.

E. Key Elements of the EIM Market Design

In consideration of participating in the EIM, NV Energy reviewed key elements of the market design throughout the stakeholder process. Significant elements of the market design review are described below:

Resource Sufficiency: Some entities in the West have expressed concern about the possibility that entities would “lean” on the EIM to provide them access to energy if they were not sufficiently resourced to serve their load. To address this concern, the EIM is designed to ensure that each participating BA has sufficient resources to serve load. The ISO does this by performing a series of tests each hour, including a flexible ramping sufficiency test. The ISO will impose limitations on transfers into or out of an EIM Entity that fails the test, thereby ensuring that each EIM Entity has sufficient resources to avoid leaning.

California Greenhouse Gas Costs: The market design also recognizes the need for resources that serve load in the California ISO BAA through the EIM to comply with California’s greenhouse gas (“GHG”) cap and trade regulations. As it currently does for resources participating in its real-time market, the ISO will allow EIM Participating Resources to comply with California’s GHG cap and trade regulations.

ESP Amendments - EIM Narrative
Resources to include the costs of compliance in their energy bids and will incorporate this cost into its dispatch of generation as appropriate. However, in the EIM the ISO will not consider this GHG compliance cost when it dispatches generation that is attributable to serving load outside the ISO BAA. As a result, California GHG compliance costs will not be passed to non-California load, including NV Energy customers.

Transmission Capacity Use: NV Energy anticipates use of “as available” Available Transmission Capacity (“ATC”) for EIM transactions. Studies to date indicate that existing, non-committed ATC between NV Energy and the ISO would be sufficient to meet anticipated levels of EIM transactions. Additionally, this methodology would not impact existing or potential users of the transmission system negatively as the capacity could still be used for existing tariff products like Network Integration Transmission Service or Point-to-Point Service. The Company expects to file revisions to its OATT in early 2015 to allow the FERC to review NV Energy’s OATT revisions and issue an order prior to the expected October 2015 “go-live” date.

Transmission Charges: Transmission access to the EIM will be provided under the applicable transmission service provider tariffs. As part of a reciprocal arrangement between EIM Entities, initially it is anticipated that there will be no incremental transmission charge for the use of transmission to support EIM transfers between participating BAs. EIM Participating Resources within NV Energy’s BAA would be required to have sufficient transmission service in accordance with their needs on an hourly or greater basis. This practice is intended to eliminate use of EIM by non-paying parties. Within the first year of operation, before NV Energy is expected to participate, the ISO and PacifiCorp will consider in consultation with stakeholders whether to continue this reciprocity arrangement or make modifications.

Market Oversight: The EIM includes market monitoring which will be provided by the ISO Department of Market Monitoring. Related, the ISO will use a process based on its existing local market power mitigation approach to mitigate market power in each participating BA and assess the application of market power mitigation before and after implementation.

SECTION 4 – ECONOMIC ANALYSIS

A. Modeling Approach

The ISO and NV Energy retained the services of ABB and E3 Consulting to perform the economic analyses of the benefits of NV Energy participating in the ISO EIM and document the findings. ABB used its proprietary production cost software GridView. E3 was retained to perform the economic analysis and document the results. E3 has direct experience with the economic analysis and was the consultant that performed the economic analysis on the PacifiCorp-ISO EIM benefit study. The E3 final report is included as Technical Appendix Item 1.

The core of GridView is a transmission constrained economic dispatch algorithm. GridView mimics the operation of an electric market by dispatching generating units.
based on their bid prices while taking into account the flow limits on transmission lines and interfaces under normal, as well as contingency conditions. The outputs of GridView are information such as hourly unit dispatch, locational marginal prices ("LMPs") at buses, flow on lines and congestion cost of limiting lines.

GridView determines the least-cost security constrained dispatch of generating units to satisfy a given demand, based on dispatch according to their variable costs. The major advantage of GridView is its ability to simulate the hourly operation of generating units and transmission systems (e.g., transformers, lines, phase shifters, busses) in significant detail. For example, it represents capacity constraints, minimum start up time limitations, and thermal constraints on the transfer capability of transmission lines, line and unit contingencies and scheduling limitations of hydro-plants. As such, GridView provides a detailed simulation of the hourly operation of the individual generating units and transmission system that constitute the wholesale market.

The GridView database was created from the Transmission Expansion Planning Policy Committee ("TEPPC") 2022 database as updated by the ISO and NV Energy. The TEPPC is a committee of the Western Electricity Coordinating Council ("WECC") that is responsible for the oversight and maintenance of a public database for production cost and related analysis. The TEPPC develops and implements planning processes to improve the economic analysis and modeling of the Western Interconnection. The TEPPC 2022 database incorporates load forecasts from each of the BAAs, existing and planned generation, transmission infrastructure, and expected generation retirements.

The ISO updated the TEPPC 2022 database to reflect the ISO’s transmission expansion plan for compliance with California’s renewable portfolio standard and reliability needs. The ISO also updated the TEPPC 2022 database to reflect the best available information on generation retirements, such as the San Onofre Nuclear Generating Station, and conventional and renewable generation additions.

The economic analysis incorporated assumptions on PacifiCorp’s participation in the EIM including 400 MW of transfer capability between ISO and PacifiCorp systems via the California-Oregon transmission intertie.

Finally, NV Energy provided ABB and E3 with updates to better reflect the NV Energy system from the information in the TEPPC 2022 database. ABB and E3 used that data to model the business-as-usual case and the EIM change case.

B. Modeling Assumptions Used in the Economic Analysis

The ISO provided the following modeling inputs for the economic analysis:

- The fuel price forecast used in the economic analysis was from the ISO’s 2021 transmission planning. NV Energy reviewed and approved the fuel forecast for each of the regions in the Western Interconnection.

- Generic resource additions to satisfy reliability requirements in the Los Angeles basin and San Diego load pockets.
California greenhouse gas emissions allowance prices based on the California Energy Commission forecast for compliance with the emissions targets under California Assembly Bill 32.

NV Energy provided the following modeling inputs to economic analysis:

- Updated the energy profiles of existing renewable purchase power agreements for consistency with NV Energy’s planning assumptions in the 2013 Sierra Pacific Power Integrated Resource Plan.
- Updated the NV Energy reserve requirements for balancing variable energy resources, specifically solar and wind, consistent with those provided in the 2013 Sierra Pacific Power Integrated Resource Plan.
- Provided transmission capabilities in the form of WECC Path Ratings. These ratings exist for each of the Companies’ paths into, and out of, the NV Energy BA. In cases where path ratings are limited by seasonal conditions like hydroelectric output, regional temperatures or fuel prices the seasonal limits, known as Operating Transfer Capabilities, were used.
- Confirmed transmission facility ratings for the study group for each Company transmission system element in the model. Expected ratings for new facilities were provided but because of limited transmission expansion planned prior to 2022, the only major change in ratings was the inclusion of the planned Harry Allen transformer in both the 2017 and 2022 cases.

ABB and E3 generated model outputs using GridView which were then used to calculate economic benefits. The model outputs included forecast energy prices, namely LMP. NV Energy reviewed the model outputs, including the following:

- Path flows,
- The average LMPs produced by the model,
- Total generation (Unit annual production for the entire West), and
- Total generation costs.

As a result of the parties’ continued review of the initial results of the economic analysis, and to capture more recent developments as the modeling effort continued, the ISO and NV Energy modified additional generation and transmission input assumptions. The modified input assumptions included the following actions:

- Incorporated the decision to retire the San Onofre Nuclear Generating Station.
- Included changes to reflect the adoption of Nevada Senate Bill 123, including:
- Modeled retirement dates of Reid Gardner units 1, 2, and 3 by December 31, 2014, and modeled Reid Gardner Unit 4 retirement by December 31, 2017

- Addition of 350 MW of solar capacity.

- Addition of 550 MW of combined cycle gas capacity.

- Added the retirement of one 750 MW unit at the Navajo Generating Station as of December 31, 2019, as proposed by the joint owners to the Environmental Protection Agency to satisfy the requirements of the Clean Air Act.

- Transmission Topology - Based on a reconfiguration by the BAs around Eldorado, NV Energy gained ownership of two direct connections to ISO, with bidirectional capacity of approximately 1,500 MW between the ISO and NV Energy. This increased capacity was reflected in the subsequent modified assumptions.3

- Contract rights and capacities were modeled into hubs to ensure tariff charges were not applied to LMP calculations for the Company’s transactions through adjacent BAs that were using NV Energy’s existing transmission contract rights.

C. Economic Benefits

The final report prepared by E3 provides a range of potential economic benefits, with the low range reflecting a scenario in which assumptions were generally chosen to be conservative and a high range that used less conservative assumptions.

An expanded EIM that includes the Companies, in addition to the ISO and PacifiCorp, would allow participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources between the ISO, PacifiCorp and NV Energy systems, and thereby reduce production costs, flexibility reserves, and renewable generation curtailments. Specifically, the economic analysis concludes that participation of NV Energy in the EIM would yield the following three principal economic benefits:

- Interregional dispatch savings by realizing the efficiency of combined 5-minute dispatch and real-time unit commitment across the NV Energy, ISO and PacifiCorp BAAs. That would reduce “transactional friction” and alleviate structural impediments currently impacting trade on ties between the ISO and NV Energy BAAs;

- Reduced flexibility reserve by offsetting the three systems’ load, wind, and solar variability and forecast errors; and

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3 The Economic Analysis did not adjust the post-EIM cases to reflect the removal of hurdle rates between NV Energy and PacifiCorp (see direct testimony of Mr. Whalen).
• Reduced renewable energy curtailment by allowing BAAs to export or reduce imports of renewable generation when they would otherwise need to curtail their own resources. During low load periods, BAAs will have excess generation due to the must-take nature of renewable resources, rather than curtailing the resources that may be dispatched to serve other participating BAAs’ requirements.

These benefits are expected to reduce the Companies’ energy production costs, with the cost savings accruing to customers.

Table 1 provides a summary of the estimated gross annual benefits to the EIM area (i.e., NV Energy, PacifiCorp, and the ISO) for the study years of 2017 and 2022. The study year 2017 was chosen because it represents a near-term time period after the ISO EIM will be in operation.

The study year 2022 represents a period when significant system changes will have been implemented, including: (1) full build-out of renewable resources to meet California’s 33% Renewable Portfolio Standard target; (2) full expected retirement and/or replacement of ISO thermal generating capacity due to once-through-cooling (“OTC”) regulations; (3) construction of a number of planned and proposed transmission projects; and (4) projected higher CO2 permit prices in California as a result of full implementation of California’s GHG statute and regulations. Projected benefits increase slightly in study year 2022 due to a higher dispatch and a higher flexibility reserve. Table 2 provides the estimated gross annual benefits to NV Energy.

Table 1. Estimated gross annual EIM benefits to EIM Area (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017 Low range</th>
<th>High range</th>
<th>2022 Low range</th>
<th>High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interregional dispatch</td>
<td>$6.2</td>
<td>$9.3</td>
<td>$8.9</td>
<td>$13.4</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>$2.6</td>
<td>$5.0</td>
<td>$5.7</td>
<td>$12.0</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.4</td>
<td>$4.0</td>
<td>$0.4</td>
<td>$4.0</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$9.2</strong></td>
<td><strong>$18.2</strong></td>
<td><strong>$15.0</strong></td>
<td><strong>$29.4</strong></td>
</tr>
</tbody>
</table>

Note: Individual estimates may not sum to total benefits due to rounding.
Table 2. Estimated gross annual EIM benefits to NV Energy (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017 Low range</th>
<th>2017 High range</th>
<th>2022 Low range</th>
<th>2022 High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interregional dispatch</td>
<td>$3.1</td>
<td>$4.7</td>
<td>$4.5</td>
<td>$6.7</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>$2.8</td>
<td>$3.6</td>
<td>$3.2</td>
<td>$4.3</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.1</td>
<td>$1.2</td>
<td>$0.1</td>
<td>$1.2</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$6.0</strong></td>
<td><strong>$9.5</strong></td>
<td><strong>$7.7</strong></td>
<td><strong>$12.2</strong></td>
</tr>
</tbody>
</table>

Note: Individual estimates may not sum to total benefits due to rounding.

Table 3 describes the assumptions used to develop the low range and high range of benefits. In the low range the assumption was made that NV Energy units would not participate during the summer peak period, rather such resources would only be utilized to serve NV Energy loads in that season. In the high range the units were assumed to be available year round and able to be dispatched as needed when NV Energy was not dispatching the units to meet its own load needs.

Table 3. Key assumptions in low and high range benefit scenarios

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Low range</th>
<th>High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Availability of NV Energy generators to participate in EIM</td>
<td>Unavailable during June-Sept</td>
<td>Available in all months for EIM dispatch; full-year dispatch benefits used</td>
</tr>
<tr>
<td>Calculation of flexibility reserve benefits</td>
<td>Quantity reduction in reserve requirement valued at benchmark of average ISO historical ancillary service market price levels</td>
<td>Simulation directly calculates benefits of reduced reserves, and improved efficiency through enabling optimal procurement of reserves from across the EIM footprint, subject to transmission constraints</td>
</tr>
<tr>
<td>Share of identified renewable energy curtailment value avoided in California</td>
<td>10%</td>
<td>100%</td>
</tr>
</tbody>
</table>
D. Estimated Cost of NV Energy Participation in the ISO EIM

NV Energy has developed an estimate of the costs it will incur to implement and participate in the ISO EIM by identifying known cost components such as the ISO start up fees, NV Energy’s start-up costs, and ongoing costs. The major cost categories for the implementation and operation of the EIM include the following:

**Capital Costs**

- **Software Implementation**: System implementation and/or modifications are necessary related to resource and load systems, scheduling, generation imbalance, settlements, and interfaces, EMS real time network modeling, outage management and resource optimization.

- **Metering**: Select meter upgrades are necessary and it is anticipated that approximately 38 meters will be replaced.

- **Telecommunication**: Select telecommunication enhancements are anticipated.

- **Meter Data Management System**: Implementation of the software to transfer the meter data from the participating resources.

- **Implementation Fee**: The upfront fee paid to ISO to expand the ISO’s network model to include NV Energy in the Energy Imbalance Market.

**Operations and Maintenance Costs**

- **Software Implementation**: The annual licensing fees associated with the implemented modified software applications for the EIM.

- **Grid Operations**: The hiring of four new full time equivalent employees (“FTEs”) to manage scheduling and real-time operations associated with the EIM.

- **Metering**: The costs associated with maintaining the meters.

- **Telecommunication**: The costs associated with maintaining incremental telecommunication facilities.

- **Meter Data Management System (MDMS)**: The annual licensing fee associated with implementing the MDMS system. This also includes the hiring of one FTE to support the interface of the meter data for the EIM.

- **Merchant Settlement**: The hiring of two new FTEs to handle the market analysis and merchant settlements requirements associated with the EIM.

- **Transmission Settlement**: The cost of a FTE to allocate and invoice
transmission customers for tariffed transmission services.

- **Administration Fee**: The fee paid to ISO, annually, to participate in the EIM.

- **Transaction Fees**: The fees paid to the ISO, for each transaction, when participating in the EIM.

Estimates for metering and telecommunications were developed working with NV Energy technical staff and assessing the existing infrastructure to determine what facilities will need to be upgraded or replaced. The cost to integrate the computer systems was determined by working directly with the ISO and PacifiCorp staff on the implementation concepts, while customizing the system interface information specific to NV Energy. NV Energy’s initial estimated costs to implement the EIM are shown in Table 4, which summarizes the major work stream items and the upfront capital costs and ongoing O&M costs. The budget shown in Table 4 includes the upfront implementation fee to be paid to the ISO of $1.1 million along with estimates for ongoing transactional fees.

In addition, Table 4 illustrates the cost necessary to upgrade metering and telecommunication at some of the NV Energy generation units and also includes the estimates to upgrade the scheduling, trading, and settlement computer systems required to operate in the EIM.

Contained in the O&M budget is the estimated increase of eight FTEs necessary to carry out the functions of participation in the EIM and to maintain the system. Of the eight budgeted FTEs, four are to support real-time grid operations performing transmission scheduling, monitoring and operation coordination functions; one is to support incremental meter data management; one is to perform merchant ISO market analysis; one for merchant ISO settlement validation; and one to support transmission settlement billing and validation.

Because the EIM is a new market, there is some level of uncertainty about staffing requirements. NV Energy’s transmission and merchant function will re-evaluate staffing needs following the October 2014 go-live of the EIM with the additional benefit of PacifiCorp’s experience with post-EIM market operations. This may require the addition of up to four additional FTEs depending on how the implementation impacts existing merchant operations. It is estimated the four incremental FTEs could cost approximately $600 thousand per year. These additional costs are not included in the O&M total in Table 4.
Table 4 – NV Energy Estimated Costs to Implement and Operate the EIM (w/o AFUDC)\(^4\)

<table>
<thead>
<tr>
<th>Capital</th>
<th>1 Software Modification/Implementation</th>
<th>$2,150,000</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2 Metering</td>
<td>$547,592</td>
</tr>
<tr>
<td></td>
<td>3 Telecommunications</td>
<td>$1,038,000</td>
</tr>
<tr>
<td></td>
<td>4 Meter Data Management</td>
<td>$287,559</td>
</tr>
<tr>
<td></td>
<td>5 Project Support</td>
<td>$3,350,000</td>
</tr>
<tr>
<td></td>
<td>6 Loadings</td>
<td>$427,666</td>
</tr>
<tr>
<td></td>
<td>7 Contingency (30 percent)</td>
<td>$2,340,365</td>
</tr>
<tr>
<td><strong>Capital Subtotal</strong></td>
<td></td>
<td><strong>$10,141,582</strong></td>
</tr>
<tr>
<td></td>
<td>8 Implementation Fee</td>
<td>$1,100,000</td>
</tr>
<tr>
<td><strong>Capital Total</strong></td>
<td></td>
<td><strong>$11,241,582</strong></td>
</tr>
</tbody>
</table>

| O&M | 1 Software Modification/Implementation | $261,000 |
|     | 2 Grid Operations                      | $600,000 |
|     | 3 Metering                             | $6,125   |
|     | 4 Telecommunications                    | $15,000  |
|     | 5 Meter Data Management                 | $157,513 |
|     | 6 Merchant Settlement/Market Monitoring | $300,000 |
|     | 7 Transmission Settlements             | $150,000 |
|     | 8 Administration Fees                  | $706,640 |
|     | 9 Transaction Fees                      | $55,884  |
|     | 10 Loadings                             | $130,591 |
|     | 11 Contingency (10 percent)             | $238,215 |
| **O&M Total** |                                | **$2,620,368** |

E. Net Economic Benefits

The Economic Analysis was conducted using the ISO data set for years 2017 and 2022. As part of the Economic Analysis, E3 calculated an estimated 20-year net present value (“NPV”) by assuming an increasing level of benefits would occur throughout the 20-year study period. This estimate was based on a linear interpolation of 2017 and 2022 data and then a conservative 2% inflation rate from 2022 through 2035. The NPV captured the benefits and costs starting in 2016. Netting out the capital and ongoing costs, the 20-year NPV benefit to NV Energy customers is estimated to be between $40.3 million and $87.6 million.

The estimated revenue requirement necessary for the Companies to recover the capital and ongoing O&M costs for participation in the EIM is $4.4 million in 2017 and $4.1 million in 2022. Comparing this to the annual range of economic benefits shown in

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\(^4\) The Initial Study costs have not been included in this cost estimate because these costs have already been incurred and so are not properly part of this ESP amendment. The companies anticipate that the Study costs will be presented to the commission in the 2016 Sierra general rate case and the 2017 Nevada Power general rate case.
Table 1 for 2017 of $6.0 to $9.5 million yields an annual net benefit to NV Energy customers of $1.6 to $5.1 million in 2017. Comparing the range of economic benefits shown in Table 1 for 2022 of $7.7 and $12.2 million to the annual revenue requirement yields an overall annual net benefit to NV Energy’s customers of $3.6 to $8.1 million in 2022.

SECTION 5 – RELIABILITY BENEFITS

NV Energy’s participation in the ISO EIM is expected to produce reliability benefits in addition to the economic benefits discussed above. These reliability benefits generally fall into two broad categories: 1) improved management of imbalances, and transmission constraints, 2) enhanced situational awareness. Reliability benefits were not quantified for the economic analysis.

A. Improved Management of Imbalances

The ISO EIM will deliver a mechanism to effectively aggregate the resource to load imbalances of the participating BAs and provide a dispatch solution relative to transmission capacity from a wider suite of available resources than would be available if each BA were to manage imbalances independently. For instance, where one BA encounters a negative imbalance (under-generating) the EIM dispatch option includes not only the resources within that BAAs, but also resources from the other participating BAAs from which an economic dispatch solution can be achieved. The dispatched generation will be governed by real-time and anticipated transmission flows based on the state estimator model. This makes more resources available to react to imbalances, thereby not only improving reaction time and performance, but doing so in a way that does not negatively impact transmission limits while achieving superior efficiency.

In the event that two BAs have imbalances of opposite signs (i.e. one over-generating and the other under-generating) to the extent that the resources have been dispatched economically at the outset, the EIM solution will tend to establish interchange between the two BAs in order to resolve the imbalance. In such a situation, the generating resources need not be re-dispatched at all, thus resulting in reduced ramping of the generating resources in both BAs and lower wear-and-tear on the equipment. This concept also diversifies variable generation fluctuation across geographic regions.

B. Enhanced Situational Awareness

Lack of situational awareness of operating personnel has been a key factor in a number of recent electric system disturbances, most notably the August 2003 blackout in the Eastern Interconnection. The September 2011 disturbance affecting large portions of Southern California also served to underscore the importance of situational awareness in the West. The EIM will improve situational awareness in at least two ways: first by enhancing the modeling and visibility of the combined footprint of the participating BAs, and second by more accurately predicting the loads and resources in a shorter time increment than is done in the current paradigm.
In the present hourly dispatch approach, the determination of forecast load and unit commitment is made before the operating hour. Given the myriad of unknowns and uncertainties, not the least of which is the production levels of renewable resources, such an approach invariably leads to mismatches and imbalances going into the hour. This requires manual operator intervention to correct the imbalance. By contrast, the EIM makes forecast and commitment determinations on a five-minute basis. The shorter time horizon results in reductions in mismatches between loads and resources.

As a result of incorporating the EIM area into the ISO network model, the operational tools that the ISO uses within the existing market area become available to the entire EIM area. Using already-implemented operations tools, the ISO performs real-time stability analyses that necessarily consider the entire Western Electricity Coordinating Council region, and observes voltages and other conditions outside the existing market footprint, to identify conditions that may have impacts on the market area that may need to be managed.

The EIM will complement NV Energy’s reliability functions by providing additional situational awareness of neighboring areas as well as the market footprint. The optimization of the 5-minute dispatch will be performed using a security constrained economic dispatch model that enforces flow based limits in the market footprint thus enhancing reliability within the market footprint. This reduces the potential impact on neighboring systems, enhances situational awareness and enhances reliability for the entire Western Electricity Coordinating Council (“WECC”) region. This allows operators’ decisions to be as informed as possible about pertinent system conditions as well as achieve cost savings in scheduling of resources.

The reliability benefits the EIM will produce are highlighted in two recent reports issued by staff of the North American Electric Reliability Corporation (“NERC”) and FERC. In response to the September 2011 Southern California outage, FERC and NERC Staff issued a report entitled “Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations.” That report makes several recommendations for increasing situational awareness in the WECC region, including: (1) expanding entities’ external visibility in their models through more complete data sharing; (2) improving the use of real-time tools to ensure the constant monitoring of potential internal or external contingencies that could affect reliable operations; and (3) improving communications among entities to help maintain situational awareness.

In a February 2013 report, FERC Staff found that an EIM could provide reliability benefits through (1) security constrained economic dispatch for better management of imbalances and enhanced ability to manage flows within system operating limits, (2) enhanced situational awareness, (3) potentially fewer energy emergency alerts, (4) faster

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dispatch and delivery of replacement generation after contingency reserve sharing assistance ends and for contingencies beyond reserve obligations, and (5) assisting with the integration of diverse conventional and emerging technologies including variable energy resources and demand response.

SECTION 6 – IMPLEMENTATION OF THE EIM

If the Commission approves this Joint Application, the Companies expect to participate in the EIM starting in October 2015. The ISO allows entities to enter the EIM once a year in October. Implementation requires approximately 18 months.

In cooperation with ISO, NV Energy has developed discrete work streams, a comprehensive project schedule, and has established a project implementation team with executive leadership oversight. Consistent with the cost estimate presented above, NV Energy will take the following actions to participate in the EIM:

- Coordinate with the ISO on the Full Network Model expansion for NV Energy
- Install new software systems
- Install new metering and telecommunications equipment
- Test the new systems
- Train Company staff
- Obtain regulatory approvals
- Conduct Market Simulation
- System Deployment and Go Live

In order to achieve the implementation schedule, the ISO and NV Energy have executed the Implementation Agreement. The Implementation Agreement provides the scope of work to be accomplished between the parties and sets forth specific milestone payments to be delivered to the ISO as the implementation progresses. By June 1, 2014, NV Energy and the ISO will develop and initiate a final project management plan that describes specific project tasks each Party must perform, delivery dates, project team members, meeting requirements, and a process for approving changes to support completion of the Project.

The Implementation Agreement is contained in the Technical Appendix as Item 2. NV Energy has created an implementation team to carry the project through completion. The team is led by senior management in an executive steering role with a leadership team focused on implementation and delivery as well as strategy and outreach. The specific milestones contained in the Implementation Agreement are summarized below:

ESP Amendments - EIM Narrative
• Milestone 1 - Agreement made effective.
  ○ Upon approval of FERC and the Commission
  ○ Estimated to be August 27, 2014
  ○ Payment to the ISO $300,000

• Milestone 2 - This milestone is completed upon modeling NV Energy into the ISO Full Network Model through the EMS which will be deployed into production using the ISO's network and resource modeling process.
  ○ January 28, 2015
  ○ Payment to the ISO $200,000

• Milestone 3 - ISO to promote market network model including NV Energy area to non-production system and allow NV Energy to connect and exchange data in advance of market simulation.
  ○ May 15, 2015
  ○ Payment to the ISO $200,000

• Milestone 4 - The EIM market simulation will allow NV Energy and the ISO to conduct specific market scenarios in a test environment prior to the production deployment to ensure that all system interfaces are functioning as expected and to produce simulated market results. To complete this milestone, the commencement of EIM simulation will signal that NV Energy and the ISO have independently completed EIM system design, development, and testing to participate in joint testing.
  ○ August 10, 2015
  ○ Payment to the ISO $200,000

• Milestone 5 – This milestone is complete upon the first production NV Energy EIM trade date.
  ○ October 1, 2015
  ○ Payment to the ISO $200,000

SECTION 7 – EIM GOVERNANCE

The expansion of the ISO EIM outside of its BAA has caused interested parties in the West to press for a change in governance that would give EIM participants and other regional interests a voice in EIM decision-making, as well as propose a long-term independent governance structure.

In response, the ISO conducted a stakeholder process to develop a proposal to broaden participation in EIM decision-making. The proposal, which was approved by the ISO Board in December 2013, outlines steps to develop meaningful changes in governance, starting with the formation of a transitional EIM stakeholder committee (the “Transitional Committee”). NV Energy participated in the stakeholder process that will result in the transitional committee. It is also important to note that NV Energy has a guaranteed seat on the Transitional Committee, which NV Energy will utilize to support the development
of good operational and governance policies. Finally, the EIM will have been operation for a year, and the transitional committee in place for almost 18 months when NV Energy begins to participate in the EIM.

A. Transitional Committee Structure

The Transitional Committee will be composed of members nominated by a broad cross-section of EIM stakeholders from different sectors. Three of the seats are designated for EIM Entities that have signed Implementation Agreements with the ISO. By signing the Implementation Agreement now, NV Energy will be a member of the Transitional Committee. PacifiCorp, which has already signed an implementation agreement, is also guaranteed a seat on the Transitional Committee. The intent is to have a Transitional Committee that is composed of a diverse group of participants. It will be formed through open stakeholder processes of which the Companies were a part. A final selection of committee members will be completed in May.

B. Operation of the Transitional Committee

The Transitional Committee will be established in late May 2014. It will serve as an advisory committee to the ISO Board and will offer comments to the ISO Board and Management on matters related to EIM implementation. In addition, the Transitional Committee will be tasked over the subsequent 12-18 months with developing a recommendation for establishing an independent EIM governance structure including defined authority over EIM matters.

The Transitional Committee meetings and deliberations will be subject to ISO open meeting policies and notice requirements. Its work will result in a proposal (or possibly multiple proposals) for consideration by the ISO Board. Implementation of the proposal(s) will require ISO Board approval and FERC approval of any needed tariff changes.

An ISO staff person will perform a liaison function for the committee, attend committee meetings, and facilitate the provision of ISO support to the committee. This will ensure that the Transitional Committee has the benefit of extensive market design expertise and that it is informed regarding, and can accomplish its goals in conjunction with, the existing ISO governance and management structures.

SECTION 8 – AMENDMENT OF THE COMPANIES’ RESPECTIVE ENERGY SUPPLY PLANS

The Companies propose to amend their respect Energy Supply Plans as follows:

(1) Section IV.A.5 (“Current Portfolio Optimization Procedures”) of the Nevada Power Energy Supply Plan approved in Docket No. 12-06053 as updated in Docket No. 13-08024 attached in the appendix as Item 3; and

ESP Amendments - EIM Narrative

The amendment to the Current Portfolio Optimization Strategy of each Company’s Energy Supply Plan adds the Companies’ participation in the ISO EIM. Participation in the EIM further optimizes the Companies’ energy supply portfolios for the benefit of their customers.
TESTIMONY
SHAWN M. ELICEGUI
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
Energy Imbalance Market Energy Supply Plan Amendment

Docket No. 14-04____

PREPARED DIRECT TESTIMONY OF

Shawn M. Elicegui

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

   A. My name is Shawn M. Elicegui. I am the Vice President of Regulation for 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”). My business address is 6100 Neil Road, Reno, Nevada. I am filing
   testimony on behalf of the Companies.

2.  Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT
OF REGULATION.

   A. As Vice President of Regulation, I am responsible for the load research, pricing,
   rate setting, resource planning, and regulatory policy functions within the
   Companies. I also am an executive sponsor on the energy imbalance market
   steering committee, overseeing the activities of the team the Companies formed to
   deliver this important project. As it relates to this proceeding, the resource
   planning function develops long-term integrated resource and short-term energy
   supply plans for the Companies. The Companies communicate their power
   procurement, fuel procurement and risk management strategies to the Public
   Utilities Commission of Nevada (the “Commission”) and stakeholders through
energy supply plans, annual energy supply plan updates and, when necessary, energy supply plan amendments.

3. Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.
   A. I hold a Bachelor of Arts in Political Science and International Affairs from the University of Nevada Reno. I earned a law degree from the University of California, Davis. Before joining the Companies in 2009, I practiced law with the law firm of Lionel Sawyer & Collins. Between 2009 and 2013, I served as an Associate General Counsel for the Companies. I focused on matters related to ratemaking and resource planning. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Exhibit Elicegui-Direct-1.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
   A. The California Independent System Operator (“ISO”) is developing an energy imbalance market (“EIM”), which is scheduled to begin operating October 1, 2014. On that date, PacifiCorp’s two balancing authority areas (“BAAs”) will become the first BAAs to participate in the EIM operated by the ISO.

   After extensive evaluation, the Companies completed the analysis of the costs, benefits and risks of participating in the EIM. The results of the analysis show that the potential benefits for the Companies’ customers outweigh the costs and risks. Accordingly, the Companies have decided to participate in the EIM.
My testimony covers three subjects. First, I explain why the Companies are requesting approval to participate in the EIM. Second, I explain why the Companies are seeking authorization through an amendment to their respective energy supply plans. Third, I discuss the interim governance structure that the ISO has developed for the EIM.

I also sponsor Section 1 and portions of Section 7 of the Narrative.

5. Q. WHY ARE THE COMPANIES PROPOSING TO PARTICIPATE IN THE ISO EIM?

A. The EIM provides the Companies with an additional market opportunity to optimize assets and realize benefits that reduce the overall cost of providing electric service to customers. The Companies continuously seek opportunities to minimize the impact of their operations on customer rates. Participation in the EIM provides a low-cost, low-risk opportunity to minimize the cost of providing service to customers. Customers realize the benefits of participation through increased use of existing facilities and lower costs realized through the base tariff energy rate and Nevada’s deferred energy accounting procedures.

6. Q. PLEASE SUMMARIZE THE BENEFITS THE COMPANIES BELIEVE PARTICIPATION IN THE ISO EIM WILL PROVIDE CUSTOMERS.

A. There are three benefits that the Companies believe will accrue to customers as a result of participation in the EIM:

   1. Economic benefits as described in the Economic Analysis, which are discussed in more detail in the Direct Testimony of Mr. Reyes and Mr. Rothleder.
2. Reliability benefits, which are described in the Direct Testimony of Mr. Whalen. The Companies provide a qualitative assessment of potential reliability benefits since the economic analysis did not attempt to quantify reliability benefits.

3. Facilitation of additional variable renewable energy resources, such as wind and solar, within the state of Nevada by aggregating flexible resources from neighboring states.

7. Q. WHY ARE THE COMPANIES SEEKING AUTHORIZATION TO PARTICIPATE IN THE ISO EIM THROUGH AN AMENDMENT TO THEIR RESPECTIVE ENERGY SUPPLY PLANS?

A. In Docket No. 13-07021, the Companies committed to request permission from the Commission before the Companies implemented any plan to jointly dispatch generating units:

“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.”

In its order approving the stipulation in Docket 13-07021, including this part of Stipulation 13, the Commission stated:

“Additionally, the 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.
(Tr. at 145.)[1].”

The energy supply plan contains the Companies’ power procurement, fuel
procurement and risk management strategies. The Companies’ power
procurement plans include a section entitled “Current Portfolio Optimization
Procedures” (the “Portfolio Optimization Strategy”). The Portfolio Optimization
Strategy sets forth the Companies’ strategies for optimizing assets (such as
generating units and gas transportation assets) for the benefit of customers. The
addition of this new element (the EIM) therefore falls squarely within the
Companies’ Portfolio Optimization Strategy.

8. Q. WHAT ARE THE COMPANIES REQUESTING IN THIS ENERGY
SUPPLY PLAN AMENDMENT?

A. The Companies are asking the Commission to accept the amendment to their
respective power procurement plans and find that the amended energy supply plan
is prudent pursuant to Section 704.9494 of the Nevada Administrative Code. The
Commission may make that finding if it determines:

1. That the energy supply plan, 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;

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[1] See Nev. Admin. Code § 704.9061(2) (an energy supply plan is composed of a purchased power procurement
plan, fuel procurement plan and risk management strategy).
2. That the energy supply plan, as amended, optimizes the value of the overall supply portfolio of the utility for the benefit of bundled retail customers; and,

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

The Commission can make each of these findings. Importantly, the Commission recently found that the Companies existing energy supply plans are prudent. Through this filing, the Companies are adding an additional portfolio optimization option – a new, short-term energy imbalance market – that will further reduce the cost of supply, and increase reliability over the period of the plans. The additional option also will allow the Companies to further optimize the value of their respective generation portfolios for the benefit of retail customers. By finding that the amended power procurement plan, with a new portfolio optimization element is prudent, the Commission would be authorizing the Companies to participate in the EIM. The Companies thus would have complied, at least in part, with their obligation under the stipulation in Docket No. 13-07021.

9. Q. WHAT ARE THE BENEFITS OF OBTAINING APPROVAL TO PARTICIPATE IN THE EIM AT THIS TIME?

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2 See Order, Application of Nevada Power Company d/b/a NV Energy for approval of its energy supply plan update for 2014-2015, ¶ 5, Docket No. 13-08024 ("The Commission accepts and approves the following: the Power Procurement Plan and the constituent elements of the plan including the portfolio optimization plans . . . The Commission finds the elements of the ESP Update . . . are prudent pursuant to NAC 704.9494(3)."), Order: Phase I – Energy Supply Plan, Application of Sierra Pacific Power Company d/b/a NV Energy for approval of its 2014-2033 triennial integrated resource plan and 2014-2016 energy supply plan, ¶ 2, Docket No. 13-07005 (accepting stipulation in which the parties agreed that the power procurement plan met the requirements of NAC 704.9494).
A. Participating in the EIM now will produce at least three categories of benefits for the Companies and our customers: (1) early action benefits; (2) immediate economic benefits; and (3) renewable development benefits for the State of Nevada.

First, with respect to early action benefits, the next two companies that execute an EIM implementation agreement with ISO will receive seats on the Transitional Committee of the EIM. The Transitional Committee will act as an advisory body to the ISO Board of Governors. By beginning participation in the EIM now, and thereby obtaining a seat on the Transitional Committee, the Companies will be better positioned to shape the ultimate governance structure of the EIM in ways that better ensure that the benefits of the EIM will accrue to Nevada.

Second, the Companies believe, based on the results of the study commissioned by NV Energy and the ISO, that participation in the EIM will produce economic benefits for our customers in the first year of participation. There is no reason to defer realization of these benefits, which reduce the cost of providing electric service to customers and minimize the impact of the Companies’ operations on customers.

Third, renewable generating resources – primarily solar and geothermal resources – are a means of diversifying the Companies’ fuel mix. The Companies need to take measured and calculated steps to enhance the development of renewable resources to maintain their ability to have a balanced portfolio. Participation in the EIM could facilitate the development of additional variable renewable generation in Nevada by enhancing the Companies’ ability to cost-effectively balance
increased amounts of variable power. This could allow the Companies to take a meaningful step towards true energy independence.

10. Q. WHY ARE THE COMPANIES TARGETING OCTOBER 2015 FOR EIM PARTICIPATION?

A. The ISO and NV Energy estimate it takes approximately 18 months to put in place and integrate software and facilities upgrades that are needed to participate in the ISO EIM and to put in place necessary processes, tariff filings, and stakeholder processes associated with those filings. The ISO allows new entrants into the EIM in October of any given year. October 2015 is therefore the earliest the Company can participate.

11. Q. HOW WILL THE BENEFITS AND COSTS THAT ARE ASSOCIATED WITH PARTICIPATION IN THE ISO EIM BE ALLOCATED TO CUSTOMERS?

A. The cost savings and other benefits that the Companies obtain through participation in the EIM will accrue entirely to the Companies’ customers. Benefits come in the form of lower fuel and purchase power costs through optimization of energy supply resources. The Companies will receive compensation when its energy supply is used to meet real-time imbalance requirements. Conversely, the Companies also benefit through costs savings realized when higher cost resources are displaced with more efficient EIM resource alternatives. The Companies will allocate energy imbalance transaction revenues and costs between Nevada Power and Sierra pursuant to the interim joint dispatch agreement for resources owned or managed by the Companies.
The Companies will make an initial capital investment to participate in the ISO EIM. Under Nevada’s rate-setting regime, capital costs are “jurisdictionalized” – that is, assigned to Nevada jurisdictional customers and non-jurisdictional customers based on functional allocators. Accordingly, capital costs will, just like any other capital investment, be assigned to Nevada jurisdictional customers and non-jurisdictional customers in each general rate case filed with the Commission. The Commission will, as it does today, set retail rates using the Nevada jurisdictional revenue requirement, not the total company revenue requirement. The Companies also will incur on-going costs to participate in the EIM. These costs will consist of labor and payroll, administrative and general expenses, and a payment to the ISO. Similar to all other operation and maintenance expenses, these on-going costs will be allocated to Nevada jurisdictional and non-jurisdictional customers using the functional allocation process.

12. Q. BY PARTICIPATING IN THE EIM, ARE THE COMPANIES TRANSFERRING CONTROL OF ASSETS OR OPERATIONS TO THE ISO?

A. No. The Companies will maintain control of their generation, purchase power, transmission and distribution assets and will continue to use those to serve load and provide reliable service as they do today. By participating in the EIM, the Companies do not cede control of their assets to the ISO. The Companies remain responsible for providing safe and reliable electric service to customers at just and reasonable rates. Each BAA participating in the ELM is responsible for providing sufficient resources to meet anticipated load. This requirement prevents the ISO or PacifiCorp from “leaning” on Nevada, and prevents the Companies from “leaning” on resources in California or PacifiCorp’s BAAs. Participation in the
EIM does not relieve NV Energy of the fundamental obligations to integrate resource plans in advance of real-time balancing needs, maintain load-interchange-generation balance within the BAA, and support interconnection frequency in real time.

13. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?
   A. Yes, it does.
QUALIFICATIONS OF WITNESS
Shawn M. Elicegui
Vice President, Regulation
NV Energy
6100 Neil Rd.
Reno, NV 89511

EDUCATION
University of California-Davis, King Hall School of Law
J.D., Order of the Coif – 1996
University of Nevada-Reno
B.A., Political Science and International Affairs, With Distinction – 1993

PROFESSIONAL EXPERIENCE
NV ENERGY, Reno, Nevada
Vice President Regulation, 2013 to Present
Associate General Counsel, 2009-2013

- As Vice President, Regulation, my responsibilities include overseeing the rates and regulatory team and the resource planning team.
- As an Associate General Counsel, I provided legal and regulatory advice to the Companies. I also represented the Companies in contested cases, investigations and rulemaking proceedings before the Public Utilities Commission of Nevada.

LIONEL, SAWYER & COLLINS, Reno, Nevada
Shareholder, January 2005-2009
Associate, August 1997-December 2004

- Represented corporate and individual clients in a variety of regulatory matters before local, state and federal governmental agencies, and the Nevada legislature. Practice focused on representation of utilities of customers in the energy, telecommunications, and water and wastewater industries. Experience included prosecuting rate increase applications, obtaining regulatory approval of mergers and acquisitions, and advocating the interests of utilities of customers in proceedings involving changes to tariff provisions. Practice included representing banks, trust companies and financial institutions, professional licensees, and corporations and individuals involved in the gaming industry. Civil litigation experience included representing clients in general commercial litigation, and appellate and judicial review proceedings.

RELEVANT INDUSTRY/PROFESSIONAL INFORMATION
Utility Executive Summit, University of Idaho College of Business and Economics 2012
High and Dry in Nevada: When Water Rights Trump Development, ABA Section of Business Law, Business Law Today, Volume 15, No. 4, March/April 2006 (with D. Reaser, W. McKean and D. Cannon)
Rio Revs up the Power, Casino Enterprise Management, volume 2, Iss. 6, June 2004 (profiling role in combined heat and power project at Rio All Suites Hotel)
STATE OF NEVADA  
COUNTY OF CLARK  

I, SHAWN M. ELICEGUI, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

SHAWN M. ELICEGUI

Subscribed and sworn to before me
this ___ day of April, 2014.

DEBRA J. MOYERS
NOTARY PUBLIC
MARC D. REYES
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
Energy Imbalance Market Energy Supply Plan Amendment

Docket No. 14-04___

PREPARED DIRECT TESTIMONY OF

Marc D. Reyes

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

A. My name is Marc D. Reyes. I am the Manager of Market Fundamentals for
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”). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada.
I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER OF
MARKET FUNDAMENTALS.

A. As Manager of Market Fundamentals, my responsibilities include the
development of market price forecasts for wholesale power and natural gas
delivered to the relevant regional market hubs. Additionally, I am responsible for
regional market fundamentals analysis that supports the Companies’ energy
supply and resource planning functions.
3. Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Arts in Economics from New Mexico State University. I have been employed by the Companies since May 2007 and have served as the Manager of Market Fundamentals since May 2011. Prior to my current role in Resource Planning and Analysis, I was a power trader for the Companies, where I performed analysis and negotiated short-term wholesale transactions to optimize the Companies resource portfolio. Before joining the Companies, I was employed as a wholesale power trader for El Paso Electric Company. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Exhibit Reyes-Direct-1.

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

A. I present the Companies’ role in the study of economic benefits that was performed by ABB Inc. (“ABB”) and Energy and Environmental Economics, Inc. (“E3”) (together, the “consultants”), in conjunction with the California Independent System Operator Corporation (the “ISO”). In particular, I describe how the modeling was conducted, from the Companies’ perspective, the input assumptions it provided for use in the “NV Energy-ISO Energy Imbalance Market Economic Assessment” dated March 25, 2014 (the “Economic Analysis”), the review of the other input assumptions used in the Economic Analysis, and the Companies’ review of the results of the Economic Analysis. I also describe the costs that the Companies estimate will be incurred to implement the EIM with the ISO and annual costs the Companies expect to incur related to participation in the energy imbalance market (the “EIM”). I sponsor Sections 6 and 8 and portions of Section 4 of the Narrative.
5. Q. PLEASE DESCRIBE HOW THE ECONOMIC ANALYSIS WAS PERFORMED.

A. The ISO and NV Energy retained the services of ABB and E3 to conduct an Economic Analysis of NV Energy's participation in the EIM and report on that analysis based on the study years 2017 and 2022.

The Companies created a technical team consisting of members from Strategic Planning, Transmission Planning, Resource Planning, Project Management, and Regulatory. The team worked closely with ISO, ABB, and E3 to review and comment on the input assumptions, modeling results, and final conclusions of the analysis. The team met with the ISO and the consultants on a regular basis and performed reviews of modeling results through the various stages of the study. The results of the Economic Analysis are described in Section 4 of the Narrative.

6. Q. PLEASE SUMMARIZE THE ECONOMIC BENEFITS THAT ARE MEASURED IN THE ECONOMIC ANALYSIS.

A. The Economic Analysis is composed of three benefit categories. These benefits capture the economic dispatch savings, the savings related to reduced flexible reserves, and reductions in renewable energy curtailments. The Economic Analysis also provided a range of benefits where assumptions were varied to produce a low and high range of values. The Economic Analysis is more fully provided in the testimony of Mr. Rothleder. Participation by the Companies in the EIM is expected to yield the following three principal economic benefits:

- Interregional dispatch savings, by realizing the efficiency of combined 5-minute dispatch and real-time unit commitment across the NV Energy, PacifiCorp, and ISO BAAs.
• Reduced flexibility reserve, by offsetting EIM area, load, wind, and solar variability and forecast errors; and

• Reduced renewable energy curtailment, by allowing BAs to export or reduce imports of renewable generation when they would otherwise need to curtail their own renewable resources.

NV Energy's attributed share of these gross benefits is estimated to range from $6.0 million to $9.5 million in 2017 and from $7.7 million to $12.2 million in 2022. Netting out the costs out of the benefits, the study concluded that participation in the EIM would produce a net present value (“NPV”) savings to the Companies of between $40.3 million and $87.6 million.

The estimated revenue requirement for 2017 and 2022 to recover the capital and ongoing operations and maintenance (“O&M”) costs is $4.4 million and $4.1 million respectively. Comparing this to the annual range of benefits shown in Table 2 of the Narrative for 2017 of $6.0 million to $9.5 million yields an estimated annual benefit to the Companies customers of $1.6 million to $5.1 million in 2017. For 2022, comparing the range of benefits shown in Table 2 of the Narrative as $7.7 million and $12.2 million to the revenue requirement yields an overall annual benefit to NV Energy customers of $3.6 million to $8.1 million.

7. Q. PLEASE DESCRIBE THE START-UP AND ONGOING COSTS THE COMPANIES EXPECT TO INCUR TO PARTICIPATE IN THE ISO EIM.

A. The Companies estimate that it will incur capital start-up costs of $11.2 million in order to participate in the EIM. Startup costs include upgrades to metering and telecommunications equipment at some of NV Energy’s generating facilities,
upgrades to grid control center software to enable the necessary data communications with the ISO, interchange and resource scheduling, trading, and settlement systems required to operate in the EIM.

The Companies estimate ongoing annual costs of $2.6 to $3.2 million. Contained in the O&M budget are eight new full-time equivalent employees ("FTEs") necessary to carry out the functions of the participation in the EIM and to maintain the incremental operating systems. Four of the FTEs support real-time grid operations performing transmission scheduling coordination functions; one is to support incremental meter data management; one FTE to support transmission settlement billing and validation, and two FTEs to perform market analysis and merchant CAISO settlements. NV Energy’s transmission and merchant function will re-evaluate staffing needs following PacifiCorp’s October 2014 go-live of the EIM. This may include the addition of up to another four FTEs depending on how the implementation impacts existing merchant operations. In the event that merchant operations require four additional FTEs, that is expected to add $600 thousand per year to the ongoing annual costs.

The start-up and ongoing costs are described in more detail in Section 4.D of the Narrative.

8. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?
   A. Yes, it does.
STATEMENT OF QUALIFICATIONS

MARC D. REYES

My name is Marc D. Reyes. My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am the Manager of Market Fundamentals for Nevada Power Company, d/b/a NV Energy and Sierra Pacific Power Company, d/b/a NV Energy.

I graduated from New Mexico State University with a Bachelor of Arts Degree in Economics in 2000 and earned a Certificate in Utility Management from Willamette University in 2010.

I have been employed as the Manager of Market Fundamentals since May 2011. I am responsible for leading a staff of economists who perform fundamental analysis and market price forecasting for natural gas and wholesale power in the western U.S. I evaluate the process used to forecast natural gas and power prices and implement changes as markets evolve. I prepare reports and communicate the findings of analysis to management.

From May 2007 until May 2011, I was employed as an Energy Trader in Resource Optimization for NV Energy. I was responsible for executing daily to monthly wholesale power and natural gas transactions to optimize the Companies short-term portfolio. I performed market surveys to identify liquidity and obtain price discovery. I performed market research to identify new opportunities to reduce fuel and purchased power costs.
and worked with the credit and contracts groups to establish new counterparties. I mentored and developed junior traders.

From October 2005 until May 2007, I was employed as a Power Trader for El Paso Electric Company. I was responsible for executing real time power trades as part of the wholesale power marketing group’s profit and loss book. I worked closely with the day-ahead and term traders to optimize the company portfolio in the Western Electric Coordinating Council and Southwest Power Pool regions.
STATE OF NEVADA

COUNTY OF CLARK

I, MARC D. REYES, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

MARC D. REYES

Signed and sworn to before me

this 9th day of April, 2014.

Notary Public

Debra J. Moayers

Notary Public
BRIAN J. WHALEN, JR.
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
Energy Imbalance Market Energy Supply Plan Amendment

Docket No. 14-04____

PREPARED DIRECT TESTIMONY OF

Brian J. Whalen, Jr.

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

A. My name is Brian J. Whalen, Jr. I am the Director of Transmission Planning for
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"). My business address is 6100 Neil Road, Reno, Nevada. I am filing
testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF
TRANSMISSION PLANNING.

A. I am responsible for all transmission planning functions for the Companies. These
functions include providing the transmission and interconnection support for the
resource planning process and planning for the provision of transmission services
offered under NV Energy’s Open Access Transmission Tariff ("OATT") for
Network Service, Interconnection, and Point-to-Point transmission customers.

3. Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
EMPLOYMENT EXPERIENCE.
A. I have a Bachelor of Science degree and a Master of Science degree in Electrical Engineering from the University of Nevada Reno. I am a registered Professional Engineer in the state of Nevada. I began my employment with NV Energy as a student engineer in 1988. I have experience in transmission planning, business development, federal policy, regional reliability, generation siting and development, substation design, and protective relaying. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Exhibit Whalen-Direct-1.

4. **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**
   A. I describe the transmission system, planning studies, and technical transmission data provided by NV Energy in our joint effort with the California Independent System Operator (“ISO”) to develop the “NV Energy-ISO Energy Imbalance Market Economic Assessment” (“Economic Analysis”). I also explain NV Energy’s proposed transmission policies related to the OATT with regard to EIM implementation. I sponsor the transmission-related portions of Sections 3, 4, and 5 of the Narrative.

5. **Q. PLEASE DESCRIBE THE TRANSMISSION-RELATED MATERIAL YOU PROVIDED FOR THE ECONOMIC ANALYSIS.**
   A. I provided the ISO, ABB, and E3 with specific information related to transmission path capacities, facility ratings, transmission tariff rates, transmission topology changes - both current and planned, and contractual transmission rights. This information is discussed in more detail in Section 4 of the Narrative.
6. Q. WHY WAS THIS INFORMATION REQUIRED FOR THE EIM ECONOMIC ANALYSIS?

A. This transmission information was needed to update models and to include costs in the development of Locational Marginal Prices (“LMPs”) due to congestion, losses, and transactional friction. This information is also required to test each economic dispatch pattern for reliability and deliverability using power flow analysis.

7. Q. WHAT TRANSMISSION CAPACITY EXISTS BETWEEN NV ENERGY AND THE ISO THAT YOU ANTICIPATE WILL BE AVAILABLE FOR EIM TRANSFERS?

A. The capacity for direct transfers between NV Energy and the ISO is largely composed of the 230 kV capacity at the Eldorado Substation. This capacity is approximately 1,500 MW bi-directional. NV Energy has limited transmission capability with the ISO at NV Energy’s Northwest Substation, Summit Substation and Bishop Control Substation. The transmission capacity between NV Energy and the ISO was not a binding constraint in the Economic Analysis.

8. Q. DID THE ECONOMIC ANALYSIS MEASURE THE BENEFITS OF UTILIZING THE COMPANIES’ INTERCONNECTIONS WITH PACIFICORP?

A. No, the Economic Analysis estimated benefits based solely on the NV Energy-ISO interconnections. The Economic Analysis was initiated prior to PacifiCorp’s announced intent to participate in the EIM. The modeling assumptions for the Economic Analysis were adjusted to incorporate PacifiCorp’s participation in the EIM after the Federal Energy Regulatory Commission (“FERC”) approved the
ISO-PaciﬁCorp Implementation Agreement. The Economic Analysis incorporated an assumption of 400 MW of transfer capabilities between the ISO and the PaciﬁCorp West BAA via the California-Oregon Intertie and 200 MW of east to west transfer capability between the PaciﬁCorp-East and PaciﬁCorp-West BAAs. The Economic Analysis showed positive net economic beneﬁt without modeling EIM transfers between NV Energy and PaciﬁCorp-East. NV Energy has two interconnections with the PaciﬁCorp-East BAA at the Nevada-Utah border. Including EIM transfers between the Companies and PaciﬁCorp-East would only show additional net economic beneﬁts.

9. Q. HOW DO YOU EXPECT TO STRUCTURE THE EIM FROM A TRANSMISSION POLICY PERSPECTIVE?

A. NV Energy will be required to ﬁle a revised OATT incorporating changes required to participate in the EIM. It will do so after holding stakeholder meetings on the matter.1 These meetings will be held in 2014 with the FERC tariff ﬁling expected in early 2015. NV Energy’s OATT revisions are subject to FERC jurisdiction and must be approved by an order from the FERC before they may become effective.

NV Energy plans to structure the EIM to maximize transmission utilization, maintain existing transmission availability for non-EIM use, and prevent use of the EIM by non-paying parties. NV Energy proposes, subject to stakeholder input and FERC acceptance, three methods to address these issues.

1 The stakeholder process will be focused on key elements of the ISO EIM, the steps customers will need to take in order to participate in the EIM, and review of changes to the NV Energy OATT that will be made to participate in the EIM. One example of a potential change relates to the pricing of imbalance charges following NV Energy’s EIM participation.
1. NV Energy does not intend initially to charge an additional transmission rate to customers who hold existing transmission rights. Accordingly, Native Load, Transmission Customers with Network Integration Transmission Service or Point-to-Point Service will pay no additional charge for transmission capacity for EIM transactions that are within those capacity rights. Because the costs of the transmission system are already being paid for by these customers, their use of capacity for EIM transactions should not be assessed an additional rate. Tariff schedules for ancillary services will be revised to recover the cost of implementation and operation of the NV Energy EIM.

2. NV Energy intends to use “as available” capacity for EIM transfers. This means there will not be a reduction in Available Transmission Capacity (“ATC”) because of the EIM. ATC is the transmission capacity remaining after committed uses for existing and future customers, such as Network Integration Transmission Service or Point-to-Point Transmission Service, are subtracted from the total transmission available. EIM transfers will only use transmission that is not committed for other tariff services. Studies have showed sufficient capacity exists between the ISO and NV Energy to capture EIM benefits using “as available” transmission.

3. A potential EIM Participating Resource that does not hold any existing transmission rights will need to qualify under the NV Energy’s OATT, including a requirement to purchase capacity (either Network Integration Transmission Service or Point-to-Point Transmission Service) for the period and quantity that the EIM Participation Resource intends to utilize.
10. Q.  PLEASE EXPLAIN HOW THE EIM IS GOING TO AFFECT SYSTEM RELIABILITY.

A. The Economic Analysis did not attempt to quantify the reliability benefits that the EIM will provide, but the EIM is expected to improve reliability in several ways:

1. The EIM will improve situational awareness across participating Balancing Authority Areas, ("BAAs") by giving all EIM Balancing Authorities ("BAs"), access to a wider view of system operations. This view comes in two forms. First, the transmission entities will have an enhanced system representation and monitoring capability through the EIM. Second, the participants will have increased ability to see how the dispatch within the EIM is occurring, thereby allowing them to respond accordingly.

2. The EIM enhances the ability of the system to respond to energy imbalances. By automating and coordinating five minute dispatch across the footprint, the EIM generates a single security-constrained economic dispatch solution. Currently, BAs each create individual solutions that typically are coordinated only within the BAA or with minimal external counterparties. This can lead to inefficient results and potentially contradictory adjustments to the interconnected system.
3. The EIM manages flows within transmission limits during dispatch. Transmission capacities previously left unused can now be utilized with the EIM.

4. The EIM will reduce the number of imbalance events that will require resolution through manual operator intervention.

11. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?
   
   A. Yes, it does.
QUALIFICATIONS
OF
BRIAN J. WHALEN, JR.

My name is Brian J. Whalen, Jr. My business address is 6100 Neil Road, Reno, Nevada. I have been employed with Sierra Pacific Power Company ("Sierra" or “the Company”) since 1988. I am currently the Director of Transmission System Planning for Sierra and Nevada Power Company (“Nevada Power”, or collectively “the Companies”). I have administered and coordinated all transmission planning functions for the Companies for the last 10 years. Prior to this I was a Principal Engineer in charge of the Federal Policy Department for our transmission business line. I performed this job for approximately two years, coordinating the Companies’ efforts on federal issues related to transmission.

From September of 1999 through mid-2001, I was a Senior Consultant, Transmission Business Development. My primary function was IPP Project Manager for the Transmission Business Line. In this role I managed IPP transmission and interconnection issues for both Sierra and Nevada Power.

Prior to that, I held numerous engineering positions in the Transmission Planning Department.

In these listed positions, I have managed the modeling, design and interconnection of thousands of megawatts of generation and transmission capacity - including the Alturas, Centennial and ON Line Transmission Projects.
I have provided extensive expert testimony before the Federal Energy Regulatory Commission and the Public Utilities Commission of Nevada. I represented NV Energy on the Western Electricity Coordinating Council’s Transmission Expansion Planning Policy Committee and am the former Chairman of the WestConnect Sierra Sub-regional Planning Committee. I was a member of the Nevada Governor’s Renewable Energy Transmission Access Advisory Committee and was Sierra’s Western System Coordinating Council Planning Policy Committee representative. I have spoken before numerous industry groups about the capabilities and limitations of the Nevada and Western Interconnection transmission systems – including wind, solar and geothermal forums.

I am a Registered Professional Engineer in Nevada -- License #10624. I graduated from the University of Nevada, Reno in 1987 with a Bachelor of Science Degree in Electrical Engineering and in 1991 with a Master of Science in Electrical Engineering – specializing in power systems modeling.

By virtue of my employment, background, experience and education, I am a qualified witness with regards to the NV Energy system and all transmission planning issues associated with the Companies’ PUCN and FERC filings.
AFFIRMATION

STATE OF NEVADA       )
COUNTY OF CLARK       )

I, BRIAN J. WHALEN JR., do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

[Signature]
BRIAN J. WHALEN JR.

Subscribed and sworn to before me this [ ]th day of April, 2014.

[Signature]
DEBRA J. MOYERS
NOTARY PUBLIC
MARK A. ROTHLEDER
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
Energy Imbalance Market Energy Supply Plan Amendment

Docket No. 14-04____

PREPARED DIRECT TESTIMONY OF

Mark A. Rothleder

I. INTRODUCTION

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

A. My name is Mark A. Rothleder. I am employed as Vice President of Market
Quality and Renewable Integration for the California Independent System
Operator Corporation (“ISO”). My business address is 250 Outcropping Way,
Folsom, California. I am filing testimony in support of Nevada Power Company
d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV
Energy (“Sierra”) (together, the “Companies” or “NV Energy”).

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT
OF MARKET QUALITY AND RENEWABLE INTEGRATION.

A. I play a lead role in the design and implementation of ISO market rules and
operating procedures, and the evaluation of the market’s performance and
enhancement opportunities. I oversee the assessment of regional coordination
opportunities, renewable integration studies to determine operational requirements
and fleet capability. I am responsible for developing solutions to systemic issues
to ensure that the market is efficiently meeting the reliability needs of the system.
In the development of the energy imbalance market ("EIM"), I have worked on market policies, market design, and cost-benefit analyses.

3. **Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.**

   A. I have been employed at the ISO in various positions since July 1997. Prior to my current position, I was the Executive Director, and before that Director, of Market Analysis and Development for the ISO. I also held the role of Principle Market Developer for the ISO in the lead role in the implementation of market rules and software modifications related to the ISO’s Market Redesign and Technology Upgrade. I played a lead role in designing many of the aspects of the ISO’s revised market design, implemented on March 31, 2009. Since joining the ISO, I have worked extensively on implementing and integrating the market rules for California’s competitive energy and ancillary services markets and the rules for congestion management, real-time economic dispatch, and real-time market mitigation of the operations of the ISO balancing authority area. I have also held the position of Director of Market Operations. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Rothleder-Direct-1.**

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

   A. I elaborate on certain aspects of the development of the EIM and the study of the economic benefits of NV Energy participating in the EIM that was performed by ABB Inc. ("ABB") and Energy and Environmental Economics, Inc. ("E3") in conjunction with the ISO and NV Energy, "NV Energy-ISO Energy Imbalance Market Economic Assessment" dated March 25, 2014 (the "Economic Analysis")
which is provided as Item 1 in the Technical Appendix. The Economic Analysis describes and quantifies the benefits and costs associated with NV Energy participation in the EIM. I also sponsor Sections 2 and 3 and portions of Section 7 of the Narrative.

II. DEVELOPMENT AND OPERATION OF EIM

5. Q. PLEASE DESCRIBE THE ENERGY IMBALANCE MARKET.
   A. The EIM is a set of rules and procedures under which the ISO is making its real-time market available to other balancing authorities ("BAs") that choose to use that market to more efficiently dispatch resources while meeting imbalance energy needs. At its core, the EIM provides a platform under which resources of the participants can be economically dispatched throughout the EIM footprint in a 5-minute time horizon.

6. Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE ENERGY IMBALANCE MARKET.
   A. For the last several years, industry leaders in the western interconnection have examined the potential benefits of a regional EIM. Such a market could replace the energy imbalance services that utilities in the region currently offer under schedules 4 and 9 of their respective open access transmission tariffs ("OATT"), as Federal Energy Regulatory Commission ("FERC") Order Nos. 888 and 890 require.

   In 2010, the Western Electricity Coordinating Council ("WECC") launched a major initiative and study effort. In late 2011, commissioners from 12 western
state regulatory commissions formed a group (the "PUC-EIM Group") to explore issues related to an EIM in the west.

In March 2012, the ISO provided the PUC-EIM group a conceptual proposal under which the ISO would provide energy imbalance services through its existing market platform to BAs that choose to participate. The ISO explained that, under its proposal, interested BAs would have the opportunity to participate voluntarily in the ISO’s existing real-time market with a low up-front cost and a proven design. By leveraging its functioning market platform, the ISO could offer a solution with less risk and lower costs than could be achieved by creating an entirely new market design and infrastructure. In addition, because the ISO did not need to build a new platform for the regional EIM, its proposal offered BAs the opportunity to begin participating in the market when they are ready to do so under a “pay-as-you-go” approach. Participants would pay a one-time up-front fee to cover the cost of ISO modeling, licensing and other preparatory work. Once the BA’s participation in the EIM is operational, it would pay ongoing fees based on its level of participation consistent with the ISO’s grid management charge structure.

In April 2013, PacifiCorp signed an Implementation Agreement for PacifiCorp to participate in the ISO EIM.¹

Between April 2013 and November 2013, the ISO developed the design for the EIM and the proposed tariff revisions and agreements through an extensive

stakeholder process. On February 28, 2014, the ISO filed proposed tariff changes with the FERC for ISO operation of the EIM.\textsuperscript{2} The ISO is planning to start market simulation in July 2014 in order to effectuate the implementation of the EIM October 1, 2014, with PacifiCorp as the first EIM market participant for the two balancing authority areas ("BAAs") it manages.

\section*{WHAT ENTITIES WILL BE INVOLVED IN THE OPERATION OF THE EIM?}

\subsection*{A.}
The operation of the EIM will include the following types of entities or functional roles:

\textbf{EIM Entity:} The EIM Entity is a BA that elects to participate in the EIM. As an EIM Market Participant, the EIM Entity is responsible (1) for obtaining unconstrained transmission intertie capacity from participating transmission service providers in its BAA for use in the ISO’s real-time market and, (2) for scheduling all load and resources in its BAA including those resources that do not participate in the real-time market (known as non-participating load and non-participating resources) and for paying charges related to non-participating load and non-participating resources. NV Energy will be an EIM Entity.

\textbf{EIM Entity Scheduling Coordinator:} The EIM Entity Scheduling Coordinator is the entity through which the EIM Entity provides information to the real-time market. In order to prevent the inappropriate sharing of information regarding transmission and generation, an EIM Entity Scheduling Coordinator cannot be a

\textsuperscript{2} FERC Docket No. ER14-1386-000

Rothleder - DIRECT
scheduling coordinator for a supply resource unless it is a transmission provider subject to the FERC’s standards of conduct in 18 C.F.R. § 358.

EIM Participating Resources (“EPR”): The EIM Participating Resources are the owners or operators of EIM resources that wish to bid supply into the real-time market. EPRs can be generating units, participating load, demand resource providers, or other resources qualified to deliver energy or similar services, such as non-generation resources. Each type of resource that is eligible to participate in the current ISO real-time market is eligible to participate through the EIM, but only if the EIM Entity supports participation by that type of resource and the resource meets the technical requirements for such participation.

EIM Participating Resource Scheduling Coordinator: The EIM Participating Resource Scheduling Coordinator is the entity through which the EIM Participating Resource participates in the real-time market. To prevent the inappropriate sharing of information regarding transmission and generation, an EIM Participating Resource Scheduling Coordinator cannot be an EIM Entity Scheduling Coordinator unless it is a transmission provider subject to the FERC’s standards of conduct in 18 C.F.R. § 358.

Market Operator: The ISO will perform the role of the Market Operator. The Market Operator performs the following functions:

1. Forecast of expected imbalance energy requirements,
2. Clearing of bid offers to meet expected imbalances,
3. Production of prices used for settlement of imbalance energy, and
4. Settlement of imbalance energy.
The Market Operators settles imbalance energy with EIM Participating Resource
Scheduling Coordinators for all EIM Participating Resources and with the EIM
Entity Scheduling Coordinators for all non-participating resources.

8. Q. HOW WILL THE ENERGY IMBALANCE MARKET BE STRUCTURED
AND OPERATE?

A. The following illustrative diagram shows structural relationships and
communication of information between different functional roles.
1 - Base schedule forecasts for all resources and interchange to EIM SIBR Portal (Market Operator produces load forecast)
2 - MW bid range and economic bids
3 - MW bid range
4 - Resource plan, including balanced base schedule information
5 - Planned resource outages and after-the-fact forced outages (including estimated return time); revenue meter data (also applicable to Loads)
6 - Approved outages (all resources & transmission, real time and scheduled); revenue meter data
7 - Market Operator advisory schedules
8 - Dispatch instructions and imbalance settlement for participating resources
9 - Imbalance settlement for loads, interchange and non-participating resources, including BAA neutrality & uplift charges
10 - EIM Entity sub-allocation settlement for loads, interchange and non-participating resources; including BAA neutrality & uplift charges
The EIM Entity Scheduling Coordinator plays an important role ensuring and informing the Market Operator of the resource plan that balances EIM Entities’ forecast demand plus exports. This plan may be made of both resources inside the EIM area or imports from other BAs. The EIM Entity Scheduling Coordinator will submit the balanced base schedule and resource plan to the Market Operator prior start of the EIM market. Prior to the start of the EIM, the Market Operator will evaluate the base schedules and provide advisory information back to the EIM Entity Scheduling Coordinator to provide an opportunity for the EIM Entity to ensure the base schedules are balanced and feasible from a congestion perspective. The EIM Participating Resources Scheduling Coordinator will submit to the Market Operator bid offers for increased or decreased dispatch for EIM Participating Resources relative to their base schedules. The Market Operator will optimize all real-time bid offers using a security constrained economic commitment and dispatch process every 15-minute and 5-minute interval of the hour for which the EIM Participating Resources was offered for EIM dispatch. Since a resource may have some of its capacity committed to the BA for operating reserve or regulation, the EIM Entity Scheduling Coordinator will also inform the Market Operator of such committed resource capacity so that the Market Operator does not dispatch such committed resource capacity via the EIM.

The Market Operator will issue dispatch instructions and compensate EIM Participating Resources via the EIM Participating Resource Scheduling Coordinator. The Market Operator will settle and allocate imbalance and other associated costs attributable to the EIM BA to the EIM Entity Scheduling
Coordinator. The EIM Entity Scheduling Coordinator will allocate such costs to its customers pursuant to its tariff.

9. Q. HOW WILL THE EIM RELATE TO THE FIFTEEN-MINUTE MARKET WHICH THE ISO HAS CREATED IN RESPONSE TO FERC ORDER 764?

A. FERC Order 764 required that all transmission providers make available the opportunity for 15-minute schedules. The EIM builds on the ISO’s recently enhanced real-time market structure and implementation of FERC Order 764. Implementation of the EIM on top of the enhanced real-time market structure creates an opportunity for the ISO to implement real-time market design changes to address a number of real-time market inefficiencies in a manner that was not possible before FERC instituted these reforms.

The implementation of the EIM will not change the operation of the enhanced real-time market. Rather, the EIM tariff amendments establish certain distinct procedures for the EIM Entities other than the ISO BAA to accommodate certain differences between the ISO BAA and the EIM Entities. These include the fact that the EIM Entities are participating only in the ISO’s real-time energy market; they are not also participating in the ISO’s day-ahead and ancillary services markets.

10. Q. HOW IS EIM PARTICIPATION DIFFERENT FROM JOINING THE ISO AS A PARTICIPATING TRANSMISSION OWNER?
A. EIM participation is limited to real-time operations. Unlike a participating transmission owner, the EIM Entity maintains all reliability, planning and transmission control and revenue recovery functions.

The EIM Entities’ approach to meeting their reliability responsibilities, such as resource adequacy, differ from the requirements that current participants in ISO’s markets must satisfy. Two of these differences deserve mention, because they are relevant to the matters I will discuss below.

First, in the ISO BAA, the day-ahead market assures that hourly forward schedules are balanced and feasible with respect to congestion, and through resource adequacy offer obligations, that entities serving load in the current market satisfy the requirements for resource adequacy. In order to accommodate for the absence of these safeguards in other BAAs, the EIM establishes certain sufficiency tests and remedial action in response to failed tests.

The second difference arises from the need to establish a different mechanism for use as a baseline against which to measure deviations in the real-time market. Hourly day-ahead schedules provide that baseline in the exiting ISO market. In order to establish a comparable baseline, EIM Entity Scheduling Coordinators must submit hourly resource plans, which include hourly base schedules, and demand and supply, in advance of the real-time market. The EIM Entity is responsible for the final content of the base schedule.

11. **Q. WILL NV ENERGY’S GENERATING UNITS BE PLACED UNDER THE CONTROL OF THE ISO IF NV ENERGY PARTICIPATES IN THE EIM?**
A. No. NV Energy maintains operational control over its generating resources. NV Energy may allow direct communication of EIM dispatch instructions. However, NV Energy will continue receive, review and carry out dispatch instructions provided by the ISO only to the extent NV Energy voluntarily offers a bid for the resource to be dispatched and such dispatch does not conflict with any other obligation.

12. Q. HOW WILL THE ISO SETTLE IMBALANCE ENERGY FOR BOTH PARTICIPANTS AND NON-PARTICIPANTS?

A. For participating resources, instructed imbalance energy will be settled with the EIM Participating Resource Scheduling Coordinator based on the locational marginal price for the respective resource location. For participating resources, any uninstructed imbalance energy (deviations from base or instructed level), will also be settled with the EIM Participating Resource Scheduling Coordinator based on the locational marginal price for the respective resource location. For non-participating resources, any uninstructed imbalance energy (deviations from base schedule), will be settled with the EIM Entity Scheduling Coordinator based on the locational marginal price for the respective resource location. Such imbalance energy settlement reflects the value of energy. Uninstructed energy deviations may also be subject to allocation of other neutrality and offset costs that accrued from operation of the EIM in the EIM Entity BA. It will be up to NV Energy to determine how it will settle for imbalances with any non-participating resources or loads.

13. Q. WHAT MECHANISMS EXIST TO ENCOURAGE EIM PARTICIPANTS TO ACCURATELY SCHEDULE SUFFICIENT RESOURCES?
A. To encourage resource sufficiency and accuracy of scheduling of base schedules, an under- and over-scheduling charge is proposed. EIM Entities that use the ISO's demand forecast and approve EIM base schedules for their resources within one percent of the ISO's demand forecast will be exempt from such under and over scheduling charges because such EIM Entities have taken steps to ensure the availability of sufficient resources to meet the ISO's demand forecast. However, if the EIM Entity chooses to use its own demand forecast, the ISO will assess charges in two levels, according to the deviations from the EIM base schedule: if metered demand deviates from the schedule by between five to ten percent (level 1), and if metered demand deviates from the schedule by more than ten percent (level 2). If the deviation within either range is at least two megawatts, the following charges apply: the level 1 charge will be a 25 percent increase (under-scheduling) or decrease (over-scheduling) of the hourly real-time load aggregation point price for the entire deviation; the level 2 charge will be a 100 percent increase or 50 percent decrease.

This threshold approach encourages the submission of valid and accurate base schedules and recognizes that greater deviations from the base schedule impose greater costs and burden on the ISO and other EIM market participants. The ISO will distribute the revenues from these charges pro rata to load in the EIM Area that was not subject to under or over scheduling charges.

III. ECONOMIC ANALYSIS

A. NV Energy and the ISO contracted with ABB and E3 to perform the economic analysis of NV Energy's participation in the EIM. The objective of the production simulation is to minimize the cost of operations subject to meeting constraint including meet the expected demand and enforces a variety of resource and transmission constraints.

The Economic Analysis quantifies the costs and economic benefits of NV Energy's participation in the EIM.

A. ECONOMIC ANALYSIS ASSUMPTIONS

15. Q. PLEASE EXPLAIN THE ASSUMPTIONS THAT WERE USED IN THE ECONOMIC ANALYSIS.

A. The input assumptions used in the performance of the Economic Analysis are documented in the technical appendix of the Economic Analysis, attached as Item 1 in the Technical Appendix. I briefly describe the most significant input assumptions here.

- The Economic Analysis assumes that PacifiCorp is an existing participant in the EIM in the business as usual case.
- The Economic Analysis is based on expected transmission and operational conditions in years 2017 and 2022. The starting network model and resources is based on WECC's Transmission Expansion Planning Policy Committee 2022 common case.
- The assessment of benefits can depend on the amount of transfer capability between NV Energy and the ISO and other participating EIM Entities. For the purposes of assessing the incremental benefits of NV
Energy’s participation, the assessment assumes that a transfer capability between PacifiCorp west BAA and the ISO of 400 MW exists and 200 MW of east to west transfer capability from PacifiCorp’s east BAA to PacifiCorp’s west BAA. The transfer capability modeled between NV Energy and the ISO was approximately 1,500 MW through 230 kV capacity at the Eldorado Substation. In addition, the model considered additional transfer capability that NV Energy has with the ISO at other interconnections and rights using third-party transmission providers.

- NV Energy and ISO jointly agreed on input assumptions regarding expected load, fuel prices, generation and transmission expected additions and changes, transmission wheeling rates, quantity of flexible reserves necessary for each area.
- In order to quantify a conservative range of benefits the Economic Analysis developed a low range of assumptions and a high range of assumptions.

B. ECONOMIC ANALYSIS METHODOLOGY

Q. PLEASE SUMMARIZE THE BENEFITS THAT WERE QUANTIFIED BY THE ECONOMIC ANALYSIS.

A. The Economic Analysis quantified three categories of benefits: 1) Inter-regional benefits, 2) flexibility reserve benefits and 3) renewable curtailment benefits. Interregional dispatch savings are those benefits realized from the efficiency of combined 5-minute dispatch and real-time unit commitment across the EIM area, by reduced “transactional friction” and alleviating structural impediments currently preventing trade on ties between the ISO and NV Energy BAAs. To quantify the interregional benefits a production simulation is performed once for a
case representing the business as usual case with existing transactional friction and impediments conservatively modeled based on existing hourly firm transmission rates between NV Energy and the ISO. Then a second production simulation is performed representing NV Energy’s participation in the EIM by removing costs transfer between the ISO and NV Energy. The difference in production costs for all supply between the business as usual case and the EIM case quantifies the expected interregional benefits.

Flexibility reserve benefits are realized from reduced flexibility reserve requirements, by aggregating the three systems’ load, wind, and solar variability and forecast errors. Flexibility reserve benefits also account for the benefits of NV Energy supply being able to be compensated for meeting real-time flexibility reserve requirements. The ISO compensates resources meeting the flexibility reserve requirement based on the opportunity costs of the marginal resource meeting the flexibility reserve requirement.

Reduced renewable energy curtailment quantifies the benefits to the ISO of reducing risk of having to curtail renewable energy production when there are over generation conditions in the ISO. By allowing BAs to export more or reduce imports during such condition, renewable generation could be used to serve demand in another BA rather than having to curtail.

NV Energy and the ISO also assessed the potential for intraregional dispatch benefits but determined that based on the fact that NV Energy resources are currently dispatched among sites that are largely located in the same part of the grid, and there is minimal amount of congestion in the NV Energy transmission
network, no attempt was made to quantify the benefit of intraregional dispatch benefits.

Finally, a recent FERC report identified additional reliability benefits that may arise from an EIM, which are not quantified in this report. These include enhanced situational awareness, security constrained dispatch, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.

C. ECONOMIC ANALYSIS RESULTS

17. Q. PLEASE SUMMARIZE THE RESULTS OF THE ECONOMIC ANALYSIS.

   A. The Economic Analysis quantified a low range and a high range of total annual EIM benefits across all participants in 2017 of $9.2 million to $18.2 million, respectively, and $15 million to $29.4 million, respectively in 2022.

18. Q. PLEASE PROVIDE A MORE DETAILED EXPLANATION OF THE RESULTS OF THE ECONOMIC ANALYSIS.

   A. Annual interregional benefits for the EIM area range from $6.2 million to $9.3 million in 2017 and range from $8.9 to $13.4 million in 2022. For the purpose to attributing interregional benefits between existing EIM participants (ISO and PacifiCorp) and NV Energy, it was assumed that benefits would split 50/50. A 50/50 split is based on the concept that if the production cost is reduced by $4

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(i.e., $20 to $16) both the seller and buyer would be able trade at a price that would split the benefits. If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefits of $4 ($2 + $2) will match the total production cost saving of $4.

Annual flexibility reserve benefits for the EIM area range from $2.6 million to $5.0 million in 2017 and range from $5.7 to $12 million in 2022. There are two components that make up the flexibility reserve benefits. The first components accounts for the total production cost savings in flexibility reserve benefit category were allocated between NV Energy and the current EIM participants in proportion to their standalone load following requirements (4 percent to NV Energy, 96 percent to current EIM participations). The second component accounts for the amount of revenue NV Energy generation may earn from participating in the ISO’s flexi-ramp market while participating in the EIM. In 2013, approximately $23 million was paid to suppliers in the ISO for flexibility reserve. Based on NV Energy 15 percent share of gas and hydro capacity versus the ISO and PacifiCorp, it was assumed that NV Energy would receive approximately 15 percent of the flexibility reserve revenue.

Annual benefits of reduced curtailment ranged from $0.4 to $4.0 million in 2017 and 2022. Since the Economic Analysis quantified only the risk of curtailment of ISO resources, it was assumed that all the reduced curtailment benefits are benefits to ISO customers.
The Economic Analysis evaluated the net benefits based on the estimated costs of implementing and administering a NV Energy EIM. There are ISO costs and NV Energy costs. There is a one-time fixed charge of approximately $1.1 million and $0.7 million per year in administrative charges. In addition, NV Energy has estimated its implementation cost to be $11.2 million and ongoing operational costs from $2.6 million to $3.2 million. Based on these costs and the benefits described above, E3 calculated the net present value of EIM for NV Energy over a 20 year period to be $40.3 million to $87.6 million.

After implementation of EIM, the ISO intends to quantify actual benefits using the actual EIM results.

19. **Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?**

   **A. Yes, it does.**
MARK ROTHLEDER, P.E.

PROFESSIONAL EXPERIENCE

California ISO Folsom, CA 1997-Present

- **Vice-President, Market Quality and Renewable Integration**
  - Responsible for renewable integrations studies
  - Assessment of regional coordination opportunities
  - Responsible for monitoring and reporting on market performance and effectiveness
  - Responsible for developing solutions to systemic issues to ensure market is efficiently meeting the reliability needs of the system
  - Lead renewable integration studies to determine operational requirements and fleet capability and needs in meeting 20% RPS in 2012 and 33% RPS in 2020

- **Executive Director of Market Analysis and Development**
  - Strategic planner of market initiatives and renewable integration
  - Responsible for monitoring and reporting on market performance and effectiveness
  - Responsible for developing solutions to systemic issues to ensure market is efficiently meeting the reliability needs of the system
  - Lead renewable integration studies to determine operational requirements and fleet capability and needs in meeting 20% RPS in 2012 and 33% RPS in 2020
  - Coordinate and guide real-time operation practices with market functionality
  - Provider of market and operational expertise to organization and stakeholders
  - Mentor to developing subject matter experts

- **Principal Market Developer**
  - Technical lead responsible for the successful implementation of $150+ million market redesign and technology upgrade (MRTU) project
  - Expert witness on resource adequacy policy related to implementation of MRTU
  - Principal developer of market and software requirements for market systems

- **Director of Market Operations**
  - Responsible for organization that facilitates the only transparent, non-discriminatory, $20 billion a year market for transmission and reliability services in the West
  - Provider of value added processes and data that enhance reliable grid operation and provides for an error free financial settlement of market transactions
  - Fiscal and operational management of Market Operations department, including direct supervision of four Market Managers and over 30 staff Market Engineers
  - Navigating major organizational change as a result of restructuring due to attrition and shift away from utilizing consulting staff
  - Chairperson for MRTU Customer Team supplying guidance and oversight for major program milestones and market design decisions
  - Senior member of Market Services staff providing leadership and direction in meeting and exceeding corporate objectives
  - Partnering with Market Quality, Settlements, Grid Operations, Information Services, and Client Relations to execute strategic and tactical plans to achieve corporate objectives
  - Sponsoring major cross functional efforts to address the Enterprise System Testing and summer 2005 assessments
- **Project Manager**
  - Responsible for successful implementation multi-million dollar real-time market re-design project
  - Simultaneous responsibility for managing production Market Integration activities with same staff and resources
  - Ensured all internal and external criteria to make project “go-live” decision with full integrity
  - Created new stakeholder process to provide opportunity for input to project at various development stages that ultimate became model for other projects
  - Navigated new market systems through live cutover and during critical few hours of.
  - Communicated to project status to Executive Sponsors and Governing Board

- **Manager of Market Integration**
  - Responsible for the ensuring the market application operated consistent with business requirements
  - Lead team to ensure data produced or received by market applications were consistent with other internal and external business needs
  - Performed data analysis and studies to ensure applications were operating consistent with business rules

- **Manager of Market Engineering**
  - Responsible for developing and documenting business requirements used to create or modify market applications
  - Coordinate with legal and regulatory to ensure consistency between market application and tariff
  - Performed vendor technical management

- **California ISO Start-up Staff**
  - One of the original employees responsible for California ISO start-up
  - Identified need and executed variety of engineering, testing, procedure development, tariff review and vendor management tasks critical to successful start-up

---


- **Operations Engineering**
  - Performed operational including contingency, transient and voltage studies. Developed operating procedures based.
  - Maintained network model and participated in WSCC operational work groups.
  - Participated on WSCC major disturbance work group form after 1996 disturbances.

- **Planning Engineering**
  - Performed planned studies for 230 kV and 115 transmission system in local area. Developed annual transmission plan
  - Performed impact studies of transmission customer projects.

- **Substation Engineering**
  - Designed upgrades to 230kV and 500kV substations
  - Specified equipment for bid and procurement process.
  - Designed relay schemes.
  - Performed field engineering and relay testing.
Sacramento Municipal Utility District  Sacramento, CA 1987-1989
  • Engineering Assistant - Substations
    o Prepared design upgrades to 230kV substations
    o Specified equipment for bid and procurement process

EDUCATION
  • MS Computer Information Systems, University of Phoenix, 2001
  • Master of Electrical Engineer coursework, Santa Clara University, 1990-1995
  • BS Electrical Engineer, California State University Sacramento, 1989

CERTIFICATIONS and HONORS
  • ISO Leadership Academy
  • Professional Electrical Engineer, California
  • NERC and WECC certified (2002-2006)
  • WECC, Market Issues Committee
  • IEEE, San Francisco Power Engineering Society, Past President
  • Tau Beta Pi, Engineering Honor Society

PUBLICATIONS and PRESENTATIONS
  • Co-Author and presenter UC Berkeley Energy Institute: Integration of Wind and Solar Energy in the California Power System: Results from Simulations of a 20% Renewable Portfolio Standard
  • Co-Author of IEEE PES Transactions / Papers
    o A Rational Buyer Algorithm Used For Ancillary Service Markets
    o Pricing Energy and Ancillary Service and Energy in Integrated Market System by an Optimal Power Flow
  • Presenter or panel member at industry conferences
STATE OF NEVADA
COUNTY OF CLARK

I, MARK ROTHLEDER, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

MARK ROTHLEDER

Subscribed and sworn to before me
this ___ day of April, 2014.

Notary Public
TECHNICAL APPENDIX
ITEM-1

ABB/E3 NV ENERGY-ISO ENERGY IMBALANCE MARKET ECONOMIC ANALYSIS AND TECHNICAL APPENDIX, DATED MARCH 25, 2014
NV Energy-ISO
Energy Imbalance Market
Economic Assessment

March 25, 2014
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Executive Summary

This report examines the benefits and costs of NV Energy’s participation in the California Independent System Operator’s (ISO’s) energy imbalance market (“EIM” or “the EIM”). ISO’s EIM is a regional 5-minute balancing market, as well as real-time unit commitment capability, which is expected to be operational in Fall 2014. ISO and PacifiCorp, referred to in this study as “current EIM participants,” are assumed to be participating in the EIM by the time that NV Energy participation would commence, which is currently estimated to be Fall 2015.

The report estimates a range of potential benefits, with the low range reflecting a scenario in which assumptions were chosen to be conservative. For the year 2017, total estimated gross benefits for all participants range from $9 million to $18 million (in 2013$); for 2022, total gross benefits range from $15 million to $29 million. NV Energy’s attributed share of these gross benefits is estimated to range from $6 million to $10 million in 2017 and from $8 million to $12 million in 2022. Based on NV Energy’s preliminary cost estimates, its participation in the EIM would produce net present value (NPV) savings to the NV Energy balancing authority (BA).¹ NV Energy participation in the EIM would also produce significant

¹ A balancing authority (BA) is an entity responsible for integrating resource plans in advance of real-time balancing needs, maintaining load-interchange-generation balance within a balancing authority area, and supporting interconnection frequency in real time. A balancing authority area (BAA) is the collection of generation, transmission, and loads within the metered boundaries of a BA.
incremental savings for current EIM participants, and is expected to create no incremental implementation costs for current EIM participants beyond those that are recovered from NV Energy through ISO fixed and administrative charges. Thus, NVE Energy participation in the EIM is expected to produce positive incremental net benefits for all EIM participants collectively, including NV Energy.

Given NV Energy’s estimated start-up costs of $11.2 million and ongoing costs of $2.6 million,² even the low range of estimated benefits in 2017 in this report support the conclusion that NV Energy’s participation in the EIM provides a low-risk means of achieving operational cost savings for NV Energy and the current EIM participants. The results also confirm that total EIM benefits can increase as new participants, such as NV Energy, join the EIM, bringing incremental load and resource diversity, real-time transfer capability utility, and flexible generation resource availability to benefit all market participants.

Changes in the electricity industry in the Western U.S. are making the need for greater coordination among BAs increasingly apparent. Recent studies have suggested that it will be possible to reliably operate the current western electric grid both more efficiently and with high levels of variable wind and solar generation, but doing so will require improving and supplementing the hourly bilateral markets used in the Western states with mechanisms that allow shorter scheduling timescales and greater coordination.

An EIM provides such a mechanism. By allowing BAs to pool load and wind and solar resources, an EIM would lower total flexibility reserve requirements and

²Preliminary cost estimates provided by NV Energy.
reduce curtailment of wind and solar generation for the region as a whole, lowering costs for customers. An EIM may also help to improve compliance with Federal Energy Regulatory Commission (FERC) Order 764, which emphasizes 15-minute scheduling over interties but may not be implemented on an optimized basis due to the difficulty of bilateral trading on such short time intervals.

To respond to these needs and opportunities, the ISO has pursued plans to create a regional EIM by Fall 2014, and ISO has worked with stakeholders throughout 2013 to finalize details of the EIM’s structure and functions. The EIM is designed to be a balancing market that optimizes generator dispatch within and between balancing authority areas (BAAs) every five minutes by leveraging the functionality of ISO’s existing real-time market. It does not replace the day-ahead or hourly markets and scheduling procedures that exist in the Western Interconnection today. Throughout the EIM stakeholder process, ISO has emphasized that the EIM is being designed to enable other BAs throughout the Western Interconnection to join.

ISO and NV Energy staff have worked together to assess potential opportunities for improved regional coordination and capabilities between their BAAs, including through an EIM. As part of this collaboration, the ISO retained Energy and Environmental Economics, Inc. (E3), a consulting firm, to estimate the potential benefits of NV Energy joining the EIM, and Asea Brown Boveri (ABB), whose consulting staff ran ABB’s production simulation software to calculate a

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portion of the estimated benefits. This report describes the findings of E3 and ABB, who are together referred to as “the study team” in the report.

The report evaluates benefits using an approach consistent with that used in E3’s PacifiCorp-ISO Energy Imbalance Market Benefits report, which was released in March 2013. The current ISO-NV Energy study focuses on the incremental benefits and costs of NV Energy’s participation in the EIM, which assumes PacifiCorp is already an EIM participant in its base case. This study incorporates additional details provided by NV Energy staff to improve the accuracy with which the NV Energy system is represented in the modeling.

An expanded EIM that includes NV Energy, in addition to the current EIM participants, would allow participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources between the three systems, reducing production costs, operating reserve requirements, and renewable generation curtailment. Specifically, the participation of NV Energy in the EIM would yield the following three principal benefits:

+ **Interregional dispatch savings**, by realizing the efficiency of combined 5-minute dispatch and real-time unit commitment across the NV Energy, PacifiCorp, and ISO BAAs, which would reduce “transactional friction”.

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5 This analysis represents various forms of “transactional friction” to inter-BA trade using each BA’s tariff wheeling charges on transactions between the ISO and NV Energy, which are removed in the EIM cases. The ISO has proposed to not charge wheeling rates on EIM transactions for at least the first year of EIM operation beginning with the PacifiCorp participation. The ISO intends to review policy associated with transmission used to support EIM transfers, following initial operation and results of EIM. If the ISO finds it appropriate to recover fixed costs.
and alleviate structural impediments currently preventing trade on ties between the ISO and NV Energy BAAs;\footnote{See Section 2.1.3.4 for a discussion of the transmission ties between the NV Energy and PacifiCorp East BAAs.}

+ \textit{Reduced flexibility reserve}, by aggregating the three systems' load, wind, and solar variability and forecast errors; and

+ \textit{Reduced renewable energy curtailment}, by allowing BAs to export or reduce imports of renewable generation when they would otherwise need to curtail their own resources.\footnote{The PacifiCorp-ISO EIM analysis modeled a wide range of potential avoided curtailment as a result of the EIM. NV Energy's incremental participation in the EIM would raise the expected levels of avoided curtailment to a higher point within that range.}

E3's PacifiCorp-ISO EIM study included a fourth benefit category, intraregional dispatch savings, which arises from PacifiCorp generators being able to be dispatched more efficiently through the ISO's automated nodal dispatch software, reducing transmission congestion within the PacifiCorp BAAs. Based on NV Energy staff's experience that there is little internal congestion within the NV Energy transmission system, the study team assumed this benefit would be very small and therefore did not include it in this analysis.

The above benefit categories are indicative but not exhaustive. A recent FERC report identified additional reliability benefits that may arise from an EIM, which are not quantified in this report. These include enhanced situational awareness, security constrained dispatch, faster delivery of replacement
generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.\textsuperscript{6}

The study team estimated the benefits of NV Energy's participation in the EIM using the GridView\textsuperscript{9} production modeling software to simulate operations in the Western Interconnection for the years 2017 and 2022, with and without NV Energy as an EIM participant. The year 2017 was selected to represent likely, or "normal," system conditions within the first several years after the EIM becomes fully operational. The year 2022 represents the medium-term planning horizon, consistent with other transmission planning cases at the Western Electricity Coordinating Council (WECC) and ISO, after additional renewable generation and more regional transmission facilities have been constructed, and with higher flexibility reserve requirements for supporting higher levels of wind and solar penetration. The study team's analysis also incorporates California's greenhouse gas regulations and the associated dispatch costs.

The estimated benefits are sensitive to several key assumptions and modeling parameters. These include: (1) the extent to which NV Energy generators are available to participate in the EIM during summer months, during which NV Energy may have more restrictive requirements to use these generators for local load service and balancing; and (2) the ability of ISO and NV Energy to realize incremental value through optimal use of intra-hour flexibility reserves from across the two systems. The results are also sensitive to assumptions


\textsuperscript{9} GridView is ABB's production simulation software.
about the amount of renewable energy curtailment in California that could be reduced through an expanded EIM.

The study team developed low and high range benefit scenarios to address key uncertainties in the modeling. These scenarios reflect the limitations of existing tools to characterize all of the changes to system operations that would occur under an EIM. These include but are not limited to the modeling of reserves, renewable energy curtailment, and greenhouse gas regulations. They also capture uncertainties about the extent to which future industry developments would allow cost savings to occur both with and without an EIM. Table 1 below summarizes some of the key assumptions that were used to create the low and high benefit ranges.\(^\text{10}\)

\(^{10}\) The PacifiCorp-ISO EIM study indicated that cost savings for PacifiCorp’s EIM participation were sensitive to assumptions about the availability of hydropower to provide flexibility reserves, and that analysis modeled a range of benefits by assuming that between 12% and 25% of the total nameplate capacity of hydropower generation is available to provide flexibility reserves, with the 25% assumption resulting in a more conservative EIM benefit estimate. For NV Energy, hydropower makes up a smaller portion of generation resources than for PacifiCorp, so the availability of hydropower to provide reserves would likely have a less significant impact on the expected benefits in this analysis. This NV Energy-ISO study uses only the conservative range, modeling all scenarios with a 25% cap on reserve contribution from hydropower resources.
Table 1. Key assumptions in low and high range benefit scenarios

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Low range</th>
<th>High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Availability of NV Energy generators to participate in EIM</td>
<td>Unavailable during June-Sept; annual dispatch benefits scaled downward by one-third (4/12ths)*</td>
<td>Available in all months for EIM dispatch; full-year dispatch benefits used</td>
</tr>
<tr>
<td>Calculation of flexibility reserve benefits</td>
<td>Quantity reduction in reserve requirement valued at benchmark of average ISO historical ancillary service market price levels</td>
<td>Simulation directly calculates benefits of reduced reserves, and improved efficiency through enabling optimal procurement of reserves from across the EIM footprint, subject to transmission constraints</td>
</tr>
<tr>
<td>Share of identified renewable energy curtailment value avoided in California</td>
<td>10%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Note: *See Section 2.1.3.6 for additional detail.

Across these scenarios, the study team estimated that NV Energy participation in the EIM generates total annual cost savings to all participants (in 2013$) of $9.2 to $18.2 million in 2017, and $15.0 to $29.4 million in 2022. These benefits are incremental to those estimated for the creation of the initial EIM between PacifiCorp and ISO. Table 2 and Figure 1 below show the estimated low and high range benefits for the expanded EIM, for each of the three benefit categories.
Table 2. Low and high range incremental gross annual benefits to all participants from NV Energy Participation in EIM for 2017 and 2022 (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017 Low range</th>
<th>2017 High range</th>
<th>2022 Low range</th>
<th>2022 High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interregional dispatch</td>
<td>$6.2</td>
<td>$9.3</td>
<td>$8.9</td>
<td>$13.4</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>$2.6</td>
<td>$5.0</td>
<td>$5.7</td>
<td>$12.0</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.4</td>
<td>$4.0</td>
<td>$0.4</td>
<td>$4.0</td>
</tr>
<tr>
<td>Total benefits</td>
<td>$9.2</td>
<td>$18.2</td>
<td>$15.0</td>
<td>$29.4</td>
</tr>
</tbody>
</table>

*Note: Individual estimates may not sum to total benefits due to rounding.*

Figure 1. Low and high range incremental gross annual benefits to all participants from NV Energy Participation in EIM (2013$)

*Note: Figure represents total incremental benefits to all EIM participants as a result of NV Energy’s participation in the EIM.*
The study team’s attribution of these benefits between the NV Energy balancing authority (BA) and the current EIM participants is shown in Tables 3 and 4 below, and indicate that NV Energy’s participation could deliver operational savings to both parties.

Table 3. Attribution of expanded EIM gross annual benefits to NV Energy BA (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low range</td>
<td>High range</td>
</tr>
<tr>
<td>Interregional dispatch</td>
<td>$3.1</td>
<td>$4.7</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>$2.8</td>
<td>$3.6</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.1</td>
<td>$1.2</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$6.0</strong></td>
<td><strong>$9.5</strong></td>
</tr>
</tbody>
</table>

*Note: Attributed values may not match totals due to independent rounding.*

Table 4. Attribution of expanded EIM gross annual benefits to current EIM participants (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low range</td>
<td>High range</td>
</tr>
<tr>
<td>Interregional dispatch</td>
<td>$3.1</td>
<td>$4.7</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>-$0.2</td>
<td>$1.4</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.3</td>
<td>$2.8</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$3.2</strong></td>
<td><strong>$8.8</strong></td>
</tr>
</tbody>
</table>

*Note: Attributed values may not match totals due to independent rounding.*

The annual benefit estimates described in this report are gross benefits and are not net of estimated costs. NV Energy’s preliminary cost projection for joining and participating in the EIM includes the four cost categories listed in Table 5.
Table 5. NV Energy estimated one-time and annual costs to participate in EIM (million 2013$)

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Timing</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>One-time capital costs for setup in preparation to participate in EIM</td>
<td>One-time</td>
<td>$10.1</td>
</tr>
<tr>
<td>One-time ISO initial setup fee</td>
<td>One-time</td>
<td>$1.1</td>
</tr>
<tr>
<td><strong>Total One-time costs:</strong></td>
<td></td>
<td><strong>$11.2</strong></td>
</tr>
<tr>
<td>Ongoing costs for staff, software, &amp; administration</td>
<td>Annual</td>
<td>$1.9</td>
</tr>
<tr>
<td>Estimated annual ISO usage fees</td>
<td>Annual</td>
<td>$0.7</td>
</tr>
<tr>
<td><strong>Total ongoing annual costs:</strong></td>
<td></td>
<td><strong>$2.6</strong></td>
</tr>
</tbody>
</table>

These costs include $11.2 million in one-time setup costs and fees plus $2.6 million in annual operating costs and usage charges, for a total 20-year present value cost of $41.8 million.\(^{11}\) The present value gross benefits to the NV Energy BA over this time period range from $82.1 million to $129.4 million,\(^{12}\) resulting in 20-year NPV benefits of between $40.3 million and $87.6 million.

NV Energy’s addition as an incremental participant to the EIM is assumed to create no additional costs for current EIM participants, beyond those that are covered in ISO fixed and administrative charges. On a present value basis over 20 years, NV Energy’s participation in the EIM would bring incremental gross and net benefits to current EIM participants of $68.9 million to $166.9 million.

---

\(^{11}\) All present value estimates are shown in 2013$ and use an 8.1% nominal discount rate and 2.0% annual inflation rate over the study period. Setup costs are assumed to be incurred in 2015, and annual ongoing costs are assumed to begin in the assumed project start year of 2016, which is the expected first full year of NV Energy participation in the EIM.

\(^{12}\) The present value benefit calculations assume that gross benefits in the project start year of 2016 are equal to the 2017 estimate. Annual benefits for the years 2018-2021 were interpolated from the 2017 and 2022 benefit estimates; benefits for 2022 through 2035 were conservatively assumed to grow at the rate of inflation. Results from the GridView model are inflated from 2012$ to 2013$ at 1.5%.
Summing the estimated NPV benefits for all EIM participants — $40.3 to $86.7 million for NV Energy and $68.9 to $166.9 million for current participants — leads to an estimate of total incremental NPV benefits to all participants of $109.2 million to $254.5 million that result from NV Energy’s participation in the EIM.
1 Introduction

1.1 Background and Goals

NV Energy and ISO initiated a joint study to evaluate the potential benefits of improved coordination and capabilities between their systems, including NV Energy’s participation in an EIM operated by ISO. The ISO and NV Energy retained the study team to identify and quantify the incremental benefits of NV Energy’s participation in the EIM, and to examine the allocation of benefits between NV Energy and current EIM participants — PacifiCorp and ISO.

This report describes the study team’s methods and findings. The analysis uses an approach that is consistent with that used in E3’s PacifiCorp-ISO Energy Imbalance Market Benefits report, released in March 2013. Throughout the study process, the study team worked closely with both NV Energy and ISO to refine scenario assumptions and data inputs, and to estimate benefits consistent with how each party believes its system operates today and would operate in the future under each of the defined scenarios.

1.2 Structure of this Report

The remainder of the report is organized as follows. Section 2 identifies key assumptions (2.1), specifies methods (2.2) and scenarios (2.3), and presents
benefits (2.4) and benefit attribution (2.5) for the analysis. Section 3 provides context for interpreting the results, describing where the assumptions lie along a conservative-moderate-aggressive spectrum (3.1) and how the results compare against other EIM studies (3.2). The Technical Appendix also describes the modeling assumptions and methods in more detail.
2 EIM Analysis

2.1 Key Assumptions

2.1.1 WHAT IS AN EIM AND WHAT WOULD IT DO?

The EIM considered in this study would consist of a voluntary, sub-hourly market covering the NV Energy, PacifiCorp West, PacifiCorp East, and ISO BAAs. ISO’s EIM is a regional five-minute balancing market, as well as real-time unit commitment. EIM software would automatically dispatch imbalance energy across these BAAs every five minutes using a security-constrained least-cost dispatch algorithm. By providing an interregional market for intra-hour imbalance energy, the expanded EIM would complement NV Energy’s existing procedures for transacting with the ISO’s day-ahead markets on a bilateral basis. This study assumes that ISO hour-ahead and day-ahead markets will remain unchanged and that NV Energy will continue its existing practices for resource adequacy planning, unit commitment prior to real-time, regulation and contingency reserves, and regional reserve sharing agreements.

NV Energy participation in the EIM is expected to lead to three principal changes in system operations for NV Energy and the current EIM participants:

+ More efficient interregional dispatch. The EIM would allow more efficient use of generators and transmission systems by reducing “transactional friction” and structural impediments between NV Energy
and ISO BAAs,\textsuperscript{13} eliminating within-hour limitations, and enabling more efficient dispatch between BAAs relative to current scheduling practices.

+ \textbf{Reduced flexibility reserve requirements.} By pooling variability in load and wind and solar output, NV Energy, and the current EIM participants would each reduce the quantity of reserves required to meet flexibility needs.

+ \textbf{Reduced renewable energy curtailment in the ISO.} By having the additional NV Energy generators to reduce output when the ISO faces an “over-generation” situation, the expanded EIM would reduce the amount of renewable energy ISO would otherwise need to curtail. The study quantification focused on benefits of reduced ISO curtailment. There could be wider curtailment benefits throughout the EIM footprint that were not quantified in the study.

This study calculates the benefits associated with these changes by comparing the total cost of operating the combined systems under two cases: (1) an NV Energy (NVE) BAU Case, representing operating practices under a “business-as-usual” case in which NV Energy does not participate in the EIM; versus (2) an NVE EIM Case, in which the EIM is extended to include the NVE BAAs.\textsuperscript{14} The cost difference between the NVE BAU Case and the NVE EIM Case represents the incremental benefits of NV Energy participating in the EIM. The study also

\textsuperscript{13} This study conservatively assumed that interties between NV Energy and the Pacificorp East system cannot be utilized for the EIM based on existing contractual rights over those ties. It is uncertain at this time whether existing contractual rights would support the use of these facilities by the EIM. If they are ultimately available to the EIM, these paths may create additional savings from dispatch efficiency improvements not modeled in this analysis.

\textsuperscript{14} NV Energy has historically operated as two BAAs, Nevada Power and Sierra Pacific Power, but those entities increasingly operate as a jointly coordinated single system. For clarity, NV Energy is treated as a single BA in this modeling work and in the descriptions in this report. This assumption has a negligible impact on the modeling results. NV Energy consolidated its two BAAs on January 1, 2014.
provides a high-level estimate of how these benefits might be apportioned between NV Energy and current EIM participants.

2.1.2 EIM COSTS

The costs of an EIM include those incurred by the market operator to set up and operate the EIM, and those incurred by EIM market participants. Expanding the EIM to include NV Energy would require some expansion of ISO’s EIM software capabilities, but much of the initial setup is expected to be completed by October 2014. In this study, NV Energy is assumed to be the only incremental EIM participant, and NV Energy’s participation in the EIM is assumed to create no additional costs for the current EIM participants, beyond those that are covered in ISO initial setup and administrative charges.

The ISO’s EIM Draft Final Proposal outlines the initial setup fee and ongoing administration fee that the ISO will charge participants for joining and using the EIM.\(^5\) The ISO’s proposed operator charges for the EIM use a “pay-as-you-go” approach, which allows the EIM to expand as new market participants join. The one-time upfront charge depends on the size of the BAA and covers the cost of making the modeling, systems, and other preparations to include an entity in the EIM. Ongoing administrative charges cover costs to operate the EIM, and are based on the same cost structure as ISO’s existing grid management charge and the EIM participant’s level of usage. For NV Energy to participate in the EIM,

ISO estimates that NV Energy would incur a one-time fixed charge of approximately $1.1 million and $0.7 million per year in administrative charges.\textsuperscript{16}

NV Energy provided estimates its hardware and organizational costs to participate in the EIM. These include new metering or communications hardware to enable effective communication between parties, and some amount of staff training and organizational development to more fully take advantage of the market opportunities offered by the EIM. NV Energy’s preliminary cost projections, including ISO’s one-time setup fees and annual usage fees, are listed in Table 6. Using these estimates, total fixed and operating costs for NV Energy’s participation in the EIM would consist of $11.2 million in one-time startup costs, and $2.6 million per year in annual ongoing costs.

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Timing</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>One time capital costs for setup in preparation to participate in EIM</td>
<td>One-time</td>
<td>$10.1</td>
</tr>
<tr>
<td>One-time ISO intial setup fee</td>
<td>One-time</td>
<td>$1.1</td>
</tr>
<tr>
<td><strong>Total One-time costs:</strong></td>
<td></td>
<td><strong>$11.2</strong></td>
</tr>
<tr>
<td>Ongoing costs for staff, software, &amp; administration</td>
<td>Annual</td>
<td>$1.9</td>
</tr>
<tr>
<td>Estimated annual ISO usage fees</td>
<td>Annual</td>
<td>$0.7</td>
</tr>
<tr>
<td><strong>Total ongoing annual costs:</strong></td>
<td></td>
<td><strong>$2.6</strong></td>
</tr>
</tbody>
</table>

\textsuperscript{16} ISO annual administrative fee is based on a participant's gross imbalance energy of both load and generation with a minimum volume set at 5% of the gross generation and 5% of the gross load. The exact rate for 2015 and following years will be determined as part of the ISO GMC (General Management Charge) stakeholder process but ISO staff currently anticipate a rate of approximately $0.20/MWh. Other cost and risk allocation issues associated with the EIM, and the proposed rules to address these issues, have been discussed as part of the EIM stakeholder process. See “Energy imbalance market,” CAISO, accessed November 21, 2013, http://www.caiso.com/Informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx
2.1.3 KEY MODELING ASSUMPTIONS

Eight key modeling assumptions are important for understanding the results in this study: 1) the use of wheeling rates for power transfers between BAAs; (2) dispatch on an hourly time scale; (3) the treatment of flexibility reserves; (4) transfer capabilities between NV Energy and the current EIM participants, and over facilities jointly owned with third parties; (5) limits on hydropower contributions to reserves; (6) the availability of NV Energy generation to participate in the EIM; (7) the impact of the EIM on unit commitment; and (8) attribution of EIM benefits. This section provides a brief overview of the rationale for these assumptions.

2.1.3.1 Wheeling rates at BAA boundaries

Within the Western Interconnection’s bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;

+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, resulting, in some cases, in multiple or “pancaked” loss
requirements that are added to the "pancaked" fixed costs described above; and

+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such as the standard 16-hour "Heavy-Load Hour" and 8-hour "Light-Load Hour" day-ahead trading products defined by the Western Systems Power Pool, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

In production simulation modeling, which attempt to minimize the cost of plant dispatch, these impediments to trade are typically represented by price adders, charged in $/MWh of flow over specific transmission interfaces, that inhibit power flow over transmission paths that cross BAA boundaries. Due to the complexity of the transmission system topology in the area where their systems’ connect, the ISO and NV Energy study team conservatively chose to use only a "wheeling rate," based on existing point-to-point transmission tariff rates and ISO’s projected wheeling access charges, to represent the various types of impediments to trade. Use of a wheeling rate in the ISO NVE study is a conservative assumption, as it may allow generators in the NVE BAU Case to be dispatched in a more optimized, lower cost pattern than typically occurs in actual practice across the boundaries of BAAs in the Western Interconnection.

An EIM would perform a security-constrained, least-cost dispatch across the entire EIM footprint for each 5-minute settlement period, eliminating the barriers listed above and allowing more efficient (i.e., lower cost) dispatch. This effect is represented conservatively in this analysis by removing the wheeling rate between the NV Energy and ISO BAAs in the NVE EIM Case.
The removal of wheeling rates in the analysis mirrors proposed changes under the EIM. The ISO has proposed to not charge wheeling rates on EIM transactions for at least the first year of EIM operation beginning with the PacifiCorp participation. The ISO intends to review policy associated with transmission used to support EIM transfers, following initial operation and results of the EIM. If the ISO finds it appropriate to recover additional fixed costs from EIM participants in future years, the ISO would attempt to implement those charges in a manner that mitigates any negative impacts on potential efficiency savings from the EIM. Also, the other forms of transactional friction described above would continue to be alleviated by the EIM regardless of fixed cost recovery modifications.

2.1.3.2 Hourly dispatch

While the EIM will dispatch generators on a 5-minute timestep, the study team used GridView simulation runs with an hourly timestep to estimate the change in operating costs associated with NV Energy’s participation in the EIM. This hourly dispatch approach was done in order to simplify the computational process and reduce model runtime, and because of the limited quantity of sub-hourly data available for the Western Interconnection.

This assumption introduces two potentially offsetting modeling inaccuracies. On the one hand, since hourly operations would continue to be performed using today’s operating practices, the use of an hourly timestep might overestimate the potential benefits of the EIM, because changes in dispatch that are feasible on an hourly timestep might not be feasible on a 5-minute timestep due to ramping limitations. On the other hand, this method excludes EIM savings due
to more efficient dispatch of resources to serve net load requirements inside the operating hour to meet potential intra-hour ramping shortages.

Other studies have indicated that the cost savings from sub-hourly dispatch may be substantial. Those savings would be additional to the benefits reported here. With the release of Order 764, which requires 15-minute scheduling across BA boundaries, FERC has recognized that sub-hourly dispatch can significantly reduce costs. An EIM would provide significant additional cost savings over sub-hourly bilateral scheduling by providing automated, optimized software for facilitating cost-effective transactions on a time scale that may not be feasible through bilateral trading alone.

### 2.1.3.3 Flexibility reserves

BAs hold reserves to balance discrepancies between forecasted and actual load within the operating hour. These “flexibility” reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies. Flexibility reserves generally fall into two categories: regulation reserves automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to five minutes, while load following reserves provide ramping capability to meet changes in net loads between a 5-minute and hourly timescale.

Higher penetration of wind and solar energy increases the amount of both regulation and load following reserves needed to accommodate the uncertainty

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17 This study assumes that contingency reserves would be unaffected by an EIM, and that NV Energy would continue to participate in its existing regional reserve sharing agreement for contingency reserves.
and variability inherent in these resources while maintaining acceptable balancing area control performance. By pooling load and resource variability across space and time, total variability can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by requiring fewer thermal generators to be committed and operated at less efficient set points.

For this analysis, the study team performed statistical calculations to approximate the reduction in flexibility reserves that would occur if NV Energy joins the EIM. The reserve quantities are a function of the variability and uncertainty of the within-hour net load signal. These requirements decline when the calculations are performed for a larger geographic area and a more diverse portfolio of wind and solar resources. In keeping with the 5-minute operational timestep of a potential EIM, the study team assumed that the diversity benefit from an EIM results in savings from reduced load following reserves, but not regulation reserves. Contingency reserves were assumed not to change under the EIM operation.

There are two implicit assumptions embedded in this approach: (1) that in the NVE BAU Case, NV Energy and current EIM participants would carry the calculated levels of load following reserves, and (2) that the EIM would include a mechanism to take advantage of increased net load diversity by reducing the quantities of load following reserves that would need to be carried, and by allowing load following reserves to be carried at the EIM level rather than at the BAA level.
With regard to the first assumption, while there is currently no defined requirement for BAs to carry load following reserves, all BAs must carry load following reserves in order to maintain control performance standards within acceptable bounds, and reserve requirements will grow under higher renewable penetration scenarios. ISO already has implemented a “flexi-ramp” constraint in its dispatch process to maintain sufficient upward flexibility in the system within the hour; this mechanism includes payments to compensate these generators selected for the ramp they provide.\(^\text{18}\) ISO is also in the process of introducing a “flexi-ramp” product for this purpose, which could including a process in ISO markets to most efficiently determine the generation that provides flexi-ramp.

With regard to the second assumption, while the specific design of a the flexi-ramp product has not been finalized, it is logical to assume that the ISO’s flexi-ramp requirements (for the product or the flexi-ramp constraint) would be calculated in such a way as to maximize diversity benefits across the entire EIM footprint, within the context of its 5-minute operational timestep.\(^\text{19}\) It should be noted that this product may not be in place by the time the EIM becomes operational, and EIM participants may require a period of operational experience before the full benefits of flexibility reserve savings can be achieved.

At a minimum, however, when the EIM becomes operational, the flexible ramp constraint and settlement will exist. In addition, the ISO will determine flexible ramp constraint requirements for the ISO and each EIM Entity based on the


\(^{19}\) For more detail regarding the proposed approach for determining, procuring and allocating flexibility requirements under EIM, see Section 3 A.3 of ISO, Energy Imbalance Market Draft Final Proposal http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092513.pdf
aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate profiles, the benefits of diversity will be realized with the initial EIM implementation. Furthermore, the EIM design will compensate resources for their contribution to meeting the flexibility constraint. As a result, the EIM does provide an opportunity both for resources to be compensated and also for load serving entities to efficiently meet their flexibility requirements with recognition of the load and resource diversity benefits.

The low range scenario for flexibility reserve benefits captures a more conservative arrangement, by valuing the quantity reduction in load following requirements at historical ISO ancillary service market prices. This low range scenario would reflect a situation in which the flexi-ramp product must initially be held within the ISO BAA and is not allowed to be selected on an EIM-wide basis. While this still enables the total quantity of flexibility reserves across the EIM to be reduced, it limits the ability of load serving entities to substitute more expensive sources of load following reserves inside the ISO BAA with purchase of flexibility reserves from less expensive sources in other EIM participants’ BAAs, even when it would be economic.

2.1.3.4 Transmission transfer capability

E3’s PacifiCorp-ISO EIM study indicated that physical or contractual transmission transfer capability limits can constrain EIM operations and limit the resulting benefits. For this report, the study team assumed that, in all cases (including the
BAU case), the initial EIM between ISO and PacifiCorp will be operating with 400 MW of transfer capability between the ISO and PacifiCorp West systems.\(^\text{20}\)

NV Energy and ISO have significantly more transmission capacity directly connecting their two BAAs than PacifiCorp and ISO. NV Energy and ISO interconnections include 230 kV lines connecting the Desert View (ISO/VEA) to Northwest (NVE) substations, the Eldorado (ISO) to Magnolia (NVE) substations, and the Eldorado (ISO) to Nevada Solar One (NVE) substations, and a small number of additional connections at lower voltages. In addition, NV Energy and ISO each co-own transmission rights with the Western Area Power Authority (WAPA) to the Mead substation, and NV Energy and the Los Angeles Department of Water and Power (LADWP) co-own 1500 MW of transmission rights over the 500 kV lines connecting the Crystal and McCullough substations,\(^\text{21}\) and both also own rights in the 230 kV lines that connect the McCullough substation to the ISO’s Eldorado substation. Based on guidance from NV Energy and the ISO staff on how they schedule power over these co-owned facilities, both entities indicated that these facilities could be utilized on a dynamic, sub-hourly basis to facilitate transactions under the EIM. Also, NV Energy and ISO would not be required to pay wheeling rates to LADWP or WAPA provided that scheduled flows over these co-owned facilities do not exceed the portion of transmission capability owned or controlled by NV Energy and ISO. In aggregate, the Southern Nevada Transmission Interface, composed of numerous facilities and contract rights was set at the WECC approved Accepted Path

\(^{20}\) This transfer capability level has not been defined and is part of an ongoing stakeholder discussion. The 400 MW assumed for this study is the value used in the middle range scenario of the PacifiCorp-ISO EIM analysis, which also modeled 100 MW and 800 MW transfer levels.

\(^{21}\) NV Energy owns a 522 MW share of these transmission facilities.
Rating of 4,465 MW and 3,948 MW for north to south and south to north capabilities, respectively. In addition, all known thermal and path limitations were enforced.

This study conservatively assumed that interties between NV Energy and the PacifiCorp East system cannot be utilized for the EIM. If utilized by the EIM, these paths may create additional savings from dispatch efficiency improvements that are not captured in this analysis. Even without utilization of those paths, NV Energy’s participation in the EIM could still provide incremental efficient dispatch opportunities and flexibility diversity through each participant’s EIM interaction over ties shared with ISO.

2.1.3.5 Limits on hydropower contributions to flexibility reserves

The PacifiCorp-ISO EIM study indicated that cost savings from reduced flexibility reserves are sensitive to assumptions about the availability of hydropower to provide flexibility reserves. To address this sensitivity, in the PacifiCorp-EIM study E3 modeled a range of benefits by assuming that between 12% and 25% of the total nameplate capacity of hydropower generation is available to provide flexibility reserves. EIM benefits were higher in the scenario where hydropower’s ability to provide flexibility reserves is restricted, because a higher proportion of reserves are being provided by thermal resources that can be optimized using the EIM dispatch software.

For NV Energy, hydropower makes up a smaller portion of generation resources than for PacifiCorp, so the availability of hydropower to provide reserves would likely have a less significant impact on the expected benefits in this analysis. For simplicity, this study models all scenarios with the less restrictive 25% cap on
reserves from hydropower resources, which is consistent with the reserve flexibility provided by hydro units in the ISO BAA during 2011 and 2012.\textsuperscript{22}

\textbf{2.1.3.6 Availability of NV Energy generation to participate in the EIM}

The EIM will dispatch imbalance energy from generators that voluntarily bid to increase or reduce output. Because generator participation is voluntary, BAs would always have the option to continue to operate some or all of their generators per existing practices (i.e., by not bidding them into the EIM). NVE staff have indicated the potential that, at least in the early phases of EIM operation, certain NV Energy generators may need to be held out of the EIM if they are needed for local ramping and peak load service during high load summer months (June through September).\textsuperscript{23}

If some or all NV Energy generators did not participate in the EIM during certain months, NV Energy could still realize a smaller portion of EIM benefits by obtaining access to flexible generation in the ISO BAA to serve NV Energy ramping needs, and could still benefit from the EIM’s reduced load following reserve requirements. The study team addressed the possibility that some NV Energy generators may not participate in the EIM during summer high load months by scaling interregional dispatch benefits downward by one-third, the fraction of months in which NV Energy generators might not be available to participate in the EIM. This low range scenario would also cover a situation in

\textsuperscript{22} ISO data indicates that the average flexibility offered by ISO hydro units as a percentage of nameplate capacity was 22\% in 2011 and 29\% for 2012.

\textsuperscript{23} This assumption does not imply that resources are expected to be held out of the EIM for these months, but creates a low case scenario to book-end sub-optimal participation during a portion of the year.
which a subset of NV Energy generators self-schedule their dispatch and do not participate in the EIM for certain hours, even if not for an entire four-month span, reducing the opportunities for optimized dispatch between BAAs to a level between the low and high ranges.

2.1.3.7 Impact of the EIM on unit commitment

While the original EIM concept was limited to a 5-minute dispatch, the ISO’s proposed EIM design also now leverages real-time commitment capability, as well as an optimized dispatch market on a 15-minute basis as well as 5-minute dispatch.24 The unit commitment process that exists today and therefore the process that would exist under an EIM is highly uncertain and variable across the Western Interconnection. NV Energy, for instance, has a mix of slow-start and fast-start generating units with a range of start-times. Faster starting units, including combustion turbines (CTs), can more easily make more efficient commitment decisions based on dispatch signals from an EIM, whereas long-starting units lack this flexibility. Units with medium-length start times of 5 to 6 hours, however, can also benefit from EIM market demand and price signals to create a more optimal commitment pattern that is consistent with the real-time market. The EIM’s real-time commitment capability will use a 5-hour time horizon that could pre-start certain units. NV could also choose to self-schedule its own generators in the day-ahead time period based on its

24 FERC Order 764 policy directs transmission operators to permit system users to submit schedules on a 15-minute basis. The proposed EIM, however, would provide significant additional cost savings over sub-hourly bilateral scheduling by providing automated, optimized software for facilitating cost-effective transactions on a time scale that may not be feasible through bilateral trading alone. ISO has incorporated real-time unit commitment into the EIM functionality to provide further opportunities for improved efficiency.
expectation of EIM market demands and prices. Convergence bidding in the ISO market can also help to link market decisions in real-time and at day-ahead.

Given the uncertainty in the number and frequency that different types of generators will participate directly or indirectly, the high scenario for interregional dispatch benefits assumes that in the EIM scenarios, market participants will alter unit commitment decisions bids based on learning and anticipation of the conditions of the 5-minute dispatch with EIM, or that ISO’s real-time unit commitment capability will be able to facilitate more efficient unit commitment decisions. A full joint unit commitment between the BAs would also lead to this outcome. To the extent that more efficient unit commitment decisions by long- and medium-start generation units in response to the EIM is more limited, interregional dispatch benefits could be lower than those estimated in the high scenario.

The low scenario, which reduces interregional dispatch benefits by one-third compared to high case scenario, results in a lower savings level that can account for more limited unit commitment efficiency improvements through learning by long-start generators in the BAAs of EIM participants. The low scenario does also still include dispatch efficiency improvements on fast-starting units as well as long-start units that are already committed and can vary their real-time dispatch level within an online operating range in response to the EIM.

Also, for calculating dispatch benefits, the GridView model commits generation using perfect foresight of the identical hourly net load requirements that will occur in real-time for both the BAU and EIM cases. By contrast, in actual operations, the expected load requirements change between the day-ahead
unit commitment and real-time, and generators dispatch levels must adjust to respond to these changes. The EIM can provide value through improving the efficiency of how generators in the EIM footprint respond to these real-time changes in need. In the simulation, however, this value may not be fully captured in the dispatch benefits of the low or high case scenarios due to the absence of change in anticipated load levels and other supply variability during the unit commitment versus real-time dispatch period. Additionally, the quantified dispatch savings in both high and low scenarios excludes all potential EIM savings inside the operating hour to meet potential intra-hour ramping shortages and sub-hourly changes in anticipated net load requirements, which may be a substantial additional source of interregional dispatch efficiency improvement.

2.1.3.8 Attribution of EIM benefits

In the GridView results, a portion of the generation changes that produce the savings reported here occur in other WECC regions, such as LADWP, WAPA, and APS in the desert southwest.

This assumption is balanced by offsetting limitations in GridView. GridView determines dispatch and power flows based on transmission system impedances, which creates two types of modelling deficiencies. First, the model tends to under-predict that actual flow that would be created between the direct EIM participants. In actual operations, these flows are partially dictated through contract path, which would allow for more transactions that produce savings to be concentrated within participating jurisdictions than can be simulated in GridView.
Second, a portion of the generation changes that produce the dispatch savings reported here occur in other WECC regions, such as LADWP and WAPA and APS in the desert southwest. In practice, NV Energy participation in the EIM may bring indirect benefits to certain entities as they respond to greater efficiencies in regional dispatch; such efficiency improvements outside of the EIM footprint are expected to result in savings for EIM participants through lower cost purchases. We have assumed that the impact of these modeling limitations is well within the range of the high and low scenario savings levels modeled.

2.2 Methods

2.2.1 INTERREGIONAL DISPATCH SAVINGS

NV Energy's participation in the EIM would reduce transactional friction between NV Energy and current EIM participants, enabling improved dispatch efficiency and reducing the cost to serve load for NV Energy and the current EIM participants. The study team estimated these interregional dispatch savings by running parallel production cost simulations using GridView: one with NV Energy participation in the EIM (NVE EIM Dispatch Case) and one without NV Energy participation (NVE BAU Case).

The NVE BAU Case simulates status quo operational arrangements, and includes wheeling rates based on point-to-point transmission tariffs to conservatively represent barriers to trade across BAA boundaries. The NVE EIM Dispatch Case eliminates the wheeling rates charged on power flows between NV Energy and ISO, resulting in more efficient dispatch and lower production costs. In eliminating the wheeling rates, the study team implicitly assumed that no
variable transmission costs are incurred for EIM transactions. An additional charge was also applied to imports to California BAAs (ISO, LADWP, Balancing Area of Northern California, and Imperial Irrigation District) to simulate the need for market participants to acquire CO₂ allowances when delivering “unspecified” electric energy into California. These CO₂-related charges were kept in place for both the NVE BAU and the NVE EIM Dispatch Cases. Interregional dispatch benefits from NV Energy participation in the EIM are measured as the difference in production costs between the NVE BAU and NVE EIM Dispatch Cases. The production cost difference used to calculate dispatch benefits for this report does not include any wheeling costs reductions from the simulation case results, only generator cost savings.

The interregional dispatch benefits results include high and low range scenarios. The high range includes the full difference in production costs between the NVE BAU and NVE EIM Dispatch Cases. The low range reflects the potential that all NV Energy generators may not be available for dispatch under the EIM during high load summer months. As described above, the study team accounted for this possibility by scaling the full interregional dispatch efficiency benefits downward by one-third (4 months of non-availability divided by 12 months in the year).

2.2.2 REDUCED FLEXIBILITY RESERVES

Currently, NV Energy meets its flexibility reserve requirements by procuring and utilizing existing generating capacity within its BAA. An expanded EIM would lower the total cost of procuring and utilizing flexibility reserves for both NV Energy and current EIM participants in two ways: (1) reducing flexibility reserve
quantities by combining NV Energy’s, and the current EIM participants’ forecast error for load and variable generation; and (2) enabling flexibility reserves to be procured from thermal or hydropower resources anywhere in the expanded EIM footprint, subject to transmission constraints. The result is that the combined cost of procuring flexibility reserves with an expanded EIM is less than it would be if NV Energy and current EIM participants procured them independently.

The study team used three steps to estimate incremental cost savings from reduced flexibility reserves that result from NVE joining the EIM:

1. Estimate the quantity of flexibility reserves required by NV Energy and current EIM participants, as separate entities. In this first step, flexibility reserve requirements were calculated for NV Energy, as a separate BAA, and for the PacifiCorp-ISO EIM (NVE BAU Case). Flexibility reserves requirements for NV Energy were based on NVE’s 2013 IRP Analysis, which projected the need for 41 MW of load following reserves in 2017 and 91 MW in 2022. Flexibility reserve requirements for ISO were based on its updated projection of upward flexibility needs for each period, and adjusted downward to reflect reductions in flexibility reserve requirements enabled by the PacifiCorp-ISO EIM, subject to a 400 MW transmission constraint between PacifiCorp and ISO.

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NV Energy is also assumed to require 35 MW of regulation reserves in all hours based on NV Energy IRP projections. ISO staff provided 2017 and 2022 hourly regulation and load following requirements for California based on recent internal analysis; For PacifiCorp, the model used the load following reserve requirement levels developed for the PacifiCorp-ISO EIM analysis at the 400 MW transfer capability level.
2. **Estimate the quantity of flexibility reserves required by the combined, expanded EIM.** In the second step, the study team calculated flexibility reserve requirements for the combined EIM footprint (NVE EIM Flexibility Reserve Case).\(^{27}\) The reduction in the total required flexibility reserves is the difference between the flexibility reserve requirements in the NVE BAU Case and NVE EIM Flexibility Reserve Case. The reserve requirements for the current and the expanded EIM are calculated as the geometric sum of the reserve requirement in individual balancing area of each participant.\(^{28}\)

Table 7 shows the study team’s estimates of the combined minimum reserve requirements for NV Energy and the current EIM participants, with and without NVE’s participation in the EIM. In the NVE BAU Case, NV Energy must hold 76 MW of flexibility reserves (35 MW regulation plus 41 MW load following) in 2017 and 126 MW in 2022; the PacifiCorp-ISO EIM must hold 1,968 MW (551 MW regulation and 1,415 MW load following) in 2017 and 2,545 MW (685 MW regulation and 1,859 MW load following) in 2022.

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\(^{27}\)These results, when scaled back from 2017, are similar in size to the levels of reserves procured in each jurisdiction today for regulation and load following.

\(^{28}\)This approximation of the impact of diversity on reserve requirements assumes minimal covariance between neighboring balancing areas; separate analysis has concluded that the covariance is very small relative to the variance when calculated across a larger geographic area, and on narrow times scale, such as the 5-minute to one hour time frame.
Table 7. Estimated total minimum reserve holdings under the NVE BAU Case and NVE EIM Flexibility Reserve Case in 2017 and 2022

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulation Reserves Requirements (All cases)</td>
<td>586</td>
<td>720</td>
</tr>
<tr>
<td><strong>Load Following Reserves Requirement for:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NVE BAU Case (NVE as Standalone)</td>
<td>1,457</td>
<td>1,950</td>
</tr>
<tr>
<td>NVE EIM Flexibility Reserve Case</td>
<td>1,416</td>
<td>1,851</td>
</tr>
</tbody>
</table>

As the table indicates, NV Energy’s participation in the EIM reduces the minimum required reserve holdings by 41 MW in 2017 and 89 MW in 2022. The size of the load following reduction in 2022 is more than twice as large as in 2017 because NV Energy anticipates that it will have a larger standalone load following requirement after additional renewables come online by 2022.

3. *Estimate the production cost savings attributable to needing to hold fewer flexibility reserves and being able to procure them from a larger more diverse mix of resources.* In the third step, the study team applied the estimated flexibility reserve requirements to production cost simulation runs for each case, using GridView. In the NVE BAU Case and NVE EIM Dispatch Cases, NV Energy must procure both regulation and load following reserves from capacity located in its own BAA to meet estimated reserve requirements, and NV Energy generation is ineligible to serve load following requirements of the current EIM participants. In the NVE EIM Flexibility Reserve Case, NV Energy and the current EIM participants’ generation is eligible to meet a combined load following reserve requirement for the EIM footprint, subject to transmission constraints.30

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30 Totals include the sum of regulation and load following requirements.
31 The amount of transfer capability between ISO and NV Energy is quite high, and did not appear to be a binding constraint to efficient procurement of flexibility reserves between ISO and NV Energy EIM Reserve scenario, but the 400 MW PacifiCorp-ISO transfer capability constraint was binding on flexibility reserve procurement.
Each BA must still meet its own regulation reserve requirement with generation located within its BAA, consistent with the EIM’s 5-minute dispatch.

The difference in production costs between the NVE EIM Dispatch Case and NV EIM Flexibility Reserve Case represents the annual benefit of reduced flexibility reserves, over and above dispatch benefits.

To account for uncertainty in EIM participants’ ability to procure flexibility reserves from across the EIM footprint, the study team produced a high range and a low range benefits scenarios. The high range scenario includes the full estimated benefits described above. For the low range scenario, the study team valued the reduction in load following reserve quantities in Table 3 at ISO’s historical market prices for ancillary services, rather than using the difference in production costs estimated from GridView. Again, this low range scenario is conservative in that it does not include additional savings from being able to procure flexibility reserves from across the expanded EIM.

2.2.3 REDUCED RENEWABLE ENERGY CURTAILMENT

High penetrations of variable generation increase the likelihood of over-generation conditions. In these situations, curtailment of variable generation may be necessary since the system is not flexible enough to reduce the output from other resources within the same BAA. Based on discussions with ISO, over-generation conditions and the curtailment of renewable generation are likely to be a long-term issue as additional wind and solar resources come online.

As a standalone BA, the ISO schedules imports on an hour-ahead basis and may find it difficult to back down imports on shorter timescales if local renewable
generation is higher or if load is lower than expected. NV Energy participation in the EIM could potentially avoid over-generation situations since it could enable ISO to reduce imports from NV Energy in real-time, rather than having to curtail renewables during minimum generation or ramp-constrained intervals.

The study team calculated the total benefits of reduced energy curtailment in the ISO BAA by multiplying estimates of: (1) the annual amount of renewable energy curtailed when simulating ISO operations as a standalone entity without an EIM, and (2) the value of curtailed renewable energy (in $/MWh). The result represents the cost of renewable energy curtailment that an EIM could help to avoid, assuming that generation in the other EIM participant BAs is available to back down during these situations. To estimate the incremental curtailment savings from NV Energy participation in the expanded EIM (i.e., as compared to the initial PacifiCorp-ISO EIM), the study team assumed that PacifiCorp’s participation in the EIM (in the NV BAU Case) has already reduced 50% of total renewable curtailment, lowering the remaining quantity of renewable energy curtailment that could be reduced through NV Energy EIM participation by 50%.

The PacifiCorp-ISO EIM Study assumed a range of 10% to 100% of the modeled curtailment in the ISO BAA could be addressed by the initial EIM. If a very high percentage of curtailment is reduced by the PacifiCorp-ISO EIM (near 100%), then only a small amount of remaining curtailment could be reduced through NV Energy’s incremental participation in the EIM. More generally, the additional participation of NV Energy in the EIM is expected to result in total avoided renewable curtailment by the EIM at a level closer to the at a higher end of the 10% to 100% range modeled, as NV Energy brings additional thermal generation that could decrease output if needed, and NVE adds an EIM.
connection to the southeastern end of the ISO system, reducing the likelihood
that internal congestion on the ISO system impedes the EIM’s ability to fully
reduce curtailment.

To estimate the level of renewable energy curtailment in the ISO BAA, the study
team developed a methodology that uses outputs from two sequential GridView
model runs. In the first run, representing unit commitment based on forecasted
needs, projected solar, wind, and load profiles were used to estimate economic
imports into ISO. In the second run, representing real-time dispatch, actual
solar, wind, and load profiles were used along with minimum import limits set
to the level of economic imports from the first simulation. This limit prevented
the model from lowering the interchange below the level determined by the
unit commitment process. This reduction in system flexibility resulted in
approximately 120 GWh of renewable energy curtailed by the ISO in 2022. By
assuming that the initial EIM with PacifiCorp relieves 50% of this curtailment,
the remaining curtailment that could be addressed by NV Energy participation in
the EIM is 60 GWh.\footnote{For NV Energy’s participation in the EIM to alleviate renewable energy curtailment in the ISO BAA, NV Energy
would need sufficient generation capability online to ramp down and reduce exports to (or, equivalently, to
increase imports from) ISO, based on the quantity of energy that would otherwise need to be curtailed. An
examination of dispatch in the NV EIM cases indicates that NV Energy generators would typically have sufficient
operating room to ramp down by the curtailment quantities, and that this constraint would have negligible
impact on the potential EIM savings. Ninety-seven percent of the total modeled curtailment quantity would be
unaffected by NV Energy generator headroom constraints in 2017, and 99% of total curtailment would be
unaffected by NV generator headroom constraints in 2022, without requiring NV Energy to decommit thermal
units.}

This estimate of the level of renewable energy curtailed by the ISO (i.e., 120
GWh) is likely conservative. Production simulation models are designed to
utilize normative assumptions regarding load, hydropower conditions, thermal
resource outages, and other variables in order to produce reasonable, mid-range estimates of resource dispatch and prevailing power flows. However, renewable curtailment occurs during extreme events such as very high output of wind, solar, and hydropower resources combined with very low load conditions. These conditions are not well-represented in production simulation modeling inputs. Hence, renewable curtailment is likely to be understated in production simulation model outputs.

The study team calculated avoided curtailment savings based on a $66/MWh value of avoided renewable energy curtailment, as the sum of: (1) a RPS compliance value of $35/MWh based on market prices for bundled renewable energy certificates (REC) from in-state production;\(^{32}\) (2) an average Federal production tax credit (PTC) value of $11/MWh;\(^{33}\) and (3) an estimated $20/MWh avoided production cost of a thermal unit located in the NV Energy BA that an EIM enables to dispatch down to reduce imports to (or increase exports from) ISO. This unit is assumed to be compensated for the decremental ("dec") bid.

The RPS compliance value is based on the cost of renewable energy to satisfy California’s RPS targets. In the short term, the RPS compliance value for avoided in-state curtailment may be lower than $35/MWh for California utilities that have a long renewable energy position in the lead up to the 2020 RPS

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\(^{32}\) Data from Platts McGraw Hill Financial indicates that bid offer range for bundled (Bucket 1) RECs in 2012 was $35 to $40/MWh (http://www.platts.com/news-feature/2012/rec/chart).

\(^{33}\) The $11/MWh average PTC used here is based on the 2013 Federal PTC rate for wind generation of $23/MWh (http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F), applied to the portion of modeled renewable curtailment occurring during night-time hours when wind energy is curtailed, which represented 47% of total simulated curtailment.
compliance date, if the utility does not need to replace the curtailed renewable energy to satisfy its RPS target or is able to purchase significantly less costly unbundled RECs to meet its near-term target. This analysis, however, is focused primarily on benefits over the longer term (i.e., extending beyond 2022), where short-term fluctuations in RPS compliance values are expected to be averaged out by the implementation of new, higher RPS targets or by higher energy (MWh) procurement requirements that result from load growth. With continued growth in renewable procurement amounts, reductions to expected curtailment will reduce the amount of additional renewable energy procurement needed to reach a given RPS target amount. Thus, reduced renewable energy curtailment would be avoiding the cost of procuring additional renewable generation.

The study team used the $66/MWh avoided curtailment value with the simulated renewable curtailment quantity results to develop low and high range scenario benefits for reduced renewable energy curtailment in 2017. In the low range scenario, the study team assumed that reduced curtailment is 10% of the total potential, or 6 GWh. In the high range scenario, the study team assumed that reduced curtailment is 100% of the total potential, or 60 GWh. This range of curtailment estimates was then multiplied by the value of avoided renewable energy curtailment to calculate low and high range estimates of $0.4 million (= 6 GWh * $66/MWh) to $4.0 million (= 60 GWh * $66/MWh), respectively, in benefits for reduced renewable energy curtailment in 2022. For simplicity and transparency, the study team assumed the benefits of reduced renewable energy curtailment were $0.4-$4.0 million for both 2017 and 2022.
The resulting low and high scenarios for avoided renewable curtailment benefits cover a wide range of potential RPS compliance values. In the short term, if we assume a very conservative avoided curtailment value that excludes any REC value and includes only the $11/MWh PTC value and $20/MWh value of the avoided energy production cost out of state generation that are paid to decrement its dispatch, the resulting avoided energy curtailment value ($31/MWh) would represent 47% of the $66/MWh high case value. The resulting total benefit from avoided curtailment, however, would be well above the low sensitivity used for this report, which assumes that only 10% of the high case avoided renewable curtailment benefits are obtained.\textsuperscript{34}

The projected renewable build-out in the ISO BAA is anticipated to continue over the 2017 to 2022 time period, so it is reasonable to expect that avoided curtailment savings in 2017 would fall toward the lower end of the above range, and savings in 2022 would be on the higher end. Moreover, if state RPS targets are raised to higher levels after 2020, resulting renewable curtailment levels could be significantly higher than those modeled here.\textsuperscript{35} Thus, the range of EIM benefits from avoided curtailment included in this analysis would be a highly conservative savings estimate for later years if a higher RPS target is pursued.

\textsuperscript{34} The combined sensitivity of a very low level of curtailment and a very low value per MWh of avoided curtailment could produce resulting benefits below this range, but the 10% low case represents a combination of reasonable low sensitivities on both cases (e.g., 47% of high case curtailment value and 21% of the high case curtailment quantity).

\textsuperscript{35} In a recent study jointly sponsored by California's five largest electric utilities, E3 evaluated the operational challenges, RPS in California by 2030. The studies cases, created using E3's Renewable Energy Flexibility (REFLEX) model on ECO International's ProMaxIT production simulation platform, identified overgeneration and potential need for curtailment in California of 2,000 GWh under a 40% RPS for 2030, and 12,000 GWh under a 50% RPS with significant solar for 2030. The study identified enhanced regional coordination between California and neighboring jurisdictions as a potential solution to help this issue. See E3, "Investigating a Higher Renewables Portfolio Standard in California", January 2014, (http://www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf), p. 15.
2.3 EIM Scenarios

The study team estimated benefits from NV Energy’s participation in the EIM based on two study years: 2017 and 2022. The study team chose 2017 to represent a period after the EIM is operational, but prior to significant changes in load, generation, and transmission. In particular, the modeling of the 2017 study year excludes: (1) a portion of the full build out of renewable resources necessary to meet California’s 33% RPS; (2) the full expected retirements and replacements of ISO thermal generating capacity due to once-through cooling (OTC) regulations; and (3) a number of planned and proposed transmission projects, such as Gateway West. The 2017 scenario does reflect retirement of the San Onofre Nuclear Generation Station (SONGS) in 2013, as well as the subset of OTC generators that are scheduled for retirement before 2017.

By comparison, the 2022 study year represents a medium-range planning case, and includes the full build out of renewable resources to meet a 33% RPS target in California and a number of proposed conventional generation and transmission projects in the West, as well as a projection of higher CO₂ permit prices in California and somewhat higher gas prices through the WECC. While not modeled for this analysis, a number of studies have indicated that longer-term developments post-2022, such as the possibility for higher RPS target levels, would be expected to increase the potential need of, and resulting savings from, regional coordination efforts such as an EIM.

The study team used scenario assumptions to indicate how sensitive benefits are to: (1) the availability of NV Energy generators to participate in the EIM for the full year including summer months; (2) limits on the ability to procure the
least-cost flexibility reserves from across the expanded EIM; and (3) the extent of renewable energy curtailment value that can be avoided through an EIM. These scenarios are designed to reflect the limitations of existing tools to characterize all of the changes to system operations that would occur under an EIM, particularly the modeling of reserves and renewable curtailment. In addition, the two time periods for the scenarios capture a range of uncertainties about the extent to which future industry developments would allow cost savings to occur both with and without an EIM. Table 8 provides a synopsis of key assumptions under the low and high range scenarios.

**Table 8. Low and high range assumptions for 2017 and 2022 cases**

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Low range</th>
<th>High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Availability of NV Energy generators to participate in EIM</td>
<td>Unavailable during June-Sept; annual simulation dispatch benefits scaled downward by one-third (4/12ths)</td>
<td>Available in all months for EIM dispatch; full-year simulation benefits used</td>
</tr>
<tr>
<td>Calculation of flexibility reserve benefits</td>
<td>Quantity reduction in reserve requirements valued at benchmark of average ISO historical ancillary service market price levels</td>
<td>Simulation directly calculates benefits of reduced reserves benefits, and improved efficiency through allowing optimum use of reserves from across EIM footprint (subject to transmission constraints)</td>
</tr>
<tr>
<td>Share of identified renewable energy curtailment value avoided in California</td>
<td>10%</td>
<td>100%</td>
</tr>
</tbody>
</table>
2.4 Benefits of NV Energy Participation in EIM

Figure 2 and Table 9 show the low and high range of benefits from NV Energy's participation in the EIM in 2017 and 2022, and the benefits attributed to each category. Total annual benefits to all participants in 2017 range from $9.2 to $18.2 million; total annual benefits for 2022 range from $15.0 to $29.4 million (2013$).

Figure 2. Low and high range incremental gross annual benefits to all participants from NV Energy Participation in EIM (2013$)

Note: Figure represents total incremental benefits to all EIM participants as a result of NV Energy's participation in the EIM.
Table 9. Low and high range annual benefits to all participants for 2017 and 2022 (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low range</td>
<td>High range</td>
</tr>
<tr>
<td>Interregional dispatch</td>
<td>$6.2</td>
<td>$9.3</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>$2.6</td>
<td>$5.0</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.4</td>
<td>$4.0</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$9.2</strong></td>
<td><strong>$18.2</strong></td>
</tr>
</tbody>
</table>

*Note: Individual estimates may not sum to total benefits due to rounding.*

The low range in Table 9 assumes: (a) NV Energy generators are not available for EIM participation for four summer months of the year; (b) flexibility reserve benefits result only from the reduced quantity of flexibility reserves needed, and do not include reduced costs from procuring reserves across the expanded EIM footprint; and (c) the value of renewable energy curtailment is 10% of the full estimated value. The high range assumes: (a) NV Energy generators are available for full EIM participation throughout the entire year; (b) flexibility reserves can be procured in the lowest cost manner from across the expanded EIM footprint, subject to transmission transfer constraints; and (c) the value of renewable energy curtailment is 100% of the full estimated value.

Differences in individual benefit categories provide important insights into the impact of scenario assumptions on the results.

- Interregional dispatch savings range from $6 million to $9 million in 2017 and from $9 to $13 million in 2022. Year-round participation of NV Energy generators (i.e., as in the high range scenario) raises the benefit level in either year. However the largest sensitivity is the year modeled, with the resource mix and fuel costs assumptions used here for 2022 creating greater opportunities for dispatch efficiency gains compared to
2017. These savings levels are modest relative to total production costs; they represent a production cost reduction of between $0.03 and $0.05 per MWh of load in the NV Energy and ISO BAAs for 2017 and $0.05 to $0.09 per MWh of load in 2022.\textsuperscript{36}

Annual cost savings from reduced flexibility reserves range from $3 to $5 million in 2017, and from $6 to $12 million in 2022. The low to high ranges in both time periods are distinguished by whether NV Energy participation in EIM would solely create cost savings by reducing quantity of flexibility reserves required, or whether NV Energy’s participation can also enable cost reductions from optimal selection of the most efficient sources of reserves from across the EIM footprint. The large difference in results suggests that creating a mechanism to allow optimal selection of flexibility reserves from across an expanded EIM is a very important benefit that should yield significant cost savings.

Cost savings from reduced renewable curtailment are very uncertain. The results here suggest that, even under conservative assumptions, these savings can be an important component of EIM benefits. Because an EIM would provide an automated mechanism for facilitating renewable resource curtailment solutions, as well as clearing any payment required in the event of curtailment, this is likely to be an important and growing EIM benefit going forward.

The results shown in Table 9 show that, even under conservative assumptions, the incremental benefits of NV Energy’s participation in the EIM would be greater than the expected costs, described in Section 2.1.2. The results also

\textsuperscript{36} Calculations based on a total forecasted ISO and NV Energy BAA load of 267 TWh in 2017 and 284 TWh in 2022. If assuming that the EIM will affect energy transactions equal to 10% of BAA loads, these dispatch savings levels would represent cost reductions of $0.34 to $0.53/MWh of affected transactions in 2017 and $0.46 to $0.88/MWh in 2022.
indicate that the benefits of an EIM for the Western Interconnection region are likely to grow as additional participants are added.

2.5 Attribution of EIM Benefits

The study team assumed that the benefits of an expanded EIM would be attributed between NV Energy and current EIM participants as follows:

+ **Interregional dispatch savings.** Savings were split evenly between NV Energy and current EIM participants to reflect: (1) the reduced cost to serve current EIM participants’ load, since expensive internal generation is displaced by low-cost imports from NV Energy; and (2) additional revenues for NV Energy, since it exports additional power to current EIM participants when it joins the EIM. Assuming NV Energy and the initial EIM are the only two entities in the Western Interconnection that change dispatch under the EIM, an even split makes the savings proportional to the absolute value of changes in generator dispatch, as any interval in which NV Energy generation increases under the EIM will have an equal and opposite reduction in dispatch for the initial EIM participants.

**Reduced flexibility reserves.** Flexibility reserve benefits were attributed based on two separate factors. First, the total production cost savings were allocated between NV Energy and the current EIM participants in proportion to their standalone load following requirements, based on the assumption that final load following responsibilities within the EIM would be ultimately allocated based on what each participant would have had to procure as a standalone entity. This results in a roughly 3% and 4% share of benefits attributed to NV Energy and a 97% and 96%
share attributed to the current EIM participants in 2017 and 2022, respectively. The higher share attributed to NV Energy in 2022 is due to its proportionally larger increase in load following requirements between 2017 and 2022.

Additionally, the study team also expects some of the NV Energy's generation to participate directly in the ISO flexi-ramp market when NV Energy becomes an EIM participant. Revenues related to NV Energy generation offering services in the anticipated flexi-ramp product market, or contributing toward the ISO's flexi-ramp dispatch constraint, were modeled as a transfer of a portion of flexi-ramp market revenue from ISO, whose generators are currently receiving 100% of the revenue related to the flexi-ramp constraint, to NV Energy generators.

This transfer was estimated as the product of: (a) ISO's current total flexi-ramp constraint payments in the previous year multiplied by (b) NV Energy generators' share of total capacity of gas and hydro generation in the combined EIM. Total payments to generators related to ISO's flexi-ramp constraint over the most recent 12-month period, from November 2012 to October 2013, were $23.2 million for the entire 12 months, with an average hourly quantity of 433 MW (a $6.1/MWh average cost), and $18.0 million if excluding the summer months of June through September. NV Energy gas-fired and hydropower generation capacity represents 15% of the total gas and hydropower capacity in the expanded EIM footprint. This translates to a range of $2.7 million (excluding summer months) for the low case to $3.5 million for the entire year for the high case. This amount would represent a transfer from the ISO BA to the NV Energy BA entities, which is included as a

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37 This calculation limited PacifiCorp contribution to total EIM gas and hydro capacity to 400 MW to reflect transmission constraints on connection between PacifiCorp and ISO system.
positive value in the attribution of benefits to the NV Energy BA and a negative value in attribution of benefits to current EIM participants.

+ **Reduced renewable energy curtailment.** The bulk of benefits of reduced curtailment (related to avoided loss of RPS compliance value of $35/MWh and PTC value of $11/MWh) were attributed to ISO, because all of the expected reduced curtailment, over the time period considered, would take place within the ISO footprint. NV Energy is attributed a portion (20/66ths, or 30%) of the savings related to $20/MWh avoided costs of thermal generation on the units located in NV Energy BA that decrease output that is replaced by the renewable energy exported from ISO (or reduction to exports from NV Energy to ISO).

The attribution of expanded EIM benefits described above is summarized in Tables 10 and 11. NV Energy achieves annual cost savings of $6-10 million in 2017 and $8-12 million in 2022. Annual cost savings to current EIM participants are $3-9 million by 2017 and $7-17 million by 2022.

**Table 10. Attribution of expanded EIM annual benefits to NV Energy (million 2013$)**

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>2017 Low range</th>
<th>2017 High range</th>
<th>2022 Low range</th>
<th>2022 High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interregional dispatch</td>
<td>$3.1</td>
<td>$4.7</td>
<td>$4.4</td>
<td>$6.7</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>$2.8</td>
<td>$3.6</td>
<td>$3.2</td>
<td>$4.3</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.1</td>
<td>$1.2</td>
<td>$0.1</td>
<td>$1.2</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$6.0</strong></td>
<td><strong>$9.5</strong></td>
<td><strong>$7.7</strong></td>
<td><strong>$12.2</strong></td>
</tr>
</tbody>
</table>

*Note: Attributed values may not match totals due to independent rounding.*
Table 11. Attribution of expanded EIM annual benefits to current EIM participants (million 2013$)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Low range</th>
<th>High range</th>
<th>Low range</th>
<th>High range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interregional dispatch</td>
<td>$3.1</td>
<td>$4.7</td>
<td>$4.5</td>
<td>$6.7</td>
</tr>
<tr>
<td>Flexibility reserves</td>
<td>-$0.2</td>
<td>$1.4</td>
<td>$2.5</td>
<td>$7.7</td>
</tr>
<tr>
<td>Renewable curtailment</td>
<td>$0.3</td>
<td>$2.8</td>
<td>$0.3</td>
<td>$2.8</td>
</tr>
<tr>
<td><strong>Total benefits</strong></td>
<td><strong>$3.2</strong></td>
<td><strong>$8.8</strong></td>
<td><strong>$7.3</strong></td>
<td><strong>$17.2</strong></td>
</tr>
</tbody>
</table>

*Note: Attributed values may not match totals due to independent rounding.*

The approach described above simply attributes total cost savings between NV Energy and current EIM participants and does not attempt to account for changes in market revenues relative to today’s bilateral system. It is not intended to be a methodology for allocating costs and benefits. The actual net costs and benefits that would flow to the NV Energy system and those of the current EIM participants may be different from the assumptions used here.
3 Interpreting the Results

3.1 Conservative Nature of the Results

Because of the difficulties in modeling the operational complexities of an EIM, the study team’s approach was intended to use conservative to moderate assumptions to generate credible results, both as a standalone analysis and relative to other studies. Table 12 provides a high-level overview of the nature of assumptions (conservative, moderate, aggressive) used for each of the three identified categories of benefits, and an explanation of why the assumptions were considered to be conservative or moderate. Based on NV Energy staff guidance that the NV Energy BAA currently has minimal internal congestion, the study team made the conservative assumption that intra-regional dispatch savings would be negligible, and it was not included in this study.
Table 12. Categorization of assumptions used in this study

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Assumptions (conservative, moderate, aggressive)</th>
<th>Rationale</th>
</tr>
</thead>
</table>
| Interregional dispatch | Conservative-Moderate | • Study used wheeling tariff rates to inhibit trade between ISO and NVE in NV BAU Case, a conservative assumption that does not add additional charges for other forms of friction that may also impede trade in current operating context  
• Hourly cost differences between natural gas-fired generators are understated in production simulation models due to the use of uniform heat rates assumptions and normalized system conditions; these models understate potential benefits of NV Energy participating in EIM  
• Study assumed that EIM will facilitate more efficient real-time unit commitment, a moderate assumption, based on learning over time and the EIM’s real-time unit commitment capability  
• Study assumed that all incremental cost savings from dispatch changes under the EIM accrue to EIM members, a moderate assumption |
| Flexibility reserves | Conservative | • Study modeled low range based on the quantity reduction in reserves requirements prices historical ISO market prices, which would not incorporate the potential savings for substitution of lower cost resources for reserves from across the EIM footprint in place of higher cost reserves within the local BA if no EIM were available  
• Study included operating cost only; no capacity cost savings are included, which limited EIM benefits  
• Study allowed 25% of total hydropower capacity to contribute to flexibility reserves in the low range estimates, which limited EIM benefits  
• Study did not require lock-down of dispatch 45 minutes prior to the operating hour, as done in other studies, which would have raised the quantity of reserves required and increased EIM benefits |
<p>| Renewable | Conservative | • Study did not evaluate renewable curtailment |</p>
<table>
<thead>
<tr>
<th>curtailment</th>
<th>for NV Energy, which limited EIM benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• In low range estimate, study assumed wind and solar not producing significant over-generation (conservative assumption)</td>
</tr>
<tr>
<td></td>
<td>• Production simulation models understate the frequency with which low net load/high generation events occur due to their use of idealized operating assumptions; these models limit EIM benefits</td>
</tr>
<tr>
<td>Within-hour dispatch</td>
<td>Conservative</td>
</tr>
<tr>
<td></td>
<td>• Production simulation analysis modeled at hourly level, omitting potential benefits of sub-hourly dispatch (other studies indicate that these benefits could be substantial)</td>
</tr>
</tbody>
</table>

### 3.2 Comparison to other Studies

Several recent studies have examined the potential benefits of greater balancing area coordination in the Western Interconnection. These include:

+ **PaciﬁCorp-ISO EIM Study** — examined the benefits of an initial EIM between PaciﬁCorp and ISO;\(^38\)

+ **WECC EIM Analysis (completed in 2011)** — examined the benefits of an hourly EIM in parts of the WI region; undertaken by E3 for WECC;\(^39\)

+ **PUC EIM Group Analysis (completed in 2012)** — examined the benefits of a 10-minute EIM in parts of the WI region; undertaken by the National Renewable Energy Laboratory (NREL) for the PUC-EIM Group;\(^40\)

+ **WECC VGS (completed in 2013)** — examined the benefits of 10-minute bilateral scheduling for the entire WECC region; undertaken by the

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\(^39\) See [http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf](http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf) for the final report.

Pacific Northwest National Laboratory (PNNL) for WECC as part of the WECC Variable Generation Subcommittee (VGS), 41

**NWPP EIM (completed in 2013)** — examining the benefits of 5-minute security constrained economic dispatch for the Northwest Power Pool (NWPP) footprint, undertaken by PNNL for the NWPP Market Assessment and Coordination (MC) Initiative using a 10-minute dispatch model. 42

The above studies can be broadly categorized into two different approaches. The first three studies use hurdle rates to capture transactional friction between BAAs in the base case, which are removed in the EIM case. They also assume that an EIM will enable BAs to reduce the quantity of flexibility reserves that they would need to carry for wind and solar integration. The last two studies assume transactional friction between balancing areas is not alleviated by an EIM on an hourly timestep, and that an EIM will not reduce the quantity of regulation and flexibility reserves required for wind and solar integration. Instead, they conduct detailed analysis of dispatch changes that would occur on a 10-minute timestep compared to a fixed hourly interchange schedule between BAAs.

The assumptions and methodologies selected for the analyses above informed the development of this study. The approach used in this study is consistent with the PacifiCorp-ISO EIM, WECC EIM, and PUC Group EIM analyses. It does benefit, however, from the NWPP EIM study assumption used to limit the

amount of hydropower that would qualify and be available to provide contingency and flexible reserves. Table 9 (next page) provides a high-level comparison between the benefit estimates in this study and the five aforementioned studies, describing key drivers of differences.

The estimated annual benefits in this study are smaller than in other studies because of:

+ The smaller geographic footprint of this study, which covered only the NV Energy, PacifiCorp, and the ISO areas and not the larger Western Interconnection region;

+ The modeling scope in this study, which did not include sub-hourly dispatch; and

+ The modeling assumptions used in this study, which resulted in a smaller base case operating reserve requirement, and hence a smaller change in reserves in the EIM case, than the PUC EIM Group analysis.

The results in this study should thus be viewed as conservative relative to other studies.

Table 13. Comparison of annual benefits and geographic scope between this study and other EIM studies

<table>
<thead>
<tr>
<th>Study (Organization)</th>
<th>Annual Benefits (SMIW)</th>
<th>Geographic Scope</th>
<th>Key Drivers of Differences with this Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>NV Energy-ISO EIM study</td>
<td>$9-18 in 2017; $15-29 in 2022</td>
<td>Incremental benefits from adding NV Energy with PacifiCorp, and ISO</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp-ISO EIM study</td>
<td>$21-$129 in 2017</td>
<td>PacifiCorp and ISO</td>
<td></td>
</tr>
<tr>
<td>--------------------------</td>
<td>------------------</td>
<td>--------------------</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Similar methodology framework and benefit categories.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• NV Energy-ISO study includes PacifiCorp-ISO EIM in base case</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• PacifiCorp-ISO study uses benchmarked hurdle rates rather than wheeling rates to represent friction across BAA boundaries</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• PacifiCorp-ISO study includes intra-regional dispatch savings in PacifiCorp</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• PacifiCorp-ISO study also models high range case with 12% cap on hydro contribution to reserves, which increases flexibility benefits from EIM</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• NV Energy-ISO Study generator assumptions include retirement of San Onofre Nuclear Generation Station (SONGS) and additional retirement and replacement of thermal units through the study period due to once-through cooling (OTC) regulations in California</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• NV Energy-ISO Study incorporates additional transmission modeling detail in Southwest to represent NV Energy system and rights on co-owned facilities.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>WECC EIM (E3)</th>
<th>$141 in 2020</th>
<th>WECC excluding ISO and AESO</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>• WECC EIM study had similar approach to this study</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• WECC EIM study had larger EIM footprint than this study</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• WECC study excluded intraregional dispatch savings; this study includes intraregional dispatch savings</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No assessment of renewable curtailment reduction in WECC study; this study includes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>benefits of renewable curtailment reduction</td>
</tr>
<tr>
<td>----------------------</td>
<td>------------------------</td>
<td>---------------------------------------------</td>
</tr>
</tbody>
</table>
| **PUC EIM Group**    | $146-294 in 2020 for EIM (plus additional $1,312 if moving from hourly to 10-minute dispatch interval) | • PUC EIM study had larger EIM footprint than this study  
• PUC EIM study modeled 10-minute dispatch; this study models hourly dispatch  
• PUC EIM study required more reserve in base case due to earlier schedule lockdown, increasing EIM benefits; this study assumed later lockdown  
• PUC EIM study included regulation reserve savings for EIM; this study assumes no regulation reserve savings |
| (NREL)               | **WECC excluding ISO and AESO** |                                             |
| **WECC VGS**         | $349-$755 in 2020 ($1,112 for 27% renewable mix scenario in 2020) | • WECC VGS study had larger EIM footprint than this study  
• VGS study modeled 10-minute bilateral scheduling, not EIM  
• In VGS study, reduction of reserves requirements not explicitly modeled, and no savings due to reduced reserves or reduced transactional friction. Focused on savings due to within-hour efficiency gains; ISO-PAC study includes savings from reduced reserves & transactional friction |
| (Energy Exemplar)    | **Entire WECC**        |                                             |
| **NWPP EIM**         | $40-70 million in 2020, with $17-125 million range for additional sensitivities | • Similar approach to WECC VGS study  
• Detailed multi-step model, with additional information provided by NWPP stakeholders especially on hydro representation |
| (PNNL)               | **NWPP**               |                                             |
Technical Appendix
Technical Appendix

Overview
This technical appendix provides a detailed description of the methods and assumptions used in calculating the benefits of NVE participation in the EIM through improving efficient interregional dispatch and reducing flexibility reserves requirements. Following this overview, the first section of this appendix describes methods for calculating inputs to the NV BAU Case, including wheeling rates between BAAs and flexibility reserve requirements in the NV BAU Case. The second section describes the changes made to wheeling rates in the NV EIM Dispatch Case to reduce friction on transactions between the NV Energy and ISO BAA. The third section describes the calculation of reserve requirements for the NV EIM Flexibility Reserves Case and discusses the approach used to estimate a low and high range of flexibility reserve savings.

The study team estimated the benefits of more efficient interregional dispatch and reduced flexibility reserves using a combination of statistical analysis and production simulation modeling. All production simulation modeling was conducted using ABB’s GridView model.\(^1\)

The study team modeled three simulation cases to evaluate the benefits of NV Energy participation in the EIM:

- **NV BAU Case**, reflecting a business-as-usual scenario that includes an EIM operating between two current EIM participants (Pacificorp and ISO,) but continued obstacles to interregional dispatch between NV Energy and ISO, and independent procurement of flexibility reserve needs for NV Energy;
- **NV EIM Dispatch Case**, in which obstacles to more efficient interregional dispatch are removed but NV Energy flexibility reserves needs are still calculated and procured separately; and
- **NV EIM Flexibility Reserve Case**, in which obstacles to more efficient interregional dispatch are removed and NV Energy pools its flexibility reserves with the existing EIM participants.

The NV BAU Case was developed using the Western Electricity Coordinating Council’s (WECC’s) Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case as a starting point, with updates developed for ISO’s Transmission Planning Process (TPP) GridView simulation “Branch Cases” for 2017 and 2022 to improve accuracy inside of California. The study team also adjusted load forecasts, fuel price forecasts, generators retirements and additions, and transmission details for 2017 and 2022 based on additional information provided by NV Energy and ISO. Finally, the team implemented changes developed from the ISO-Pacificorp EIM Benefits study to reflect in the NV BAU scenario the operation of an EIM with the “current participants” of ISO and Pacificorp.

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\(^1\) For more on GridView, see http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

Page 1A
The NV EIM Dispatch Case and NV EIM Flexibility Reserve Case were used to isolate the benefits, relative to the NV BAU Case, of more efficient interregional dispatch and reduced flexibility reserves as a result of NV Energy participating in the EIM. In the NV EIM Dispatch Case, the study team modeled the incremental benefits of more efficient interregional dispatch by eliminating the wheeling rates between NV Energy and ISO that are used to reflect impediments to electricity trades in the NV BAU Case.\(^2\) In the NV EIM Flexibility Reserve Case, the study team modeled the incremental benefits of reduced flexibility reserves by calculating the reduction in flexibility reserves that results from pooling load, wind, and solar variability between the NV Energy BAA and the current EIM participants’ BAAs (subject to transmission constraints), and then by reducing the amount of required reserves in GridView runs.\(^3\)

As described in the main report, for the NV BAU Case, the NV EIM Dispatch Case and the NV EIM Flexibility Reserve Case, the study team modeled both the year 2017 to represent likely system conditions within the first several years after the EIM becomes fully operational, as well as the year 2022 to identify the potential benefits over a medium-term planning horizon, after additional renewable generation and more regional transmission facilities have been constructed in the Western Interconnection, and with additional flexibility reserves needed to support the higher levels of regional wind and solar penetration. Figure 1A illustrates the study team’s modeling approach.

\(^2\) A component of wheeling rates that reflects the need to acquire CO\(_2\) allowances when delivering electricity from neighboring states into California, as required by California’s greenhouse gas “cap-and-trade” program developed in compliance with AB32, was retained in all cases.

\(^3\) As discussed later in this Technical Appendix, the low range benefit level for reduced flexibility reserves savings was instead calculated by valuing the quantity reduction in flexible reserve requirements based on historical ISO market prices.
Figure 1A. Modeling approach for creating NV BAU, NV EIM Dispatch, and NV EIM Flexibility Reserves Cases

As described in the main report of the NV Energy-ISO EIM analysis, the study team calculated a high range and low range benefit level for both 2017 and 2022 by utilizing different assumptions regarding the availability of NV Energy generators to participate in the EIM, the value of flexibility reserves, and the share of identified curtailment avoided. Production cost results used for the high and low range scenarios are described in this Appendix. All cases for this analysis assume PacifiCorp and ISO as current EIM participants by the time NV Energy participation would commence, and all cases (including the NV BAU Case) assume 400 MW transfer capability between PacifiCorp and ISO over transmission facilities at COI. All cases for this assessment also limit hydropower’s ability to contribute to contingency and flexibility reserves to 25% of nameplate capacity.

NV BAU Case
The NV BAU Case used WECC’s TEPPC 2022 Common Case as a starting database. Inputs to the TEPPC database are developed from a collaborative stakeholder process, and are used in studies to assess regional economic transmission in the Western Interconnection. In addition, the TEPPC database has been used in ISO’s TPP, and in other studies of the benefits of an EIM throughout the Western Interconnection.4

Adjustments to the TEPPC Common Case
In developing its 2017 and 2022 TPP “Branch Cases”, ISO staff made adjustments to the TEPPC 2022 Common Case to improve transmission and generation modeling accuracy within California. The study team incorporated those adjustments and made further modifications to the ISO 2017 and 2022 Branch Cases in three primary areas: (1) fuel price forecast, (2) load forecast, and (3) generation and transmission.

Fuel price forecast
Natural gas prices were based on the ISO’s long-term procurement plan (LTPP), adjusted to match annual average Henry Hub fuel prices from NYMEX. Within California, these prices reflect ISO’s recent updates to provide more granular prices for distinct locations within California load areas. Table 1A shows fuel prices by region, for the TEPPC regions within the ISO, NV Energy, and PacifiCorp BAAs.

<table>
<thead>
<tr>
<th>Area</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas – NEVP (Southern NV)</td>
<td>3.92</td>
<td>4.51</td>
</tr>
<tr>
<td>Gas – SPP (Northern NV)</td>
<td>4.19</td>
<td>4.81</td>
</tr>
<tr>
<td>Gas - PG&amp;E Kern River</td>
<td>4.18</td>
<td>4.81</td>
</tr>
<tr>
<td>Gas - PG&amp;E PGE_C_BB</td>
<td>4.15</td>
<td>4.77</td>
</tr>
<tr>
<td>Gas - PG&amp;E PGE_C_LT</td>
<td>4.27</td>
<td>4.90</td>
</tr>
<tr>
<td>Gas - PG&amp;E SoCal_BT</td>
<td>4.24</td>
<td>4.87</td>
</tr>
<tr>
<td>Gas - SCE SoCal_BT</td>
<td>4.24</td>
<td>4.87</td>
</tr>
<tr>
<td>Gas - PACE_ID</td>
<td>4.05</td>
<td>4.65</td>
</tr>
<tr>
<td>Gas - PACE_UT</td>
<td>3.87</td>
<td>4.45</td>
</tr>
<tr>
<td>Gas - PACE_WY</td>
<td>4.00</td>
<td>4.60</td>
</tr>
<tr>
<td>Gas - PACW</td>
<td>3.97</td>
<td>4.56</td>
</tr>
</tbody>
</table>

Load forecast
For 2022, load data was used from the TEPPC Common Case database with updates in California based on a CEC demand forecast from September 2012. A load forecast for 2017 was provided directly by PacifiCorp for the PacifiCorp East and PacifiCorp West BAAs as part of the ISO-PacifiCorp EIM Benefits study. For all other load areas, monthly peak and energy values were adjusted for 2017 based on WECC Load-Resource Subcommittee (LRS) 2012 data submittals of forecasted demand by BAA.

Generation and transmission
For the 2017 cases, some generation and transmission projects were removed from the TEPPC 2022 Common Case because they were not expected to be online by 2017, based on input from ISO and NV Energy. For modeling purposes, generation in 2017 was assumed to precede the majority of expected OTC-related retirements and replacements in California; the 2022 cases includes the planned repowering of some generation to replace retired OTC units.
Consistent with the latest ISO planning costs, both the 2017 and 2022 scenarios reflect the retirement of the San Onofre Nuclear Generation Station (SONGS) Units 2 and 3 in 2013; based on the CAISO TPP assumptions, generic gas-fired generation is added in California as a partial replacement for the retired SONGS capacity. The Navajo coal-fired plant in Arizona is also assumed to be retired in 2019.

In Nevada, Reid Gardner Units 1, 2, and 3 are retired for both the 2017 and 2022 cases, and Reid Gardner Unit 4 is modeled online in the 2017 cases, but retired for the 2022 cases. NV Energy provided input data for generic gas-fired plant additions, as well as solar generation, to partially replace the retired Reid Gardner capacity.

Based on NV Energy staff input, the study team updated the Southern Nevada Transmission Interface (SNTI) path limit to 3,948 MW in the south-to-north direction and to 4,465 MW in the north-to-south direction, and made additional updates to the model to correctly reflect other Nevada paths limits and transmission facilities.

**Wheeling rates**
The NV BAU Case applied tariff-based wheeling rates to power transfers between BAAs, based on a summary by ISO staff of the most recent wheeling tariffs for transmission providers in the Western Interconnection. These wheeling rates were adjusted to reflect the additional impact of anticipated CO₂ allowance costs for unspecified power imports into California. For power flows from NV Energy (NVE) to ISO, the study team used a value of $12.23/MWh in 2017, which included a $5.52/MWh cost for CO₂ allowances on NV Energy exports to ISO (Table 2A). This $5.52/MWh adder was based on a default CO₂ emissions factor from the California Air Resources Board of 0.428 metric tons/MWh, and CO₂ prices for 2017 of $11.53 (2013$) per short ton of CO₂, consistent with ISO's assumptions for the 2012 LTPP.

For 2022, the study team applied a total wheeling rate of $12.23/MWh, which included a $10.65/MWh cost for CO₂ allowances on NV Energy exports to ISO (based on a 2022 CO₂ price of $22.57 per short ton). For power flows from ISO to NVE, the study team used a wheeling rate of $10.10/MWh in 2017 and $10.39/MWh in 2022. As described in the main report, the study team conservatively assumed that interties between NVE and PACE cannot be utilized for the EIM, and thus applied a $6.71/MWh wheeling rate on flows from NVE to PACE and a $2.93/MWh wheeling rate on flows from PACE to NVE; these wheeling rates were unchanged in all EIM scenarios.

<table>
<thead>
<tr>
<th>Case</th>
<th>Wheeling Rate ($/MWh)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CO₂-related</td>
<td>NVE → ISO</td>
<td>Non-CO₂ related</td>
<td>Total</td>
</tr>
<tr>
<td>NV BAU Case – 2017</td>
<td>$5.52</td>
<td>$6.71</td>
<td>$12.23</td>
<td>$10.10*</td>
</tr>
<tr>
<td>NV BAU Case – 2022</td>
<td>$10.65</td>
<td>$6.71</td>
<td>$17.36</td>
<td>$10.39*</td>
</tr>
</tbody>
</table>

5 Total NV Energy gas-fired additions includes the assumed addition of one 646 MW CCGT added in southern Nevada by 2017, plus additions for the 2022 case of one 273 MW CCGT and 21 combustion turbine (CT) units totaling 1,690 MW.
*No CO₂-related wheeling rate is applied to ISO exports to NV Energy because CO₂ permit cost under AB32 is directly modeled in the dispatch for generators located inside California.*

**Flexibility reserves**

To determine the production costs associated with flexibility reserve levels in the NV BAU Case, the study team obtained load following and regulation reserve requirements, and then set the total as an upward constraint on the minimum level of generation capacity committed in each BAA by GridView. Load following here is defined as the capacity needed to manage the difference between the hourly unit commitment schedule and 10-minute forecasted net load. Regulation is defined as the capacity needed to manage the difference between 10-minute forecasted net load and 10-minute actual net load. These flexibility reserve requirements are in addition to the spinning reserve requirements, which are carried against generation or transmission system contingencies, and were also modeled as a constraint in Gridview. Supplemental reserves, downward regulation and downward load following were not explicitly modeled in GridView.

For California, ISO provided flexibility reserves requirements for each hour based on the load, wind and solar in CPUC’s commercial interest portfolio to meet 33% RPS in California. To calculate these requirements ISO used a stochastic process developed by ISO and Pacific Northwest National Laboratory (PNNL) that employs Monte Carlo simulations to represent the variability and forecast error of load, wind, and solar over multiple iterations and to evaluate the resulting regulation and load following requirements needed to ensure sufficient system flexibility. For the PacifiCorp BAAs, the study team used the hourly regulation and load following requirements developed from the PacifiCorp-ISO EIM study.

NV Energy staff provided an estimate of its flexibility reserve requirements based on analysis used in NV Energy’s 2013 IRP analysis. NV Energy anticipates requiring 35 MW of regulation reserves in all hours for 2017 and 2022. In addition, NV Energy projects an average need of 41 MW of load following reserves in 2017 and 91 MW in 2022. In the NV BAU Case, these requirements were used as a separate constraint on minimum level of committed capacity within NV Energy’s individual BAA.

In the NV BAU Case, to reflect the impact of ISO and PacifiCorp as existing participants in an EIM, the study team estimated flexibility reserve requirements that could be met across the existing EIM footprint, subject to transmission constraints. For each hour, the study team calculated the load following flexibility reserve requirements as the geometric sum of the standalone requirements of the individual BAAs for each existing participant. The study team also applied constraints to the amount of load following reserve that must be carried within ISO, PacifiCorp East, and PacifiCorp West BAAs based on the transmission transfer capability available between these participants, as described in the PacifiCorp-ISO EIM Benefits report.⁶

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⁶ This includes the 400 MW transfer capability level between ISO and PacifiCorp at COI assumed for this analysis, as well as an assumption that PacifiCorp East is able to transfer 200 MW to PacifiCorp West within the hour but with no transfer capability in the reverse direction for EIM transactions.
Table 3A shows the resulting average hourly load following and regulation reserve requirements for both NV Energy and the existing EIM participants in 2017 and 2022.

**Table 3A. Estimated minimum flexibility reserve holdings under the NVE BAU Case in 2017 and 2022**

<table>
<thead>
<tr>
<th>NV BAU Case</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NV Energy</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulation Reserves Requirements</td>
<td>35</td>
<td>35</td>
</tr>
<tr>
<td>Load Following Reserves Requirement</td>
<td>41</td>
<td>76</td>
</tr>
<tr>
<td><strong>Existing EIM participants (ISO-PacifiCorp)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulation Reserves Requirements</td>
<td>551</td>
<td>685</td>
</tr>
<tr>
<td>Load Following Reserves Requirement</td>
<td>1,415</td>
<td>1,859</td>
</tr>
</tbody>
</table>

**NV EIM Dispatch Case**

In the NV EIM Dispatch Case, the study team modeled the reduced transactional friction between NV Energy and ISO as a result of NV Energy participation in the EIM by removing the wheeling rates applied to transmission flows between the NV Energy in the NV BAU Case (excluding the CO₂-related wheeling rates, which were left unchanged from the NV BAU scenario). In the NV EIM Dispatch Case, the NVE→ISO wheeling charge continues to include the $5.52/MWh cost for CO₂ allowances in 2017 (and $10.65/MWh for CO₂ allowances in 2022) on NV Energy flows to ISO (Table 4A).

**Table 4A. Wheeling rates for the NV BAU vs. NV EIM Dispatch Cases (2013$)**

<table>
<thead>
<tr>
<th>Case</th>
<th>Wheeling Rate ($/MWh)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CO₂-related</td>
<td>NVE → ISO</td>
<td>Non-CO₂ related</td>
<td>ISO → NVE</td>
</tr>
<tr>
<td>NV BAU Case – 2017</td>
<td>$5.52</td>
<td>$6.71</td>
<td>$5.52</td>
<td>$10.10*</td>
</tr>
<tr>
<td>NV EIM Dispatch Case - 2017</td>
<td>$5.52</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00*</td>
</tr>
<tr>
<td>NV BAU Case – 2022</td>
<td>$10.65</td>
<td>$6.71</td>
<td>$17.36</td>
<td>$10.39*</td>
</tr>
<tr>
<td>NV EIM Dispatch Case - 2022</td>
<td>$10.65</td>
<td>$0.00</td>
<td>$10.65</td>
<td>$0.00*</td>
</tr>
</tbody>
</table>

*No CO₂-related hurdle rate is applied to ISO exports to NVE because CO₂ permit cost under AB32 is directly modeled in the dispatch for generators located inside California.

Eliminating the non-CO₂ related wheeling rates for this case enables GridView to dispatch more generation in the NVE BAA to serve needs in the BAAs of the existing participants when more efficient NV Energy units are available, and vice-versa. Reduced transactional friction from removing wheeling rates lowers total generator production costs. The resulting interregional dispatch cost savings is calculated as the change in generator production cost between the NV BAU Case and the NV EIM Dispatch Case. It is important to note that this savings calculation does not include the change in wheeling costs incurred, only the change in production cost (generator fuel costs as variable O&M) as a result of dispatching more efficiently between BAAs when wheeling charges are not imposed.
Table 5A shows this resulting production costs savings for 2017 and 2022 under the high range benefits scenario, which assumes participation of NV Energy generation in the EIM during all months. As described in the main report, the low range interregional dispatch savings assumed that NV Energy generators were unavailable during June through September, so the study team scaled down the high-range benefits calculated from the simulation results by 4/12ths (33%). The table below summarizes the resulting interregional dispatch savings for all scenarios.

**Table 5A. Production cost savings in the NV EIM Dispatch Case for 2017 and 2022 (Million 2013$)**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2017 Low Range</th>
<th>2017 High Range</th>
<th>2022 Low Range</th>
<th>2022 High Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>NV EIM Dispatch Case</td>
<td>$6.2</td>
<td>$9.3</td>
<td>$8.9</td>
<td>$13.4</td>
</tr>
</tbody>
</table>

**NV EIM Flexibility Reserves Case**

For the NV EIM Flexibility Reserves Case, the study team calculated load following requirements for the expanded EIM (including NV Energy) as the geometric sum of the reserve requirement for the individual BAAs of each participant, and enforced transmission constraints to ensure realistic reserve sharing. By taking the geometric sum of NV Energy’s requirements with those of the current EIM participants, the reserve requirements in the EIM Flexibility Reserve Case reflect the diversity in forecast errors and variability for wind, load, and solar across the NV Energy, ISO, and PacifiCorp footprint, reducing the total reserves that are needed relative to the requirements in the NV BAU Case and the NV EIM Dispatch Case.

Transfer capability between NV Energy and ISO was not identified to be a limiting feature on the quantity of reserve sharing, but the 400 MW transfer capability constraint between PacifiCorp and ISO modeled in the NV BAU Case was maintained in the NV EIM Flexibility Case.

Table 6A shows the pooled flexibility reserve requirements for the expanded EIM which includes NV Energy, prior to enforcing transmission constraints between BAs. Since the EIM will operate at a 5-minute timestep, regulation reserves requirements which are required to respond to changes at a shorter timescale are modeled as unchanged from the requirements in the NV BAU Case.

**Table 6A. Pooled load following reserve requirements under the NV EIM Flexibility Reserve Case in 2017 and 2022**

<table>
<thead>
<tr>
<th>NV EIM Flexibility Case</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expanded EIM (NV Energy-ISO-PacifiCorp)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Load Following Reserves Requirement</td>
<td>1,416</td>
<td>1,861</td>
</tr>
</tbody>
</table>
Calculation of Low Range Flexibility Reserve Savings using Historical Prices
As described in the main report, for the low range benefit estimate, the study team calculated flexibility
reserves savings by valuing the quantity reduction in load following reserve requirements (as a result of
NV Energy participation in the EIM) at a benchmark of historical ancillary service prices. For each study
year, the study team multiplied the hourly reduction in reserve requirements (for the NVE EIM Flexibility
Reserves case vs. the NV BAU Case) by the average ISO regulation market prices from 2009 through
2011. Consistent with the approach taken for the GridView modeling, only savings in load following up
reserve costs were assumed to be achievable through an EIM.

Table 7A shows the average reduction in flexibility reserve requirements, the average ancillary services
prices per MWh, and the resulting low range annual flexibility reserve savings for 2017 and 2021. The
table also shows the high range flexibility reserve savings calculated from GridView simulation results as
a comparison. The low range savings are conservative in that they assume NV Energy participation in
the EIM would produce cost savings solely by reducing the quantity of flexibility reserves required. By
comparison, the high range flexibility reserve savings estimated with GridView capture the additional
cost reductions that NV Energy’s participation in the EIM could enable through optimal selection of the
most efficient sources of reserves from across NV Energy and the rest of the EIM footprint. The large
difference in results suggests that creating a mechanism to allow optimal selection of flexibility reserves
from across an expanded EIM is a very important benefit that should yield significant cost savings.

**Table 7A. Low and High Range Flexibility Reserve Savings from NV Participation in EIM (2013$)**

<table>
<thead>
<tr>
<th>Scenario Year</th>
<th>Average EIM Reduction in Flex Reserves (MW)</th>
<th>Average 2009-2011 AS Prices ($/MWh)</th>
<th>Low Range Flexibility Savings ($MM)</th>
<th>Comparison: High Range Flexibility Reserve Savings from GridView ($MM)</th>
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ITEM-2

NV ENERGY – CALIFORNIA ISO EIM IMPLEMENTATION AGREEMENT, DATED APRIL 16, 2014
ENERGY IMBALANCE MARKET
IMPLEMENTATION AGREEMENT

This Implementation Agreement ("Agreement") is entered into as of April 16, 2014, by and between Nevada Power Company d/b/a NV Energy, a Nevada corporation ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy, a Nevada Corporation ("Sierra Pacific Power" and, collectively, "NV Energy"), and the California Independent System Operator Corporation, a California nonprofit public benefit corporation ("ISO"). NV Energy and the ISO are sometimes referred to in the Agreement individually as a "Party" and, collectively, as the "Parties".

RECATALS

A. WHEREAS, NV Energy has determined there is an opportunity to secure benefits for NV Energy's customers through improved dispatch and operation of NV Energy's generation fleet and through the efficient use and continued reliable operation of existing and future transmission facilities and desires to participate in the energy imbalance market operated by the ISO ("EIM");

B. WHEREAS, NV Energy intends to seek authorization from the Public Utilities Commission of Nevada to participate in the EIM;

C. WHEREAS, the ISO has determined there are benefits to ISO market participants through greater access to energy imbalance resources in real-time and through the efficient use and reliable operation of the transmission facilities and markets operated by the ISO, and desires to expand operation of the EIM to include NV Energy;

D. WHEREAS, the ISO developed EIM market rules through a stakeholder process in which NV Energy has been a stakeholder;

E. WHEREAS, the Parties acknowledge that the rules and procedures governing the EIM must be set forth in the provisions of the ISO tariff as filed with the Federal Energy Regulatory Commission ("FERC"), as well as corresponding revisions to NV Energy’s Open Access Transmission Tariff and the execution of associated service agreements; and

F. WHEREAS, the Parties are entering into this Agreement to set forth the terms upon which the ISO will timely configure its systems to incorporate NV Energy into the EIM ("Project") on October 1, 2015 ("Implementation Date").

NOW THEREFORE, in consideration of the mutual covenants contained herein, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:
AGREEMENT

1. **Effective Date and Term.**

   (a) This Agreement shall become effective upon the latter of: (i) the date the Agreement is accepted, approved or otherwise permitted to take effect by FERC, without condition or modification unsatisfactory to either Party; and (ii) the date NV Energy is authorized by the Public Utilities Commission of Nevada to join the EIM without condition unsatisfactory to either Party ("Effective Date").

   (b) In the event FERC requires any modification to the Agreement or imposes any other condition upon its acceptance or approval of the Agreement, each Party shall have ten (10) days to notify the other Party that any such modification or condition is unacceptable to that Party. If no Party provides such notice, then the Agreement, as modified or conditioned by FERC, shall take effect as of the date determined under section 1(a). If either Party provides such notice to the other Party, the Parties shall take any one or more of the following actions: (i) meet and confer and agree to accept any modifications or conditions imposed by such FERC order; (ii) jointly seek further administrative or legal remedies with respect to such FERC order, including a request for rehearing or clarification; or (iii) enter into negotiations with respect to accommodation of such FERC order, provided however, if the Parties have not agreed to such an accommodation within thirty (30) days after the date on which such FERC order becomes a final and non-appealable order, such order shall be deemed an adverse order and the Parties shall have no further rights and obligations under the Agreement.

   (c) In the event the Public Utilities Commission of Nevada imposes any condition upon NV Energy with respect to its participation in the EIM that would require modification to the Agreement, each Party shall have ten (10) days to notify the other Party that any such condition is unacceptable to that Party. If no Party provides such notice, then the Agreement shall take effect as of the date determined under section 1(a). If either Party provides such notice to the other Party, the Parties shall meet and confer and enter into negotiations to modify the Agreement provided, however, if the Parties have not agreed to such an accommodation within the timeframe such decision becomes final and non-appealable, such decision shall be deemed adverse and the Parties shall have no further rights and obligations under the Agreement.

   (d) The term of the Agreement ("Term") shall commence on the Effective Date and shall terminate upon the earliest to occur of (1) the date FERC permits all necessary revisions to the NV Energy tariff to take effect and the service agreements under such tariff and the ISO tariff necessary for the commencement of the EIM have taken effect; (2) termination in accordance with Section 2 of this Agreement; or (3) such other date as mutually agreed to by the Parties ("Termination Date").

   (e) This Agreement shall automatically terminate on the Termination Date and shall have no further force or effect, provided that the rights and obligations set forth in
Sections 5 and 6 shall survive the termination of this Agreement and remain in full force and effect.

2. **Termination.**

   (a) The Parties may mutually agree to terminate this Agreement in writing at any time. In addition, either Party may terminate this Agreement in its sole discretion after conclusion of the negotiation period in Section 2(b), as provided in Section 2(d) or 2(e) as applicable.

   (b) If either the ISO or NV Energy seeks to terminate this agreement, it must first notify the other Party in writing of its intent to do so ("Notice of Intent to Terminate") and engage in thirty (30) days of good faith negotiations in an effort to resolve its concerns. If the Parties successfully resolve the concerns of the Party issuing the Notice of Intent to Terminate, the Party that issued such notice shall notify the other Party in writing of the withdrawal of such Notice ("Notice of Resolution").

   (c) At the time the Notice of Intent to Terminate is provided, or any time thereafter unless a Notice of Resolution is issued, NV Energy may provide written notice directing the ISO to suspend performance on any or all work on the Project for a specified period of time ("Notice to Suspend Work"). Upon receipt of a Notice to Suspend Work, the ISO shall: (1) discontinue work on the Project; (2) place no further orders with subcontractors related to the Project; (3) take commercially reasonable actions to suspend all orders and subcontracts; (4) protect and maintain the work on the Project; and (5) otherwise mitigate NV Energy's costs and liabilities for the areas of work suspended. The ISO will not invoice NV Energy pursuant to Section 4(c) of this Agreement for any milestone payment following the issuance of a Notice to Suspend Work. To the extent a Notice of Resolution is issued pursuant to Section 2(b), the Notice to Suspend Work in effect at the time shall be deemed withdrawn and the ISO shall be entitled to invoice NV Energy for any milestone completed as specified in Section 4(c) of this Agreement and NV Energy shall pay such invoice pursuant to Section 4.

   (d) Any time after 30 days from the date of the Notice of Intent to Terminate under Section 2(b), issued by either Party, and prior to the date of a Notice of Resolution, the ISO may terminate this Agreement by providing written notice to NV Energy that it is terminating this Agreement ("Termination Notice") effective immediately. The ISO may terminate this Agreement at its sole discretion for any reason, including but not limited to: (i) a lack of reasonable progress in the development of the Project in accordance with Exhibit A to this Agreement, subject to modification only as described in Section 3(c); (ii) a disagreement between the Parties regarding Project design, scope, or implementation, which disagreement the Parties are unable to resolve to their mutual satisfaction; or (iii) if the ISO determines in its sole discretion that the Project is not likely to provide the benefits the ISO is seeking to obtain.

   (e) Any time after 30 days from the date of the Notice of Intent to Terminate under Section 2(b), issued by either Party, and prior to the date of a Notice of
Resolution, NV Energy may terminate this Agreement by providing written notice to the ISO that it is terminating this Agreement ("Termination Notice") effective immediately. NV Energy may terminate this Agreement at its sole discretion for any reason, including but not limited to: (i) a lack of reasonable progress in the development of the Project in accordance with Exhibit A to this Agreement, subject only to modification only as described in Section 3(c); (ii) a disagreement between the Parties regarding Project design, scope, or implementation, which disagreement the Parties are unable to resolve to their mutual satisfaction; or (iii) if NV Energy determines in its sole discretion that the Project is not likely to provide the benefits NV Energy is seeking to obtain.

(f) In the event this Agreement is terminated by either or both of the Parties, this Agreement will become wholly void and of no further force and effect, without further action by either Party, and the liabilities and obligations of the Parties hereunder will terminate, and each Party shall be fully released and discharged from any liability or obligation under or resulting from this Agreement as of the date of the Termination Notice provided in Section 2(d) or 2(e), as applicable, notwithstanding the requirement for the ISO to submit the filing specified in Section 2(g). Notwithstanding the foregoing, the rights and obligations set forth in Sections 5 and 6 shall survive the termination of this Agreement and remain in full force and effect as specified in Sections 5 and 6, and any milestone payment obligation pursuant to Section 4(c) that arose prior to the Termination Notice in accordance with Section 2(d) or 2(e) shall survive until satisfied or resolved in accordance with Section 11.

(g) The Parties acknowledge that the ISO is required to file a timely notice of termination with FERC. The Parties acknowledge and agree that the filing of the notice of termination by the ISO with FERC will be considered timely if the filing of the notice of termination is made after the preconditions for termination have been met, and the ISO files the notice of termination within ten (10) days after the Termination Notice has been provided by either the ISO in accordance with Section 2(d) or NV Energy in accordance with Section 2(e). This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

3. Implementation Scope and Schedule.

(a) The Parties shall complete the Project as described in Exhibit A, subject to modification only as described in Section 3(c) below.

(b) The Parties shall undertake the activities described in Exhibit A with the objective of completing the Project and implementing the EIM no later than the Implementation Date, subject to modification only as described in Section 3(c) below.

(c) Either Party may propose a change in Exhibit A or the Implementation Date to the other. If a Party proposes a change in Exhibit A or the Implementation Date, the Parties shall negotiate in good faith to attempt to reach agreement on the proposal and any necessary changes in Exhibit A and any other affected provision of this Agreement, provided that any change in Exhibit A or the Implementation Date must be mutually agreed to by the Parties. The agreement of the Parties to a change in Exhibit
A or the Implementation Date shall be memorialized in a revision to Exhibit A, which will be binding on the Parties and shall be posted on the internet web sites of the ISO and NV Energy, without the need for execution of an amendment to this Agreement. Changes that require revision of any provision of this Agreement other than Exhibit A shall be reflected in an executed amendment to this Agreement and filed with FERC for acceptance.

(d) At least once per calendar month during the Term, the Parties’ Designated Executives, or their designees, will meet telephonically or in person (at a mutually agreed to location) to discuss the continued appropriateness of Exhibit A to ensure that the Project can meet the Implementation Date. For purposes of this section, “Designated Executive” shall mean the individual identified in Section 8(g), or their designee or successor.

4. **Implementation Charges, Invoicing and Milestone Payments.**

   (a) NV Energy shall pay the ISO a fixed fee of $1.1 million for costs incurred by the ISO to implement the Project (“Implementation Fee”), subject to completion of the milestones specified in Section 4(c) and subject to adjustment only as described in Section 4(b).

   (b) The Implementation Fee shall be subject to adjustment only by mutual agreement of the Parties in either of the following circumstances: (1) if the Parties agree to a change in Exhibit A or the Implementation Date in accordance with Section 3(c) and the Parties agree that an adjustment to the Implementation Fee is warranted in light of such change; or (2) the ISO provides notice to NV Energy that the sum of its actual costs through the date of such notice and its projected costs to accomplish the balance of the Project exceed the Implementation Fee.

   (c) Upon completion of the milestones identified in Exhibit A, the ISO shall invoice NV Energy for the Implementation Fee as follows:

   i. $300,000 upon the Effective Date as further described in Section 1 of this Agreement and Exhibit A as Milestone 1;

   ii. $200,000 upon deployment into the ISO test environment of the full network model database that includes the topology of the NV Energy system as further described in Exhibit A as Milestone 2;

   iii. $200,000 upon delivery to NV Energy of the EIM technical specifications and configuration guides as further described in Exhibit A as Milestone 3;

   iv. $200,000 upon commencement of EIM market simulation as further described in Exhibit A as Milestone 4; and

   v. $200,000 upon the Implementation Date as further described in Exhibit A as Milestone 5.
(d) Following the completion of each milestone identified in Section 4(c)(i) through (v), the ISO will deliver to NV Energy an invoice which will show the amount due, together with reasonable documentation supporting the completion of the milestone being invoiced. NV Energy shall pay the invoice no later than forty-five (45) days after the date of receipt. Any milestone payment past due will accrue interest, per annum, calculated in accordance with the methodology specified for interest in the FERC regulations at 18 C.F.R. § 35.19a(a)(2)(iii) (the “FERC Methodology”).

(e) If a milestone has not been completed as described in 4(c)(i), (ii), (iii), (iv), or (v) and Exhibit A, as Exhibit A may have been modified in accordance with Section 3(c), the Parties shall negotiate in good faith an agreed upon change to Exhibit A consistent with Section 3(c) such that the timing of milestone payments in Section 4(c) can be adjusted to correspond to the updated Exhibit A.

(f) If NV Energy disputes any portion of any amount specified in an invoice delivered by the ISO, NV Energy shall pay its total amount of the invoice when due, and identify the disputed amount and state that the disputed amount is being paid under protest. Any disputed amount shall be resolved pursuant to the provisions of Section 11. If it is determined pursuant to Section 11 that an overpayment or underpayment has been made by NV Energy or any amount on an invoice is incorrect, then (i) in the case of any overpayment, the ISO shall promptly return the amount of the overpayment (or credit the amount of the overpayment on the next invoice) to NV Energy; and (ii) in the case of an underpayment, NV Energy shall promptly pay the amount of the underpayment to the ISO. Any overpayment or underpayment shall include interest for the period from the date of overpayment, underpayment, or incorrect allocation, until such amount has been paid or credited against a future invoice calculated in the manner prescribed for calculating interest in Section 4(d).

(g) All costs necessary to implement the Project not provided for in this Agreement shall be borne separately by each Party and recovered through rates as may be authorized by their respective regulatory authorities.

(h) All milestone payments required to be made under the terms of this Agreement shall be made to the account or accounts designated by the Party which the milestone payment is owed, by wire transfer (in immediately available funds in the lawful currency of the United States).

5. Confidentiality.

(a) All written or oral information received from another Party in connection with this Agreement (but not this Agreement after it is filed with either FERC or the PUCN) necessary to complete the Project and marked or otherwise identified at the time of communication by such Party as containing information that Party considers commercially sensitive or confidential shall constitute “Confidential Information” subject to the terms and conditions herein.
(b) If NV Energy releases NV Energy’s Confidential Information in connection with a public process or a regulatory filing, or if the ISO releases the ISO’s Confidential Information in connection with a process or a regulatory filing, then the information released shall no longer constitute Confidential Information. In addition, Confidential Information does not include information that (i) is or becomes generally available to the public other than as a result of disclosure by either Party, its officers, directors, employees, agents, or representatives; (ii) is or becomes available to such Party on a non-confidential basis from other sources or their agents or representatives when such sources are not known by such Party to be prohibited from making the disclosure; (iii) is already known to such Party or has been independently acquired or developed by such Party without violating any of such Party’s obligations under this Section 5; (iv) is the subject of a mutual written agreement between the Parties, including an agreement evidenced through an exchange of electronic or other communications, for discussion at any stakeholder meetings or during the stakeholder process or with any regulatory authority; or (v) is the subject of a mutual written agreement between the Parties, including an agreement evidenced through an exchange of electronic or other communications, to allow for such disclosure and designation as non-confidential or public information on a case-by-case basis in accordance with Section 10 of this Agreement.

(c) The Confidential Information will be kept confidential by each Party and each Party agrees to protect the Confidential Information using the same degree of care, but no less than a reasonable degree of care, as a Party uses to protect its own confidential information of a like nature. Notwithstanding the preceding sentence, a Party may disclose the Confidential Information or portions thereof to those of such Party’s officers, employees, partners, representatives, advisors, or agents who need to know such information for the purpose of analyzing or performing an obligation related to the Project. Notwithstanding the foregoing, a Party is not authorized to disclose such Confidential Information to any officers, employees, partners, representatives, advisors, or agents without (i) informing such officer, employee, partner, representative, advisor, or agent of the confidential nature of the Confidential Information and (ii) receiving the agreement of such officer, employee, partner, representative, advisor, or agent as to the confidentiality obligation herein. Each Party agrees to be responsible for any breach of this Section 5 by such Party or a Party’s officers, employees, partners, representatives, advisors or agents.

(d) In the event that a Party becomes compelled by a court of competent jurisdiction or regulatory authority (by law, rule, regulation, order, deposition, interrogatory, request for documents, data request issued by a regulatory authority, subpoena, civil investigative demand or similar request or process) to disclose any of the Confidential Information, such Party shall (to the extent legally permitted) provide the other Party with prompt written notice of such requirement so that the other Party may seek a protective order or other appropriate remedy and/or waive compliance with the terms of this Section 5. In the event that such protective order or other remedy is not obtained, or that such Party waives compliance with the provisions hereof, the Party compelled to disclose shall (i) furnish only that portion of the Confidential Information which, in accordance with the advice of its own counsel (which may include internal
counsel), is legally required to be furnished, and (ii) exercise reasonable efforts to obtain assurances that confidential treatment will be accorded the Confidential Information so furnished.

(e) Notwithstanding the foregoing, the Parties acknowledge that they are required by law or regulation to report certain information that could embody Confidential Information from time to time, and may do so from time to time without providing prior notice to the other Party. Such reports may include models, filings, and reports of costs, general rate case filings, cost adjustment mechanisms, FERC-required reporting, investigations, annual state reports that include resources and loads, integrated resource planning reports, reports to entities such as FERC, the North American Electric Reliability Council (“NERC”), Western Electricity Coordinating Council (“WECC”), or similar or successor organizations, or similar or successor forms, filings, or reports, the specific names of which may vary by jurisdiction, along with supporting documentation. Additionally, in regulatory proceedings or investigations in all state and federal jurisdictions in which they may do business, the Parties will from time to time be required to produce Confidential Information, and may do so without prior notice using its business judgment in compliance with all of the foregoing and including the appropriate level of confidentiality for such disclosures in the normal course of business.

(f) Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

(g) Upon written request by a Party, the other Party shall promptly return to the requesting Party or destroy all Confidential Information it received, including all copies of its analyses, compilations, studies or other documents prepared by or for it, that contain the Confidential Information in a manner that would allow its extraction or that would allow the identification of the requesting Party as the source of the Confidential Information or inputs to the analysis. Notwithstanding the foregoing, neither Party shall be required to destroy or alter any computer archival and backup tapes or archival and backup files (collectively, “Computer Tapes”), provided that such Computer Tapes shall be kept confidential in accordance with the terms of this Agreement.

(h) Nothing in this Agreement shall be deemed to restrict either Party from engaging with third parties with respect to any matter and for any reason, specifically including the EIM, provided Confidential Information is treated in accordance with this Section 5.

(i) This Section 5, Confidentiality, applies for two years (24 months) after the Termination Date.
6. **Limitation of Liability; Indemnity.**

   (a) Each Party acknowledges and agrees that the other Party shall not be liable to it for any claim, loss, cost, liability, damage or expense, including any direct damage or any special, indirect, exemplary, punitive, incidental or consequential loss or damage (including any loss of revenue, income, profits or investment opportunities or claims of third party customers), arising out of or directly or indirectly related to the other Party's decision to enter into this Agreement, the other Party's performance under this Agreement, or any other decision with respect to the Project.

   (b) Each Party shall indemnify, defend and hold harmless the other Party and its officers, directors, employees, agents, contractors and sub-contractors, from and against all third party claims, judgments, losses, liabilities, costs, expenses (including reasonable attorneys' fees) and damages for personal injury, death or property damage, caused by the negligence or willful misconduct related to this Agreement or breach of this Agreement of the indemnifying Party, its officers, directors, agents, employees, contractors or sub-contractors, provided that this indemnification shall be only to the extent such personal injury, death or property damage is not attributable to the negligence or willful misconduct related to this Agreement or breach of this Agreement of the Party seeking indemnification, its officers, directors, agents, employees, contractors or sub-contractors. The indemnified Party shall give the other Party prompt notice of any such claim. The indemnifying Party, in consultation with the indemnified Party, shall have the right to choose competent counsel, control the conduct of any litigation or other proceeding, and settle any claim. The indemnified Party shall provide all documents and assistance reasonably requested by the indemnifying Party.

   (c) The rights and obligations under this Section 6 shall survive the expiration and termination of this Agreement.

7. **Representation and Warranties**

   (a) Representations and Warranties of NV Energy. NV Energy represents and warrants to the ISO as of the Effective Date as follows:

   1. It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

   2. It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

   3. It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.
(4) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any governmental requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(5) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors’ rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(6) All material governmental authorizations have been obtained by it prior to the date hereof in connection with the due execution and delivery of this Agreement, have been duly obtained or made and are in full force and effect.

(b) Representations and Warranties of the ISO. ISO represents and warrants to NV Energy as of the Effective Date as follows:

(1) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(2) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(3) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.

(4) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any governmental requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(5) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, regulatory authority, or other similar laws affecting creditors’ rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(6) All material governmental authorizations have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.
8. **General Provisions.**

(a) This Agreement, including Exhibit A to this Agreement, represents the entire agreement between the Parties and supersedes any prior written or oral agreements or understandings between the Parties relating to the subject matter of this Agreement, provided that nothing in this Agreement shall limit, repeal, or in any manner modify the existing legal rights, privileges, and duties of each of the Parties as provided by any other agreement, statute or any other law or applicable court or regulatory decision.

(b) This Agreement may not be amended except in writing signed by both of the Parties; provided, however, the Parties may mutually agree to changes in Exhibit A in accordance with Section 3(c).

(c) Any waiver by a Party to this Agreement of any provision or condition of this Agreement must be in writing signed by each Party to be bound by such waiver, shall be effective only to the extent specifically set forth in such writing and shall not limit or affect any rights with respect to any other or future circumstance.

(d) This Agreement is for the sole and exclusive benefit of the Parties and shall not create a contractual relationship with, or cause of action in favor of, any third party.

(e) Neither Party shall have the right to assign its interest in this Agreement, including its rights, duties, and obligations hereunder, without the prior written consent of the other Party, which consent may be withheld by the other Party in its sole and absolute discretion. Any assignment made in violation of the terms of this Section 8(e) shall be null and void and shall have no force and effect.

(f) In the event that any provision of this Agreement is determined to be invalid or unenforceable for any reason, in whole or part, the remaining provisions of this Agreement shall be unaffected thereby and shall remain in full force and effect to the fullest extent permitted by law, and such invalid or unenforceable provision shall be replaced by the Parties with a provision that is valid and enforceable and that comes closest to expressing the Parties’ intention with respect to such invalid or unenforceable provision.

(g) Whenever this Agreement requires or provides that (i) a notice be given by a Party to the other Party or (ii) a Party’s action requires the approval or consent of the other Party, such notice, consent or approval shall be given in writing and shall be given by personal delivery, by recognized overnight courier service, email or by certified mail (return receipt requested), postage prepaid, to the recipient thereof at the address given for such Party as set forth below, or to such other address as may be designated by notice given by any Party to the other Party in accordance with the provisions of this Section 8(g):
If to NV Energy:

NV Energy
6100 Neil Road
Reno, NV 89511
Attention: Vice President, Transmission
E-mail: rsalgo@nvenergy.com

With a copy to:

NV Energy
Office of the General Counsel
6226 West Sahara Avenue
Las Vegas, NV 89511

If to the ISO:

California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Attention: Vice President, Technology
E-mail: PRismanovic@caiso.com

Each notice, consent or approval shall be conclusively deemed to have been given (i) on the day of the actual delivery thereof, if given by personal delivery, email or overnight delivery, or (ii) date of delivery shown on the receipt, if given by certified mail (return receipt requested).

(h) This Agreement may be executed in one or more counterparts (including by facsimile or a scanned image), each of which when so executed shall be deemed to be an original, and all of which shall together constitute one and the same instrument.

(i) Nothing contained in this Agreement shall be construed as creating a corporation, company, partnership, association, joint venture or other entity, nor shall anything contained in this Agreement be construed as creating or requiring any fiduciary relationship between the Parties. No Party shall be responsible hereunder for the acts or omissions of the other Party.

(j) The decision to execute an EIM service agreement and participate in the EIM remains within the sole discretion of NV Energy and the decision whether to continue to offer EIM services remains within the sole discretion of the ISO.

(k) Nothing in this Agreement shall preclude a Party from exercising any rights or taking any action (or having its affiliates take any action) with respect to any other project.
Unless otherwise expressly provided, for purposes of this Agreement, the following rules of interpretation shall apply: (i) any reference in this Agreement to gender includes all genders, and the meaning of defined terms applies to both the singular and the plural of those terms; (ii) the insertion of headings are for convenience of reference only and do not affect, and will not be utilized in construing or interpreting, this Agreement; (iii) all references in this Agreement to any “Section” are to the corresponding Section of this Agreement unless otherwise specified; (iv) words such as “herein,” “hereinafter,” “hereof,” and “hereunder” refer to this Agreement (including Exhibit A to this Agreement) as a whole and not merely to a subdivision in which such words appear, unless the context otherwise requires; (v) the word “including” or any variation thereof means “including, without limitation” and does not limit any general statement that it follows to the specific or similar items or matters immediately following it; and (vi) the Parties have participated jointly in the negotiation and drafting of this Agreement and, in the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as jointly drafted by the Parties and no presumption or burden of proof favoring or disfavoring any Party will exist or arise by virtue of the authorship of any provision of this Agreement.

9. **Governing Law: Venue.** This Agreement shall be governed by, and construed and interpreted in accordance with, the laws of the State of California without regard to its principles of conflicts of laws. Venue for any action hereunder shall be FERC, where subject to its jurisdiction, or in any Sacramento County state or Eastern District federal court located within the State of California. Each Party waives to the fullest extent permitted by law, any right it may have to contest venue and a right to trial by jury in respect of any suit, action, claim or proceeding relating to this Agreement.

10. **Communication.** The Parties shall develop a communication protocol for the dissemination of material information associated with the Project, which shall be approved by NV Energy and the ISO. Pursuant to the communication protocol, the individual identified in Section 8(g), or their designee or successor, shall provide reasonable advance notice to the other Party of planned press releases, public statements, and meetings with the public or governmental authorities in which material information concerning the Project will be shared. The Parties shall mutually consult with each other as provided in the communication protocol prior to making such public statements or disclosures; provided that nothing herein shall prevent, limit, or delay either Party from making any disclosure required by applicable law or regulation. In the event either Party engages in material unplanned communications about the Project that otherwise should have been subject to this Section and the communication protocol, such Party shall provide notice to the other Party as promptly as possible of the nature and content of such communication.

11. **Dispute Resolution.** Unless otherwise provided herein, each of the provisions of this Agreement shall be enforceable independently of any other provision of this Agreement and independent of any other claim or cause of action. In the event of any dispute arising under this Agreement, the Parties shall first attempt to resolve the matter through direct good faith negotiation between the Parties, including a full opportunity for escalation within the Parties’ respective organizations. If the Parties are unable to
resolve the issue within thirty (30) days after presentation of the dispute, then for matters subject to FERC jurisdiction either Party shall have the right to file a complaint under Section 206 of the Federal Power Act. For all other matters, then:

(a) To the fullest extent permitted by law, each of the Parties hereto waives any right it may have to a trial by jury in respect of litigation directly or indirectly arising out of, under or in connection with this Agreement. Each Party further waives any right to consolidate, or to request the consolidation of, any action in which a jury trial has been waived with any other action in which a jury trial cannot be or has not been waived.

(b) If a waiver of jury trial is deemed by any court of competent jurisdiction to not be enforceable for any reason, then to the fullest extent permitted by law, each of the Parties hereto agrees to binding arbitration. Such arbitration shall be in accordance with the rules and procedures of the American Arbitration Association (AAA). Notwithstanding any AAA rules and procedures or any other provisions or any state or federal laws, the Parties agree that the arbitrators shall not consider or award punitive damages as a remedy. Upon request by either Party, AAA shall provide the Parties a list of arbitrators each of who have experience and expertise with respect to construction. Upon each of the Parties receipt of such list, each Party shall have ten (10) days to select an arbitrator. The two selected arbitrators shall then select a third arbitrator within thirty (30) days from the date the initial two arbitrators were selected and the matter subject to arbitration shall be arbitrated within sixty (60) days after the selection of the third arbitrator.

12. Third Party Agreements. The Parties may engage in discussions with third parties, either jointly or unilaterally, to facilitate the Project or EIM implementation process. Each Party may enter into binding agreements or tariffs or modify existing agreements or tariffs with these third parties to implement the approved terms and conditions of the Project or EIM as necessary and appropriate.

13. Compliance. Each Party shall comply with all federal, state, local or municipal governmental authority; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including FERC, NERC, WECC; or any court or governmental tribunal, in each case, having jurisdiction over either Party in connection with the execution, delivery and performance of its obligations under this Agreement. This Agreement is not intended to modify, change or otherwise amend the Parties’ current functional responsibilities associated with compliance with WECC and NERC Reliability Standards; provided however, the Parties may enter into separate mutually agreed to arrangements to clarify roles and responsibilities associated with compliance with WECC and NERC Reliability Standards.
IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Implementation Agreement as of the date first above written.

NV ENERGY

By:  
Name: Rich Salgo  
Title: Acting Vice President, Transmission

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

By:  
Name: Petar Ristanovic  
Title: Vice President, Technology
EXHIBIT A: PROJECT SCOPE AND SCHEDULE

The Project consists of the activities and delivery dates identified in this Exhibit A, implemented in accordance with the Agreement.

The Parties understand that input received from stakeholders during the course of implementing the Project, conditions imposed or questions raised in the regulatory approval process, and the activities of the Parties in implementing the Project may cause the Parties to determine that changes in the Project are necessary or desirable. Accordingly, this Exhibit A may be modified in accordance with Section 3(c) of the Agreement.

Each Party is responsible for performing a variety of tasks necessary to achieve the milestones on schedule and shall plan accordingly. The Parties shall communicate and coordinate as provided in the Agreement to support the planning and execution to complete the Project.

<table>
<thead>
<tr>
<th>Project Scope and Milestones</th>
<th>Project Delivery Dates</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Detailed Project Management Plan</strong> – The Parties will develop and initiate a final project management plan that describes specific project tasks each Party must perform, delivery dates, project team members, meeting requirements, and a process for approving changes to support completion of the Project.</td>
<td>June 1, 2014</td>
</tr>
<tr>
<td><strong>Milestone 1</strong> – The Agreement must be made effective in accordance with Section 1 of the Agreement to complete this milestone.</td>
<td></td>
</tr>
<tr>
<td><strong>Full Network Model Expansion</strong> – Full Network Model expansion for NV Energy and EMS/SCADA, including, proof of concept of export/import of EMS data; complete model into the ISO test environment; complete validation for all SCADA points from NV Energy; testing of the new market model; and validation of the Outage and State Estimator applications.</td>
<td>November 14, 2014 (estimate based on April 16, 2014 FERC and PUCN filing dates)</td>
</tr>
<tr>
<td><strong>Milestone 2</strong> - This milestone is completed upon the modeling NV Energy into the ISO Full Network Model through the EMS which will be deployed into production using the ISO’s network and resource modeling process.</td>
<td>January 28, 2015</td>
</tr>
<tr>
<td><strong>System Implementation and Connectivity Testing</strong> – System requirements and software design, the execution of necessary software vendor contracts, development of Market network model including NV Energy, allow NV Energy to connect to a non-production test system.</td>
<td>May 15, 2015</td>
</tr>
<tr>
<td>Milestone 3 - ISO to promote market network model including NV Energy area to non-production system and allow NV Energy to connect and exchange data in advance of Market Simulation.</td>
<td>May 15, 2015</td>
</tr>
<tr>
<td>Construction, Testing and Training in Preparation for Market Simulation - This task includes IT infrastructure upgrades, security testing, training simulators, and functional testing.</td>
<td>August 7, 2015</td>
</tr>
<tr>
<td>Milestone 4 - The EIM market simulation will allow NV Energy and the ISO to conduct specific market scenarios in a test environment prior to the production deployment to ensure that all system interfaces are functioning as expected and to produce simulated market results. To complete this milestone, the commencement of EIM simulation will signal that the NV Energy and the ISO have independently completed EIM system design, development and testing to participate in joint testing.</td>
<td>August 10, 2015</td>
</tr>
<tr>
<td>System Deployment and Go Live – Implementing the Project and going live will include resource registration, operating procedures and updates, execution of service agreements, completion of the NV Energy tariff process, applicable board approvals, and the filing and acceptance of service agreements and tariff changes with FERC.</td>
<td>September 30, 2015</td>
</tr>
<tr>
<td>Milestone 5 – This milestone is complete upon the first production NV Energy energy imbalance market trade date.</td>
<td>October 1, 2015</td>
</tr>
</tbody>
</table>
ITEM-3

AMENDMENT TO CURRENT PORTFOLIO OPTIMIZATIONS PROCEDURES (SECTION IV.A.5) OF NEVADA POWER COMPANY ENERGY SUPPLY PLAN
NEVADA POWER COMPANY d/b/a NV ENERGY
ENERGY SUPPLY PLAN UPDATE
2014 - 2015

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MW of firm on-peak energy and 25 MW of firm off-peak energy delivered to the Mead Substation. The power exchange agreement expires September 30, 2017.

2. QUALIFYING FACILITY PPAS

Pursuant to the Public Utility Regulatory Policies Act ("PURPA"), Nevada Power has three long-term PPAs with gas-fired Qualifying Facilities ("QFs") with a total capacity of 260 MW. All three agreements are with cogeneration plants that use natural gas as the primary fuel for generation of electricity and utilize waste heat from the electric generator for industrial purposes.

3. RENEWABLE ENERGY & RELATED PPAS

Nevada Power has executed and the Commission has approved a total of twenty long-term renewable energy PPAs representing a total capacity of 798.2 MW. Projects representing 228.5 MW are scheduled to be completed between Q3 2013 and Q3 2019. One of the largest projects under development is Crescent Dunes (110.0 MW). The Crescent Dunes project is on track to be the first large scale solar thermal facility in the United States utilizing a central receiver tower design with molten salt storage technology. Since Nevada Power’s previous IRP filing, one new PPA (Searchlight Solar) has been approved by the Commission. Offsetting this addition is the termination of Ram Power’s Clayton Valley project (53.5 MW).

Until the completion of the ON Line project (expected Q4 2013), Nevada Power will continue to utilize Commission-approved Related PPAs to sell PPA-contracted energy purchased in Sierra’s service territory, while retaining the corresponding PCs, for use towards Nevada’s RPS standard. Similarly, Sierra will resell its contractual share of the energy from the Nevada Solar One project, which is physically interconnected to Nevada Power’s system, back to Nevada Power while retaining the PCs from the project for use towards its compliance with Nevada’s RPS.

4. SHORT-TERM RFP CONTRACTS

Based on its forecasted credit requirement and supply outlook, Nevada Power does not contemplate a need for deliveries from any short-term renewable contracts (energy and credits or credit only) in order to achieve RPS compliance during the upcoming action plan period (2014-2015). However, Nevada Power will diligently monitor its portfolio and any external changes (such as change in load or law) that may cause it to revisit this requirement.

5. CURRENT PORTFOLIO OPTIMIZATION PROCEDURES

The Company’s 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 Company continuously monitors 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 through
power market trading platforms such as the Intercontinental Exchange ("ICE") and the broker markets for comparison with Nevada Power’s the Company’s internal generation costs. As conditions change and new information becomes available, the Company optimizes its portfolio to account for changes in load, cost, volatility, reliability, and other commercial or technical factors.

In 2008, Nevada Power the Company began issuing reverse RFPs to sell forward HR call options to the extent that capacity was not expected to be needed to serve load. In light of market conditions, there is no reason to expect that on average greater revenue would be realized by selling power forward as opposed to making all sales in the short-term markets. Selling forward smoothes the realization of revenue, but should not be expected to increase revenue. The revenues realized from forward sales could be higher or lower than those from short-term sales depending upon market conditions at the time a particular sale is made. A copy of the Forward Sales Procedures Manual is provided as Technical Appendix Power-1.

Each month, the Company assesses its 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 Company is expected to be short in terms of meeting system load and reserve requirements in the upcoming month, the Company may purchase energy or capacity either-through an RFP process or bi-laterally to fill the short position. If an assessment concludes that the Company is expected to be long, a market survey is conducted in order to identify sales opportunities.

The Company also prepares day-ahead plans. On a daily basis, the Company forecasts the energy position and generation costs for the scheduling day using a production cost simulation model. Internal generation cost is compared to the actual energy market prices to determine if there are any market opportunities to mitigate customer costs. The Company’s traders determine the actual energy market prices in real time by communicating with other traders and by monitoring the ICE, a real-time trading platform for global commodity and financial products marketplaces, including electronic energy markets. Per the Company’s approved procedures, a market survey is conducted in order to gauge interest among approved counterparties, and purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

On the day of delivery, the Company continues to compare hourly generation costs to hourly energy market prices and monitor hourly weather patterns, actual generation and transmission availability and costs, and hourly energy market conditions in order to balance loads and resources across the day. The Company’s traders ascertain real-time market conditions by conducting hourly market surveys through communications with other counterparties. Again, per the Company’s policies, a market survey is conducted in order to gauge interest among potential counterparties, and 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 energy imbalance market ("EIM") operated by the California Independent System Operator ("ISO"). The EIM utilizes 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 Company expects to begin participating in the EIM in October 2015. The Company’s traders will determine which resources are available for participation in the EIM and will voluntarily submit bids to the market operator for EIM purchases or sales. Participation in the EIM does not absolve the Company from compliance with reliability standards or the obligation to meet customer demand.

Short-term energy transactions or adjustments to planned 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, actual loads being higher than the amount forecasted, and transmission constraints due to forced outages or other unanticipated contingencies concerning transmission facilities inside or outside the Company’s transmission network. In any of these circumstances, the transmission system may enter a condition where, 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 reserves to regain such balance and restore the required reserve margins.

6. CONTINUOUS MONITORING AND OPTIMIZATION OF THE POWER PORTFOLIO

As opportunities present themselves, the Company will make forward power sales by entering into direct negotiations with counterparties or through a reverse RFP process as specified in the Forward Sales Procedures Manual (Technical Appendix POWER-1). Forward sales transactions will be pursued if there is confidence that a long capacity and/or energy position will exist and the transaction will yield positive economic benefits for bundled retail customers. The products to be sold on a forward basis may include HR call options, indexed power, fixed-price power, ancillary services products, or other products as approved. The Company will not make forward sales for delivery more than three gas seasons in advance (including the current gas season), unless authorized.

In order to account for opportunities or risks involved in initiating forward sale transactions, the Company will continue to use probabilistic analysis. As a practical matter, if there had to be a 100% guarantee that no transaction would expose customers to any price or reliability risks, then it would be impossible to engage in forward sales.

A stochastic production cost simulation model will be used to estimate system costs both with and without a forward power sale using a range of possible inputs for one or more variables, in a series of iterations, in order to determine a range of possible outcomes (i.e., a range of the possible incremental costs to be expected by the addition of the forward sale to the portfolio). The process entails determining the incremental costs associated with serving the forward power sale in each iteration by subtracting the total production
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AMENDMENT TO CURRENT PORTFOLIO OPTIMIZATIONS PROCEDURES (SECTION IV.A.4) OF SIERRA PACIFIC POWER COMPANY
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In order to account for opportunities or risks involved in initiating forward sale transactions, the Company will continue to use probabilistic analysis. As a practical
CERTIFICATE OF SERVICE
CERTIFICATE OF SERVICE
CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY’S APPLICATION upon the persons listed below by electronic mail:

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DATED this 16th day of April, 2014.

/s/ Lynn D’Innocenti
Lynn D’Innocenti
Legal Assistant
Sierra Pacific Power Company
Nevada Power Company