PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

June 6, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

Re: Docket UM 1689—In the Matter of PacifiCorp d/b/a Pacific Power Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing in this docket the NV Energy-ISO Energy Imbalance Market Economic Assessment, dated March 25, 2014. PacifiCorp is providing this document in response to a request from the Public Utility Commission of Oregon during a workshop held May 28, 2014.

Questions regarding this filing may be directed to Natasha Siores, Director of Regulatory Affairs & Revenue Requirement, at (503) 813-6583.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: Chair Susan Ackerman
Commissioner John Savage
Commissioner Stephen Bloom
Judge Sarah Rowe
UM 1689 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's NV Energy-ISO Energy Imbalance Market Economic Assessment on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

UM 1689

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 SW Broadway, STE 400
Portland, OR 97205
dockets@oregoncub.org

Robert Jenks (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway, STE 400
Portland, OR 97205
Bob@oregoncub.org

G. Catriona McCracken (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway, STE 400
Portland, OR 97205
catriona@oregoncub.org

Tyler C Pepple (W) (C)
Davison Van Cleve, PC
333 SW Taylor, Suite 400
Portland, OR 97204
tcp@dvclaw.com

S Bradley Van Cleve (W) (C)
Davison Van Cleve, PC
333 SW Taylor, STE 400
Portland, OR 97204
bvc@dvclaw.com

Bradley Mullins (W)
Mountain West Analytics
333 SW Taylor, STE 400
Portland, OR 97204
brmullins@mwanalytics.com

Michael T Weirich (W) (C)
PUC Staff - Department of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
Michael.weirch@state.or.us

Oregon Dockets (W)
PacifiCorp, dba Pacific Power
825 NE Multnomah St., STE 2000
Portland, OR 97232
oregondockets@pacificorp.com

Sarah Wallace (W)
Pacific Power
825 NE Multnomah St., STE 1800
Portland, OR 97232
Sarah.wallace@pacificorp.com

Katherine A McDowell (W)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
Katherine@mcd-law.com

Deborah Garcia (W) (C)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
deborah.garcia@state.or.us

John Crider (W) (C)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
john.crider@state.or.us

Donald Light (W)
Portland General Electric
121 SW Salmon 1WTC1711
Portland, OR 97204
donald.light@pgn.com

Jay Tinker (W)
Portland General Electric
121 SW Salmon 1WTC-0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

Dated this 6th of June 2014.

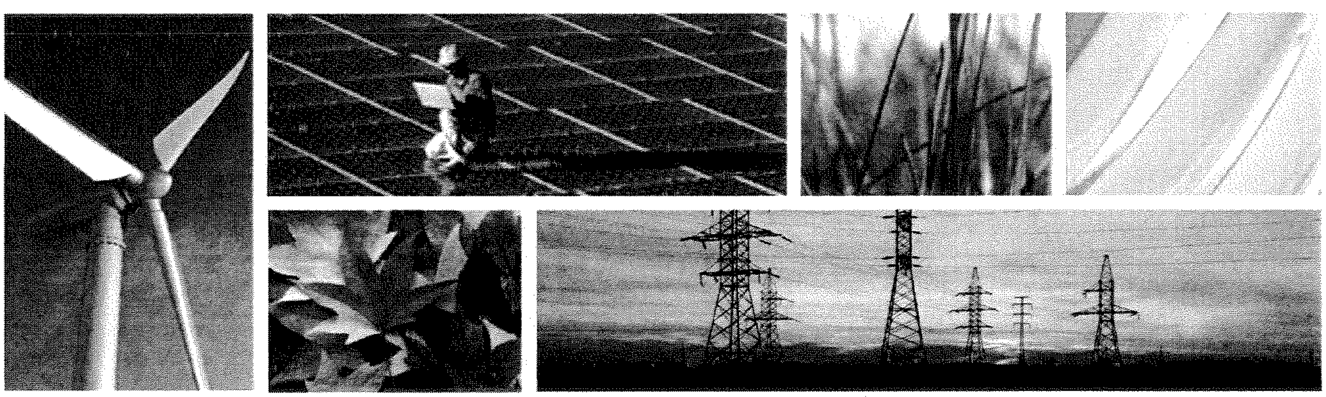
Amy Eissler
Coordinator, Regulatory Operations

NVEnergy

California ISO
Shaping a Renewed Future

NV Energy-ISO
Energy Imbalance Market
Economic Assessment

March 25, 2014



Energy+Environmental Economics

ABB

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

[redacted]

Table of Contents

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 significant net present value (NPV) savings to the NV Energy balancing authority (BA).[1] NV Energy participation in the EIM would also produce

[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.

significant 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 $11.3 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

[2] Preliminary 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.[3] 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

[3]For the latest details of the EIM market, see "Energy imbalance market," CAISO, accessed November 21, 2013, http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx; CAISO, "Energy Imbalance Market Draft Final Proposal," September 23, 2013, http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf.

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.[4] 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"[5]

[4] See E3, "PacifiCorp-ISO Energy Imbalance Market Benefits," March 13, 2013, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.

[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;[6]

+ *Reduced flexibility reserve*, by aggregating the three systems' 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 resources.[7]

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

from the EIM during future years, the ISO would attempt to implement transmission compensation policy in a manner that mitigates any negative impacts on potential efficiencies savings from the EIM.

[6] See Section 2.1.3.4 for a discussion of the transmission ties between the NV Energy and PacifiCorp East BAAs.

[7] 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.

[redacted]

generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.[8]

The study team estimated the benefits of NV Energy's participation in the EIM using the GridView[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

[8] Staff of the Federal Energy Regulatory Commission, "Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market," February 26, 2013, http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf.

[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.[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

Assumption	Low range	High range
Availability of NV Energy generators to participate in EIM	Unavailable during June-Sept; annual dispatch benefits scaled downward by one-third (4/12ths)*	Available in all months for EIM dispatch; full-year dispatch benefits used
Calculation of flexibilty reserve benefits	Quantity reduction in reserve requirement valued at benchmark of average ISO historical ancillary service market price levels	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
Share of identified renewable energy curtailment value avoided in California	10%	100%

*Note: *See Section 2.1.3.6 for additional detail.*

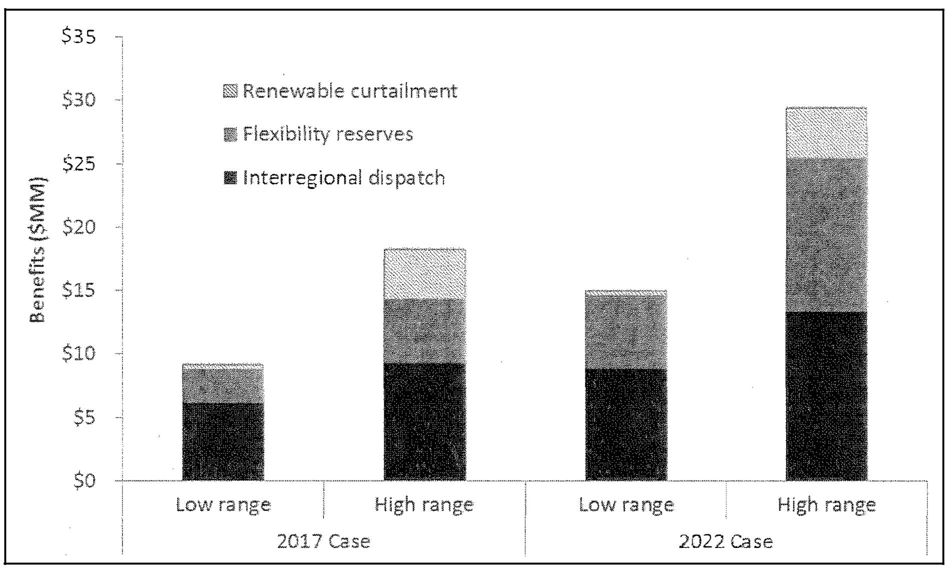
Across these scenarios, the study team estimated that NV Energy participation in the EIM generates total annual cost savings to all participants (in 2013$) of $9.2 to $18.2 million in 2017, and $15.0 to $29.4 million in 2022. These benefits are incremental to those estimated for the creation of the initial 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 benefits to all participants from NV Energy Participation in EIM for 2017 and 2022 (million 2013$)

Benefit Category	2017 Low range	2017 High range	2022 Low range	2022 High range
Interregional dispatch	$6.2	$9.3	$8.9	$13.4
Flexibility reserves	$2.6	$5.0	$5.7	$12.0
Renewable curtailment	$0.4	$4.0	$0.4	$4.0
Total benefits	**$9.2**	**$18.2**	**$15.0**	**$29.4**

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

Figure 1. Low and high range incremental gross 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 benefits to NV Energy BA (million 2013$)

Benefit Category	2017		2022	
	Low range	High range	Low range	High range
Interregional dispatch	$3.1	$4.7	$4.5	$6.7
Flexibility reserves	$2.8	$3.6	$3.2	$4.3
Renewable curtailment	$0.1	$1.2	$0.1	$1.2
Total benefits	**$6.0**	**$9.5**	**$7.7**	**$12.2**

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

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

Benefit Category	Low range	High range	Low range	High range
Interregional dispatch	$3.1	$4.7	$4.5	$6.7
Flexibility reserves	-$0.2	$1.4	$2.5	$7.7
Renewable curtailment	$0.3	$2.8	$0.3	$2.8
Total benefits	**$3.2**	**$8.8**	**$7.3**	**$17.2**

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$)

Cost Component	Timing	Cost
One time capital costs for setup in preparation to participate in EIM	One-time	$10.1
One-time ISO intial setup fee	One-time	$1.1
Total One-time costs:		**$11.3**
Ongoing costs for staff, software, & administration	Annual	$1.9
Estimated annual ISO usage fees	Annual	$0.7
Total ongoing annual costs:		**$2.6**

These costs include $11.3 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%.

[redacted]

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,[13] eliminating within-hour limitations, and enabling more efficient dispatch between BAAs relative to current scheduling practices.

+ **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.
+ **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.[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

[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.

[14] NV Energy has historically operated as two BAs, 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 BAs 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.[15] 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,

[15]Energy Imbalance Market Draft Final Proposal," September 23, 2013, http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf

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.[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 $11.3 million in one-time startup costs, and $2.6 million per year in annual ongoing costs.

Table 6. NV Energy estimated one-time and annual costs to participate in EIM (million 2013$)

Cost Component	Timing	Cost
One time capital costs for setup in preparation to participate in EIM	One-time	$10.1
One-time ISO intial setup fee	One-time	$1.1
Total One-time costs:		**$11.3**
Ongoing costs for staff, software, & administration	Annual	$1.9
Estimated annual ISO usage fees	Annual	$0.7
Total ongoing annual costs:		**$2.6**

[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.[17] 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

[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.[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.[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

---

[18] See ISO, Draft Proposal for Flexible Ramping Product:
http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

[19] For more detail regarding the proposed approach for determining, procuring and allocating flexibility requirements under EIM, see Section 3.4.3 of ISO, Energy Imbalance Market Draft Final Proposal
http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.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.[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,[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. It is uncertain at this time whether existing contractual rights over these paths could currently be used dynamically under an 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

[redacted]

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.[22]

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).[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

[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.

[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.

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 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. NVE could also choose to self-

[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.

schedule its own generators in the day-ahead time period based on its 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

[redacted]

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 CO_2 allowances when delivering "unspecified" electric energy into California. These CO_2-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).

[redacted]

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.[25] 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

[25] NV Energy is also assumed to require 35 MW of regulation reserves in all hours based on NV Energy IRP projections.

reserve requirements enabled by the PacifiCorp-ISO EIM, subject to a 400 MW transmission constraint between PacifiCorp and ISO.[26]

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.

[26] 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.
[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[29] under the NVE BAU Case and NVE EIM Flexibility Reserve Case in 2017 and 2022

Scenario	2017	2022
Regulation Reserves Requirements (All cases)	586	720
Load Following Reserves Requirement for:		
NVE BAU Case (NVE as Standalone)	1,457	1,950
NVE EIM Flexibility Reserve Case	1,416	1,861

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]

[29] Totals include the sum of regulation and load following requirements.
[30] 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.[31]

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

[31] 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 NVE 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.

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

[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 on 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.[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.[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.

[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).

[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 ECCO International's ProMaxLT 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 CO_2 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.

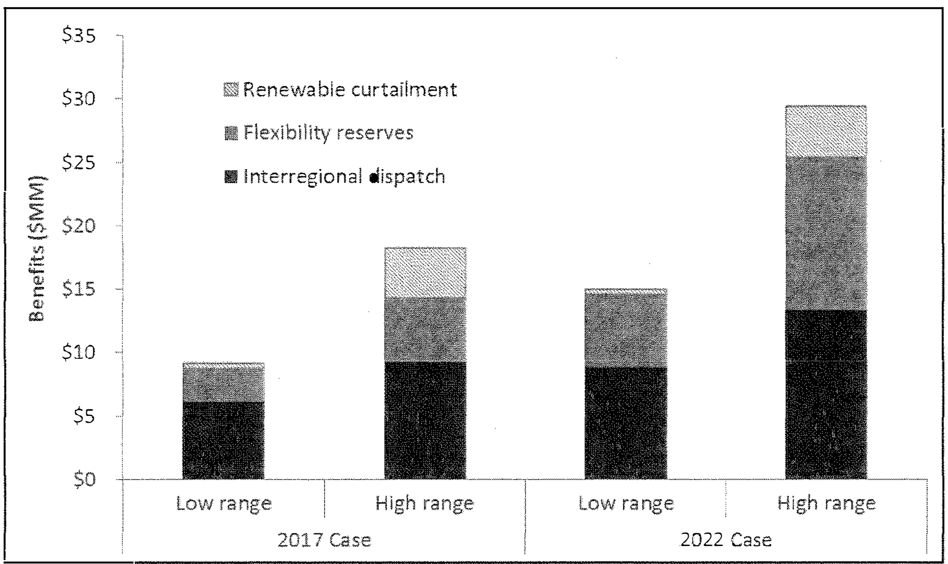
Table 8. Low and high range assumptions for 2017 and 2022 cases

Assumption	Low range	High range
Availability of NV Energy generators to participate in EIM	Unavailable during June-Sept; annual simulation dispatch benefits scaled downward by one-third (4/12ths)	Available in all months for EIM dispatch; full-year simulation benefits used
Calculation of flexibility reserve benefits	Quantity reduction in reserve requirements valued at benchmark of average ISO historical ancillary service market price levels	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)
Share of identified renewable energy curtailment value avoided in California	10%	100%

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 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$)

Benefit Category	2017		2022	
	Low range	High range	Low range	High range
Interregional dispatch	$6.2	$9.3	$8.9	$13.4
Flexibility reserves	$2.6	$5.0	$5.7	$12.0
Renewable curtailment	$0.4	$4.0	$0.4	$4.0
Total benefits	**$9.2**	**$18.2**	**$15.0**	**$29.4**

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.[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

[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 affects 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.[37] 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

[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 BAA 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 benefits to NV Energy (million 2013$)

Benefit Category	2017		2022	
	Low range	High range	Low range	High range
Interregional dispatch	$3.1	$4.7	$4.4	$6.7
Flexibility reserves	$2.8	$3.6	$3.2	$4.3
Renewable curtailment	$0.1	$1.2	$0.1	$1.2
Total benefits	**$6.0**	**$9.5**	**$7.7**	**$12.2**

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

Table 11. Attribution of expanded EIM benefits to current EIM participants (million 2013$)

Benefit Category	Low range	High range	Low range	High range
Interregional dispatch	$3.1	$4.7	$4.5	$6.7
Flexibility reserves	-$0.2	$1.4	$2.5	$7.7
Renewable curtailment	$0.3	$2.8	$0.3	$2.8
Total benefits	**$3.2**	**$8.8**	**$7.3**	**$17.2**

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

Benefit Category	Assumptions (conservative, moderate, aggressive)	Rationale
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
Renewable	Conservative	• Study did not evaluate renewable curtailment

curtailment		for NV Energy, which limited EIM benefits • In low range estimate, study assumed wind and solar not producing significant over-generation (conservative assumption) • 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
Within-hour dispatch	Conservative	• Production simulation analysis modeled at hourly level, omitting potential benefits of sub-hourly dispatch (other studies indicate that these benefits could be substantial)

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

[38] See http://www.caiso.com/Documents/ PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf for the final report.
[39] See http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf for the final report.
[40] See http://www.westgov.org/PUCeim/ for the PUC EIM website and link to the NREL final report at http://www.nrel.gov/docs/fy13osti/57115.pdf.

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

[41] See http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf.
[42] See http://www.nwpp.org/documents/MC-Public/NWPP_EIM_Final_Report_10_18_2013.pdf.

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

Study (Organization)	Annual Benefits ($MM)	Geographic Scope	Key Drivers of Differences with this Study
NV Energy-ISO EIM study	$9-18 in 2017; $15-29 in 2022	Incremental benefits from adding NV Energy with PacifiCorp, and ISO	

PacifiCorp-ISO EIM study	$21-$129 in 2017	PacifiCorp and ISO	• Similar methodology framework and benefit categories. • NV Energy-ISO study includes PacifiCorp-ISO EIM in base case • PacifiCorp-ISO study uses benchmarked hurdle rates rather than wheeling rates to represent friction across BAA boundaries • PacifiCorp-ISO study includes intra-regional dispatch savings in PacifiCorp • PacifiCorp-ISO study also models high range case with 12% cap on hydro contribution to reserves, which increases flexibility benefits from EIM • 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 • NV Energy-ISO Study incorporates additional transmission modeling detail in Southwest to represent NV Energy system and rights on co-owned facilities.
WECC EIM (E3)	$141 in 2020	WECC excluding ISO and AESO	• WECC EIM study had similar approach to this study • WECC EIM study had larger EIM footprint than this study • WECC study excluded intraregional dispatch savings; this study includes intraregional dispatch savings • No assessment of renewable curtailment reduction in WECC study; this study includes

			benefits of renewable curtailment reduction
PUC EIM Group (NREL)	$146-294 in 2020 for EIM (plus additional $1,312 if moving from hourly to 10-minute dispatch interval)	WECC excluding ISO and AESO	• 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
WECC VGS (Energy Exemplar)	$349-$755 in 2020 ($1,112 for 27% renewable mix scenario in 2020)	Entire WECC	• 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
NWPP EIM (PNNL)	$40-70 million in 2020, with $17-125 million range for additional sensitivities	NWPP	• Similar approach to WECC VGS study • Detailed multi-step model, with additional information provided by NWPP stakeholders especially on hydro representation

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.

---

[1] For more on GridView, see http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

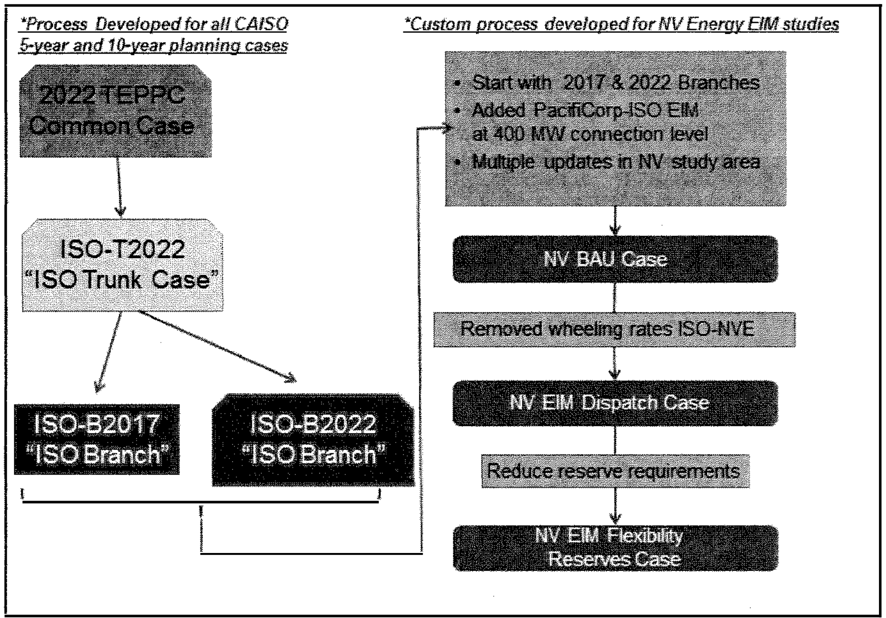
The NV EIM Dispatch Case and NV EIM Flexibility Reserve Case were used to isolate the benefits, relative to the NV BAU Case, of more efficient interregional dispatch and reduced flexibility reserves as a result of NV Energy participating in the EIM. In the NV EIM Dispatch Case, the study team modeled 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]

---

[4] ISO, 2013, *Draft 2012-2013 Transmission Plan,* http://www.caiso.com/Documents/Draft2012-2013TransmissionPlan.pdf; E3, 2011, WECC EDT Phase 2 EIM Benefits Analysis & Results (October 2011 Revision), http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf.

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 1A. Average annual burnertip gas price (2013$/MMBtu)

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

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,[5] 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 CO_2 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 CO_2 allowances on NV Energy exports to ISO (Table 2A). This \$5.52/MWh adder was based on a default CO_2 emissions factor from the California Air Resources Board of 0.428 metric tons/MWh, and CO_2 prices for 2017 of \$11.53 (2013\$) per short ton of CO_2, 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 CO_2 allowances on NV Energy exports to ISO (based on a 2022 CO_2 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 2A. Wheeling rates used in the NV BAU Case (2013\$)

	Wheeling Rate (\$/MWh)			
	NVE → ISO			ISO → NVE
Case	CO_2-related	Non-CO_2 related	Total	
NV BAU Case – 2017	\$5.52	\$6.71	\$12.23	\$10.10*
NV BAU Case – 2022	\$10.65	\$6.71	\$17.36	\$10.39*

[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 CO_2-related wheeling rate is applied to ISO exports to NV Energy because CO_2 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]

[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

NV BAU Case	2017	2022
NV Energy		
Regulation Reserves Requirements	35	35
Load Following Reserves Requirement	41	76
Existing EIM participants (ISO-PacifiCorp)		
Regulation Reserves Requirements	551	685
Load Following Reserves Requirement	1,415	1,859

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 CO_2-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 CO_2 allowances in 2017 (and \$10.65/MWh for CO_2 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$)

	Wheeling Rate ($/MWh)			
	NVE → ISO			ISO → NVE
Case	CO_2-related	Non-CO_2 related	Total	
NV BAU Case – 2017	$5.52	$6.71	$12.23	$10.10*
NV EIM Dispatch Case - 2017	$5.52	$0.00	$5.52	$0.00*
NV BAU Case – 2022	$10.65	$6.71	$17.36	$10.39*
NV EIM Dispatch Case - 2022	$10.65	$0.00	$10.65	$0.00*

**No CO_2-related hurdle rate is applied to ISO exports to NVE because CO_2 permit cost under AB32 is directly modeled in the dispatch for generators located inside California.*

Eliminating the non-CO_2 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$)

Scenario	2017 Low Range	2017 High Range	2022 Low Range	2022 High Range
NV EIM Dispatch Case	$6.2	$9.3	$8.9	$13.4

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

NV EIM Flexibility Case	2017	2022
Expanded EIM (NV Energy-ISO-PacifiCorp)		
Load Following Reserves Requirement	1,416	1,861

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$)

Scenario Year	Average EIM Reduction in Flex Reserves (MW)	Average 2009-2011 AS Prices ($/MWh)	Low Range Flexibility Savings ($MM)	Comparison: High Range Flexibility Reserve Savings from GridView ($MM)
2017	41	$7.32	$2.6	$5.0
2022	89	$7.32	$5.7	$12.0