BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 296

PACIFICORP

PAC/900 to Cross-Examination Statement

ICNU Response to PacifiCorp Data Request No. 10

August 18, 2015

PACIFICORP DATA REQUEST NO. 10 TO ICNU:

Refer to page 32, lines 15-17 of Mr. Mullins' testimony, where Mr. Mullins states: "As a result of its participation in the EIM and the use of the Cal-ISO SCED model to manage inter-hour operations, the Company now has greater ability to transfer flexibility reserve requirements between balancing authorities." Please provide the evidence or authorities upon which Mr. Mullins relied to develop and support this statement.

RESPONSE TO PACIFICORP DATA REQUEST NO. 10:

The ability to effectuate sub-hourly transfers between balancing authorities means that, if the East Balancing Area is out of balance (i.e., if its ACE exceeds L_{10}), then the West Balancing Area—through the mechanics of the EIM and the Cal-ISO SCED model—can provide imbalance energy, bringing the East back into balance. In terms of calculating forecast error and reserves, it goes without saying that the ability to transfer imbalance between Balancing Areas is a substantial reliability benefit, one that is not currently reflected in the Company's modeling.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/901 to Cross-Examination Statement

PacifiCorp's 2012 Wind Integration Study

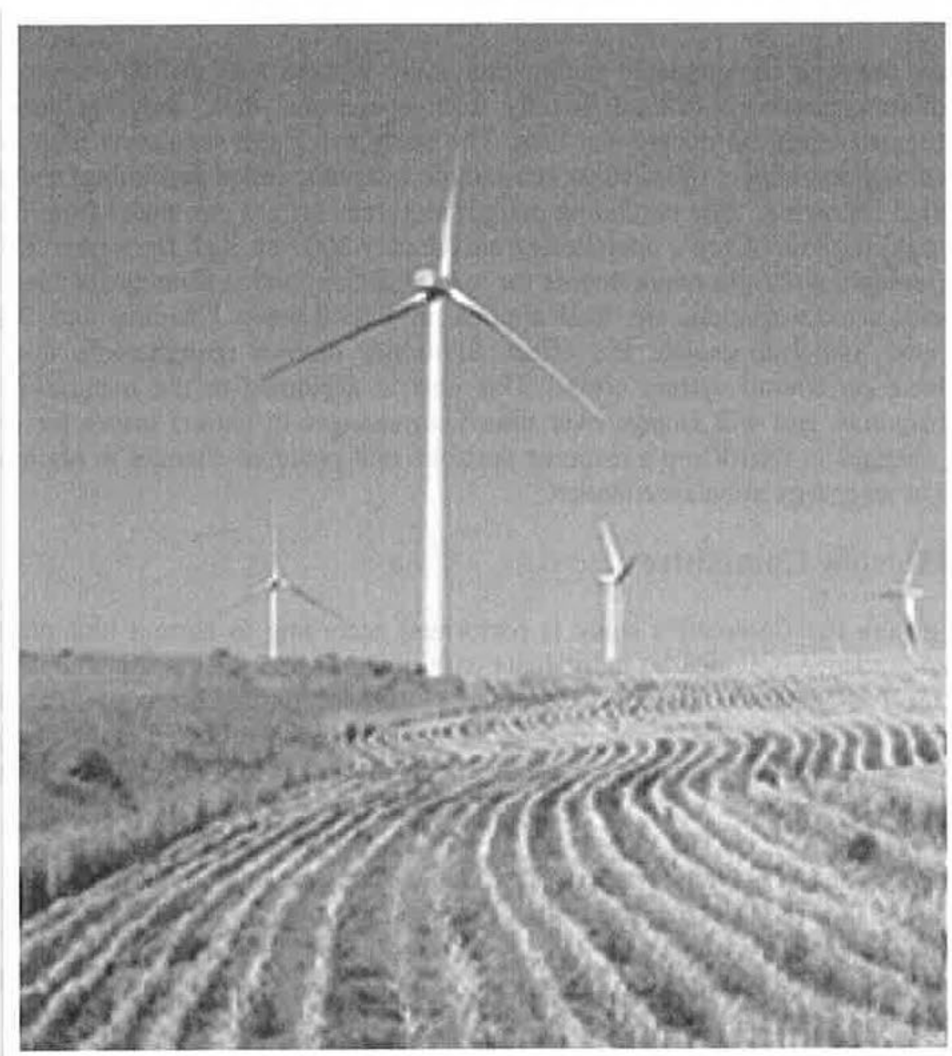
August 18, 2015

APPENDIX H – WIND INTEGRATION STUDY

This appendix provides the 2012 Wind Integration Study conducted during the 2013 IRP planning process. A draft version of this study was sent to participants in November 2012. The 2012 Wind Integration Study will be presented to the Technical Review Committee for approval in May 2013.

PACIFICORP

2012 WIND INTEGRATION RESOURCE STUDY



APRIL 30, 2013

1. Introduction

The purpose of this study is to estimate the operating reserves required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. The Company must provide sufficient operating reserves to allow the Balancing Authority to meet NERC's control performance criteria (See BAL-007-1[21]) at all times, incremental to contingency reserves which the Company maintains to comply with NERC Standard BAL-002-0[22]. These incremental operating reserves are necessary to maintain area control error[23] within required parameters, apart from disturbance events that are addressed through contingency reserves, due to sources outside direct operator control including intra-hour changes in load demand and wind generation. The study results in an estimate of operating reserve volume and estimated cost of these operating reserves required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas (BAAs).

The operating reserves contemplated within this study represent regulating margin, which is comprised of ramp reserve extracted directly from operational data, and regulation reserve, which is estimated based on operational data. The study calculates regulating margin demand over two common operational timeframes: ten-minute intervals, called regulating; and one-hour-intervals, called following. The regulating margin requirements are calculated from operational data recorded during PacifiCorp's operations from January 2007 through December 2011 (Study Term). The regulating margin requirements for load variation, and separately for load variation combined with wind variation, are then applied in PacifiCorp's Planning and Risk (PaR) production cost model to isolate the effect additional reserve requirements due to wind generation have on overall system costs. This cost is attributed to the integration of wind generation resources and will change over time with changes in market prices for power and natural gas, changes in PacifiCorp's resource portfolio and potential changes in regional market design, such as an energy imbalance market.

Technical Review Committee

In order to ensure the Company's study is performed according to current best practices and benefits from guidance provided by individuals with diverse wind integration study experience, PacifiCorp used a Technical Review Committee (TRC) for its 2012 Study. The TRC was involved during the Study process, and their recommendations are reflected in the Study method and scenarios addressed. All study results have been presented to and reviewed by the TRC. The members of the TRC are:

- Andrea Coon - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- Randall Falkenberg – President, RFI Consulting, Inc.
- Matt Hunsaker - Manager, Renewable Integration for the Western Electricity Coordinating Council (WECC)
- Michael Milligan - Lead research for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory (NREL)

[21] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf.
[22] NERC Standard BAL-002-0: http://www.nerc.com/files/BAL-002-0.pdf
[23] "Area Control Error" is defined in the NERC glossary here: http://www.nerc.com/files/Glossary_12Feb08.pdf

- J. Charles Smith - Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Robert Zavadil - Executive Vice President of Power Systems Consulting, EnerNex

The study method incorporates improvements resulting from recommendations made by TRC members as well as analyses requested by them. The Company thanks all the TRC members for their reviews of the study method and professional feedback.

1.1 Executive Summary

The 2012 Wind Integration Study (the "Wind Study") estimates the regulating margin requirement from historical load and wind generation production data. The regulating margin is required to manage variations to area control error due to load and wind variations within PacifiCorp's BAAs. The Wind Study estimates the regulating margin requirement based on load combined with wind variation and separately estimates the regulating margin requirement based solely on load variation. The difference between these two calculations, with and without the estimated regulating margin required to manage wind variability and uncertainty, provides the amount of incremental operating reserves required to maintain system reliability due to the presence of wind generation in the PacifiCorp's BAAs. The resulting regulating margin requirement was evaluated deterministically in PaR, a production cost model used in the Company's Integrated Resource Plan (IRP) to evaluate stochastic risk in selection of a preferred resource portfolio, so that the incremental cost of the regulating margin required to manage wind resource variability and uncertainty can be reported on a dollar per megawatt hour (MWh) of wind generation basis.[24]

Table H.1 depicts the combined PacifiCorp BAA annual average regulating margin calculated in this Wind Study, and separates the regulating margin due to load from the regulating margin due to wind.

Table H.1 - Average Annual Regulating Margin Reserves, 2012 Wind Study (MW)

	West BAA	East BAA	Combined
Load-Only Regulating Margin	147	247	394
Incremental Wind Regulating Margin	54	131	185
Total Regulating Margin	202	378	579

Table H.2 depicts the cost to integrate wind generation in PacifiCorp's BAAs. The cost to integrate wind includes the incremental regulating margin reserves to manage intra-hour variances as outlined above and the costs associated with day-ahead forecast variances that affect daily system balancing. Each of these component costs were calculated using PacifiCorp's PaR model. A series of PaR simulations were completed to isolate each wind integration cost component by using a "with and without" approach. For instance, PaR was first used to calculate system costs solely with the regulating margin requirement due to load variations, and then again

[24] The PaR model can be run with stochastic variables in Monte Carlo simulation mode or in deterministic mode whereby variables such as natural gas and power prices do not reflect random draws from probability distributions. For purposes of the Wind Study, the intention is not to evaluate stochastic portfolio risk, but to estimate production cost impacts of incremental operating reserves required to manage wind generation on the system based on current projections of future market prices for power and natural gas.

with the increased regulating margin requirements due to load combined with wind generation. The change in system costs between the two PaR simulations results in the wind integration cost.

Table H.2 - Wind Integration Cost (2012$ per MWh of Wind Generation)

Study	2010 Wind Integration Study	2012 Wind Integration Study
Wind Capacity Penetration	2046 MW	2126 MW, 2011 Operational Data
Tenor of Cost	3-year levelized, 2010$	1 year levelized, 2012$
Hourly Reserve ($/MWh)	$8.85	$2.19
Interhour/System Balancing ($/MWh)	$0.86	$0.36
Total Wind Integration ($/MWh)	$9.70	$2.55

The 579 megawatts of regulating margin identified in this study (in Table H.1) is comparable to the 530 megawatts of regulating margin identified in the prior wind integration study developed for the 2011 IRP. While overall operating reserve levels are similar, this Study shows the estimated costs of these operating reserves are lower, and that the reduced cost is primarily driven by declining natural gas and power market prices. Table H.3 compares natural gas and power price assumptions used in the 2010 Wind Integration Study to those used in the 2012 Wind Integration Study.

Table H.3 - Nominal Levelized Natural Gas and Power Prices Used in the 2010 and 2012 Wind Integration Studies

	Palo Verde High Load Hour Power	Palo Verde Low Load Hour Power	Opal Natural Gas
2010 Wind Study	$51.26	$35.60	$5.36
2012 Wind Study	$37.05	$25.74	$3.43

The effect of changing power and natural gas prices on the cost of wind integration is significant, even if the volume of wind being integrated does not change. The value of reserves is often the opportunity cost of a lost sale at a given generation station. This opportunity cost is foregone margin (which is equal to the lost revenue from the wholesale sale) less the variable cost to run the generation plant at a higher level, which is primarily the cost of fuel. Second to hydro generation, natural gas generation is often used to meet the Company's reserve requirements and to manage variability and uncertainty in wind and retail load. This is because gas-fired generation typically has less economic impact when used for reserves than coal-fired generation and has the operational flexibility to ramp up and down as the load and wind fluctuate. As natural gas prices have fallen, the costs of holding reserve capacity have correspondingly dropped even though the quantity of regulating margin requirement has increased.

2. Data

2.1 Overview

The calculation of regulating margin reserve requirement was based entirely on actual historical load and wind production data over the Study Term from January 2007 through December 2011. No simulated wind production data was incorporated in the Wind Study, which is a change from prior studies that did not have the benefit of a more complete historical data set. Table H.4

shows that the ten-minute interval data for wind resources grew substantially during this period as wind resources came online in PacifiCorp's BAAs.

Table H.4 - Historical Wind Production and Load Data Inventory

	Nameplate Capacity	Beginning of Data	End of Data	Location
Wind Plants within PacifiCorp BAAs				
Chevron Wind	17	12/1/2009	12/31/2011	East
Combine Hills	41	1/1/2007	12/31/2011	West
Dunlap I Wind	111	10/1/2010	12/31/2011	East
Foote Creek Generation	85	1/1/2007	12/31/2011	East
Glenrock Wind	99	1/1/2009	12/31/2011	East
Glenrock III Wind	39	1/17/2009	12/31/2011	East
High Plains Wind	99	9/13/2009	12/31/2011	East
Marengo I	140	8/3/2007	12/31/2011	West
Marengo II	70	6/26/2008	12/31/2011	West
McFadden Ridge Wind	29	9/29/2009	12/31/2011	East
Mountain Wind 1 QF	61	7/2/2008	12/31/2011	East
Mountain Wind 2 QF	80	9/29/2008	12/31/2011	East
Oregon Wind Farm QF	65	3/31/2009	12/31/2011	West
Rock River I	50	1/1/2007	12/31/2011	East
Rolling Hills Wind	99	1/17/2009	12/31/2011	East
Seven Mile Wind	99	12/31/2008	12/31/2011	East
Seven Mile II Wind	20	12/31/2008	12/31/2011	East
Spanish Fork Wind 2 QF	19	7/31/2008	12/31/2011	East
Stateline Contracted Generation	150	1/1/2007	12/31/2011	West
Three Buttes Wind	99	12/1/2009	12/31/2011	East
Top of the World Wind	200	10/1/2010	12/31/2011	East
Wolverine Creek	65	1/1/2007	12/31/2011	East
Long Hollow Wind		1/1/2007	12/31/2011	East
Stateline Transmission Customer		1/1/2007	12/31/2011	West
Campbell Wind		12/1/2009	12/31/2011	West
Jolly Hills 1		10/1/2010	12/31/2011	East
Jolly Hills 2		10/1/2010	12/31/2011	East
Wind Plants out of PacifiCorp BAAs				
Goodnoe Hills Wind	94	5/31/2008	12/31/2011	West - out of BAA
Leaning Juniper 1	101	1/1/2007	12/31/2011	West - out of BAA
Load Data				
PACW Load		1/1/2007	12/31/2011	West
PACE Load		1/1/2007	12/31/2011	East

2.2 Historical Load and Load Forecast Data

The historical hourly day-ahead load forecasts and day-ahead hourly wind forecasts used to operate the generation system through the Study Term (2007-2011) were retrieved from Company records. Historical load data for the PacifiCorp East (PACE) and PacifiCorp West (PACW) BAAs were collected for the Study Term from the PacifiCorp PI system[25]. These data

[25] The PI system collects load and generation data and is supplied to PacifiCorp by OSISoft. The Company Web site is http://www.osisoft.com/software-support/what-is-pi/what_is_PI_.aspx .

were used for all the calculations involving historical load in the Study. The raw load data were reviewed for anomalies prior to further use. Data anomalies can include:

- Incorrect or reversal of sign (recorded data switching from positive to negative)
- Significant and unexplainable changes in load from one ten-minute interval to the next
- Excessive load values

After such review, out of 262,944 ten-minute intervals in the Wind Study, only three ten-minute intervals were identified as representing spurious data; each had extremely high load values that would have been impossible to serve. As depicted in Table H.5, these values were corrected by interpolating the values of the prior and successive ten-minute periods to create a smooth line across the spurious intervals. Since reserves demands are created by sudden, unexpected changes from one period to the next, this correction was intended to mitigate the impacts of spurious data on the calculation of the eventual reserve requirements and costs in this study. No other load data issues were encountered in this study.

Table H.5 - Load Data Anomalies and their Interpolated Solutions

Time	Original	Final	Replacement
8/12/2010 9:10	2,654.20	2,654.20	
8/12/2010 9:20	-288,687,072.00	2,669.24	Average of 9:10 and 9:30
8/12/2010 9:30	2,684.28	2,684.28	
2/3/2011 9:50	3,135.41	3,135.41	
2/3/2011 10:00	409,630.75	3,103.82	9:50 + 1/3 of (10:20 minus 9:50)
2/3/2011 10:10	213,667.91	3,072.23	9:50 + 2/3 of (10:20 minus 9:50)
2/3/2011 10:20	3,040.65	3,040.65	

2.3 Historical Wind Generation and Wind Generation Forecast Data

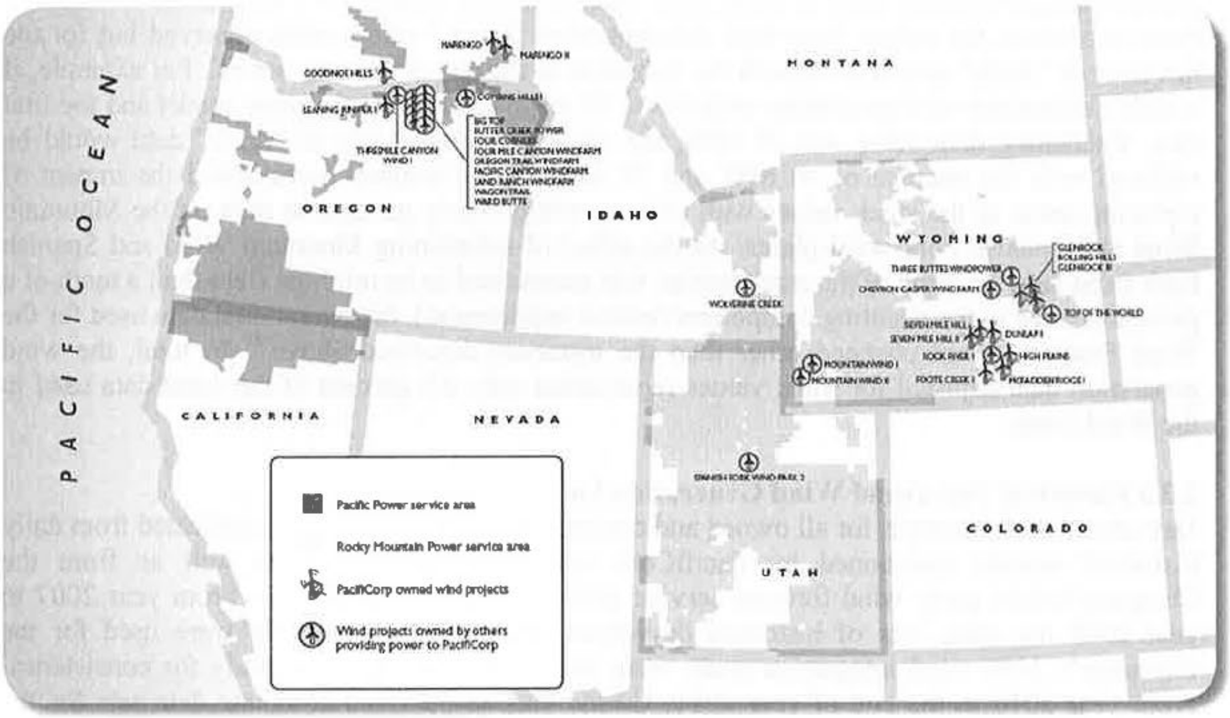
2.3.1 Overview of the Wind Generation Data Used in the Analysis

Over the Study Term, ten-minute interval wind generation data were available for the wind sites as summarized in Table H.4. The wind output data were collected from the PI system. In addition to historical wind generation data, the Wind Study requires historical day-ahead wind forecasts. All of these data sets were needed to establish wind integration costs using the PaR model, and are discussed in turn below.

2.3.2 Historical Wind Generation Data

As shown in Figure H.1, a cluster of PacifiCorp owned and contracted wind generation plants is located in PACW and another cluster is located in PACE. It is worth noting that three wind sites, Wolverine Creek in Idaho, Spanish Fork in Utah, and Mountain Wind in Wyoming, are within PACE, but are geographically distant from both the western and the eastern clusters.

Figure H.1 - Representative Map of PacifiCorp Wind Generating Stations Used in this Study



The wind data collected from the PI system is grouped into a series of sampling points, or nodes, each of which may represent one or more wind plants' output. In consideration of occasional irregularities in the system collecting the data, the raw wind data was reviewed for reasonableness considering the following criteria:

- Incorrect or reversal of sign (recorded data switching from positive to negative)
- Commercial operation date of wind facilities
- Output greater than expected for the wind generation capacity being collected at a given node
- Wind generation appearing constant over a period of days or weeks at a given node

Some PI system data streams exhibit large negative generation output readings in excess of that attributable to station service. These readings reflect positive generation and a reversed polarity on the meter, rather than negative generation or system load. The meter polarity generally remains constant for a long period, and in such instances, the sign was reversed for all data in the period of polarity reversal.

Most of the wind plants in the Wind Study first came online within the Study Period. To reduce one-time impacts due to startup testing or partial facility output as individual wind generators at a given plant were commissioned, wind generation prior to each facility's commercial operation date was not included in the Wind Study.

The PI system ten-minute interval data streams also sometimes exhibit unduly long periods of unchanged or "stuck" values for a given node. Because reserve requirements are driven by large, sudden changes in either wind or load, these data anomalies needed to be addressed. To address these anomalies, the values were held constant when "stuck" values were observed but for the last hour of "stuck" output to smooth the transition to the rest of the data series. For example, if a node's measured wind generation output was 50 megawatts (MW) for three weeks and the first new, fluctuating data value was 75 MW, the value of the last hour of "stuck" data would be replaced with the average of 50 MW and 75 MW. The Company investigated the impact of replacing some of the stuck values with corresponding hourly generation data on the Mountain Wind and Spanish Fork wind plants. As the effect of substituting Mountain Wind and Spanish Fork wind data for some of the stuck values was ascertained to be minimal (less than a tenth of a percent change in the resulting component reserve requirement), the operational data used for the Wind Study was not changed other than the instances described above.[26] In total, the wind generation data adjusted for stuck values represented only 0.5 percent of the wind data used in the Wind Study.

2.3.3 Historical Day-ahead Wind Generation Forecasts

Day-ahead wind forecasts for all owned and contracted wind resources were collected from daily historical records maintained by PacifiCorp commercial operations as well as from the Company's third party wind forecast service provider, Garrad Hassan Co. From year 2007 to year 2009 the same sets of historical day-ahead wind forecast data that were used for the Company's 2010 wind integration study were used again for the 2012 study for consistency. From year 2010 to the end of year 2011, Garrad Hassan provided complete data sets for the historical day-ahead wind forecasts. For transmission customers' resources the Company used the actual hourly wind generation data, eliminating the contribution of day-ahead "forecast error" from these resources, which is consistent with the fact PacifiCorp does not schedule transmission customers' resources located within the Company's BAAs.

During the review process of the 2010 and 2011 data sets, PacifiCorp found the following issues:

- Negative wind generation forecast for a period of consecutive hours
- Wind forecast data shown before the wind resources' official operational dates
- Missing forecast on some hours or on consecutive days

Only one resource had a negative generation forecast, Goodnoe Hills, for the 3-day period 10/3/2011 through 10/6/2011. After confirming the resource was not in station service or maintenance, the sign was corrected and reversed to positive. Any forecast generation before the official commercial operational date was removed from the data series of then newly added resources, consistent with the practice adopted for actual generation as described in the section above.

In the 2010 and 2011 day-ahead forecast data sets, 1.3 percent of the forecast hours were missing data, from one hour up to a week consecutive. If only one hour was missing, that hour forecast was created using the average of the previous hour forecast and the next hour forecast in order to smooth out the fluctuation in the data set. If several days' forecasts were missing, then the latest

[26] By leaving stuck values in place but for the last interval, variability and uncertainty in wind generation from a facility was removed for those intervals in which "stuck" values were observed, which all else equal would result in understating regulation margin requirements.

24 hours of forecast data immediately before the missing days were copied and repeated to fill in the days-long gap. This approach is intended to preserve the smoothness of forecast data while trying not to reduce intermittency in real wind generation forecasts.

3. Method

3.1 Method Overview

This section presents the approach used to establish regulating margin reserve requirements and the method for calculating the associated wind integration costs. Ten-minute interval load and wind data was used to estimate the amount of regulating margin reserves, both up and down, needed to manage variation in load and wind generation within PacifiCorp's BAAs.

3.1.1 Operating Reserves

In order to clarify this requirement, this section discusses the NERC regional reliability standard operating reserve requirement and how it fits into this study. NERC regional reliability standard BAL-STD-002-0[27] requires each Balancing Authority, such as PacifiCorp, to carry sufficient operating reserve at all times. Operating reserve consists of contingency reserve and regulating margin. These reserve requirements necessitate available generation surplus to that required to meet load obligations. Each of these types of operating reserve is further defined below.

Contingency reserve is capacity the Company holds in reserve that can be used to respond to contingency events on the bulk power system (e.g., an instantaneous trip of a large generator). The amount of required contingency reserve is defined in NERC BAL-STD-002-0. Contingency reserve may not be applied to manage other system fluctuations such as changes in load or wind generation output. Therefore, this study focuses on the operating reserve component to manage load and wind generation variations, which is incremental to contingency reserve, and also referred to in NERC BAL-STD-002-0 as regulating margin.

Regulating margin is the additional capacity the Company holds in reserve to ensure it has adequate reserve at all times to meet the NERC Control Performance Criteria in BAL-007-1[28]. NERC Control Performance Criteria require the Company to carry regulating reserves incremental to contingency reserves to maintain reliability. However, these additional regulating reserves are not defined by a simple formula, but rather are the amount of reserves required by each BA to meet the control performance standards. Since the Company's 2010 Wind Integration Study[29], the performance standards have evolved from a calculated Control Performance Standard 2 (CPS2)[30] mandated by NERC BAL-001-0[31] to a more dynamic regime mandated by

[27] http://www.nerc.com/files/BAL-STD-002-0.pdf

[28] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf. According to WECC Operating Committee meeting highlights (page 4, item 5), the field trial of this standard has been extended an additional year. The highlights are published here: http://www.wecc.biz/committees/StandingCommittees/OC/20130108/Lists/Agendas/1/OC%20Voting%20Record%20January%202013_Final_Revised.pdf

[29] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, page 11

[30] PacifiCorp has not controlled to CPS2 since March 1, 2010.

[31] http://www.nerc.com/files/BAL-001-0_1a.pdf

NERC BAL-007-1, called Balancing Authority ACE Limit (BAAL), in which the Company's performance standard can be affected by the frequency of the interconnection. This new standard allows a greater ACE during periods when the ACE is helping frequency. However, the Company cannot plan on knowing when ACE will help or exacerbate frequency so the L_{10} is used for the bandwidth in both directions of the ACE. Thus the Company determines, based on the unique level of wind and load variation in its system, and the prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and wind changes throughout the delivery hour. PacifiCorp further segregates regulating margin into two components to assist in the analysis: ramp reserve and regulation reserve.

Ramp Reserve: Due to a number of factors (fluctuations in customer demand, spot transactions, varying amounts of generation produced by variable resources such as wind and solar generation) the net balancing area load changes from minute-to-minute, hour-to-hour continuously at all times. This variability (increasing and decreasing load) requires ready capacity to follow continuously, through short deviations, at all times. Treating this variability as though it is perfectly known for future time intervals (as though the operator would know exactly what the net balancing area load would be a minute from now, ten minutes from now, and an hour from now) defines the ramp of the system.

Regulation Reserve: Changes in load or wind generation are not considered contingency events, yet these events still require that capacity be set aside. The Company has defined two types of regulation reserve – regulating and following reserves. Regulating reserve covers short term variations (seconds to minutes, normally using automatic generation control) in system load and wind, whereas following reserve covers uncertainty across an hour normally using manual generation control.

To summarize, regulating margin represents operating reserves the Company holds over and above the mandated contingency reserve requirement to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts; ramp reserve and regulation reserve. The ramp reserve represents a minimum amount of flexibility required to follow the actual net system load (load minus wind generation output) with dispatchable generation. The regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors about the net system load, and consists of four components: load following, load regulating, wind following, and wind regulating.

3.1.2 Method Steps

The regulating margin requirements are calculated for each of the Company's BAAs from production data via a five step process, each described in more detail later in this section. The five steps include:

1. Calculation of the ramp reserve from the historical data (with and without wind generation).
2. Creation of hypothetical forecasts from historical load and wind production data.
3. Compare actual generation and load values in each ten-minute interval of the study term to the hypothetical forecast values, and record the differences as deviations.
4. Group these deviations into bins that can be analyzed for the reserves requirements per forecast value of wind and load, respectively, such that a specified percentage (or

tolerance level) of these deviations would be covered by some level operating reserves.
5. Apply the reserve requirements noted for the various wind and load forecast values are then applied back to the operational data, enabling an average reserves requirement to be calculated for any chosen time interval within the Study Term.

Once the amount of regulating margin is estimated, the cost of holding the specified reserves on PacifiCorp's system is estimated using the PaR model. In addition to using PaR for evaluating operating reserve cost, the PaR model is also used to estimate wind integration cost associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time.

3.2 Regulating Margin Requirements

As noted above, ten-minute interval wind generation and load data drives the calculation of the regulating margin requirement for ramp reserve and regulation reserve. The approach for calculating regulating margin requirements necessary to supply adequate operational capacity is based on merging current operational practice with a survey of papers on wind integration[32] and input from the TRC.

3.2.1 Ramp Reserve

The ramp reserve represents the minimal amount of flexible system capacity required to follow the net load requirements without any error or deviation; in other words, if a system operator had the gift of perfect foresight for following changes in load and wind generation from minute-to-minute, and hour-to-hour. These amounts are as follows:

- If system is ramping down: [(Net Area Load Hour H – Net Area Load Hour (H+1))/2]
- If system is ramping up: [(Net Area Load Hour (H+1)– Net Area Load Hour H)/2]

Essentially, the ramp reserve is half the absolute value of the difference between the net balancing area load at the top of one hour minus the net balancing load at the top of the prior hour.

The ramp reserve is calculated for load using only the load values for each BAA at the top of each hour. The ramp reserve for load and wind is calculated using the net load (load minus wind generation output) at the top of each hour. The ramp reserve required for wind is the difference between that for load and that for load and wind.

3.2.2 Regulation Reserve

As ramp reserves represent the system flexibility required to follow the system's requirements without any uncertainty or error, the regulation reserve is necessary to cover uncertainty ever-present in power system operations. Very short-term fluctuations in weather, load patterns, wind generation output and other system conditions cause short term forecasts to change at all times.

[32] Many of the external studies PacifiCorp has relied on can be found on the Utility Variable Integration Group (UVIG) website at the following link: http://www.uwig.org/opimpactsdocs.html

Therefore, system operators rely on regulation reserve to allow for the unpredictable changes bound to occur between the time the next hour's schedule is made and the arrival of the next hour, or the ability to follow net load. Also, these very same sources of instability are active throughout each hour, requiring flexibility to regulate the generation output to the myriad ups and downs of customer demand, fluctuations in wind generation, and other system disturbances. To assess the regulation reserve requirements for PacifiCorp's BAAs, the Company compared the operational data to hypothetical forecasts as described below.

3.2.3 Hypothetical Operational Forecasts

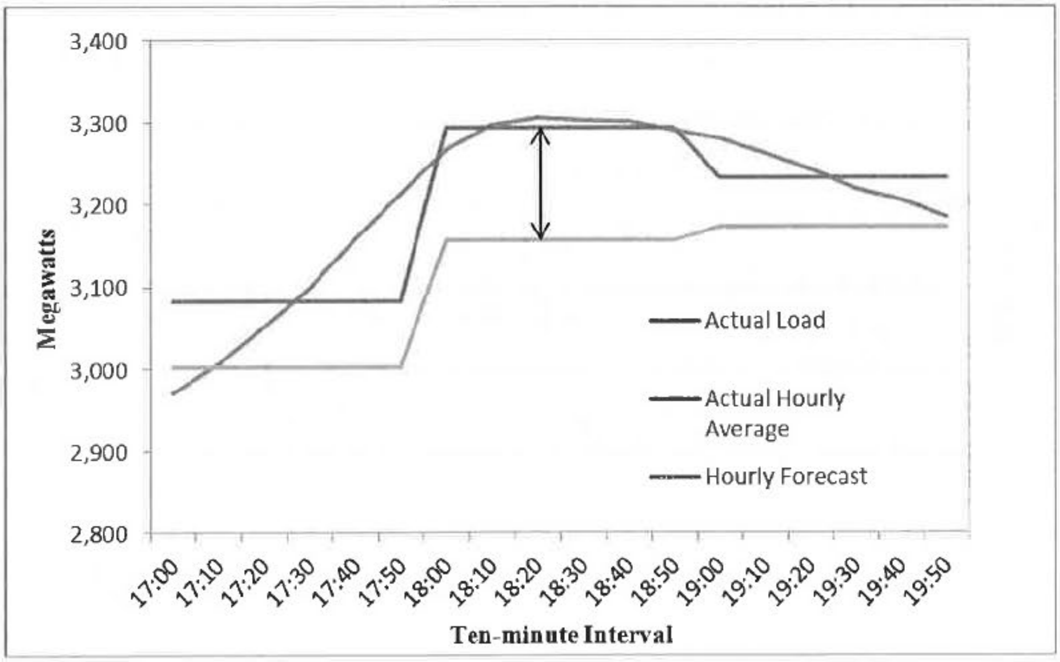
Regulation reserve consists of two components: (1) regulating, which is developed using the ten-minute interval data, and (2) following, which is calculated using the same data but estimated on an hourly basis. The Study Term load data and wind generation data are applied individually to calculate estimated reserve requirements for each month in the Study Term. For purposes of the Study, the regulating calculation compares observed ten-minute interval load and wind generation production to a ten-minute interval forecast, and following compares observed hourly averages to an average hourly forecast. Therefore, the calculation of regulation reserve requirements begins with the development of four component requirements: load following, wind following, load regulating, and wind regulating.

3.2.3.1 Hypothetical Load Following Operational Forecast

PacifiCorp maintains system balance by optimizing its operations to an hourly forecast every hour with changes in generation and market activity. This planning interval represents hourly changes in generation that are assessed roughly 20 minutes into each hour to account for a bottom-of-the-hour (30 minutes after the hour) scheduling deadline. Taking into account the conditions of the present and the expected load and wind generation, PacifiCorp must schedule generation to meet demands with an expectation of how much higher or lower load (net of wind generation) may be.

PacifiCorp's real-time desk updates the next hour's load forecast forty minutes prior to each operating hour. This forecast is created by comparing the current hour load to the load of a similar-load-shaped day. The hour-to-hour change in load from the similar day and hours (the load difference or "delta") is applied to the "current" hour load and the sum is used as the forecast for the ensuing hour. For example, on a given Monday the PacifiCorp real-time desk operator may be forecasting hour to hour changes in system load by referencing the hour to hour changes on the prior Monday, a similar-load-shaped day. If the hour to hour load change between the same hours that occurred from the prior Monday's was 5 percent, the operator will use a 5 percent change in load as the next hour's following forecast. For purposes of the calculation made in this Wind Study, the load forecast was modeled per the approximation described above with a shaping factor calculated using the day from one week prior, and applying a prior Sunday to shape any NERC holiday schedules. The differences observed between hourly average load and the load following forecasts comprise the load following deviations. Figure H.2 shows an illustrative example of a load following deviation using operational data from PACW, depicted by the black arrow.

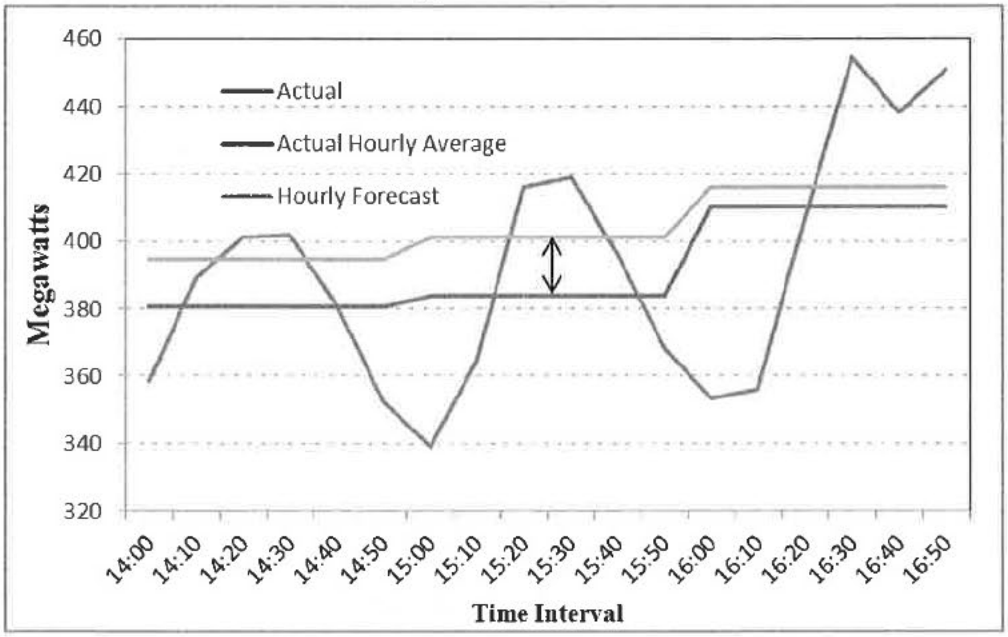
Figure H.2 - Illustrative Load Following Forecast and Deviation



3.2.3.2 Hypothetical Wind Following Operational Forecast

For the corresponding short term hourly operational wind forecast, the hourly wind forecast is prepared based on the concept of persistence; applying the instantaneous sample of the wind generation output 20 minutes past the current hour to the next hour as a forecast and balancing the system to that point. For purposes of the calculation made in this study, the hourly wind forecast consisted of the 20th minute output from the prior hour, and this output is assumed to be the volume of wind produced in the ensuing hour. For example, if the wind generation is producing 200 MW of power at 1:20pm in PACW, then it is assumed that 200 megawatt-hour (MWh) of power will be generated from the wind plants between 2:00pm and 3:00pm that day. The difference observed between hourly average wind generation and the wind following forecast represents the wind following deviation. Figure H.3 shows an illustrative example of a wind following deviation using operational data from PACW, depicted by the black arrow.

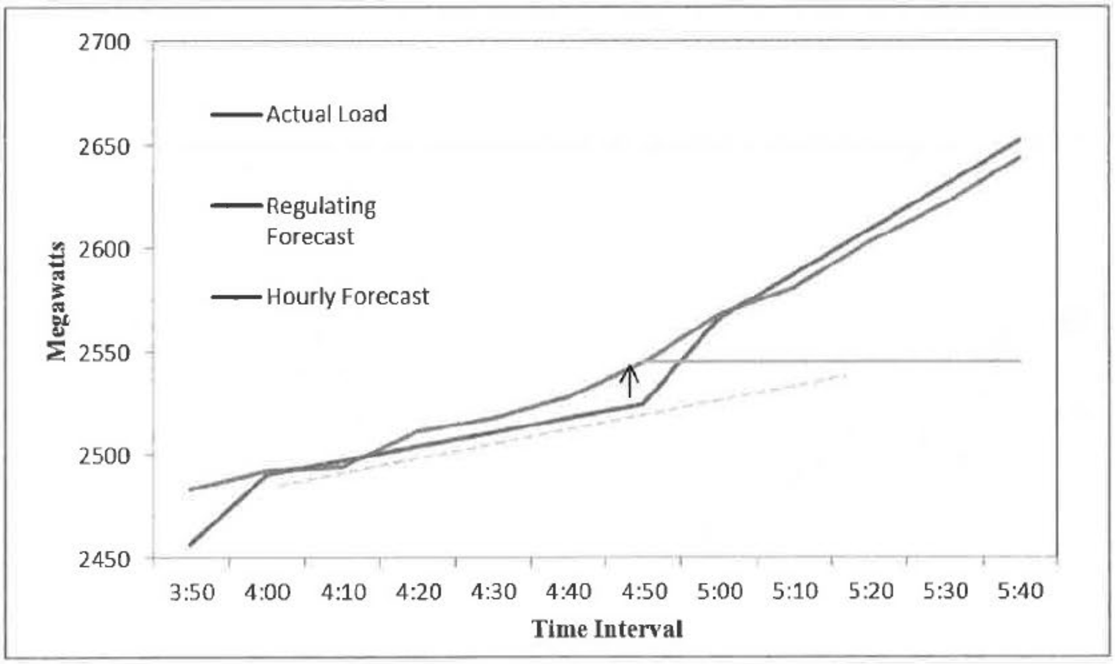
Figure H.3 - Illustrative Wind Following Forecast and Deviation



3.2.3.3 Hypothetical Load Regulating Operational Forecast

Separate from the variations in the hourly scheduled loads, the ten-minute load variability and uncertainty was analyzed by comparing the ten-minute actual load values to a line of intended schedule, which was represented by a line interpolated between an actual top-of-the-hour load value and the next hour's load forecast target at the bottom of that (next) hour. A sample of how the intended schedule compares to actual load data is shown in Figure H.4, with the trend of the line of intended schedule tracking the orange line toward the load following forecast at the middle of the ensuing hour as based upon data from PACW from December 2010. The method approximates the real time operations process for each hour. At the top of the given hour, the actual load is known and a forecast for the next hour was made. For the purposes of this study, a line joining the two points was made to represent the ideal path for the ramp or decline expected within the given hour. The actual ten-minute load values were compared to this straight line to produce a corresponding strip of load regulating deviations at each ten-minute interval, with one such deviation represented by the black arrow in Figure H.4.

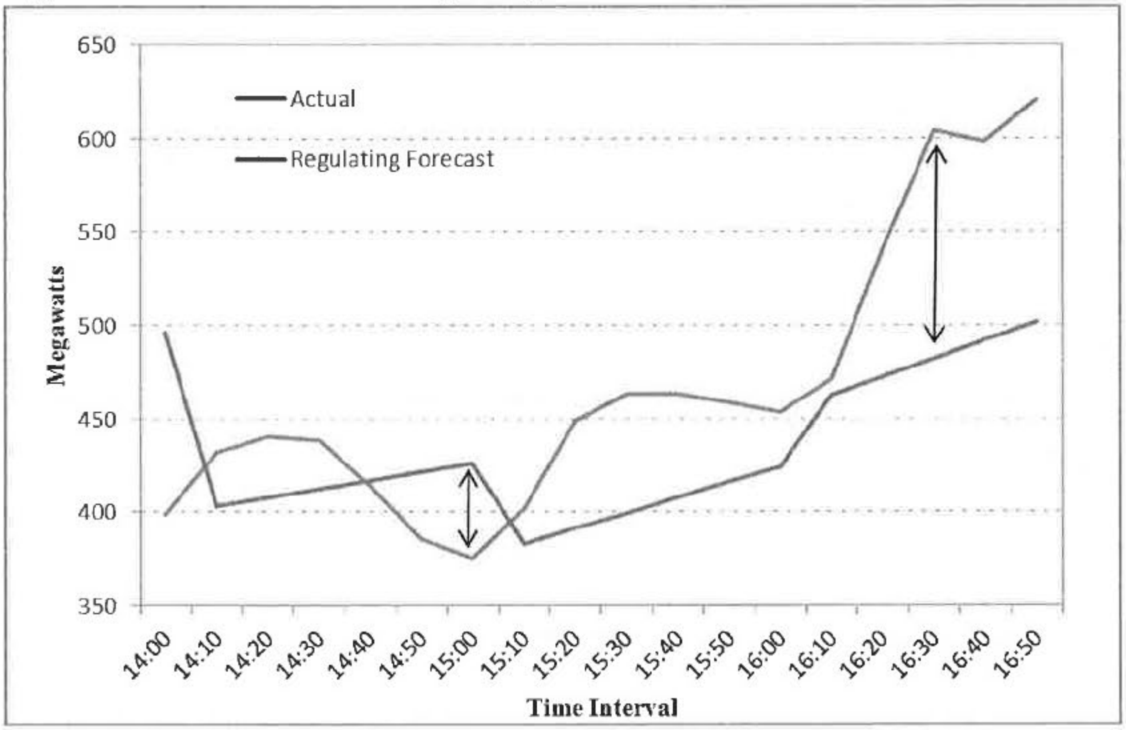
Figure H.4 - Illustrative Load Regulating Forecast and Deviation



3.2.3.4 Hypothetical Wind Regulating Operational Forecast

To parse the ten-minute interval wind variability from the following analysis, a line of intended schedule similar to that applied to load regulating deviations is developed. A line is drawn from the top of the hour's instantaneous wind output to the next hour's wind-following forecast output, but at the bottom (middle) of that next hour. This creates a line from the top of the hour actual output toward the next hour's average output. Figure H.5 shows an illustrative example using operational data from PACW of a wind regulation deviation, as depicted by the black arrow.

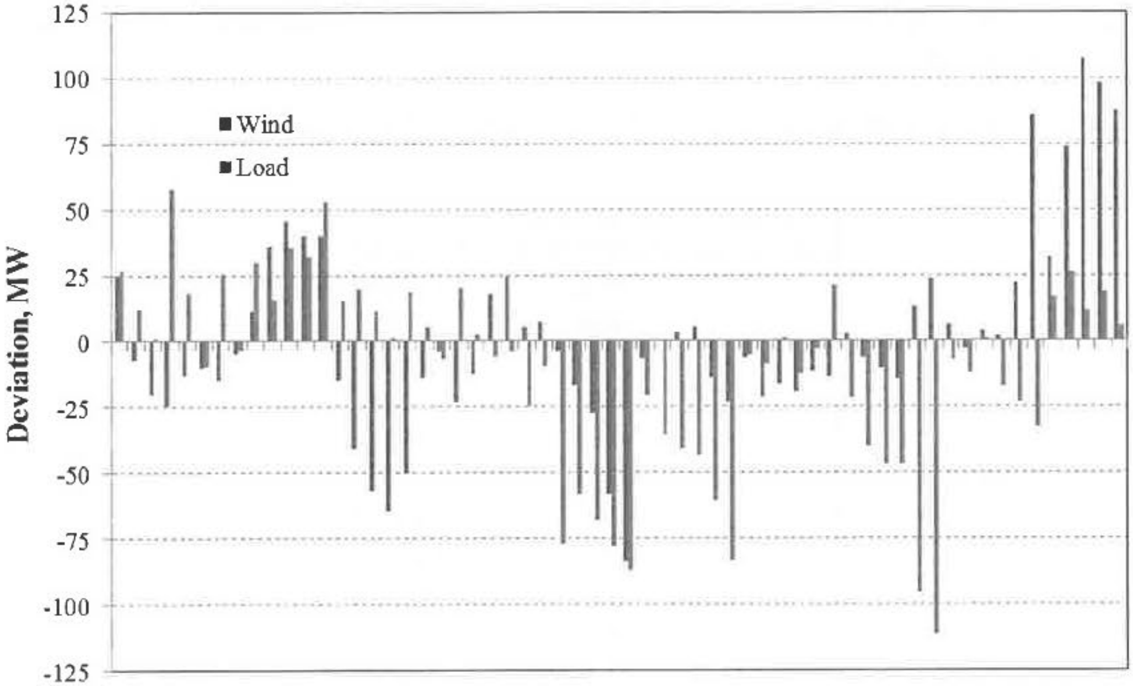
Figure H.5 - Illustrative Wind Regulating Forecast and Deviation



3.2.4 Recording of Deviations

The four hypothetical operational forecasts are netted against historical load and wind production data to derive four component forecast deviations (load following, wind following, load regulating, wind regulating). The deviations each represent different components (like vectors) of forecast error which have to be covered by operating reserves. For example, if the difference between the wind following forecast for a given hour is 550 MW, and the average wind generation on the system only produces 400 MW for that hour, then 150 average MW will have to be produced by other generation on the system to remedy the shortfall and maintain system balance. This is an example of reserves being deployed upward (additional generation dispatched) in real time. A similar effect happens when load exceeds the load forecast – additional generation is dispatched to cover the shortfall due to changing forecasts or unpredictable conditions. Figure H.6 shows an illustrative example of independent load and wind regulating deviations from the PACE on June 1, 2011. Each time interval as represented on the horizontal axis represents ten minutes. Note how the deviations are randomly constructive (both positive or both negative) or destructive (opposing, one positive and one negative).

Figure H.6 - Illustrative Example of Independent Load and Wind Regulating Deviations



The deviations are calculated for each ten-minute interval in the Study Term, for each of the four components of regulation reserves (load following, wind following, load regulating, wind regulating). Across any given hourly time interval, the six ten-minute intervals within each hour would have a common following deviation, but different regulation deviations. For example, considering load deviations only, if the load forecast for a given hour was 300 MW below the actual load realized in that hour, then a load following deviation of -300 MW would be recorded for all six of the ten-minute periods within that hour. However, as the load regulation forecast and the actual load recorded in each ten-minute interval vary, so will the deviations for load regulation. The same trend holds for wind following and wind regulating deviations. The following deviation is recorded as equal for the hour, and the regulating deviation varies each ten-minute interval.

3.2.5 Analysis of Deviations

Since the recorded deviations represent the amount of unpredictable variation on the electrical system, the key question becomes how much regulation reserve to hold in order to cover the deviations, thereby maintaining system reliability. The deviations are analyzed by separating the deviations into bins by their characteristic forecasts for each month in the Study Term. The bins are defined by every 5th percentile of recorded forecasts, creating 20 bins for each month's deviations for each component hypothetical operational forecast. In other words, each month of the Study Term will exhibit 20 bins of load following deviations, 20 of load regulating deviations, and the same for wind following and wind regulating. Tables H.6 and H.7 depict this process in action for June 2011.

Table H.6 depicts the calculation of percentiles (every 5 percent) among the load regulating forecasts for June 2011 using PACE operational data. For example, a load regulating forecast of

4,403.7 MW represents the fifth percentile of such forecasts for that month. Any forecast values below that value will be in Bin 20, along with the respective deviations recorded for those time intervals. Any forecast values between 4,403.7 MW and 4,508.8 MW will land the deviation for that particular interval in Bin 19.

Table H.6 - Percentiles Dividing the June 2011 Load Regulating Forecasts into 20 Bins

East		
Bin Number	Percentile	Load Forecast
	MAX	7,615.4
1	0.95	6,916.8
2	0.90	6,549.0
3	0.85	6,210.6
4	0.80	5,984.1
5	0.75	5,803.9
6	0.70	5,685.5
7	0.65	5,599.5
8	0.60	5,523.1
9	0.55	5,445.0
10	0.50	5,356.4
11	0.45	5,267.4
12	0.40	5,160.0
13	0.35	5,037.1
14	0.30	4,924.5
15	0.25	4,812.5
16	0.20	4,683.5
17	0.15	4,570.0
18	0.10	4,447.5
19	0.05	4,359.9
20	MIN	4,107.2

Table H.7 depicts a sample of the assignment of several intervals' data into bins following the definition of bins in Table H.6.

Table H.7 - Recorded Interval Load Regulating Forecasts and their Respective Errors, or Deviations, for June 2011 Operational Data from PACE

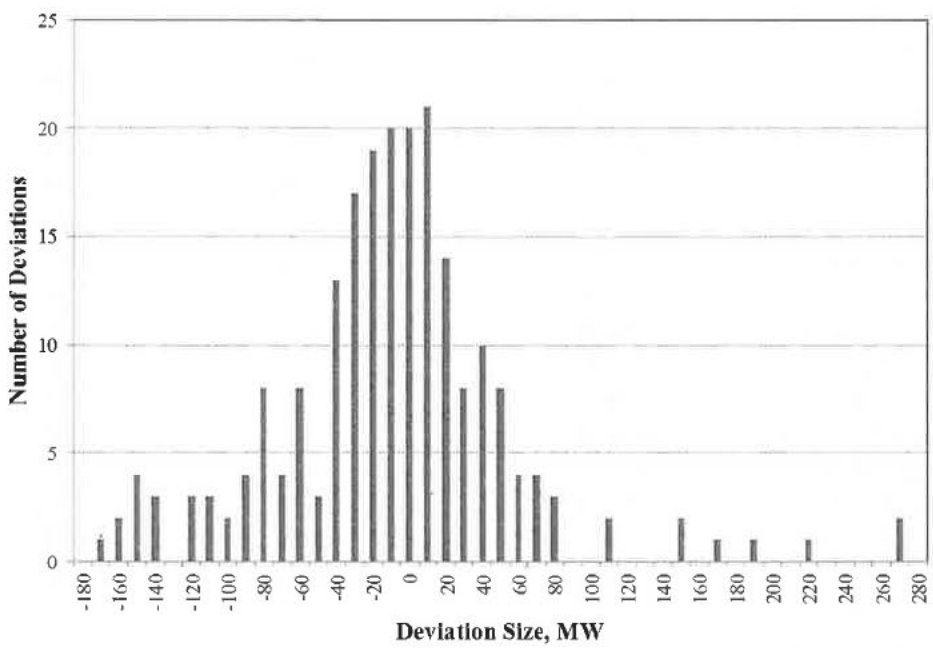
EAST			
DATE / TIME	LOAD REGULATION FORECAST	LOAD REGULATION ERROR	BIN ASSIGNMENT
06/01/2011 01:00	4,297.0	26.89	20
06/01/2011 01:10	4,277.7	12.17	20
06/01/2011 01:20	4,285.3	0.76	20
06/01/2011 01:30	4,292.9	57.93	20
06/01/2011 01:40	4,300.4	18.72	20
06/01/2011 01:50	4,308.0	-9.78	20
06/01/2011 02:00	4,315.6	25.25	20
06/01/2011 02:10	4,315.9	-3.19	20
06/01/2011 02:20	4,341.4	29.87	20
06/01/2011 02:30	4,366.9	16.33	19
06/01/2011 02:40	4,392.4	35.67	19
06/01/2011 02:50	4,417.9	32.28	19
06/01/2011 03:00	4,443.5	53.28	19
06/01/2011 03:10	4,429.4	15.66	19
06/01/2011 03:20	4,468.6	20.02	18
06/01/2011 03:30	4,507.8	11.52	18
06/01/2011 03:40	4,547.0	1.15	18
06/01/2011 03:50	4,586.2	18.98	17
06/01/2011 04:00	4,625.4	5.76	17
06/01/2011 04:10	4,658.2	-6.29	17
06/01/2011 04:20	4,696.8	20.29	16
06/01/2011 04:30	4,735.3	2.56	16
06/01/2011 04:40	4,773.9	-5.57	16
06/01/2011 04:50	4,812.5	-3.52	16
06/01/2011 05:00	4,851.0	-24.55	15
06/01/2011 05:10	4,905.0	-9.43	15

The binned approach is necessary to prevent over-assignment of reserves in different system states, owing to certain characteristics of load and wind generation. For example, when the balancing area load is near the lowest values for any particular day, it is highly unlikely the load deviation will require substantial down reserves to maintain balance because load will typically drop only so far. Similarly, when the load is near the peak of the month's load values, it is likely perhaps to go only a little higher, but could drop substantially at any time. Similarly for wind, when wind generation output is at the peak value for a system, there will not be a deviation taking the wind value above that peak. In other words, the directional nature of the reserves requirements can change greatly by the state of the load or wind output. At high load or wind generation states, there is not likely to be a significant need for reserves covering a surprise increase in those values. Similarly, at the lowest states, there is not likely to be a need for the direction of reserves covering a significant shortfall in load or wind generation.

For example, consider the deviations grouped into one of the load regulating bins for June 2011 data in Figure H.7. The deviations in this bin all occurred in time intervals with a load regulating forecast near 6,898 MW, from the PACE using June 2011 operational data. Most of the deviations are within 80 MW of the actual load value (a little over one percent, plus or minus).

However, for load regulating deviations in this range, there is apparently a greater tendency where actual load was lower (more negative deviations than positive in Figure H.7 below, and of greater magnitude), which requires the system's installed generation to have to increase its output in a very short timeframe to balance, thus requiring what are called "up reserves". It also bears noting that the deviations form a statistical distribution which is not normally shaped; and as more bins are examined, they also are not normally distributed and the longer tail can appear on either side.

Figure H.7 - Histogram of Deviations Occurring About a June 2011 PACE Load Regulating Forecast of 6,097 MW



Bin Analysis

Up and down deviations must be served by operating reserves, so the percentile equivalent to a deviation tolerance was sampled above and below the median of each of the bins. The difference between the target reliability percentiles and the median of the bins represents the implied incremental load following service for regulation reserve demand within that bin for a given tolerance level. The component reserve value for each bin, as a function of the tolerance target is represented in Equation 1:

Equation 1. Derivation of the component reserves requirement as a function of deviations recorded in each bin.

$$\textbf{Component Reserve}_j = \mathbf{f}(\mathbf{P}_{tolerance}(\textbf{Forecast Bin}_i))$$

Where:

$\mathbf{P}_{tolerance}$ = The percentile of a two-tailed distribution representing an operational tolerance target

$\textbf{Forecast Bin}_i$ = the component forecast errors in each bin

The tolerance level, per Equation 1, represents a percentage of component deviations intended to be covered by the associated component reserve. As detailed in the method overview, section 3.1, the Company cannot apply contingency reserves to manage load and wind fluctuations, and therefore must carry sufficient regulating margin to avoid dipping into contingency reserve for this purpose. Any failure to manage these fluctuations can lead to disruption of services to customers. Surveying other recent wind integration studies[33], the company focused on two other large regional entities grappling with the same concerns; BC Hydro and Bonneville Power Administration ("BPA"). BC Hydro applies a 99.7 percent tolerance to respective load and wind reserve requirements[34], while the BPA customarily applies a 99.5 percent tolerance to its balancing requirements[35]. Considering the actions of other major market participants, and the requirement to maintain contingency reserves at all times, the Company has decided to apply a 99.7 percent tolerance in the calculation of component reserves, In doing so, the Company has sought to plan for as many deviations as possible, while excluding the very largest data points to allow for the potential existence of outlier values. However, in a departure from BC Hydro's and BPA's approaches, the Company will also net the appropriate system L_{10} from the resulting total reserves requirement[36], effectively reducing the target reserve requirement to a more aggressive level than those other market participants. The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails. Despite exclusion of extreme deviations with the use of the 99.7 percent tolerance, the Company's system operators will still be expected to meet reserve requirements without exceptions. The Company may also change the tolerance based on operational and customer feedback in the future.

Taking the binned data illustrated in Figure H.7 as an example, approximately all of the deviations fall between -180 MW of deviation and +270 MW of deviation. Therefore, at a 99.7 percent tolerance level, the load regulating up reserves recommended for time intervals reflecting a load regulating forecast near 6,097 MW in the PACE in June 2011 is 173 MW. As each respective bin also has an implied probability by the number of data points falling within it (five percent), five percent of the ten-minute intervals in June 2011 will be assigned a load regulating component reserves value of 210 MW up reserves and 130 MW down reserves. The very same analysis is performed for each bin (20 in total) for wind regulating, load following, and wind following component reserves.

The binned results can be reviewed for a month at a time, and patterns in the up- and down-reserves requirements by forecast level become more apparent for load and for wind as shown in Figures H.8 and H.9. For example, Figure H.9 can be used to further explain the calculation

[33] PacifiCorp reviewed wind integration studies sponsored by other regional utilities (Portland General Electric, Avista, Idaho Power, BC Hydro, BPA) and the National Renewable Electrical Laboratory. The more recent BC Hydro and BPA approaches are consistent with the Company's requirement to maintain contingency reserve requirements at all times.
[34] BC Hydro's Wind Integration Study is part of its Integrated Resource Plan, Appendix 6E, page 6E-9: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf
[35] Pacific Northwest National Laboratory, page 5: http://energyenvironment.pnnl.gov/ei/pdf/NWPP%20report.pdf
[36] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to:
http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf

method for the resulting component reserve demand. Bin 4 describes 36 hours (five percent of June's 720 hours) of wind generation forecast outcomes in the operational data from June, 2011. The average hypothetical operational forecast modeled for these hours was 710 MW of production, and 99.7 percent of the actual hourly production values would be between 305 MW (the bottom of the green shaded area) and 955 MW (the top of the red shaded area). Therefore, for these 36 hours, and other periods in the future where the PACE wind production forecast is near 710 MW, this method recommends 405 MW of up reserves (710 – 305 = 405) in order to be prepared for a shortfall in wind production compared to the hourly forecast.

Figure H.8 - Load Following Component Reserve Profile; Operational Data from June 2011

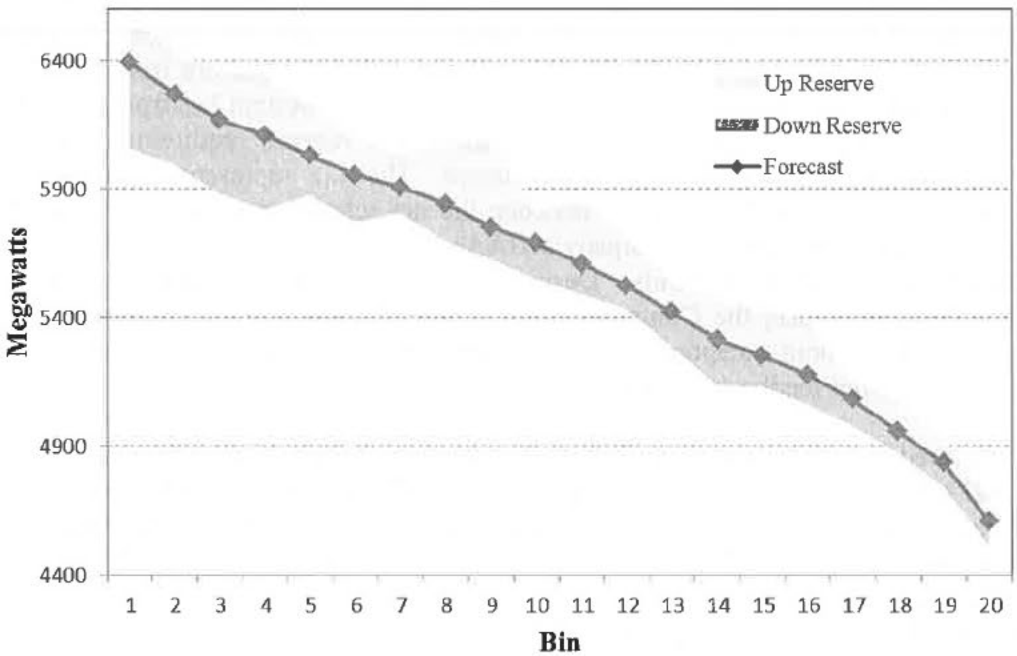
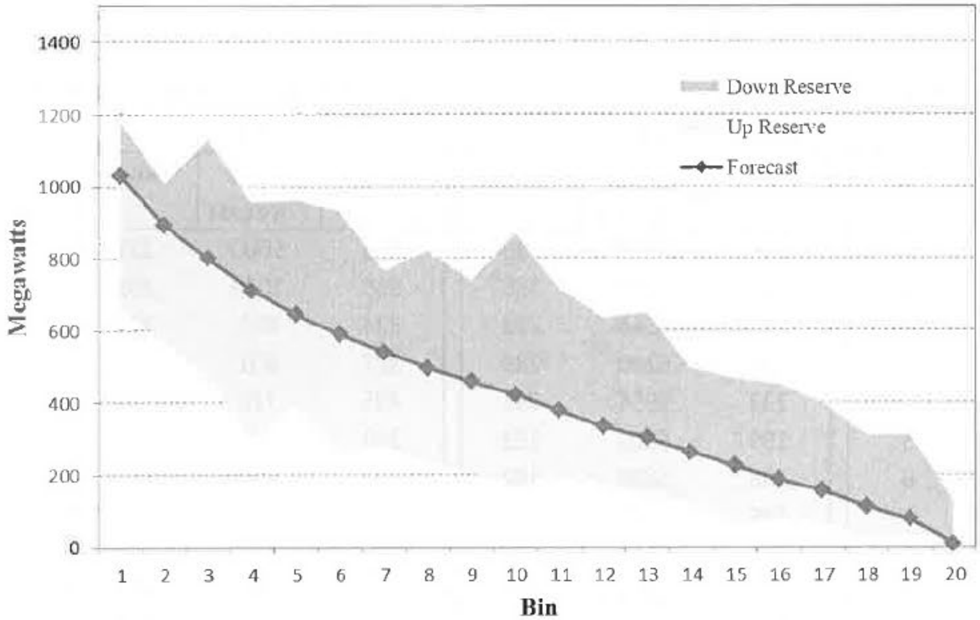


Figure H.9 - Wind Following Component Reserve Profile; Operational Data from June 2011



It is also useful to note the relatively small amount of up reserve required when the wind generation is forecast to be low (Bins 19 and 20), and vice-versa when little wind generation is forecast (Bins 1 and 2 in Figure H.9). This is how the bin analysis helps prevent over-assigning reserves—by adjusting the reserves requirements per wind generation state. For instance, the output of wind generators is less stable when the wind is picking up or slowing down, and the wind generators are speeding up or slowing down accordingly. This behavior is represented in Bins 3 through 15 in Figure H.9 above; the amount of wind following component reserve recommended in those bins (represented by the distance between the red forecast line and the blue and green lines) is greater than that needed at the higher and lower rates of production, which represent either sustained wind or sustained calmer conditions.

The result of the bin analysis is four component forecast values (load following, wind following, load regulating, wind regulating) for each ten-minute interval of the Study Period. The component forecasts and reserves requirements are then applied to the operational data and combined in the backcasting procedure described below.

3.2.6 Backcasting

Given the development of component reserves demands for regulating and following timeframes shaped to system state in section 3.2.5, reserve requirements were then assigned to each ten-minute interval in the Study term according to their respective hypothetical operational forecasts (created in the Wind Study's prior steps) to simulate the combination of the component reserves values as they would have happened in real-time operations. Doing so results in a total reserves requirement for each interval informed by the data.

To perform the backcasts, the component reserves requirements calculated from the bin analysis described above are first turned into reference tables. Table H.8 shows a sample (June 2011, PACE) reference tables for load and wind following reserves at varying levels of forecasted load and wind generation. Table H.9 shows a sample (June 2011, PACE) reference table for load and wind regulating reserves at varying forecast levels.

Table H.8 - Sample Reference Table for Load and Wind Following Component Reserves

	East			East		
Bin	Up	Load Forecast	Down	Up	Wind Forecast	Down
	163	10000	335	365	5000	151
1	163	6953	335	365	1029	151
2	172	6544	278	324	893	115
3	182	6240	289	327	801	331
4	233	5954	291	405	710	245
5	199	5802	153	252	645	316
6	138	5699	182	325	589	342
7	126	5601	99	256	540	227
8	223	5526	147	265	495	327
9	**345**	**5432**	**126**	**253**	**459**	**281**
10	123	5362	138	255	420	449
11	245	5260	120	184	377	340
12	189	5151	89	161	333	304
13	113	5033	137	158	302	348
14	145	4931	180	141	262	235
15	179	4809	120	158	224	243
16	213	4694	117	111	187	266
17	62	4551	102	86	155	246
18	119	4437	85	89	112	200
19	85	4338	97	44	77	234
20	90	4098	94	44	9	122
	90	0	94	44	0	122

Table H.9 - Sample Reference Table for Load and Wind Regulating Component Reserves

	East			East		
Bin	Up	Load Forecast	Down	Up	Wind Forecast	Down
	171	10000	263	244	10000	152
1	171	6917	263	244	1025	152
2	183	6549	251	302	902	224
3	177	6211	163	353	794	237
4	173	5984	272	224	713	180
5	204	5804	130	317	649	270
6	155	5686	156	263	585	450
7	219	5600	114	202	539	352
8	239	5523	146	260	501	394
9	**159**	**5445**	**134**	270	461	244
10	235	5356	124	**190**	**425**	**299**
11	170	5267	115	182	378	251
12	170	5160	112	149	334	265
13	239	5037	151	153	299	260
14	116	4925	138	148	261	172
15	126	4812	162	86	224	288
16	161	4683	103	122	188	287
17	98	4570	113	105	149	174
18	97	4448	95	60	112	144
19	82	4360	101	38	76	150
20	72	4107	92	39	10	82
	72	0	92	39	0	82

Each of the relationships recorded in the table is then applied to hypothetical operational forecasts. Building on the reference tables above, the hypothetical operational forecasts described in sections 3.2.3.1 through 3.2.3.4 are then used to calculate a reserves requirement for each interval of historical operational data. This is clarified in the example below.

Application to component forecasts

Each interval's component forecasts are used, in conjunction with Tables H.8 and H.9, to derive a recommended reserve requirement informed by the load and wind generation conditions for the time interval. This process is most easily explained with an example using the tables shown above, and hypothetical operational forecasts from June 2011 operational data for PACE. Table H.10 illustrates the outcome of the process for the load following and regulating components:

Table H.10 - Interval Load Forecasts and Component Reserves Requirement Data for Hour-ending 11 AM, June 1, 2011 in PACE

East	East	East	East	East	East	East	East	East
Time	Actual Load (10-min Avg)	Actual Load (Hourly Avg)	Following Forecast Load:	Load Following Up Reserves Specified by Tolerance Level	Load Following Down Reserves Specified by Tolerance Level	Regulating Load Forecast:	Load Regulating Up Reserves Specified by Tolerance Level:	Load Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	5,533.04	5,543.46	5,509.68	344.8	126.2	5500.6	159.4	134.4
06/01/2011 10:10	5,525.38	5,543.46	5,509.68	344.8	126.2	5542.6	239.4	145.5
06/01/2011 10:20	5,525.54	5,543.46	5,509.68	344.8	126.2	5552.1	239.4	145.5
06/01/2011 10:30	5,550.23	5,543.46	5,509.68	344.8	126.2	5561.6	239.4	145.5
06/01/2011 10:40	5,551.93	5,543.46	5,509.68	344.8	126.2	5571.1	239.4	145.5
06/01/2011 10:50	5,574.64	5,543.46	5,509.68	344.8	126.2	5580.7	239.4	145.5

The load following forecast for this particular hour is 5,509.68 MW, which designates reserves requirements from Bin 9 as depicted (with shading for emphasis) in Table H.8. Note the same following forecast is applied to each interval in the hour for the purpose of developing reserves requirements. The first ten minutes of the hour exhibits a load regulating forecast of 5,500.6 MW, which designates reserves requirements from Bin 9 as depicted in Table H.9. Note that the regulating forecast changes every ten minutes, and as a result, the regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast shifts the component reserves requirement from Bin 9 to Bin 8 (per Table H.8), and so the component reserves requirement changes accordingly. A similar process is followed for wind reserves, illustrated in Table H.11:

Table H.11 - Interval Wind Forecasts and Component Reserves Requirement Data for Hour-ending 11 AM June 1, 2011 in PACE

East	East	East	East	East	East	East	East	East
Time	Actual Wind (10-min Avg)	Actual Wind (Hourly Avg)	Following Forecast Wind:	Wind Follow Up Reserves Specified by Tolerance Level	Wind Follow Down Reserves Specified by Tolerance Level	East Wind Regulating Forecast:	Wind Regulating Up Reserves Specified by Tolerance Level:	Wind Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	550.82	555.26	485.02	252.87	280.56	453.5	190.0	298.9
06/01/2011 10:10	557.30	555.26	485.02	252.87	280.56	548.5	201.5	352.2
06/01/2011 10:20	529.71	555.26	485.02	252.87	280.56	546.1	201.5	352.2
06/01/2011 10:30	550.40	555.26	485.02	252.87	280.56	543.8	201.5	352.2
06/01/2011 10:40	560.53	555.26	485.02	252.87	280.56	541.4	201.5	352.2
06/01/2011 10:50	582.79	555.26	485.02	252.87	280.56	539.1	259.7	394.0

The wind following forecast for this particular hour is 485.0 MW, which designates reserves requirements from Bin 9 under wind forecasts as depicted in Table H.8. Note the following forecast is applied to each interval in the hour for the same of developing reserves requirements. Meanwhile, the regulating forecast changes every ten minutes. The first ten minutes of the hour exhibits a wind regulating forecast of 453.5 MW, which designates reserves requirements from Bin 10 as depicted in Table H.9. As for load, the wind regulating forecast changes every ten minutes, and as a result, the regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast shifts the wind regulating component reserves requirement from Bin 10 into Bin 7 (per Table H.9), and so the component reserves requirement changes accordingly.

The selection of component reserves using component hypothetical operational forecasts as depicted above is replicated for each ten-minute interval, assigning four component reserves requirements in each interval throughout the Study Term. The four components are combined into a single regulating reserves requirement as defined below.

Total Regulating Reserves Requirement

After the assignment of the component reserves requirements, each ten-minute interval of the Study Term exhibits values for load following reserves, wind following reserves, load regulating reserves, and wind regulating reserves. Each of these values is derived by comparing a unique component forecast to a unique actual value; in the case of load following, the load following forecast is compared to the average load for a given hour. For load regulating reserves requirements, the load regulating forecast is compared to the actual load observed at the same time. However, while adjusting operations for each of the four component factors is critical to maintaining system integrity, the components are not additive. Therefore, the wind and load reserve requirements are combined using the root-sum-square (RSS) calculation in each direction (up and down), assuming their variability in the short term independent or uncorrelated, by the RSS relationship in Equation 2. Then, the appropriate system L_{10} is netted from the result.

Equation 2. Total Regulation Reserves calculated from four component reserves using the root-sum-square formulation at time interval i:

$$\boldsymbol{Regulation\ Reserves_i} = \sqrt{LoadFollowing_i^{\,2} + LoadRegulating_i^{\,2} + WindFollowing_i^{\,2} + WindRegulating_i^{\,2}} - L_{10}$$

Drawing from the first ten-minute interval in the example above as depicted in Table H.s 7 and 8, the component up reserves requirements were as follows:

Load Following = 271.5 MW
Load Regulating = 142.4 MW
Wind Following = 242.5 MW
Wind Regulating = 238.1 MW
East System L_{10} = 47.9 MW

Applying Equation 2:

$$\boldsymbol{Regulation\ Reserves} = \sqrt{271.5^2 + 142.4^2 + 242.5^2 + 238.1^2} - 47.9$$

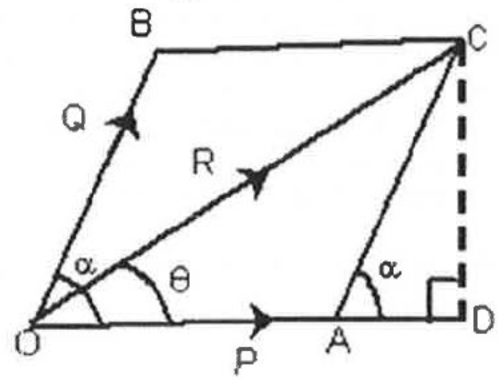
Per Equation 2, 409.8 MW of up reserves recommended for regulation reserve for the time interval between 10:00am and 10:10am, June 1, 2011 in PACE. In this manner, the component reserves requirements are used to calculate an overall reserves requirement for each ten-minute interval of the Study Term. A similar calculation is also made for the regulation reserve requirements pertaining only to the variability and uncertainty of load, which employs Equation 2 but applies zero reserves for the wind components. The incremental reserves assigned to wind generation demand are calculated as the difference between the total requirement and the load requirement. The results of these calculations can be quoted in hourly or monthly requirements by averaging the reserves requirements of all the ten-minute intervals within the specified hour or month. Annual reserves requirements are quoted as the average of the twelve monthly requirements.

Wind and Load Correlation

An important assumption underlying the application of Equation 2 is that there is no correlation between wind and load deviations. To test this assumption, this section describes an analysis of wind and load correlation.

The RSS equation is typically applied in the analysis engineering tolerances and supporting statistical concepts, and is derived from the Parallelogram Law[37].

Figure H.10 - Depiction of the Parallelogram Law



Equation 3. Vector combination as prescribed by the Parallelogram law in Figure H.10.
Resultant $\boldsymbol{R} = \sqrt{P^2 + Q^2 + 2PQ\cos\alpha}$.

If **P** and **Q** act at right angles, α =90°, and cos($\boldsymbol{\alpha}$)=0; $\boldsymbol{R} = \sqrt{P^2 + Q^2}$, which is equivalent to Equation 2.

The Parallelogram Law allows correlation to be constructive (with positive correlation) and destructive (with negative correlation). In cases of constructive correlation, the resultant (**R** in the illustration above, the parallelogram's diagonal) is increased as the angle (**α**) between (**Q**) and (**P**) is reduced. Destructive correlation causes the angle (**α**) to open wider, reducing the diagonal of the parallelogram, and reducing the length of the diagonal, **R**. The Law of Cosines can be used to illustrate a proof[38] that the cosine of angle **α** equals the correlation between vectors **P** and **Q** ($\cos(\boldsymbol{\alpha}) = \rho_{PQ}$).

In cases of zero correlation, the Parallelogram Law reduces to the RSS formulation (and **α** is a right angle, and the parallelogram is a square). For this Wind Study, rather than using two sides of a parallelogram to form a resultant (**R** in the illustration), four uncorrelated vectors

[37]A proof of the parallelogram law is available at: http://www.unlvkappasigma.com/parallelogram_law/
[38] http://www.johndcook.com/blog/2010/06/17/covariance-and-law-of-cosines/

corresponding to the component reserves for load following, load regulating, wind following, and wind regulating deviations are combined into a reserves requirement. The fact that there are four dimensions rather than two makes the process difficult to illustrate, but the effect is the same as in the two dimensional example above.

The Company applied the RSS formulation in its 2010 Wind Integration Study[39] after reviewing samples of the load and wind data used to perform the study[40], and reviewing studies by Idaho Power[41] and the Eastern Wind Integration and Transmission Study[42]. Since that time, additional studies have suggested use of this formulation directly[43] or noted that short term deviations from schedule in wind generation output and load are not correlated[44]. However, stakeholder interest has encouraged the Company to further review the correlation between wind and load reserve components.

Because reserves are intended to manage the deviations from expected load and wind generation output, the question becomes not whether the raw wind generation output and balancing area load are correlated, but rather whether the respective forecast errors between the Company's expected wind generation and load are correlated. These forecast errors drive the component reserves in the Wind Study, and reflect the level of reserves needed in real time operations. The analysis below assesses the correlation of deviations from forecasts for load and wind in both the hourly (following) and sub-hourly (regulating) timeframes.

Correlation Analysis

The forecast deviations for wind generation and load in the Company's BAAs were analyzed for correlation by performing a linear regression using the load deviation as an independent variable and the concurrent wind deviation as the dependent variable. Therefore, to estimate the East Wind Following deviation for a given time period, the East load following deviation was used as a predictive variable. The correlation between the two variables (load errors and wind errors) would be represented by the slope of the regression, and the predictive capability by the $\mathbf{r}^2$ (or goodness-of-fit). The procedure was followed for 2011 operational data applying the four component forecasts detailed previously for PACE and PACW. The results appear in Table H.12.

39 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, p. 19

40 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, Table 5, p. 6

41 http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/Addendum.pdf, pages 12, 20

42 http://www.nrel.gov/C821B4E9-F70E-4245-9C6D-D5CB68B670DC/FinalDownload/DownloadId-286D6B0AF14A941F45E5F431BACF4DCF/C821B4E9-F70E-4245-9C6D-D5CB68B670DC/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf, page 145

43 http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf, page 6E-9

44 http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf, page 92

Table H.12 - Results of Regression Analyses between Wind and Load Deviations

	Slope	r-Square
East Following	-0.097	0.45%
East Regulating	-0.087	0.63%
West Following	0.026	0.05%
West Regulating	-0.007	0.00%

The results indicate that while there is a calculable correlation between wind and load deviations in the data, the relationships are so weak such that neither explains the other, and so this relationship is not useful in an operational context. The value of the load deviation offers no ability to explain the wind deviation, and so the two are unrelated. This is consistent with the findings of wind studies noted above.

To illustrate the analysis, plots of the load and wind deviations (from their respective forecasts) have been prepared using 2011 operational data in Figures H.11 through H.14 below. Each point represents the respective deviation at any given time (a ten-minute interval for regulating deviations, a given hour for following deviations) by magnitude of the forecast error of load and wind, which would have to be managed by deploying reserves in real time operations. The magnitude of the load deviations are recorded on the horizontal (x) axis and the wind deviations on the vertical (y) axis. The correlation between the load and wind deviations is represented by slope of the (red) regression trend lines; a strongly predictive correlation would have little scatter about the line, while a weak, non-predictive correlation (with a low $\mathbf{r}^2$ value) would exhibit significant and varying amounts of scatter about the trend line.

Figures H.11 through H.14 demonstrate highly variable clouds of data, and the extension of each cloud along the horizontal axis suggest the load forecast deviations require more reserves than do the wind deviations. Additionally, the data do not follow the regression trend lines well; there is significant scatter and it varies from a dense population of occurrences in the middle to sparsely populated data at the ends of the line. These cloud patterns suggest factors other than load forecast error should be used to explain corresponding wind forecast error, and vice-versa.

For example, the greatest load deviations don't necessarily seem to occur at the same time as most of the greatest wind deviations, nor are the deviations necessarily small. The range about the red regression line for East Following (in Figure H.11) exhibits several wind following deviations of about +/- 300 MW at +100 MW load following deviation (line A) and a similar amount and range at -100 MW load deviation (line B). The data suggest that increased forecast errors in either direction for load neither increase nor decrease the expected error in the wind forecast.

Figure H.11 - PACE Following Regression Plot

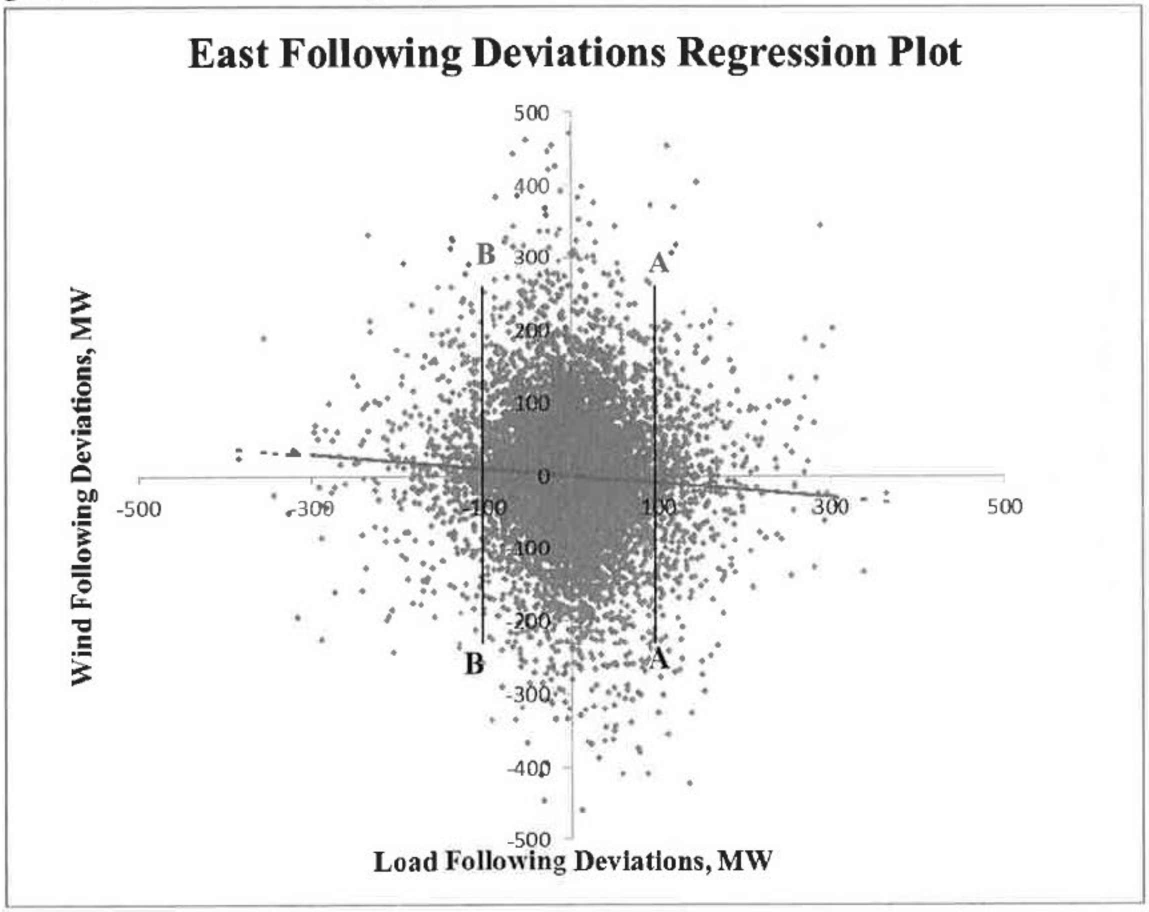
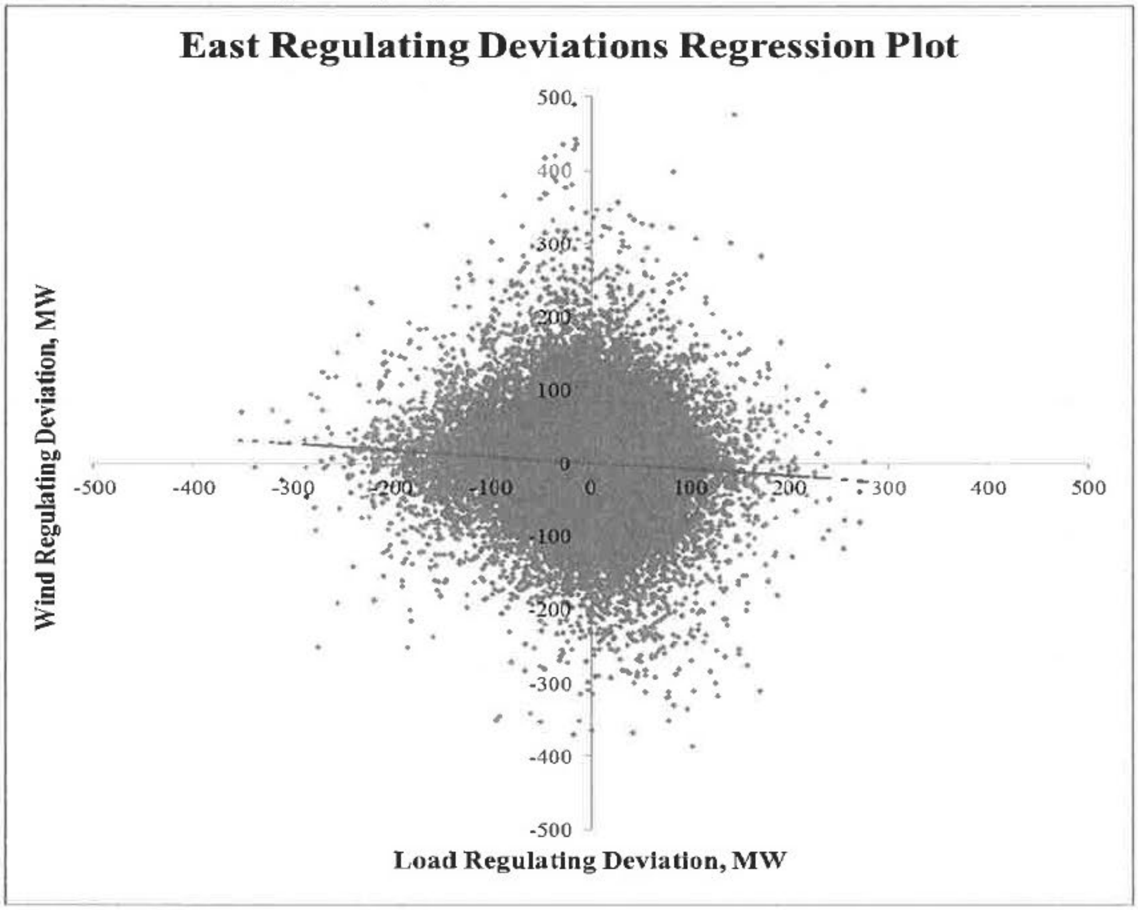
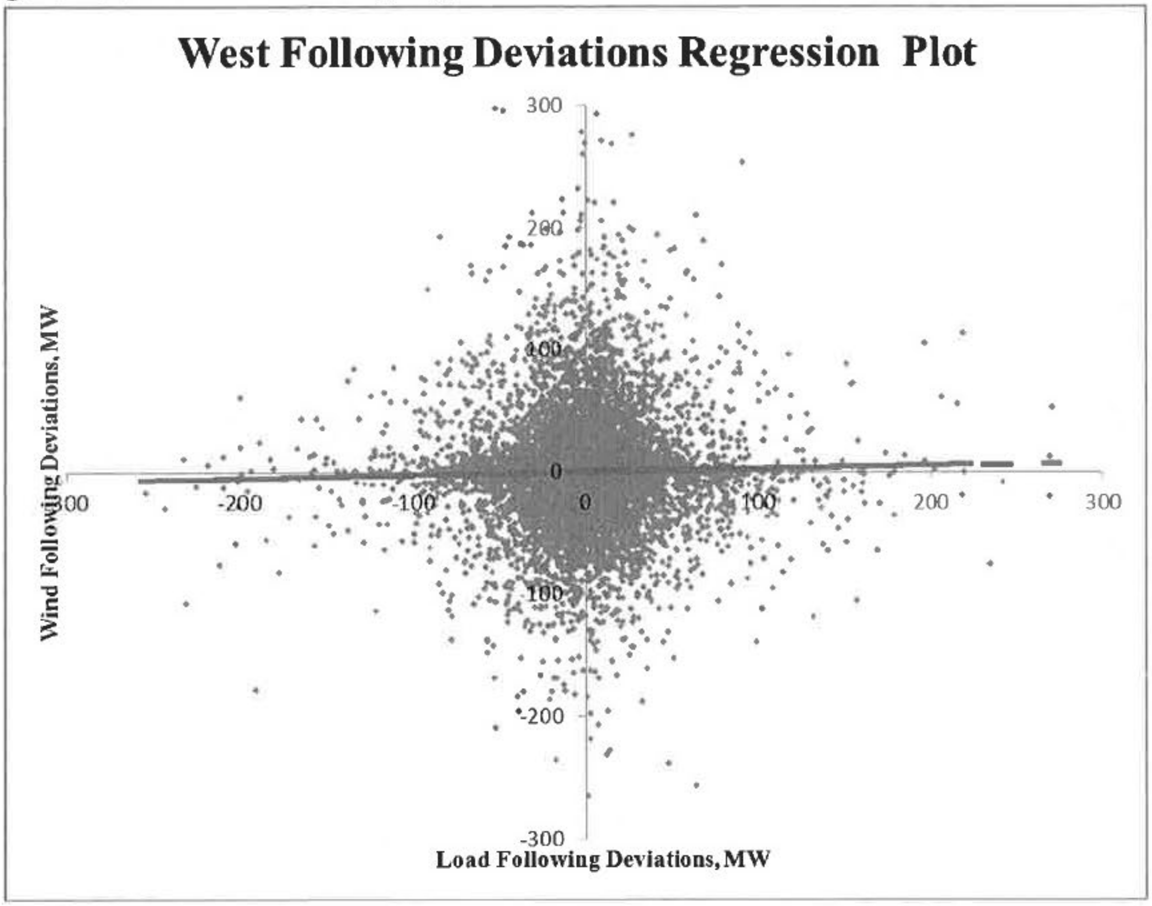


Figure H.12 - PACE Regulating Regression Plot[25]



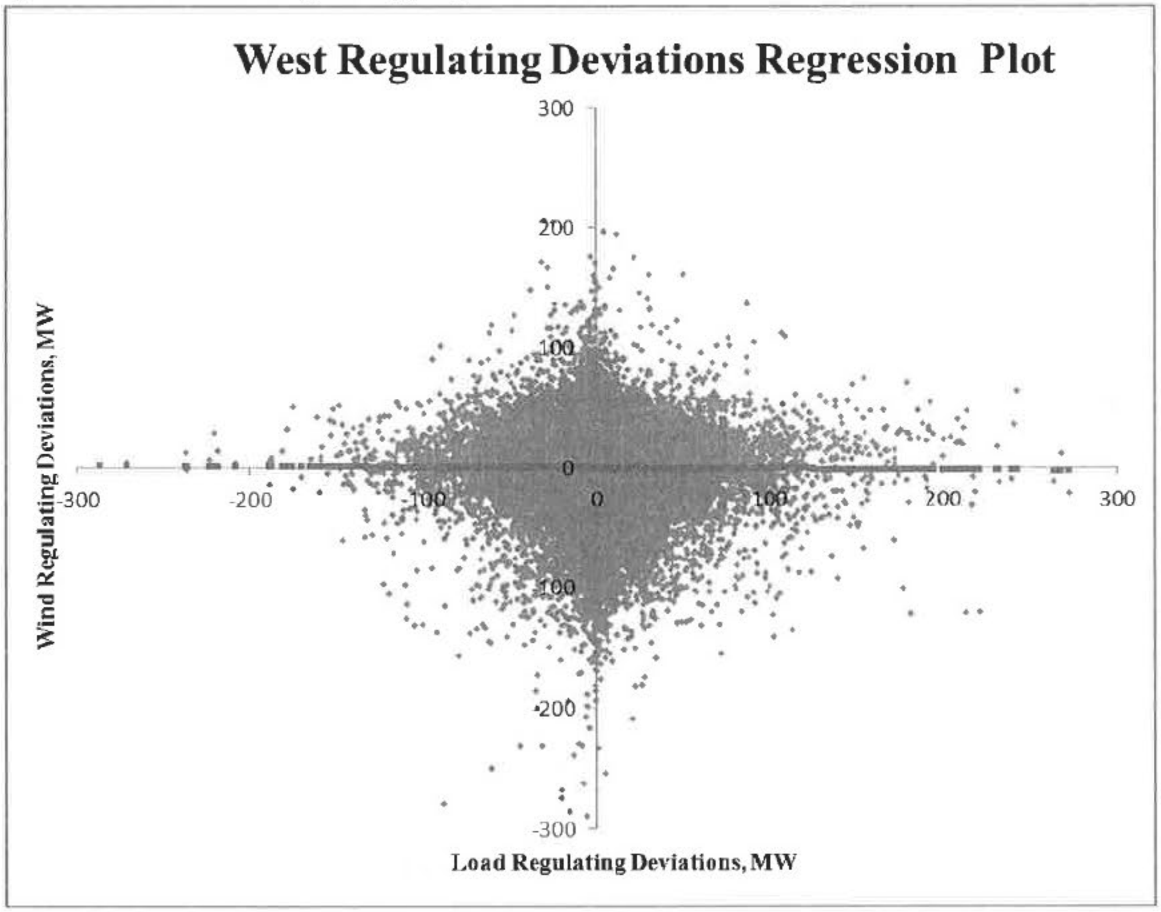
[25] Note cloud-like pattern of errors which is densest near zero, and the data does not tighten around the trend line.

Figure H.13 - PACW Following Regression Plot[26]



[26] Note another cloud of errors, with the red trend line describing little of the variation from one point to the other.

Figure H.14 - PACW Regulating Regression Plot[27]



3.3 Determination of Wind Integration Costs

3.3.1 Overview

Owing to the variability and uncertainty of load and wind generation, each hour of power system operations features a need to set aside operating reserve explicitly to cover load and contingency events inherent to the PacifiCorp system with or without wind in addition to contingency reserves. Additional costs are incurred with daily system balancing that is influenced by the unpredictable nature of wind generation on a day-ahead basis. To characterize how wind generation affects regulating margin costs and system balancing costs, the Study utilizes the PaR model, and applies the regulating margin requirements calculated by the method detailed in section 3.2.

[27] The dispersion in this cloud of data about the red regression trend line seems only to depend on how many data points are on either side of that line at any given point. Near the origin, there is a lot of data owing to most forecast errors being small, while at high deviations, there are very few points with which to assess fit, but there is scatter about the line.

PacifiCorp's PaR model, developed and licensed by Ventyx, Inc. uses the PROSYM chronological unit commitment and dispatch production cost simulation engine and is configured with a detailed representation of the PacifiCorp system. For this study, PacifiCorp developed five different PaR simulations. These simulations isolate wind integration costs associated with regulation margin reserves and enables separate calculation of wind integration costs associated with system balancing practice. The former reflects wind integration costs that arise from short-term (within the hour and hour ahead) variability in wind generation and the latter reflects integration costs that arise from errors in forecasting load and wind generation on a day-ahead basis.

The five PaR simulations used in the Wind Study are summarized in Table H.13. The first two simulations are used to tabulate operating reserve wind integration costs in forward planning timeframes. The approach uses a "P50" or expected wind profiles[28] and forecasted loads. The remaining three simulations support the calculation of system balancing wind integration costs. These simulations were run assuming operation in the 2013 calendar year, applying 2011 load and wind data. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis.[29] PacifiCorp resources used in the simulations are based upon the 2011 IRP Update resource portfolio.[30]

Table H.13 - Wind Integration Cost Simulations in PaR

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error
Regulating Margin Reserve Cost Runs					
1	2013	2013 Load Forecast	P50 Profiles	No	None
2	2013	2013 Load Forecast	P50 Profiles	Yes	None
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1					
System Balancing Cost Runs					
3	2013	2011 Day-ahead Forecast	2011 Day-ahead Forecast	Yes	None
4	2013	2011 Actual	2011 Day-ahead Forecast	Yes	For Load*
5	2013	2011 Actual	2011 Actual	Yes	For Load and Wind**
Load System Balancing Cost = System Cost from PaR simulation 4 (which uses the unit commitment from Simulation 3) less system cost from PaR simulation 3 *Wind System Balancing Cost = System Cost from PaR simulation 5 (which uses the unit commitment from Simulation 4) less system cost from PaR simulation 4*					

3.3.2 Calculating Operating Reserve Wind Integration Costs

To assess the effects of wind capacity added to the PacifiCorp system on regulating margin costs,

[28] P50 signifies the probability exceedence level for the annual wind production forecast; at P50 generation is expected to exceed the assumed generation levels half the time and to fall below the assumed generation levels half the time.

[29] The Study uses the June 29, 2012 official forward price curve.

[30] The 2011 Integrated Resource Update report, filed with the state utility commissions on March 30, 2012 is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRPUpdate/2011IRPUpdate_3-30-12_REDACTED.pdf.

the reserve requirements were simulated in PaR using 2013 load and P50 wind forecasts. Both of the first two PaR simulations excluded system balancing costs. Simulation 1 applied only the regulation reserves required for load obligations to 2013 forecast load and wind generation on PacifiCorp's systems with a 2013 resource profile. Simulation 2 used the same inputs except for adding the incremental operating reserve demand created by the variable nature of wind generation.

The system cost differences between these two simulations were divided by the total volume of wind generation to derive the wind integration costs associated with having to hold incremental operating reserve on a per unit of wind generation basis.

3.3.3 Calculating System Balancing Wind Integration Costs

PacifiCorp conducted another series of three PaR simulations to estimate daily system balancing wind integration costs consistent with the resource portfolio, labeled as Simulations 3 through 5 in Table H.13. In this phase of the analysis, PacifiCorp generation assets were committed consistent with a day-ahead forecast of wind and load, but dispatched against actual wind and load. To simulate this operational behavior, the three additional PaR simulations included the incremental reserves from Simulation 2 and the unit commitment states associated with simulating the portfolio with the day-ahead forecasts.

Simulation 3 incorporated day-ahead forecasts for both load and wind, dispatching PacifiCorp's generation to the forecasts as though there were no day-ahead forecast error. This served as the starting point for separately determining load and wind balancing impacts on total system balancing costs. Simulation 4 paired 2011 actual loads with day-ahead forecasts for wind generation, isolating the error due to load forecasting, and also applied the unit commitment state generated by Simulation 3 to capture system operations based on the day-ahead load forecasts. Simulation 5 incorporates actual wind generation output, thereby including forecast error for load and wind, and applied the unit commitment state generated by simulation 4. The change in system costs (Simulation 5 less Simulation 3) represents the total cost of day-ahead balancing on PacifiCorp's BAAs. Dividing the day-ahead wind balancing costs (Simulation 5 minus Simulation 4) by the volume of wind generation in the portfolio yields a system wind balancing cost on a per-unit of wind production basis.

3.3.4 Application of Study Results to Integrated Resource Plan Portfolio Modeling

The Study results are applied in the 2013 IRP portfolio development process as part of the costs of wind generation resources. In the portfolio development process using the System Optimizer (SO) model, the wind integration cost on a dollar per megawatt-hour basis is included as a cost to each wind resource's variable operation and maintenance cost. The exception is for prospective wind resources that could be located in the Bonneville Power Administration (BPA) balancing authority. The variable operation and maintenance adder for these resources includes BPA's variable integration charge[31]. The estimated wind integration cost is applied in the SO model (rather than increasing regulating margin) because the SO model builds least cost resource portfolios to meet system coincident peak loads with an assumed planning reserve margin. In meeting this coincident system peak capacity requirement, the SO model does not explicitly

[31] BPA's Variable Energy Balancing Service for wind resources is modeled at $1.23/kW-month, per their 2012 rate schedule, which at a 35% capacity factor equates to a charge of just over $4.80/MWh. The BPA rate schedule is available at: http://transmission.bpa.gov/Business/Rates/documents/2012_rate_schedules.pdf

evaluate operating reserve requirements. While operating reserve requirements are not explicitly in the SO model, the estimated cost of wind integration is accounted for in the development of resource portfolios.

Once candidate portfolios are developed using the SO model, additional analyses are performed using PaR, which can evaluate incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with this wind study will be used.

When modeling the production costs and risk analyses of resource portfolios in the PaR model, the incremental reserve requirements, due to additional wind plants, are incorporated as part of the PaR model's total reserve requirements. These incremental reserve requirements reflect the amount of reserves required in PACE and PACW for the regulation of wind resources. The cost impact of holding this incremental spin reserve requirement is embedded in the total production cost, but cannot be isolated for reporting purposes.

3.3.5 Allocation of Operating Reserve Demand in PaR

The five PaR Simulations require operating reserve demand inputs consistent with the Company's supply portfolio are input to the model. The PaR model distinguishes reserve types by the priority order for unit commitment scheduling, and optimizes them to minimize cost in response to demand changes and the quantity of reserve required on an hour-to-hour basis. The highest-priority reserve types are regulation up and regulation down followed in order by spinning, non-spinning, and finally, 30-minute non-spinning.[32] Table H.14 shows these reserve categories and indicates which ones are used for the study. Reserve requirements calculated in the study are allocated into these PaR reserve categories per below, and are supplemental to the contingency requirements calculated within PaR.

Table H.14 - Operating Reserve Categories Used by the PaR model

Input Field	Definition	Reserve Requirements Entered
AS1	Up Regulation	Regulation
AS2	Down Regulation	not used
AS3	Spin	Ramp and Contingency
AS4	NonSpin	Contingency
AS5	30 Minute NonSpin	not used

The regulation up and regulation down reserves in PaR are considered spinning reserve that must be met before traditional spinning and non-spinning reserve demands are met. The incremental operating reserve demand needed to integrate wind generation was assigned in PaR as regulation up. As down regulation reserves are a deployment of generation already committed to load, this feature was omitted from the Study. The traditional spinning and non-spinning reserve inputs are used for ramp and contingency reserve[33] requirements. Contingency reserve requirements

[32] In PaR, spinning reserve is defined as unloaded generation which is synchronized, ready to serve additional demand and able to reach reserve amount within ten minutes. Non-spinning Reserve is defined as unloaded generation which is non-synchronized and able to reach required generation amount within ten minutes.

[33] Contingency Reserve is specified by the North American Electric Reliability Corporation in http://www.nerc.com/files/BAL-STD-002-0.pdf .

remain unchanged among all PaR simulations in the Study. The 30-minute non-spinning reserve product is not represented in PacifiCorp's supply portfolio, and thus it is not used. Unused regulation up reserve supply can be used in PaR to satisfy spinning or non-spinning reserve demand.

The PaR model balances the system hourly, committing adequate generation to serve the forecasted net system load and meet each hour's respective reserve requirements. In actual operations, any deviation from the load forecast may cause the reserves specified to be deployed (should the net system load be greater than expected) or for the amount of open generation capacity to be increased (should the net system load be less than expected). Because the direction of the deviation, greater or lesser, is unknown and random, this calculation of the cost to hold reserves above the generation required to meet forecast load is assumed to be unbiased to actual intra-hour outcomes.

4. Results

The regulating margin required to manage fluctuations in load and wind generation output are the sum of the ramp and regulation reserve requirements. The ramp reserve is dependent only on the observed load and wind generation in the operational data used throughout the Wind Study. The regulation reserve requirement is calculated by the methods detailed in section 3.2. Table H.15 below summarizes the regulating margin requirements as calculated by the Study.

Table H.15 - Regulating Margin Requirements Calculated for PACE and PACW (MW)

	West BAA	East BAA	Combined
Load-Only Regulating Margin	147	247	394
Incremental Wind Regulating Margin	54	131	185
Total Regulating Margin	202	378	579

The operational data used to calculate these results is based on 589 MW of wind capacity installed in PACW, and 1,526 MW in PACE. Additional wind resources added to resource portfolios in the 2013 IRP contribute a pro-rated regulating margin requirement in PaR model simulations based on these results[34].

4.1 Production Cost Results

As described in section 3.3 and detailed in Table H.13, PacifiCorp applied the reserve requirements calculated in this Wind Study to a production cost simulation in the Company's PaR model. For the regulating margin costs, the regulating margin required to manage variability due to load and wind on PACE and PACW was applied using a "with and without" approach; the margin required only to manage disturbances in load was modeled in a production cost simulation, then compared to a simulation run with the regulating margin necessary to manage load and wind disturbances. The regulating margin costs represents the costs incurred to hold additional reserves for wind to manage hour-to-hour operational disturbances, whereas the

[34] The regulating margin requirement added for potential West wind developments will be the ratio of calculated incremental reserve requirement to total installed capacity, or 9.2% of the proposed generating capacity (54/589); while for East wind developments it will be 8.6% (131/1526).

system balancing costs are incurred managing the deviation between the day ahead forecast for wind production and actual recorded production on PacifiCorp's Company-owned and contracted wind resources. Transmission customers' wind resources' day-ahead variability and uncertainty are excluded from the system balancing calculation. Wind integration costs are the sum of the regulating margin and system balancing costs, as presented in Table H.16:

Table H.16 - Nominal Levelized Production Cost Results for the 2012 and 2010 Wind Studies

	Regulating Margin Cost ($/MWh)	System Balancing Cost ($/MWh)	Wind Integration Cost ($/MWh)
2012 Wind Study	$2.19	$0.36	$2.55
2010 Wind Study	$8.85	$0.86	$9.70

The 2010 Wind Study's production cost results are presented for comparison. The 2012 Study's analysis reflects a significantly depressed commodity price environment when compared to the 2010 Study; this is chiefly responsible for the cost differential. Additionally, the 2010 Wind Study's published system balancing cost includes day-ahead load forecast error, which should not be attributed to wind resources.

4.2 Additional Scenarios

To further understand differences around the set-ups of the Study and respond to requests of IRP stakeholders and the TRC, the Company has evaluated several scenario calculations to highlight the effect of selected changes in assumptions on the calculated regulating margin requirements. For the purposes of these scenarios, the same 99.7 percent tolerance level (and subtraction of L_{10}) was applied to the calculation method described above using 2011 operational data unless specified otherwise.

Historical Evaluation

The operational data available throughout the Study Term permits the estimation of historical reserves requirements. This may inform future planning, as the amount of wind generation capacity installed in PacifiCorp's system has steadily increased through the Study Term. Applying the method above to all the operational data in the Study Term, the following historical regulating margin requirements are calculated, as depicted in Table H.17. Table H.18 breaks out the incremental operating reserves calculated to manage wind generation.

Table H.17 - Historical Reserves Calculated throughout the Study Term (MW)

	Regulation West	Regulation East	Ramp	Total	Average Wind Capacity, MW
2007	184	194	134	512	606
2008	184	193	122	499	787
2009	145	211	121	477	1364
2010	152	261	122	534	1810
2011	149	302	128	579	2126

Table H.18. Incremental Reserves Due to Installed Wind Generation Capacity (MW)

	Regulation West	Regulation East	Ramp	Total	Average Wind Capacity, MW
2007	15	11	2	28	606
2008	24	14	3	40	787
2009	31	45	4	80	1364
2010	40	78	6	124	1810
2011	50	126	9	185	2126

Concurrent Evaluation

The calculations in this scenario are made for the load and wind deviations combined concurrently, by adding their concurrent errors, producing state bins and integrating the results for following and regulating reserves for load and wind separately. Despite the estimation of load and wind quantities separately in real time operations, and given no indication that short-term changes in load and wind are correlated[35], many stakeholders requested a calculation of the estimated reserves with implied correlation and other characteristics that may be observed in the short term variations of load and wind. The results of these calculations are presented in Table H.19.

Table H.19 - Concurrent Netting of Load and Wind Errors Scenario Results (MW)

	Regulation West	Regulation East	Ramp	Total
Scenario	160	279	128	567
2012 Study	149	302	128	579

The combination of errors and system state were each made following the load minus wind generation paradigm and the resulting differences were used to estimate reserves positions. This approach imputes the spurious correlation mentioned in section 3.2.5 into the results.

Reliability Based Control Market Structure

A new control performance paradigm featuring a 30-minute balancing market is under regional evaluation. Per current operational practice, the 60-minute market and operational paradigm is the base of the Wind Study design. However, to assess the potential benefits of a 30-minute clearing market for PacifiCorp's customers, an alternate calculation has been prepared by reducing the load and wind forecasting time interval to 30 minutes, and also reducing the persistence forecast intervals for regulation to 30 minutes for wind and load demands. Table H.20 compares the regulation reserves for the 30-minute balancing market scenario and the default 60-minute balancing market case for PACE and PACW. This calculation assumes adequate market depth at all 30-minute intervals such that the Company can rebalance system deviations from the market. The ramp obligation is assumed to remain supplied by the Company's hourly generation planning.

[35] Western Wind and Solar Integration Study, prepared by NREL, (May, 2010), p. 92. The report is available for download from the following hyperlink:
http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf

Table H.20 - 30-minute Balancing Interval Scenario Results (MW)

	Regulation West	Regulation East	Ramp	Total
Scenario	105	233	128	466
2012 Study	149	302	128	579

Combination of PACE and PACW

The calculations can also estimate the effect of combining PacifiCorp's two BAAs, into a single, monolithic balancing authority area. This assumption is that these calculations would mimic the effect of significant transmission development, eliminating the seams between the PACE and PACW. The respective load and wind errors for following and regulation are combined concurrently (East plus West) and the resulting component reserves demands are compared to those required by the default method described above for separate BAAs in Table H.21. However, the Company is uncertain at this time exactly how revised operational and forecasting practices would affect this scenario, and so further updates are possible.

Table H.21 - Regulating Margin Requirements Calculated Assuming a Single PacifiCorp Balancing Authority Area (MW)

	Regulation	Ramp	Total
Scenario	356	121	477
2012 Study	451	128	579

5. Summary

The purpose of this Study is to determine the additional reserve requirement to integrate wind resources into the Company's existing resource portfolio and determine a cost that is used in the portfolio development stage of the 2013 IRP.

The Study is based on actual historical data in ten-minute intervals for both load and wind generation, as well as actual historical day-ahead load and wind generation forecasts, in the Company's east and west balancing authority areas. The data were reviewed for anomalies, and revised prior to be applied in the Study.

The Study defined the two components of the regulating margin to include ramp and regulation reserves:

1) Ramp: A number of factors (fluctuations in customer demand, spot transactions, varying amounts of generation produced by variable resources such as wind and solar generation) cause the net balancing load to change from minute-to-minute, hour-to-hour continuously at all times. This variability (increasing and decreasing load) requires ready capacity to follow continuously, through short deviations, at all times. Treating this variability as though it is perfectly known (as though the operator would know exactly what the net balancing area load would be a minute from now, ten minutes from now, and an hour from now) and allowing just enough generation flexibility on hand to manage it defines the ramp reserves requirement of the system. The amount of ramp reserve required is half the difference

between the net balancing area load (load minus wind generation output) from the top of one hour to the next.

2) Regulation: Deviations from forecasted load or wind generation are not considered contingency events, yet these events still also require that capacity be set aside. Reserves maintained to manage uncertainty around the net system load is called regulation reserve. The Company has defined four components of regulation reserve (load following, load regulating, wind following, and wind regulating), estimated by comparing actual data to hypothetical forecasts. The four components are uncorrelated over operational generation planning's short time frames; and so the requirements to cover them are combined using a root-sum-square method into a single regulation reserve requirement for each time interval. The average regulation reserve requirement over any given timeframe expresses the regulation requirement for that timeframe.

To summarize, regulating margin represents operating reserves the Company holds over and above the mandated contingency reserve requirement to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts; ramp reserve and regulation reserve. The ramp reserve represents a minimum amount of flexibility required to follow the actual net system load (load minus wind generation output) with dispatchable generation. The regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors about the net system load, and consists of four components: load following, load regulating, wind following, and wind regulating.

The four components of the regulation reserves were calculated as the differences between the respective hypothetical operational forecast and actual data, sampled at a 99.7th percentile. The 99.7th percentile is selected to remove the most extreme deviation values from the assessment of the forward reserve requirements, while still providing sufficient reserve to prevent operations from running out of regulating margin due to the uncertainties prevalent in hour-to-hour power operations. In the past, the Company managed its balancing areas to a target called the Control Performance Standard 2 (CPS2), which specified a limited number of excursions from a net system interchange target. Since March 1, 2010, the PacifiCorp has been participating in a regional field test of the Reliability Based Control standard, which replaces the system interchange requirements with a regional frequency-based requirement. Among other changes, this new operational paradigm means the Company responds to area control error depending on whether their respective area control error is exacerbating or mitigating the frequency excursion at the time. As the frequency depends on the instantaneous balance between loads and resources throughout the entire Western Interconnection, the Company must plan to supply its own reserve requirements assuming its area control error is exacerbating system frequency. This has modified reserves planning from considering CPS2 to an avoidance of using contingency reserve for anything other than specified contingency events, as that is not allowed. Therefore, the regulating margin requirement evaluated in each time interval of the Wind Integration Study is intended to cover all anticipated uncertainties in short term load and wind behavior, consistent with the requirement of the Company to meet its firm load obligations and not deploy contingency reserve to cover what it should manage with regulating margin.

The sampled component reserve requirements are then backcast against the hypothetical operational forecasts and data for each ten-minute interval of the study. The resulting (selected) component reserve requirements are then combined using the root-sum-square method to arrive at the total regulation requirement, by East and West BAA (PACE and PACW, respectively). This requirement is reduced by each BAA's respective L_{10} value[36][37]. The total regulating margin is the sum of the regulation requirement plus ramp reserve. Table H.22 below is a summary of results.

Table H.22 - Regulating Margin Requirements Calculated for PacifiCorp's System (MW)

	West Regulation	East Regulation	Ramp	Combined
Load-Only Reserves	99	176	119	394
Incremental Wind Reserves	50	126	9	185
Total Reserves	149	302	128	579

The cost to hold the incremental regulating margin to integrate wind resources is estimated using the Company's PaR model (a production cost model set up to simulate the operation of PacifiCorp's electrical system)by calculating the difference in production costs with and without the incremental reserves to integrate wind resources using the projected Company's load and resource portfolio in 2013. This calculation results in the intra-hour reserves costs detailed in Table H.23. The day-ahead load and wind forecast data are used to commit the generation resources in the PaR model, and then it is set to simulate operations serving the actual system loads and received wind generation, isolating the effect of wind generation forecasts and actual generation in a three-stage process. This calculation yields the inter-hour/system balancing cost, also detailed in Table H.23:

Table H.23 - Wind Integration Costs

Study	2012 Wind Integration Study
Wind Capacity Penetration	2126 MW, 2011 Operational Data
System Assumption	2013 PacifiCorp System
Tenor of Cost	1 year levelized, 2012$
Hourly Reserve ($/MWh)	$2.19
Interhour/System Balancing ($/MWh)	$0.36
Total Wind Integration ($/MWh)	$2.55

The costs calculated in this study reflect the current market conditions for natural gas and electricity based on the June 29, 2012 official forward price curve. As these market conditions change, so will the value of the operating reserves required to meet the systems' regulating margin requirements. The total wind integration costs displayed in Table H.23 are used in the Company's System Optimizer model for IRP portfolio development, while the incremental regulating margin requirements for integrating wind displayed in Table H.22 are used to support IRP portfolio production cost modeling using the PaR model.

[36] The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails.

[37] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to:
http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/902 to Cross-Examination Statement

PacifiCorp's 2014 Wind Integration Study

August 18, 2015

APPENDIX H – WIND INTEGRATION STUDY

Introduction

This wind integration study (WIS) estimates the operating reserves required to both maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. The Company must provide sufficient operating reserves to meet NERC's balancing authority area control error limit (BAL-001-2) at all times, incremental to contingency reserves, which the Company maintains to comply with NERC standard BAL-002-WECC-2.[22,23] Apart from disturbance events that are addressed through contingency reserves, these incremental operating reserves are necessary to maintain area control error[24] (ACE), due to sources outside direct operator control including intra-hour changes in load demand and wind generation, within required parameters. The WIS estimates the operating reserve volume required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas (BAAs) and estimates the incremental cost of these operating reserves.

The operating reserves contemplated within this WIS represent regulating margin, which is comprised of ramp reserve, extracted directly from operational data, and regulation reserve, which is estimated based on operational data. The WIS calculates regulating margin demand over two common operational timeframes: 10-minute intervals, called regulating; and one-hour-intervals, called following. The regulating margin requirements are calculated from operational data recorded during PacifiCorp's operations from January 2012 through December 2013 (Study Term). The regulating margin requirements for load variation, and separately for load variation combined with wind variation, are then applied in the Planning and Risk (PaR) production cost model to determine the cost of the additional reserve requirements. These costs are attributed to the integration of wind generation resources in the 2015 Integrated Resource Plan (IRP).

Estimated regulating margin reserve volumes in this study were calculated using the same methodology applied in the Company's 2012 WIS[25], with data updated for the current Study Term. The regulating margin reserve volumes in this study account for estimated benefits from PacifiCorp's participation in the energy imbalance market (EIM) with the California Independent System Operator (CAISO). The Company expects that with its participation in the EIM future wind integration study updates will benefit as PacifiCorp gains access to additional and more specific operating data.

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[22] NERC Standard BAL-001-2: http://www.nerc.com/files/BAL-001-2.pdf

[23] NERC Standard BAL-002-WECC-2 (http://www.nerc.com/files/BAL-002-WECC-2.pdf), which became effective October 1, 2014, replaced NERC Standard BAL-STD-002, which was in effect at the time of this study.

[24] "Area Control Error" is defined in the NERC glossary here: http://www.nerc.com/pa/stand/glossary of terms/glossary_of_terms.pdf

[25] 2012 WIS report is provided as Appendix H in Volume II of the Company's 2013 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

Technical Review Committee

As was done for its 2012 WIS, the Company engaged a Technical Review Committee (TRC) to review the study results from the 2014 WIS. The Company thanks each of the TRC members, identified below, for their participation and professional feedback. The members of the TRC are:

- **Andrea Coon** - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- **Matt Hunsaker** - Manager, Renewable Integration for the Western Electricity Coordinating Council (WECC)
- **Michael Milligan** - Lead research for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory (NREL)
- **J. Charles Smith** - Executive Director, Utility Variable-Generation Integration Group (UVIG)
- **Robert Zavadil** - Executive Vice President of Power Systems Consulting, EnerNex

In its technical review of the Company's 2012 WIS, the TRC made recommendations for consideration in future WIS updates.[26] The following table summarizes TRC recommendations from the 2012 WIS and how these recommendations were addressed in the 2014 WIS.

Table H.1 – 2012 WIS TRC Recommendations

2012 WIS TRC Recommendations	2014 WIS Response to TRC Recommendations
Reserve requirements should be modeled on an hourly basis in the production cost model, rather than on a monthly average basis.	The Company modeled reserves on an hourly basis in PaR. A sensitivity was performed to model reserves on monthly basis as in the 2012 WIS.
Either the 99.7% exceedance level should be studied parametrically in future work, or a better method to link the exceedance level, which drives the reserve requirements in the WIS, to actual reliability requirements should be developed.	In discussing this recommendation with the TRC, it was clarified that the intent was a request to better explain how the exceedance level ties to operations. PacifiCorp has included discussion in this 2014 WIS on its selection of a 99.7% exceedance level when calculating regulation reserve needs, and further clarifies that the WIS results informs the amount of regulation reserves planned for operations.
Future work should treat the categories "regulating," "following," and "ramping" differently by using the capabilities already in PaR and comparing these results to those using of the root-sum-of-squares (RSS) formula.	A sensitivity study was performed demonstrating the impact of separating the reserves into different categories.
Given the vast amount of data used, a simpler and more transparent analysis could be performed using a flexible statistics package rather than spreadsheets.	PacifiCorp appreciates the TRC comment; however, PacifiCorp continued to rely on spreadsheet-based calculations when calculating regulation reserves for its 2014 WIS. This allows stakeholders, who may not have access to specific statistics packages, to review work papers underlying PacifiCorp's 2014 WIS.

[26] TRC's full report is provided at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/2012WIS/Pacificorp_2012WIS_TRC-Technical-Memo_5-10-13.pdf

2012 WIS TRC Recommendations	2014 WIS Response to TRC Recommendations
Because changes in forecasted natural gas and electricity prices were a major reason behind the large change in integration costs from the 2010 WIS, sensitivity studies around natural gas and power prices, and around carbon tax assumptions, would be interesting and provide some useful results.	Changes in wind integration costs continue to align with movements in forward market prices for both natural gas and electricity. PacifiCorp describes how market prices have changed in relation to wind integration costs as updated in the 2014 WIS. With the U.S. Environmental Protection Agency's draft rule under §111(d) of the Clean Air Act, CO_2 tax assumptions are no longer assumed in PacifiCorp's official forward price curves.
Although the study of separate east and west BAAs is useful, the WIS should be expanded to consider the benefits of PacifiCorp's system as a whole, as some reserves are transferrable between the BAAs. It would be reasonable to conclude that EIM would decrease reserve requirements and integration costs.	PacifiCorp has incorporated estimated regulation reserve benefits associated with its participation in EIM in the 2014 WIS. With its involvement in EIM, future wind studies will benefit as PacifiCorp gains access to better operating data.

Executive Summary

The 2014 WIS estimates the regulating margin requirement from historical load and wind generation production data using the same methodology that was developed in the 2012 WIS. The regulating margin is required to manage variations to area control error due to load and wind variations within PacifiCorp's BAAs. The WIS estimates the regulating margin requirement based on load combined with wind variation and separately estimates the regulating margin requirement based solely on load variation. The difference between these two calculations, with and without the estimated regulating margin required to manage wind variability and uncertainty, provides the amount of incremental regulating margin required to maintain system reliability due to the presence of wind generation in PacifiCorp's BAAs. The resulting regulating margin requirement was evaluated deterministically in the PaR model, a production cost model used in the Company's Integrated Resource Plan (IRP) to simulate dispatch of PacifiCorp's system. The incremental cost of the regulating margin required to manage wind resource variability and uncertainty is reported on a dollar per megawatt-hour ($/MWh) of wind generation basis.[27]

When compared to the result in the 2012 WIS, which relied upon 2011 data, the 2014 WIS uses 2013 data and shows that total regulating margin increased by approximately 27 megawatts (MW) in 2012 and 47 MW in 2013. These increases in the total reserve requirement reflect different levels of volatility in actual load and wind generation. This volatility in turn impacts the operational forecasts and the deviations between the actual and operational forecast reserve requirements, which ultimately drives the amount of regulating margin needed. Table H.2 depicts the combined PacifiCorp BAA annual average regulating margin calculated in the 2014 WIS, and separates the regulating margin due to load from the regulating margin due to wind. The total regulating margin increased from 579 MW in the 2012 WIS to 626 MW in the 2014 WIS.

[27] The PaR model can be run with stochastic variables in Monte Carlo simulation mode or in deterministic mode whereby variables such as natural gas and power prices do not reflect random draws from probability distributions. For purposes of the WIS, the intention is not to evaluate stochastic portfolio risk, but to estimate production cost impacts of incremental operating reserves required to manage wind generation on the system based on current projections of future market prices for power and natural gas.

Table H.2 – Average Annual Regulating Margin Reserves, 2011 – 2013 (MW)

Year	Type	West BAA	East BAA	Combined
2011 (2012 WIS)	Load-Only Regulating Margin	147	247	394
	Incremental Wind Regulating Margin	54	131	185
	Total Regulating Margin	202	378	579
	Wind Capacity	589	1,536	2,126
2012	Load-Only Regulating Margin	141	259	400
	Incremental Wind Regulating Margin	77	129	206
	Total Regulating Margin	217	388	606
	Wind Capacity	785	1,759	2,543
2013 (2014 WIS)	Load-Only Regulating Margin	166	275	441
	Incremental Wind Regulating Margin	55	130	186
	Total Regulating Margin	222	405	626
	Wind Capacity	785	1,759	2,543

Table H.3 lists the cost to integrate wind generation in PacifiCorp's BAAs. The cost to integrate wind includes the cost of the incremental regulating margin reserves to manage intra-hour variances (as outlined above) and the cost associated with day-ahead forecast variances, the latter of which affects how dispatchable resources are committed to operate, and subsequently, affect daily system balancing. Each of these component costs were calculated using the PaR model. A series of PaR simulations were completed to isolate each wind integration cost component by using a "with and without" approach. For instance, PaR was first used to calculate system costs solely with the regulating margin requirement due to load variations, and then again with the increased regulating margin requirements due to load combined with wind generation. The change in system costs between the two PaR simulations results in the wind integration cost.

Table H.3 – Wind Integration Cost, $/MWh

	2012 WIS (2012$)	2014 WIS (2015$)
Intra-hour Reserve	$2.19	$2.35
Inter-hour/System Balancing	$0.36	$0.71
Total Wind Integration	**$2.55**	**$3.06**

The 2014 WIS results are applied in the 2015 IRP portfolio development process as part of the costs of wind generation resources. In the portfolio development process using the System Optimizer (SO) model, the wind integration cost on a dollar per megawatt-hour basis is included as a cost to the variable operation and maintenance cost of each wind resource. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate the risk profiles of the portfolios in meeting load obligations, including incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with this wind study are used.

Data

The calculation of regulating margin reserve requirement was based on actual historical load and wind production data over the Study Term from January 2012 through December 2013. Table H.4 outlines the load and wind generation 10-minute interval data used during the Study Term.

Table H.4 – Historical Wind Production and Load Data Inventory

	Wind Nameplate Capacity (MW)	Beginning of Data	End of Data	BAA
Wind Plants within PacifiCorp BAAs				
Chevron Wind	16.5	1/1/2012	12/31/2013	East
Combine Hills	41.0	1/1/2012	12/31/2013	West
Dunlap 1 Wind	111.0	1/1/2012	12/31/2013	East
Five Pine and North Point	119.7	12/1/2012	12/31/2013	East
Foot Creek Generation	85.1	1/1/2012	12/31/2013	East
Glenrock III Wind	39.0	1/1/2012	12/31/2013	East
Glenrock Wind	99.0	1/1/2012	·12/31/2013	East
Goodnoe Hills Wind	94.0	1/1/2012	12/31/2013	West
High Plains Wind	99.0	1/1/2012	12/31/2013	East
Leaning Juniper 1	100.5	1/1/2012	12/31/2013	West
Marengo I	140.4	1/1/2012	12/31/2013	West
Marengo II	70.2	1/1/2012	12/31/2013	West
McFadden Ridge Wind	28.5	1/1/2012	12/31/2013	East
Mountain Wind 1 QF	60.9	1/1/2012	12/31/2013	East
Mountain Wind 2 QF	79.8	1/1/2012	12/31/2013	East
Power County North and Power County South	45.0	1/1/2012	12/31/2013	East
Oregon Wind Farm QF	64.6	1/1/2012	12/31/2013	West
Rock River I	49.0	1/1/2012	12/31/2013	East
Rolling Hills Wind	99.0	1/1/2012	12/31/2013	East
Seven Mile Wind	99.0	1/1/2012	12/31/2013	East
Seven Mile II Wind	19.5	1/1/2012	12/31/2013	East
Spanish Fork Wind 2 QF	18.9	1/1/2012	12/31/2013	East
Stateline Contracted Generation	175.0	1/1/2012	12/31/2013	West
Three Buttes Wind	99.0	1/1/2012	12/31/2013	East
Top of the World Wind	200.2	1/1/2012	12/31/2013	East
Wolverine Creek	64.5	1/1/2012	12/31/2013	East
Long Hollow Wind		1/1/2012	12/31/2013	East
Campbell Wind		1/1/2012	12/31/2013	West
Horse Butte		6/19/2012	12/31/2013	East
Jolly Hills 1		1/1/2012	12/31/2013	East
Jolly Hills 2		1/1/2012	12/31/2013	East
Load Data				
PACW Load	n/a	1/1/2012	12/31/2013	West
PACE Load	n/a	1/1/2012	12/31/2013	East

Historical Load Data

Historical load data for the PacifiCorp east (PACE) and PacifiCorp west (PACW) BAAs were collected for the Study Term from the PacifiCorp PI system.[28] The raw load data were reviewed for anomalies prior to further use. Data anomalies can include:

- Incorrect or reversal of sign (recorded data switching from positive to negative);
- Significant and unexplainable changes in load from one 10-minute interval to the next;
- Excessive load values.

After reviewing 210,528 10-minute load data points in the 2014 WIS, 1,011 10-minute data points, roughly 0.5% of the data, were identified as irregular. Since reserve demand is created by unexpected changes from one time interval to the next, the corrections made to those data points were intended to mitigate the impacts of irregular data on the calculation of the reserve requirements and costs in this study.

Of the 1,011 load data points requiring adjustment, 984 exhibited unduly long periods of unchanged or "stuck" values. The data points were compared to the values from the Company's official hourly data. If the six 10-minute PI values over a given hour averaged to a different value than the official hourly record, they were replaced with six 10-minute instances of the hourly value. For example, if PACW's measured load was 3,000 MW for three days, while the Company's official hourly record showed different hourly values for the same period, the six 10-minute "stuck" data points for an hour were replaced with six instances of the value from the official record for the hour. Though the granularity of the 10-minute readings was lost, the hour-to-hour load variability over the three days in this example would be captured by this method. In total, the load data requiring replacement for stuck values represented only 0.47% of the load data used in the current study.

The remaining 27 of data points requiring adjustment were due to questionable load values, three of which were significantly higher than the load values in the adjacent time intervals, and 24 of which were significantly lower. While not necessarily higher or lower by an egregious amount in each instance, these specific irregular data collectively averaged a difference of several hundred megawatts from their replacement values. Table H.5 depicts a sample of the values that varied significantly, as compared to the data points immediately prior to and after those 10-minute intervals. The replacement values, calculated by interpolating the prior value and the successive 10-minute period to form a straight line, are also shown in the table.

[28] The PI system collects load and generation data and is supplied to PacifiCorp by OSISoft. The Company Web site is http://www.osisoft.com/software-support/what-is-pi/what_is_PI_.aspx.

Table H.5 – Examples of Load Data Anomalies and their Interpolated Solutions

Time	Original Load Value (MW)	Final Load Value (MW)	Method to Calculate Final Load Value
1/5/2012 12:20	5,805	5,805	n/a
1/5/2012 12:30	5,211	5,793	12:20 + 1/5 of (13:10 minus 12:20)
1/5/2012 12:40	5,074	5,781	12:20 + 2/5 of (13:10 minus 12:20)
1/5/2012 12:50	5,063	5,769	12:20 + 3/5 of (13:10 minus 12:20)
1/5/2012 13:00	5,465	5,756	12:20 + 4/5 of (13:10 minus 12:20)
1/5/2012 13:10	5,744	5,744	n/a
5/6/2013 8:50	5,651	5,651	n/a
5/6/2013 9:00	4,583	5,694	Average of 8:50 and 9:10
5/6/2013 9:10	5,737	5,737	n/a

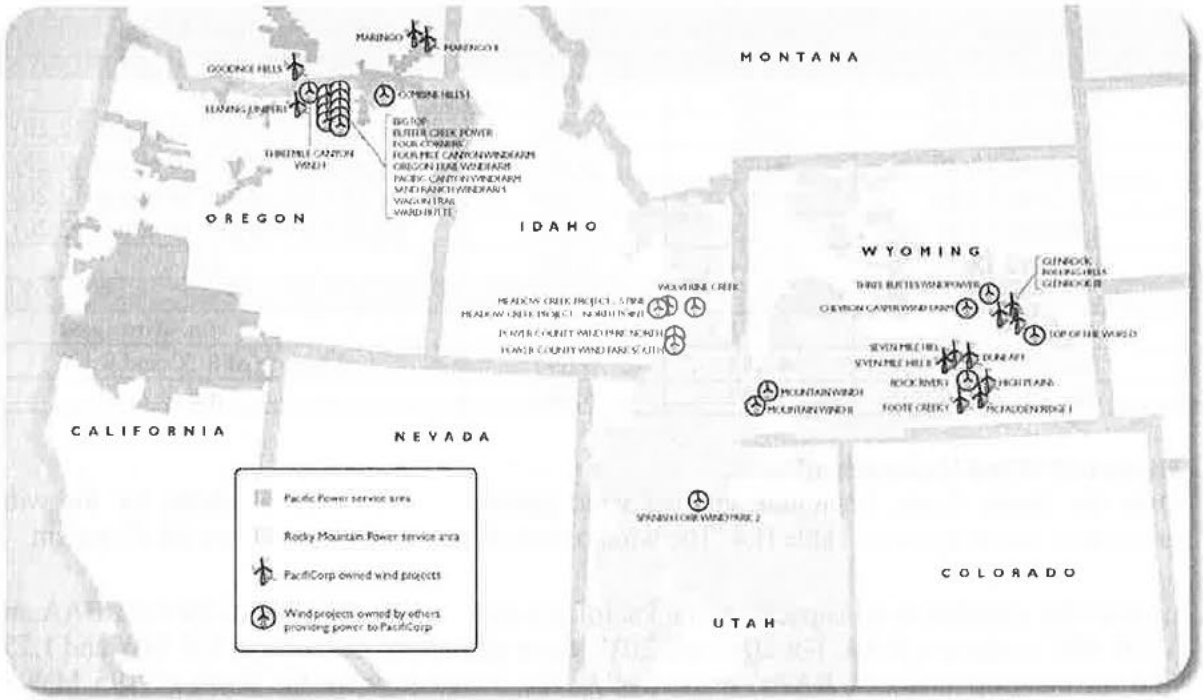
Historical Wind Generation Data

Over the Study Term, 10-minute interval wind generation data were available for the wind projects as summarized in Table H.4. The wind output data were collected from the PI system.

In 2011 the installed wind capacity in the PacifiCorp system was 589 MW in the west BAA and 1,536 MW in the east BAA. For 2012 and 2013, these capacities increased to 785 MW and 1,759 MW in the west and east BAAs, respectively. The increases were the result of 195 MW of existing wind projects transferring from Bonneville Power Administration (BPA) to PacifiCorp's west BAA, and 222 MW of new third party wind projects coming on-line during 2012 in the east BAA.

Figure H.1 shows PacifiCorp owned and contracted wind generation plants located in PacifiCorp's east and west BAAs. The third-party wind plants located within PacifiCorp's BAAs which the Company does not purchase generation from or own are not depicted in this figure.

Figure H.1 – Representative Map, PacifiCorp Wind Generating Stations Used in this Study



The wind data collected from the PI system is grouped into a series of sampling points, or nodes, which represent generation from one or more wind plants. In consideration of occasional irregularities in the system collecting the data, the raw wind data was reviewed for reasonableness considering the following criteria:

- Incorrect or reversal of sign (recorded data switching from positive to negative);
- Output greater than expected wind generation capacity being collected at a given node;
- Wind generation appearing constant over a period of days or weeks at a given node.

Some of the PI system data exhibited large negative generation output readings in excess of the amount that could be attributed to station service. These meter readings often reflected positive generation and a reversed polarity on the meter rather than negative generation. In total, only 38 of 3,822,048 10-minute PI readings, representing 0.001% of the wind data used in this WIS, required substituting a positive value for a negative generation value.

Some of the PI system data exhibited large positive generation output readings in excess of plant capacity. In these instances, the erroneous data were replaced with a linear interpolation between the value immediately before the start of the excessively large data point and the value immediately after the end of the excessively large data point. In total, only 49 10-minute PI readings, representing 0.002% of the wind data used in this WIS, required substituting a linear interpolation for an excessively large generation value.

Similar to the load data, the PI system wind data also exhibited patterns of unduly long periods of unchanged or "stuck" values for a given node. To address these anomalies, the 10-minute PI values were compared to the values from the Company's official hourly data, and if the six 10-minute PI values over a given hour averaged to a different value than the official hourly record, they were replaced with six 10-minute instances of the hourly value. For example, if a node's measured wind generation output was 50 MW for three weeks, while the official record showed different hourly values for the same time period, the six 10-minute "stuck" data points for an hour were replaced with six instances of the value from the official record for the hour. Though the granularity of the 10-minute readings was lost, the hour-to-hour wind variability over the three weeks in this example would be captured by this method. In total, the wind generation data requiring replacement for stuck values represented only 0.2% of the wind data used in the WIS.

Methodology

Method Overview

This section presents the approach used to establish regulating margin reserve requirements and the method for calculating the associated wind integration costs. 10-minute interval load and wind data were used to estimate the amount of regulating margin reserves, both up and down, in order to manage variation in load and wind generation within PacifiCorp's BAAs.

Operating Reserves

NERC regional reliability standard BAL-002-WECC-2 requires each BAA to carry sufficient operating reserve at all times.[29] Operating reserve consists of contingency reserve and regulating margin. These reserve requirements necessitate committing generation resources that are sufficient to meet not only system load but also reserve requirements. Each of these types of operating reserve is further defined below.

Contingency reserve is capacity that the Company holds in reserve that can be used to respond to contingency events on the power system, such as an unexpected outage of a generator or a transmission line. Contingency reserve may not be applied to manage other system fluctuations such as changes in load or wind generation output. Therefore, this study focuses on the operating reserve component to manage load and wind generation variations which is incremental to contingency reserve, which is referred to as regulating margin.

Regulating margin is the additional capacity that the Company holds in reserve to ensure it has adequate reserve at all times to meet the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulating reserves incremental to contingency reserves to maintain reliability.[30] However, these additional regulating reserves are not defined by a simple formula, but rather are the amount of reserves required by each BAA to meet the control performance standards. NERC standard BAL-001-2, called the Balancing Authority Area Control Error Limit (BAAL), allows a greater ACE during periods when the ACE is helping frequency. However, the Company cannot plan on knowing when the ACE will help or exacerbate frequency so the L_{10} is used for the bandwidth in both directions of the ACE.[31,32] Thus the Company determines, based on the unique level of wind and load variation in its

[29] NERC Standard BAL-002-WECC-2: http://www.nerc.com/files/BAL-002-WECC-2.pdf

[30] NERC Standard BAL-001-2:http://www.nerc.com/files/BAL-001-2.pdf

[31] The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails.

[32] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to:
http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf

system, and the prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and wind changes throughout the delivery hour. For this WIS, the Company further segregates regulating margin into two components: ramp reserve and regulation reserve.

Ramp Reserve: Both load and wind change from minute-to-minute, hour-to-hour, continuously at all times. This variability requires ready capacity to follow changes in load and wind continuously, through short deviations, at all times. Treating this variability as though it is perfectly known (as though the operator would know exactly what the net balancing area load would be a minute from now, 10-minutes from now, and an hour from now) and allowing just enough generation flexibility on hand to manage it defines the ramp reserve requirement of the system.

Regulation Reserve: Changes in load or wind generation which are not considered contingency events, but require resources be set aside to meet the needs created when load or wind generation change unexpectedly. The Company has defined two types of regulation reserve – regulating and following reserves. Regulating reserve are those covering short term variations (moment to moment using automatic generation control) in system load and wind. Following reserves cover uncertainty across an hour when forecast changes unexpectedly.

To summarize, regulating margin represents operating reserves the Company holds over and above the mandated contingency reserve requirement to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts: ramp reserve and regulation reserve. The ramp reserve represents an amount of flexibility required to follow the change in actual net system load (load minus wind generation output) from hour to hour. The regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors about the net system load, and consists of four components: load and wind following and load and wind regulating.

Determination of Amount and Costs of Regulating Margin Requirements

Regulating margin requirements are calculated for each of the Company's BAAs from production data via a five step process, each described in more detail later in this section. The five steps include:

1. Calculation of the ramp reserve from the historical data (with and without wind generation).
2. Creation of hypothetical forecasts of following and regulating needs from historical load and wind production data.
3. Recording differences, or deviations, between actual wind generation and load values in each 10-minute interval of the study term and the expected generation and load.
4. Group these deviations into bins that can be analyzed for the reserve requirement per forecast value of wind and load, respectively, such that a specified percentage (or tolerance level) of these deviations would be covered by some level of operating reserves.
5. The reserve requirements noted for the various wind and load forecast values are then applied back to the operational data enabling an average reserve requirement to be calculated for any chosen time interval within the Study Term.

Once the amount of regulating margin is estimated, the cost of holding the specified reserves on PacifiCorp's system is estimated using the PaR model. In addition to using PaR for evaluating operating reserve cost, the PaR model is also used to estimate the costs associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of load and wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time.

Regulating Margin Requirements

Consistent with the methodology developed in the Company's 2012 WIS, and the discussion above, regulating margin requirements were derived from actual data on a 10-minute interval basis for both wind generation and load. The ramp reserve represents the minimal amount of flexible system capacity required to follow net load requirements without any error or deviation and with perfect foresight for following changes in load and wind generation from hour to hour. These amounts are as follows:

- If system is ramping down: [(Net Area Load Hour H – Net Area Load Hour (H+1))/2]
- If system is ramping up: [(Net Area Load Hour (H+1) – Net Area Load Hour H)/2]

That is, the ramp reserve is half the absolute value of the difference between the net balancing area load at the top of one hour minus the net balancing load at the top of the prior hour.

The ramp reserve for load and wind is calculated using the net load (load minus wind generation output) at the top of each hour. The ramp reserve required for wind is the difference between that for load and that for load and wind.

As ramp reserves represent the system flexibility required to follow the system's requirements without any uncertainty or error, the regulation reserve is necessary to cover uncertainty ever-present in power system operations. Very short-term fluctuations in weather, load patterns, wind generation output and other system conditions cause short term forecasts to change at all times. Therefore, system operators rely on regulation reserve to allow for the unpredictable changes between the time the schedule is made for the next hour and the arrival of the next hour, or the ability to follow net load. Also, these very same sources of instability are present throughout each hour, requiring flexibility to regulate the generation output to the myriad of ups and downs of customer demand, fluctuations in wind generation, and other system disturbances. To assess the regulation reserve requirements for PacifiCorp's BAAs, the Company compared operational data to hypothetical forecasts as described below.

Hypothetical Operational Forecasts

Regulation reserve consists of two components: (1) regulating, which is developed using the 10-minute interval data, and (2) following, which is calculated using the same data but estimated on an hourly basis. Load data and wind generation data were applied to estimate reserve requirements for each month in the Study Term. The regulating calculation compares observed 10-minute interval load and wind generation to a 10-minute interval forecast, and following compares observed hourly averages to an average hourly forecast. Therefore, the regulation reserve requirements are composed of four component requirements, which, in turn, depend on differences between actual and expected needs. The four component requirements include: load following, wind following, load regulating, and wind regulating. The determination of these reserve requirements began with the development of the expected following and regulating needs (hypothetical forecasts) of the four components, each discussed in turn below.

Hypothetical Load Following Operational Forecast

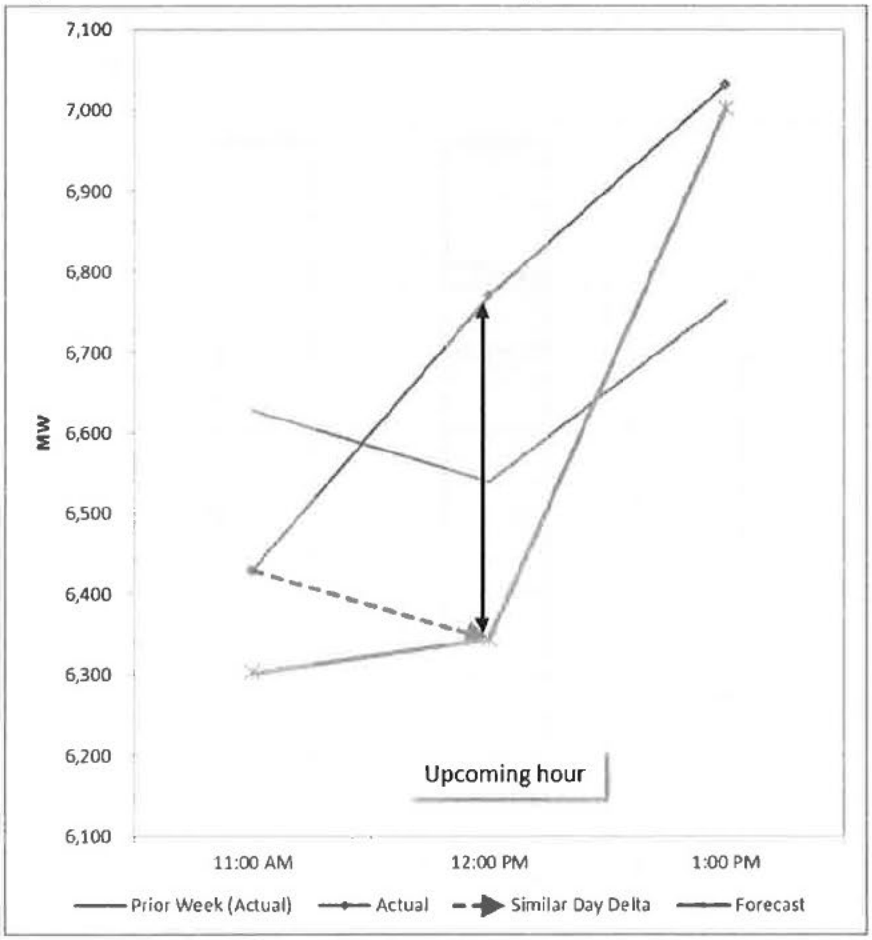
PacifiCorp maintains system balance by optimizing its operations to an hour-ahead load forecast every hour with changes in generation and market activity. This planning interval represents hourly changes in generation that are assessed roughly 20 minutes into each hour to meet a bottom-of-the-hour (i.e., 30 minutes after the hour) scheduling deadline. Taking into account the conditions of the present and the expected load and wind generation, PacifiCorp must schedule generation to meet demand with an expectation of how much higher or lower load may be. These activities are carried out by the group referred to as the real-time desk.

PacifiCorp's real-time desk updates the load forecast for the upcoming hour 40 minutes prior to the start of that hour. This forecast is created by comparing the load in the current hour to the load of a prior similar-load-shaped day. The hour-to-hour change in load from the similar day and hours (the load difference or "delta") is applied to the load for the current hour, and the sum is used as the forecast for the upcoming hour. For example, on a given Sunday, the PacifiCorp real-time desk operator may forecast hour-to-hour changes in load by referencing the hour-to-hour changes from the prior Sunday, which would be a similar-load-shaped day. If at 11:20 am, the hour-to-hour load change between 11:00 a.m. and 12:00 p.m. of the prior Sunday was five percent, the operator will use a five percent change from the current hour to be the upcoming hour's load following forecast.

For the calculation in this WIS, the hour-ahead load forecast used for calculating load following was modeled using the approximation described above with a shaping factor calculated using the day from one week prior, and applying a prior Sunday to shape any NERC holiday schedules. The differences observed between the actual hourly load and the load following forecasts comprised the load following deviations.

Figure H.2 shows an illustrative example of a load following deviation in August 2013 using operational data from PACE. In this illustration, the delta between hours 11:00 a.m. and 12:00 p.m. from the prior week is applied to the actual load at 11:00 a.m. on the "current day" to produce the hypothetical forecast of the load for the 12:00 p.m. ("upcoming") hour. That is, using the actual load at 11:00 a.m. (beginning of the purple line), the load forecast for the 12:00 p.m. hour is calculated by following the dashed red line that is parallel to the green line from the prior week. The forecasted load for the upcoming hour is the point on the blue line at 12:00 p.m. Since the actual load for the 12:00 p.m. hour (the point on the purple line at 12:00 p.m.) is higher than the forecast, the deviation (indicated by the black arrow) is calculated as the difference between the forecasted and the actual load for 12:00 p.m. This deviation is used to calculate the load following component reserve requirement for 12:00 p.m.

Figure H.2 – Illustrative Load Following Forecast and Deviation



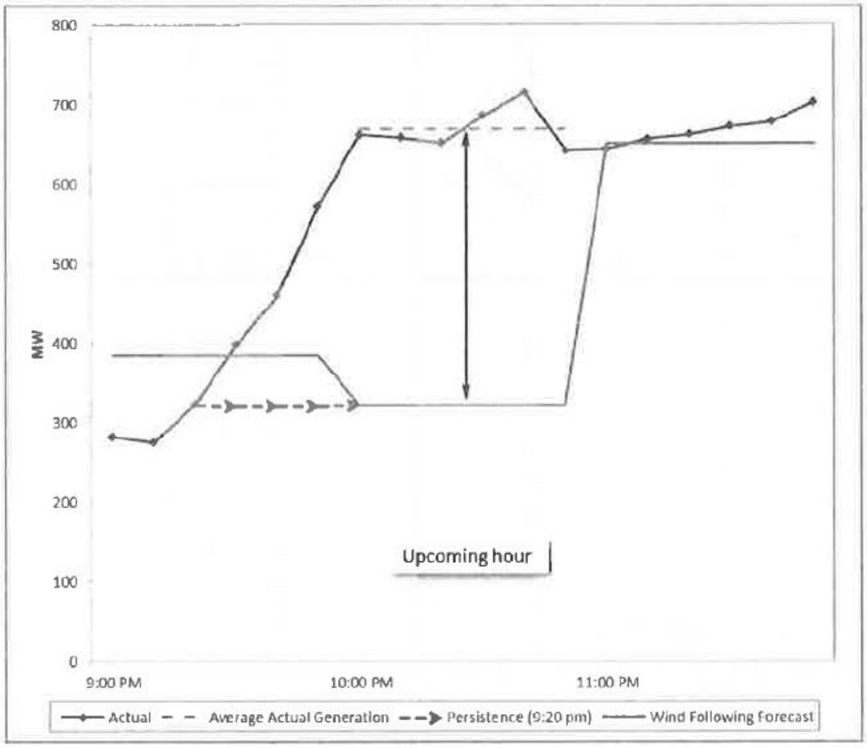
Hypothetical Wind Following Operational Forecast

The short term hourly operational wind forecast is based on the concept of persistence – using the instantaneous sample of the wind generation output at 20 minutes into the current hour as the forecast for the upcoming hour, and balancing the system to that forecast.

For the calculation in this WIS, the hour-ahead wind generation forecast for the "upcoming" hour used the 20th minute output from the "current" hour. For example, if the wind generation is producing 300 MW at 9:20 p.m. in PACE, then it is assumed that 300 MW will be generated between 10:00 p.m. and 11:00 p.m., that same day. The difference between the hourly average of the six 10-minute wind generation readings and the wind generation forecast comprised the wind following deviation for that hour.

Figure H.3 shows an illustrative example of a wind following deviation in July 2013 using operational data from PACE. In this illustration, the wind generation output at 9:20 p.m. (within the "current" hour) is the hour-ahead forecast of the wind generation for the 10:00 p.m. hour (the "upcoming" hour). That is, following persistence scheduling, the wind following need for the 10:00 p.m. hour is calculated by following the dashed red line starting from the actual wind generation on the purple line at 9:20 p.m. for the entire 10:00 p.m. hour (blue line). Since the average of the actual wind generation during the 10:00 p.m. hour (dotted green line) is higher than the wind following forecast, the deviation (indicated by the black arrow) is calculated as the difference between the wind following forecast and the actual wind generation for the 10:00 p.m. hour. This deviation is used to calculate the wind following component reserve requirement for 10:00 p.m.

Figure H.3 – Illustrative Wind Following Forecast and Deviation



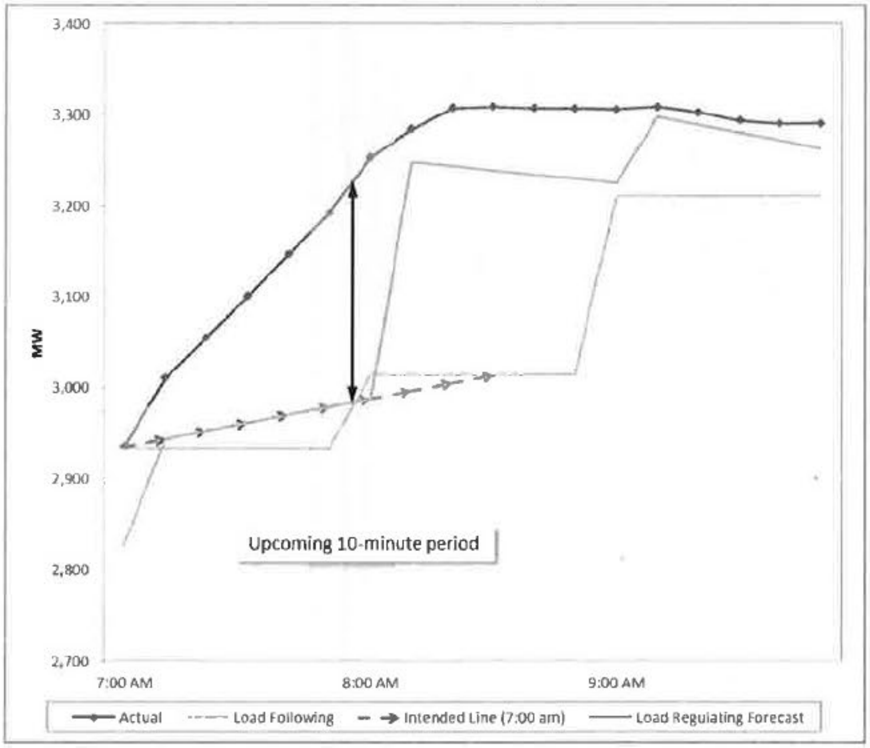
Hypothetical Load Regulating Operational Forecast

Separate from the variations in the hourly scheduled loads, the 10-minute load variability and uncertainty was analyzed by comparing the 10-minute actual load values to a line of intended schedule, represented by a line interpolated between the actual load at the top of the "current" hour and the hour-ahead forecasted load (the load following hypothetical forecast) at the bottom of the "upcoming" hour. The method approximates the real time operations process for each hour where, at the top of a given hour, the actual load is known, and a forecast for the next hour has been made.

For the calculation in this WIS, a line joining the two points represented a ramp up or down expected within the given hour. The actual 10-minute load values were compared to the portion of this straight line from the "current" hour to produce a series of load regulating deviations at each 10-minute interval within the "current" hour.

Figure H.4 shows an illustrative example of a load regulating deviation in November 2013 using operational data in PACW. In this illustration, the line of intended schedule is drawn from the actual load at 7:00 a.m. to the hour-ahead load forecast at 8:30 a.m. The portion of this line within the 7:00 a.m. hour becomes the load regulating forecast for that hour. That is, using the forecasted load for the 8:00 a.m. hour that was calculated for the load following hypothetical forecast, the line of intended schedule is calculated by following the dashed red line from the actual load at 7:00 a.m. (beginning of the purple line) to the point in the hour-ahead forecast (green line) at 8:30 a.m. The six 10-minute deviations within the 7:00 a.m. hour (one of which is indicated by the black arrow) are the differences between the actual 10-minute load readings (purple line) and the line of intended schedule. These deviations are used to calculate the load regulating component reserve requirement for the six 10-minute intervals within the 7:00 a.m. hour.

Figure H.4 – Illustrative Load Regulating Forecast and Deviation



Hypothetical Wind Regulating Operational Forecast

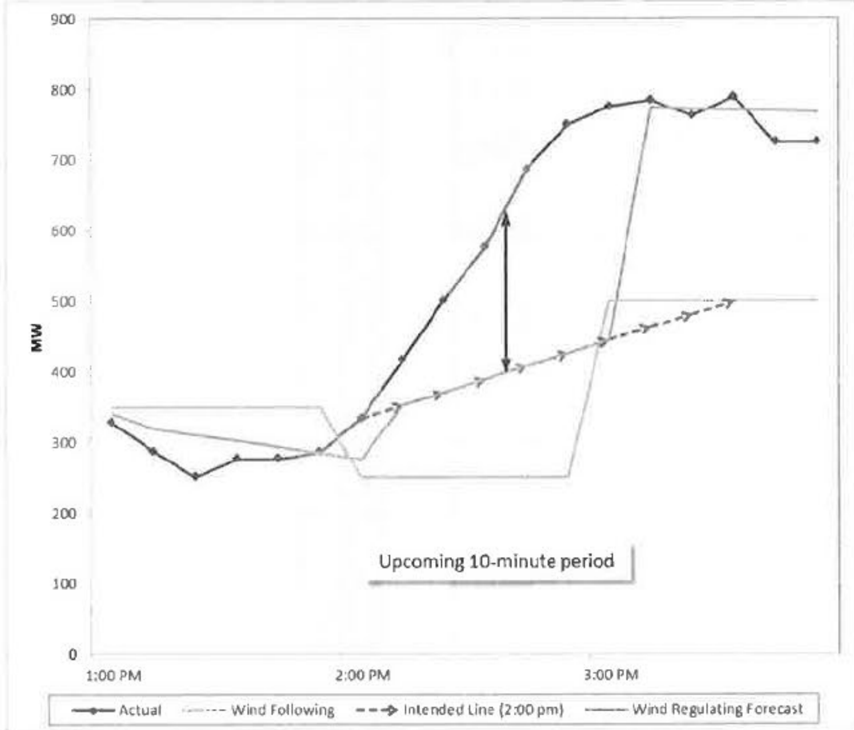
Similarly, the 10-minute wind generation variability and uncertainty was analyzed by comparing the 10-minute actual wind generation values to a line of intended schedule, represented by a line interpolated between the actual wind generation at the top of the "current" hour and the hour-ahead forecasted wind generation (the wind following hypothetical forecast) at the bottom of the "upcoming" hour.

For the calculation in this WIS, a line joining the two points represented a ramp up or down expected within the given hour. The actual 10-minute wind generation values were compared to the portion of this straight line from the "current" hour to produce a series of wind regulating deviations at each 10-minute interval within the "current" hour.

Figure H.5 shows an illustrative example of a wind regulating deviation in July 2013 using operational data in PACE. In this illustration, the line of intended schedule is drawn from the actual wind generation at 2:00 p.m. to the hour-ahead wind forecast at 3:30 p.m. The portion of this line within the 2:00 p.m. hour becomes the wind regulating forecast for that hour. That is, using the forecasted wind generation for the 3:00 p.m. hour that was calculated for the wind following hypothetical forecast, the line of intended schedule is calculated by following the dashed red line from the actual wind generation at 2:00 p.m. (beginning of the purple line) to the point in the hour-ahead forecast (green line) at 3:30 p.m. The six 10-minute deviations within the

2:00 p.m. hour (one of which is indicated by the black arrow) are the differences between the actual 10-minute wind generation readings (purple line) and the line of intended schedule (red line). These deviations are used to calculate the wind regulating component reserve requirement for the six 10-minute intervals within the 2:00 p.m. hour.

Figure H.5 – Illustrative Wind Regulating Forecast and Deviation



Analysis of Deviations

The deviations are calculated for each 10-minute interval in the Study Term and for each of the four components of regulation reserves (load following, wind following, load regulating, wind regulating). Across any given hourly time interval, the six 10-minute intervals within each hour have a common following deviation, but different regulating deviations. For example, considering load deviations only, if the load forecast for a given hour was 150 MW below the actual load realized in that hour, then a load following deviation of -150 MW would be recorded for all six of the 10-minute periods within that hour. However, as the load regulating forecast and the actual load recorded in each 10-minute interval vary, the deviations for load regulating vary. The same holds true for wind following and wind regulating deviations, in that the following deviation is recorded as equal for the hour, and the regulating deviation varies each 10-minute interval.

Since the recorded deviations represent the amount of unpredictable variation on the electrical system, the key question becomes how much regulation reserve to hold in order to cover the deviations, thereby maintaining system reliability. The deviations are analyzed by separating the deviations into bins by their characteristic forecasts for each month in the Study Term. The bins are defined by every 5th percentile of recorded forecasts, creating 20 bins for the deviations in each month for each component hypothetical operational forecast. In other words, each month of the Study Term has 20 bins of load following deviations, 20 bins of load regulating deviations, and the same for wind following and wind regulating.

As an example, Table H.6 depicts the calculation of percentiles (every five percent) among the load regulating forecasts for June 2013 using PACE operational data. For the month, the load ranged from 4,521 MW to 8,587 MW. A load regulating forecast for a load at 4,892 MW represents the fifth percentile of the forecasts for that month. Any forecast below that value will be in Bin 20, along with the respective deviations recorded for those time intervals. Any forecast values between 4,892 MW and 5,005 MW will place the deviation for that particular forecast in Bin 19.

Table H.6 – Percentiles Dividing the June 2013 East Load Regulating Forecasts into 20 Bins

Bin Number	Percentile	Load Forecast
	MAX	**8,587**
1	0.95	7,869
2	0.90	7,475
3	0.85	7,220
4	0.80	6,984
5	0.75	6,807
6	0.70	6,621
7	0.65	6,482
8	0.60	6,383
9	0.55	6,285
10	0.50	6,158
11	0.45	6,023
12	0.40	5,850
13	0.35	5,720
14	0.30	5,568
15	0.25	5,404
16	0.20	5,275
17	0.15	5,134
18	0.10	5,005
19	0.05	4,892
20	**MIN**	4,521

Table H.7 depicts an example of how the data are assigned into bins based on the level of forecasted load, following the definition of the bins in Table H.6.

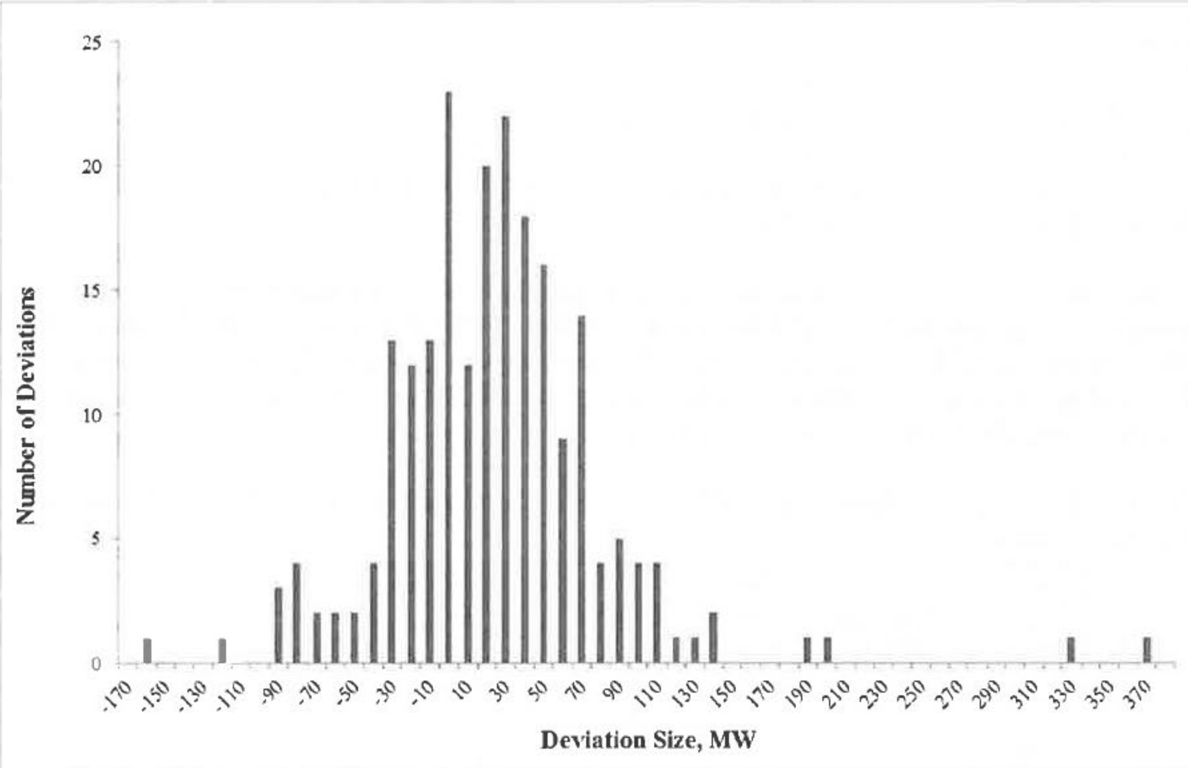
Table H.7 – Recorded Interval Load Regulating Forecasts and their Respective Deviations for June 2013 Operational Data from PACE

Date / Time	Load Regulation Forecast	Load Regulation Deviation	Bin Assignment
06/01/2013 6:00	4,755	88	20
06/01/2013 6:10	4,706	-67	20
06/01/2013 6:20	4,746	-13	20
06/01/2013 6:30	4,786	-36	20
06/01/2013 6:40	4,826	-26	20
06/01/2013 6:50	4,866	-46	20
06/01/2013 7:00	4,905	-46	19
06/01/2013 7:10	4,984	4	19
06/01/2013 7:20	5,016	-8	18
06/01/2013 7:30	5,048	-10	18
06/01/2013 7:40	5,081	16	18
06/01/2013 7:50	5,113	31	18
06/01/2013 8:00	5,145	12	17
06/01/2013 8:10	5,158	16	17
06/01/2013 8:20	5,182	-22	17
06/01/2013 8:30	5,207	-6	17
06/01/2013 8:40	5,231	4	17
06/01/2013 8:50	5,256	18	17
06/01/2013 9:00	5,280	10	16
06/01/2013 9:10	5,278	-30	16
06/01/2013 9:20	5,287	11	16
06/01/2013 9:30	5,295	2	16
06/01/2013 9:40	5,303	25	16
06/01/2013 9:50	5,311	-4	16

The binned approach prevents over-assignment of reserves in different system states, owing to certain characteristics of load and wind generation. For example, when the balancing area load is near the lowest value for any particular day, it is highly unlikely the load deviation will require substantial down reserves to maintain balance because load will typically drop only so far. Similarly, when the load is near the peak of the load values in a month, it is likely to go only a little higher, but could drop substantially at any time. Similarly for wind, when wind generation output is at the peak value for a system, there will not be a deviation taking the wind value above that peak. In other words, the directional nature of reserve requirements can change greatly by the state of the load or wind output. At high load or wind generation states, there is not likely to be a significant need for reserves covering a surprise increase in those values. Similarly, at the lowest states, there is not likely to be a need for the direction of reserves covering a significant shortfall in load or wind generation.

Figure H.6 shows a distribution of deviations gathered in Bin 14 for forecast load levels between 5,569 MW and 5,720 MW in June 2013. All of the deviations fall between -170 MW and +370 MW. Such deviations would need to be met by resources on the system in order to maintain the balance of load and resources. That is, when actual load is 170 MW lower than expected, there needs to be additional resources that are capable of being dispatched down, and when actual load is 370 MW higher than expected, there needs to be additional resources that are capable of being dispatched up to cover the increases in load.

Figure H.6 – Histogram of Deviations Occurring About a June 2013 PACE Load Regulating Forecast between 5,568 MW and 5,720 MW (Bin 14)



Up and down deviations must be met by operating reserves. To determine the amount of reserves required for load or wind generation levels in a bin, a tolerance level is applied to exclude deviation outliers. The bin tolerance level represents a percentage of component deviations intended to be covered by the associated component reserve. In the absence of an industry standard which articulates an acceptable level of tolerance, the Company must choose a guideline that provides both cost-effective and adequate reserves. These two criteria work against each other, whereby assigning an overly-stringent tolerance level will lead to unreasonably high wind integration costs, while an overly-lax tolerance level incurs penalties for violating compliance standards. Two relevant standards, CPS1 and BAAL, address the reliability of control area frequency and error. The compliance standard for CPS1 (rolling 12-month average of area frequency) is 100%, while the minimum compliance standard for BAAL is a 30-minute response. Working within these bounds and considering the requirement to maintain adequate, cost-effective reserves, the Company plans to a three-standard deviation (99.7 percent) tolerance in the calculation of component reserves, which are subsequently used to inform the need for regulating margin reserves in operations. In doing so, the Company strikes a balance between planning for as much deviation as allowable while managing costs, uncertainty, adequacy and reliability. Despite exclusion of extreme deviations with the use of the 99.7 percent tolerance, the Company's system operators are expected to meet reserve requirements without exception.

The binned approach is applied on a monthly basis, and results in the four component forecast values (load following, wind following, load regulating, wind regulating) for each 10-minute interval of the Study Period. The component forecasts and reserve requirements are then applied back to the operational data to develop summary level information for regulation reserve requirements, using the back casting procedure described below.

Back Casting

Given the development of component reserve requirements that are dependent upon a given system state, reserve requirements were assigned to each 10-minute interval in the Study Term according to their respective hypothetical operational forecasts to simulate the component reserves values as they would have happened in real-time operations. Doing so results in a total reserve requirement for each interval informed by the data.

To perform the back casts, component reserve requirements calculated from the bin analysis described above are first turned into reference tables. Table H.8 shows a sample (June 2013, PACE) reference table for load and wind following reserves at varying levels of forecasted load and wind generation, and Table H.9 shows a sample (June 2013, PACE) reference table for load and wind regulating reserves at varying forecast levels.

Table H.8 – Sample Reference Table for East Load and Wind Following Component Reserves (MW)

Bin	Up Reserve (MW)	**Load Forecast (MW)**	Down Reserve (MW)	Up Reserve (MW)	**Wind Forecast (MW)**	Down Reserve (MW)
	266	10000	283	358	5000	157
1	266	7841	283	358	1061	157
2	250	7528	192	348	940	213
3	200	7220	285	512	839	205
4	315	7005	294	298	755	290
5	262	6804	334	356	698	207
6	150	6626	321	198	627	231
7	280	6506	260	239	571	375
8	191	6381	212	332	502	308
9	147	6265	135	238	438	284
10	273	6168	99	195	395	374
11	237	6017	168	163	355	172
12	199	5859	338	166	302	241
13	279	5719	295	115	262	264
14	124	5574	151	114	226	203
15	87	5406	195	101	197	287
16	144	5264	171	84	163	326
17	179	5125	98	90	122	225
18	102	4991	86	44	78	242
19	87	4870	73	35	47	288
20	290	4505	63	41	-7	81
	290	0	63	41	-7	81

Table H.9 – Sample Reference Table for East Load and Wind Regulating Component Reserves

Bin	Up Reserve (MW)	Load Forecast (MW)	Down Reserve (MW)	Up Reserve (MW)	Wind Forecast (MW)	Down Reserve (MW)
	177	10000	261	373	10000	173
1	177	7869	261	373	1070	173
2	254	7475	183	459	935	228
3	161	7220	189	297	827	203
4	255	6984	222	277	762	306
5	271	6807	271	393	695	277
6	327	6621	253	233	628	219
7	232	6482	213	305	562	372
8	182	6383	164	279	508	225
9	179	6285	143	177	440	233
10	210	6158	158	172	394	406
11	258	6023	260	131	351	145
12	225	5850	448	134	305	168
13	237	5720	431	144	264	224
14	149	5568	353	112	229	158
15	163	5404	231	85	196	279
16	153	5275	104	74	162	494
17	96	5134	125	76	116	240
18	69	5005	111	44	82	94
19	51	4892	97	38	46	154
20	179	4521	87	21	-7	112
	179	0	87	21	-7	112

Each of the relationships recorded in the table is then applied to hypothetical operational forecasts. Building on the reference tables above, the hypothetical operational forecasts described in the previously sections were used to calculate a reserve requirement for each interval of historical operational data. This is clarified in the example outlined below.

Application to Component Reserves

For each time interval in the Study Term, component forecasts developed from the hypothetical forecasts are used, in conjunction with Table H.8 and Table H.9, to derive a recommended reserve requirement informed by the load and wind generation conditions. This process can be explained with an example using the tables shown above and hypothetical operational forecasts from June 2013 operational data for PACE. Table H.10 illustrates the outcome of the process for the load following and regulating components.

Table H.10 – Load Forecasts and Component Reserve Requirement Data for Hour-ending 11:00 a.m. June 1, 2013 in PACE

	East							
Time	Actual Load (10-min Avg) MW	Actual Load (Hourly Avg) MW	Following Forecast Load MW	Load Following Up Reserves Specified by Tolerance Level MW	Load Following Down Reserves Specified by Tolerance Level MW	Regulating Load Forecast MW	Load Regulating Up Reserves Specified by Tolerance Level MW	Load Regulating Down Reserves Specified by Tolerance Level MW
06/01/2013 10:00	5,337	5,395	5,344	144	171	5,319	153	104
06/01/2013 10:10	5,383	5,395	5,344	144	171	5,350	153	104
06/01/2013 10:20	5,386	5,395	5,344	144	171	5,363	153	104
06/01/2013 10:30	5,403	5,395	5,344	144	171	5,375	153	104
06/01/2013 10:40	5,433	5,395	5,344	144	171	5,388	153	104
06/01/2013 10:50	5,428	5,395	5,344	144	171	5,401	153	104

The load following forecast for this particular hour (hour ending 11:00 a.m.) is 5,344 MW, which designates reserve requirements from Bin 16 as depicted (with shading for emphasis) in Table H.8. Because the 5,344 MW load following forecast falls between 5,264 MW and 5,406 MW, the value from the higher bin, 144 MW, as opposed to 87 MW, is assigned for this period. Note the same following forecast is applied to each interval in the hour for the purpose of developing reserve requirements. The first 10 minutes of the hour exhibits a load regulating forecast of 5,319 MW, which designates reserve requirements from Table H.9, Bin 16. Note that the load regulating forecast changes every 10 minutes, and as a result, the load regulating component reserve requirement can change very ten minutes as well-although, this is not observed in the sample data shown above. A similar process is followed for wind reserves using Table H.11.

Table H.11 – Interval Wind Forecasts and Component Reserve Requirement Data for Hour-ending 11 a.m. June 1, 2013 in PACE

	East							
Time	Actual Wind (10-min Avg)	Actual Wind (Hourly Avg)	Following Forecast Wind:	Wind Follow Up Reserves Specified by Tolerance Level	Wind Follow Down Reserves Specified by Tolerance Level	East Wind Regulating Forecast:	Wind Regulating Up Reserves Specified by Tolerance Level:	Wind Regulating Down Reserves Specified by Tolerance Level:
06/01/2013 10:00	190	217	207	101	287	219	85	279
06/01/2013 10:10	208	217	207	101	287	193	74	494
06/01/2013 10:20	212	217	207	101	287	195	74	494
06/01/2013 10:30	231	217	207	101	287	198	85	279
06/01/2013 10:40	234	217	207	101	287	200	85	279
06/01/2013 10:50	226	217	207	101	287	203	85	279

The wind following forecast for this particular hour (hour ending 11:00 a.m.) is 207 MW, which designates reserve requirements from Bin 15 under wind forecasts as depicted in Table H.8. Note the following forecast is applied to each interval in the hour for developing reserve requirements. Meanwhile, the regulating forecast changes every 10 minutes. The first 10 minutes of the hour exhibits a wind regulating forecast of 219 MW, which designates reserve requirements from Bin 15 as depicted in Table H.9. Similar to load, the wind regulating forecast changes every 10 minutes, and as a result, the wind regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast (193 MW) shifts the wind regulating component reserve requirement from Bin 15 into Bin 16, per Table H.9, and the component reserve requirement changes accordingly.

The assignment of component reserves using component hypothetical operational forecasts as described above is replicated for each 10-minute interval for the entire Study Term. The load following reserves, wind following reserves, load regulating reserves, and wind regulating reserves are then combined into following reserves and regulating reserves. Given that the four component reserves are to cover different deviations between actual and forecast values, they are not additive. In addition, as discussed in the Company's 2012 WIS report, the deviations of load and wind are not correlated.[33] Therefore, for each time interval, the wind and load reserve requirements are combined using the root-sum-of-squares (RSS) calculation in each direction (up and down). The combined results are then adjusted as the appropriate system L_{10} is subtracted and the ramp added to obtain the final result:

$$\sqrt{Load\ Regulating_i^{\ 2} + Wind\ Regulating_i^{\ 2} + Load\ Following_i^{\ 2} + Wind\ Following_i^{\ 2}} - L_{10} + Ramp,$$

where i represents a 10-minute time interval. Assuming the ramp reserve for the east at 10:00 a.m. is 50 MW, and drawing from the first 10-minute interval in the example in Table H.10 and Table H.11.

Load $Regulating_i$ = 153 MW
Wind $Regulating_i$ = 85 MW
Load $Following_i$ = 144 MW
Wind $Following_i$ = 101 MW
East System L_{10} = 48 MW
East $Ramp_i$ = 50 MW,

The regulating margin for 10:00 a.m. is determined as:

$$\sqrt{153^2 + 85^2 + 144^2 + 101^2} - 48 + 50 = 251\ MW$$

In this manner, the component reserve requirements are used to calculate an overall reserve requirement for each 10-minute interval of the Study Term. A similar calculation is also made for the regulating margin pertaining only to the variability and uncertainty of load, while assuming zero reserves for the wind components. The incremental reserves assigned to wind generation are calculated as the difference between the total regulating margin requirement and the load-only regulating margin requirement.

[33] The discussion starts on page 111 of Appendix H in Volume II of the Company's 2012 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

Application of Regulating Margin Reserves in Operations

The methodology for estimating regulating margin requirements described above subsequently informs the projected regulating margin needs in operations. PacifiCorp applies the data from the reserve tables, as depicted in Table H.8 and Table H.9, to derive regulating margin requirements within its energy trading system, which is used to manage PacifiCorp's electricity and natural gas physical positions. As such, the regulating margin requirements derived as part of this wind integration study are used when PacifiCorp schedules system resources to cost effectively and reliably meet customer loads. In operations, scheduling system resources to meet regulating margin requirements ensures that PacifiCorp can meet the BAAL reliability standard. This standard is tied to real-time system frequency, and as this frequency fluctuates, real-time operators use regulating margin reserves to maintain or correct frequency deviations within the allowable 30-minute period, 100% of the time.

Determination of Wind Integration Costs

Wind integration costs reflect production costs associated with additional reserve requirements to integrate wind in order to maintain reliability of the system, and additional costs incurred with daily system balancing that is influenced by the unpredictable nature of wind generation on a day-ahead basis. To characterize how wind generation affects regulating margin costs and system balancing costs, PacifiCorp utilizes the Planning and Risk (PaR) model and applies the regulating margin requirements calculated by the method detailed in the section above.

The PaR model simulates production costs of a system by committing and dispatching resources to meet system load. For this study, PacifiCorp developed seven different PaR simulations. These simulations isolate wind integration costs associated with regulating margin reserves and system balancing practice. The former reflects wind integration costs that arise from short-term variability (within the hour and hour ahead) in wind generation and the latter reflects integration costs that arise from errors in forecasting wind generation on a day-ahead basis. The seven PaR simulations used in the WIS are summarized in Table H.12.

Table H.12 – Wind Integration Cost Simulations in PaR

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error	Comments
Regulating Margin Reserve Cost Runs						
1	2015	2015 Load Forecast	Expected Profile	Load	None	
2	2015	2015 Load Forecast	Expected Profile	Load and Wind	None	
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1						
System Balancing Cost Runs						
3	2015	2013 Day-ahead Forecast	2013 Day-ahead Forecast	Yes	None	Commit units based on day-ahead load forecast, and day-ahead wind forecast
4	2015	2013 Actual	2013 Actual	Yes	For Load and Wind	Apply commitment from Simulation 3
5	2015	2013 Actual	2013 Day-ahead Forecast	Yes	None	Commit units based on actual Load, and day-ahead wind forecast
6	2015	2013 Actual	2013 Actual	Yes	For Wind	Apply commitment from Simulation 5
7	2015	2013 Actual	2013 Actual	Yes	None	Commit units based on actual Load, and actual wind forecast
Load System Balancing Cost = System Cost from PaR Simulation 4, which uses the unit commitment from Simulation 3 based on day-ahead forecast load (and day-ahead wind) less System Cost from PaR Simulation 6, which uses the unit commitement from Simulation 5 based on actual load (and day-ahead wind)						
Wind System Balancing Cost = System Cost from PaR Simulation 6, which uses the unit commitment from Simulation 5 based on day-ahdead wind (and actual load) less System Cost from PaR Simulation 7, which commits units based on actual wind (and actual load)						

The first two simulations are used to determine operating reserve wind integration costs in forward planning timeframes. The approach uses "P50", or expected, wind generation profiles and forecasted loads that are applicable to 2015. [34] Simulation 1 includes only the load regulating margin reserves. Simulation 2 includes regulating margin reserves for both load and wind, while keeping other inputs unchanged. The difference in production costs between the two simulations determines the cost of additional reserves to integrate wind, or the intra-hour wind integration cost. The remaining five simulations support the calculation of system balancing costs related to committing resources based on day-ahead forecasted wind generation and load. These simulations were run assuming operation in the 2015 calendar year, applying 2013 load and wind data. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis, as well as the current resource portfolio.[35] PacifiCorp resources used in the simulations are based upon the 2013 IRP Update resource portfolio.[36]

Determining system balancing costs requires a comparison between production costs with day-ahead information as inputs and production costs with actual information as inputs. 2013 was the most recent year with the availability of these two types of data. Day-ahead wind generation forecasts for all owned and contracted wind resources were collected from the Company's wind forecast service provider, DNV GL.[37] For 2012 and 2013, DNV GL provided data sets for the historical day-ahead wind forecasts. The day-ahead load forecast was provided by the

[34] P50 signifies the probability exceedance level for the annual wind production forecast; at P50 generation is expected to exceed the assumed generation levels half the time and to fall below the assumed generation levels half the time.

[35] The Study uses the December 31, 2013 official forward price curve (OFPC).

[36] The 2013 Integrated Resource Update report, filed with the state utility commissions on March 31, 2014 is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/es/irp.html

[37] This is the same service provider as used by the Company previously, Garrad Hassan. Garrad Hassan is now part of DNV GL.

Company's load forecasting department. There are five PaR simulations to estimate daily system balancing wind integration costs, labeled as Simulations 3 through 7. In this phase of the analysis, PacifiCorp generation assets were committed consistent with a day-ahead forecast of wind and load, but dispatched against actual wind and load. To simulate this operational behavior, the five additional PaR simulations included the incremental reserves from Simulation 2 and the unit commitment states associated with simulating the portfolio with the day-ahead forecasts.

Load system balancing costs capture the difference between committing resources based on a day-ahead load forecast and committing resources based on actual load, while keeping inputs for wind generation unchanged. Similarly, wind system balancing costs capture the difference between committing resources based on day-ahead wind generation forecasts and committing resources based on actual wind generation, while keeping inputs for load unchanged. Simulation 3 determines the resource commitment for load system balancing and Simulation 5 determines the resource commitment for wind system balancing. The difference in production costs between Simulations 4 and 6 is the load system balancing cost due to committing resources using imperfect foresight on load. The difference in production cost between Simulations 6 and 7 is the wind system balancing cost due to committing resources using imperfect foresight on wind generation.

Table H.12 above is a revision from what was presented in the 2012 WIS. The revision was made to remove the impact of volume changes between day-ahead forecasts and actuals on production costs. Table H.13 lists the simulations performed in the 2012 WIS, which shows that wind system balancing costs were determined based on the change in production costs between Simulation 5 and Simulation 4. The wind system balancing costs are captured by committing resources based on a day-ahead forecast of wind generation, while operating the resources based on actual wind generation. However, between Simulation 4 and Simulation 5, the volume of wind generation is different. As a result, the production cost of Simulation 5 is impacted by changes in wind generation. Using the approach adopted in the 2014 WIS as discussed above isolates system balancing integration costs to changes unit commitment.

Table H.13 – Wind Integration Cost Simulations in PaR, 2012 WIS

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error
Regulating Margin Reserve Cost Runs					
1	2015	2015 Load Forecast	Expected Profile	No	None
2	2015	2015 Load Forecast	Expected Profile	Yes	None
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1					
System Balancing Cost Runs					
3	2015	2013 Day-ahead Forecast	2013 Day-ahead Forecast	Yes	None
4	2015	2013 Actual	2013 Day-ahead Forecast	Yes	For Load
5	2015	2013 Actual	2013 Actual	Yes	For Load and Wind
Load System Balancing Cost = System Cost from PaR simulation 4 (which uses the unit commitment from Simulation 3) less system cost from PaR simulation 3					
Wind System Balancing Cost = System Cost from PaR simulation 5 (which uses the unit commitment from Simulation 4) less system cost from PaR simulation 4					

Also different from the 2012 WIS, the regulating margin reserves are input to the PaR model on an hourly basis, after being reduced for the estimated benefits of participating in the EIM, as discussed in more detail below. Table H.14 shows the intra-hour and inter-hour wind integration costs from the 2014 WIS.

Table H.14 – 2014 Wind Integration Costs, $/MWh

	2014 WIS (2015$)
Intra-hour Reserve	$2.35
Inter-hour/System Balancing	$0.71
Total Wind Integration	**$3.06**

In the 2015 IRP process, the System Optimizer (SO) model uses the 2014 WIS results to develop a cost for wind generation services. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate the risk profiles of the portfolios in meeting load obligations, including incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with this wind study are used.

Sensitivity Studies

The Company performed several sensitivity scenarios to address recommendations from the TRC in its review of PacifiCorp's 2012 WIS. Each is discussed in turn below.

Modeling Regulating Margin on a Monthly Basis

As shown in Table H.10 and Table H.11, the component reserves and the total reserves are determined on a 10-minute interval basis. In the 2012 WIS, PacifiCorp calculated reserve requirements on a monthly basis by averaging the data for all 10-minute intervals in a month and applying these monthly reserve requirements in PaR as a constant requirement in all hours during a month. The TRC recommended that the reserve requirements could be modeled on an hourly basis to reflect the timing differences of reserves. In calculating wind integration costs for the 2014 WIS, the PacifiCorp modeled hourly reserve requirements as recommended by the TRC. Table H.15 compares wind integration costs from the 2012 WIS with wind integration costs from the 2014 WIS calculated using both monthly and hourly reserve requirements as inputs to the PaR model.

Table H.15 – Comparison of Wind Integration Costs Calculated Using Monthly and Hourly Reserve Requirements as Inputs to PaR, ($/MWh)

	2012 WIS Monthly Reserves (2012$)	**2014 WIS Hourly Reserves** (2015$)	**2014 WIS Monthly Reserves** (2015$)
Intra-hour Reserve	$2.19	$2.35	$1.66
Inter-hour/System Balancing	$0.36	$0.71	$0.74
Total Wind Integration	**$2.55**	**$3.06**	**$2.40**

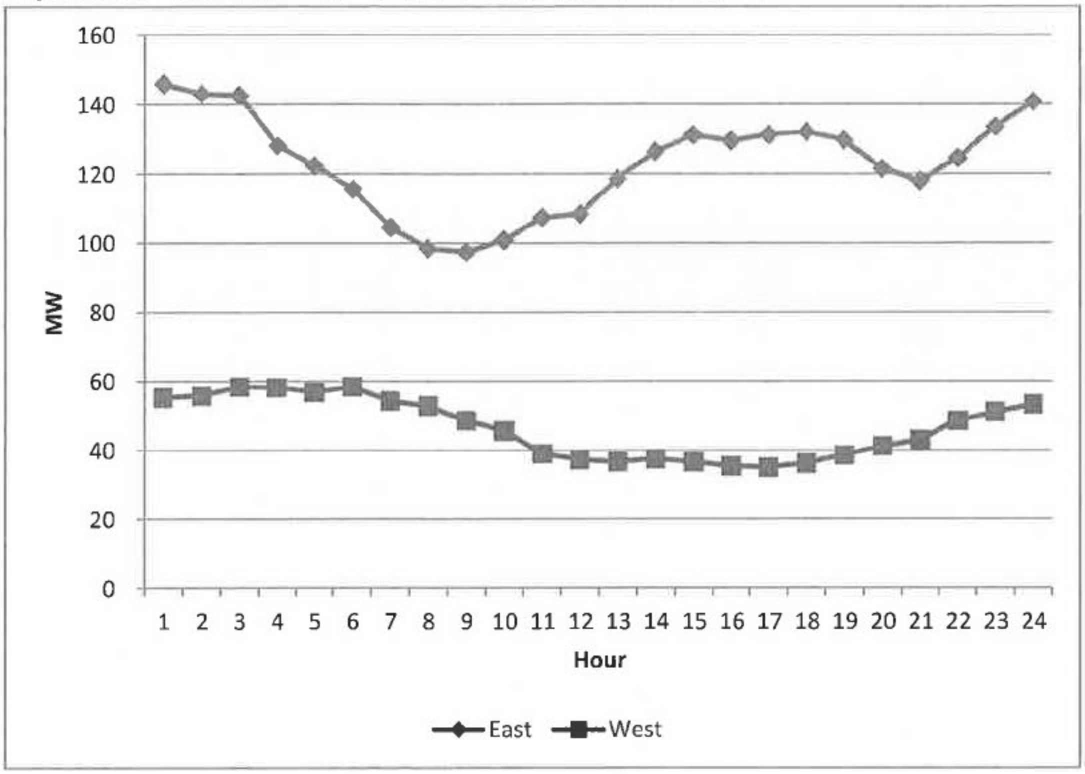
Compared to the 2012 WIS intra-hour reserve cost, the 2014 WIS intra-hour reserve cost is lower when reserves are modeled on a monthly basis in PaR. This is primarily due to the addition of a the Lake Side 2 combined-cycle plant, which can be used to cost effectively meet regulating margin requirements. Without Lake Side 2, the intra-hour reserve costs for the 2014 WIS Monthly Reserve sensitivity would increase from $1.66/MWh to $2.65/MWh. As compared to the 2012 WIS, which reported wind integration costs using monthly reserve data, the increase in cost is primarily due to increases in the market price for electricity and natural gas. Table H.16 compares the natural gas and electricity price assumptions used in the 2012 WIS to those used in the 2014 WIS.

Table H.16 – Average Natural Gas and Electricity Prices Used in the 2012 and 2014 Wind Integration Studies

Study	**Palo Verde High Load Hour Power ($/MWh)**	**Palo Verde Low Load Hour Power ($/MWh)**	**Opal Natural Gas ($/MMBtu)**
2012 WIS	$37.05	$25.74	$3.43
2014 WIS	$39.13	$29.31	$3.88

When modeling reserves on an hourly basis in PaR, the intra-hour reserve cost is higher than when modeling reserves on a monthly basis. This is due to more reserves being shifted from relatively lower-priced hours to relatively higher-priced hours. Figure H.7 shows the average profiles of wind regulating margin reserves from 2013.

Figure H.7 – Average Hourly Wind Reserves for 2013, MW



Separating Regulating and Following Reserves

In its review of the 2012 WIS, the TRC recommended treating categories of reserves differently by separating the component reserves of regulating, following and ramping. That is, instead of modeling regulating margin as:

$$\sqrt{Load\ Regulating_i^{\,2} + Wind\ Regulating_i^{\,2} + Load\ Following_i^{\,2} + Wind\ Following_i^{\,2}} - L_{10} + Ramp,$$

The TRC recommendation requires calculating regulating reserves and following reserves using two separate calculations:

$$Regulating\ Reserves = \sqrt{Load\ Regulating_i^{\,2} + Wind\ Regulating_i^{\,2}} - L_{10}, and$$

$$Following\ Reserves = \sqrt{Load\ Following_i^{\,2} + Wind\ Following_i^{\,2}} + Ramp.$$

Because regulating reserves are more restrictive than following reserves (fewer units can be used to meet regulating reserve requirements), the L_{10} adjustment is applied to the regulating reserve calculation. Ramp reserves can be met with similar types of resources as following reserves, and therefore, are combined with following reserves.

The impact of separating the component reserves as outlined above is to increase the total reserve requirement required on PacifiCorp's system. Table H.17 shows the total reserve requirement when the separately calculated regulating and following reserves are summed as compared to the total reserves combined using one RSS equation. The total reserve requirement, when calculated separately, is over 30% higher than the reserve requirement calculated from a single RSS equation. This is a significant increase in the amount of regulation reserves that is inconsistent with how the Company's resources are operated and dispatched. As a result, PacifiCorp did not evaluate this sensitivity in PaR.

Table H.17 – Total Load and Wind Monthly Reserves, Separating Regulating and Following Reserves (MW)

	Combined		Regulating		Following		Total	
	West	East	West	East	West	East	West	East
Jan	238	400	107	196	211	354	318	550
Feb	212	363	100	182	187	318	287	500
Mar	219	357	97	179	202	313	299	492
Apr	240	422	123	224	208	362	331	586
May	192	400	84	205	180	348	264	553
Jun	183	462	70	240	179	393	249	633
Jul	219	427	88	180	206	391	294	572
Aug	220	428	90	188	206	388	296	576
Sep	210	392	100	171	188	361	287	533
Oct	153	335	75	159	131	301	206	461
Nov	301	438	165	228	249	375	414	603
Dec	274	433	122	216	251	375	373	592

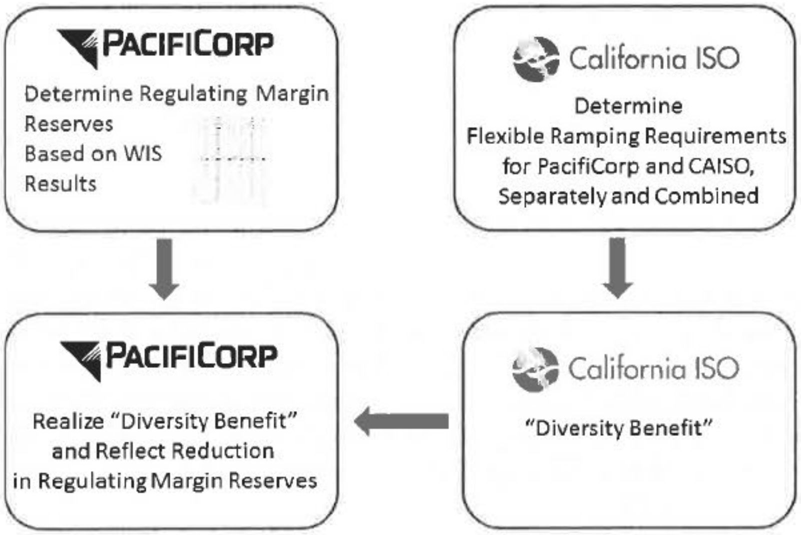
Energy Imbalance Market (EIM)

EIM is an energy balancing market that optimizes generator dispatch between PacifiCorp and the CAISO every five minutes via the existing real-time dispatch market functionality. PacifiCorp and the CAISO began a phased implementation of the EIM on October 1, 2014, when EIM was activated to allow the systems that will operate the market to interact under realistic conditions, allowing PacifiCorp to submit load schedules and bid resources into the EIM and allowing the CAISO to use its automated system to generate dispatch signals for resources on PacifiCorp's control areas. The EIM is expected to be fully operational November 1, 2014.

Once EIM becomes fully operational, PacifiCorp must provide sufficient flexible reserve capacity to ensure it is not leaning on other participating balancing authorities in the EIM for reserves. The intent of the EIM is that each participant in the market has sufficient capacity to meet its needs absent the EIM, net of a CAISO calculated reserves diversity benefit. In this manner, PacifiCorp must hold the same amount of regulating reserve under the EIM as it did prior to the EIM, but for a calculated diversity benefit.[38] Figure H.8 illustrates this process.

[38] Under the EIM, base schedules are due 75 minutes prior to the hour of delivery. The base schedules can be adjusted at 55 minutes and 40 minutes prior to the delivery hour in response to CAISO sufficiency tests. This is consistent with pre-EIM scheduling practices, in which schedules are set 40 minutes prior to the delivery hour.

Figure H.8 – Energy Imbalance Market



The CAISO will calculate the diversity benefit by first calculating the reserve requirement for each individual EIM participant and then by comparing the sum of those requirements to the reserve requirement for the entire EIM area. The latter amount is expected to be less than the sum due to the portfolio diversification effect of load and variable energy resource (wind and solar) variations. The CAISO will then allocate the diversity benefit among all the EIM participants. Finally, PacifiCorp will reduce its regulating reserve requirement by its allocation of diversity benefit.

In its 2013 report, Energy and Environmental Economics (E3) estimated the following benefits of the EIM system implementation:[39]

- PacifiCorp could see a 19 to 103 MW reduction in regulating reserves, depending on the level of bi-directional transmission intertie made available to EIM;
- Interregional dispatch savings: Five-minute dispatch efficiency will reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
- Intraregional dispatch savings: PacifiCorp generators will dispatch more efficiently through the CAISO's automated system (nodal dispatch software), including benefits from more efficient transmission utilization;
- Reduced flexibility reserves by aggregating the two systems' load, wind, and solar variability and forecast errors;
- Reduced renewable energy curtailment by allowing BAAs to export or reduce imports of renewable generation when it would otherwise need to be curtailed.

Based on the E3 study, the relationship between the benefit in reducing regulating reserve requirements and the transfer capability of the intertie is shown in Table H.18.

[39] http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

Table H.18 – Estimated Reduction in PacifiCorp's Regulating Margin Due to EIM

Transfer Capability (MW)	Reduction in Flexible Reserves (MW)
100	19
400	78
800	103

Given that the transfer capacity in this WIS is assumed to be approximately 330 MW, through owned and contracted rights, the reduction in regulating reserve is assumed to be approximately 65 MW. This benefit is applied to reduce the regulating margin on PacifiCorp's west BAA because the current connection between PacifiCorp and CAISO is limited to the west only. Table H.19 summarizes the impact of estimated EIM regulating reserve benefits assuming monthly application of reserves in PaR to be comparable to how the 2012 WIS wind integration costs were calculated. The sensitivity shows that EIM regulating reserve benefits reduce wind integration costs by approximately $0.21/MWh.

Table H.19 – Wind Integration Cost with and without EIM Benefit, $/MWh

	2012 WIS (2012$)	2014 WIS With EIM Benefits (2015$)	2014 WIS Without EIM Benefits (2015$)
Intra-hour Reserve Cost	$2.19	$1.66	$1.87
Inter-hour/System Balancing Cost	$0.36	$0.74	$0.74
Total Wind Integration Cost	**$2.55**	**$2.40**	**$2.61**

Summary

The 2014 WIS determines the additional reserve requirement, which is incremental to the mandated contingency reserve requirement, needed to maintain moment-to-moment system balancing between load and generation while integrating wind resources into PacifiCorp's system. The 2014 WIS also estimates the cost of holding these incremental reserves on its system.

PacifiCorp implemented the same methodology developed in the 2012 WIS for calculating regulating reserves for its 2014 WIS, and implemented recommendations from the TRC to implement hourly reserve inputs when determining wind integration costs using PaR. Also consistent with TRC recommendations, PacifiCorp further incorporated regulation reserve benefits associated with EIM in its wind integration costs. Table H.20 compares the results of the 2014 WIS total reserves to those calculated in the 2012 WIS.

Table H.20 – Regulating Margin Requirements Calculated for PacifiCorp's System (MW)

Year	Reserve Component	West BAA	East BAA	Ramp	Combined
2011 (2012 WIS)	Load-Only Regulating Reserves	99	176	119	394
	Incremental Wind Reserves	50	126	9	185
	Total Reserves	**149**	**302**	**128**	**579**
2012	Load-Only Regulating Reserves	95	186	119	400
	Incremental Wind Reserves	71	123	11	206
	Total Reserves	**166**	**309**	**130**	**606**
2013 (2013 WIS)	Load-Only Regulating Reserves	119	203	119	441
	Incremental Wind Reserves	51	123	12	186
	Total Reserves	**169**	**326**	**131**	**626**

The anticipated implementation of EIM with the CAISO is expected to reduce PacifiCorp's reserve requirements due to the diversification of resource portfolios between the two entities. PacifiCorp estimated the benefit of EIM regulating reserve benefits based on a study from E3. The assumed benefits reduce regulating reserves in PacifiCorp's west BAA by approximately 65 MW from the regulating reserves shown in the table above, which lowers wind integration costs by approximately $0.21/MWh.

Two categories of wind integration costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour reserve requirements, and one for inter-hour system balancing. Table H.21 compares 2014 wind integration costs, inclusive of estimated EIM benefits, to those published in the 2012 WIS.

Table H.21 – 2014 WIS Wind Integration Costs as Compared to 2012 WIS, $/MWh

	2012 WIS (2012$)	**2014 WIS** (2015$)
Intra-hour Reserve	$2.19	$2.35
Inter-hour/System Balancing	$0.36	$0.71
Total Wind Integration	**$2.55**	**$3.06**

The 2014 WIS results are applied to the 2015 IRP portfolio development process as a cost for wind generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. After resource portfolios are developed using the SO model, the PaR model is used to evaluate the risk profiles of the portfolios in meeting load obligations, including incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with the 2014 WIS are used.

Date: December 22, 2014

To: PacifiCorp

From: 2014 Wind Integration Study Technical Review Committee (TRC)

Subject: PacifiCorp 2014 Wind Integration Study Technical Memo

Background

The purpose of the PacifiCorp 2012 wind integration study as identified by Pacificorp in the Introduction to the 2015 IRP, Appendix H – Draft Wind Integration Study, is to estimate the operating reserves required to both maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. PacifiCorp must provide sufficient operating reserves to meet NERC's balancing authority area control error limit (BAL-001-2) at all times, incremental to contingency reserves, which PacifiCorp maintains to comply with NERC standard BAL-002-WECC-2.[1,2] Apart from disturbance events that are addressed through contingency reserves, these incremental operating reserves are necessary to maintain area control error[3] (ACE), due to sources outside direct operator control including intra-hour changes in load demand and wind generation, within required parameters. The wind integration study estimates the operating reserve volume required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas (BAAs) and estimates the incremental cost of these operating reserves.

PacifiCorp currently serves 1.8 million customers across 136,000 square miles in six western states. According to a company fact sheet available at http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/PC-FactSheet-Final_Web.pdf, PacifiCorp's generating plants have a net capacity of 10,595 MW, including about 1,900

[1] NERC Standard BAL-001-2: http://www.nerc.com/files/BAL-001-2.pdf

[2] NERC Standard BAL-002-WECC-2 (http://www.nerc.com/files/BAL-002-WECC-2.pdf), which became effective October 1, 2014, replaced NERC Standard BAL-STD-002, which was in effect at the time of this study.

[3] "Area Control Error" is defined in the NERC glossary here: http://www.nerc.com/pa/stand/glossary of terms/glossary_of_terms.pdf

MW of owned and contracted wind capacity, which provides approximately 8% of PacifiCorp's annual energy. PacifiCorp operates two BAAs in WECC, referenced as PACE (PacifiCorp East) and PACW (PacifiCorp West). The BAAs are interconnected by a limited amount of transmission, and the two BAAs are operated independently at the present time, so wind generation in each BAA is balanced independently.[4] PacifiCorp has experienced continued wind growth in each BAA, and has been requested to update its wind integration study as part of its IRP. The total amount of wind capacity in PacifiCorp's BAAs, which was included in the 2014 wind integration study, was 2,544 MW.

TRC Process

The Utility Variable-Generation Integration Group (UVIG) has encouraged the formation of a Technical Review Committee (TRC) to offer constructive input and feedback on wind integration studies conducted by industry partners for over 10 years. The TRC is generally formed from a group of people who have some knowledge and expertise in these types of studies, can bring insights gained in previous work, have an interest in seeing the studies conducted using the best available data and methods, and who will stay actively engaged throughout the process. Over time, the UVIG has developed a set of principles which is used to guide the work of the TRC. A modified version of these principles was used in the conduct of this study, and the same version was used for the conduct of the TRC process for the 2012 wind integration study. A copy is included as an attachment to this memo. The composition of the TRC for the 2014 PacifiCorp study was as follows:

- Andrea Coon - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- Matt Hunsaker - Manager, Operations for the Western Electricity Coordinating Council (WECC)
- Michael Milligan – Principal Researcher for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory (NREL)
- J. Charles Smith - Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Robert Zavadil - Executive Vice President of Power Systems Consulting, EnerNex

The TRC was provided with a study presentation in July of 2014, and met by teleconference on 2 occasions during the course of the study, which was completed in November 2014. PacifiCorp provided presentations on the status and results of the work on the teleconferences, with periodic updates

[4] PacifiCorp and the CAISO began operating an energy imbalance market (EIM) on Oct. 1, 2014, which will likely make wind integration somewhat easier. With the EIM, there would seem to be more impetus for this policy to be reviewed and potentially revised going forward. The TRC recommends that this topic be explored in future work.

during the course of the study, and engaged with the TRC in a robust discussion throughout the work. The teleconferences were followed up with further clarifications and responses to requests for additional information. While the conclusions appear justified by the results of the study, the TRC review should not be interpreted as a substitute for the usual PUC review process.

Introduction

The Company should be acknowledged for the diligent efforts it made in implementing the recommendations by the TRC from the 2012 wind integration study in the 2014 study, as summarized in Table H.1. For example, the company modeled the reserve requirements on an hourly basis in the production cost model, rather than on a monthly average basis; the regulating margin reserve volumes accounted for estimated benefits from PacifiCorp's participation in the energy imbalance market (EIM) with the California Independent System Operator (CAISO); and a discussion on the selection of a 99.7% exceedance level when calculating regulation reserve needs was provided, including a description of how the WIS results inform the amount of regulation reserves planned for operations. Sensitivity studies were performed, including the modeling of the regulating reserves on a monthly basis, and demonstrating the impact of separating the reserves into different categories. The 2014 wind integration study report thoroughly documents the company's analysis.

As pointed out in the report, there is a small but meaningful difference in the integration costs between the 2012 study and the 2014 study. The 2012 value of $2.55/MWh of wind generation, using monthly reserves in PaR, is slightly less than the 2014 value of $3.06/MWh, using hourly reserves in the Planning and Risk (PaR) production cost model, with the major difference attributed to the modest increase in the cost of electricity and natural gas. When modeling reserves on an hourly basis in PaR, the intra-hour reserve cost is higher than when modeling reserves on a monthly basis. This is due to more reserves being shifted from relatively lower-priced hours to relatively higher-priced hours.

Analytical Methodology

- The first paragraph on p. 24 of the revised Appendix H, entitled "Application of Regulating Margin Reserves in Operations" is a critical aspect of this study, albeit a little late to the interactions between Pacificorp and the TRC. In effect, it means that the results of this study are and have been applied in operations, which is very unique in the universe of wind integration analysis since nearly all other studies are forward looking and utilize synthesized data and other assumptions. While this paragraph sufficiently addresses the points raised by the TRC in the late summer of 2014, it should receive more prominence in the report. A comparison of the interaction between the 2012 study methodology and PacifiCorp operations with the 2014 study methodology and Pacificorp operations should be included at the front of the document.

Assumptions

- The assumptions generally seem reasonable. PAC does a good job of laying out the process they use for the modeling and analysis. They have also provided discussion of the previous suggestions (from the 2012) study made by the TRC.
- The report addresses the issue of the 99.7% coverage of variability, and says that the operators are expected to have sufficient reserves to cover all variability all of the time. It would be interesting to contrast the company's policy of ensuring 100% reserve compliance with actual system performance. In the November TRC call there was some helpful discussion on this issue. One item discussed was that using 99.7% provides some margin of error in case a lower value, such as 95%, is used in the study but insufficient if the actual variability of wind/load were to increase. It would be nice to see this discussion reflected in the report, which would provide some additional justification for the 99.7 percentile. The reason this point is raised is to magnify the point that PAC makes in the report; that there is a tradeoff between economics and reliability. Holding the system to an extremely high effective CPS performance will be somewhat costly, and it is not clear what impact this is having on wind integration costs.
- The use of actual historical wind production data is excellent, and something that many studies are unable to do. This means that the PAC study is somewhat unique and PAC is to be commended for doing this work. At the same time, the report provides some illumination on the difficulties in using actual data, because data recovery rates can compromise the time series. PAC has done a good job in analyzing and correcting these inevitable data gaps, and this should not have a significant impact on the study results.

Results

- Table H.15 documents a comparison of the monthly versus hourly reserve modeling, and shows that a constant monthly reserve is less costly than reserves modeled on an hourly basis. The explanation provided is useful, but may leave out some factors such as non-linearity in reserve supply curve. In addition, the shifting of reserves from lower price hours to higher price hours only seems to apply to the East area, as the West area exhibits the opposite characteristic.

Discussion and Conclusions

- Table H.17 shows that the total reserves increase with consideration of regulation and following separately. It should be noted that while the arithmetic sum of the reserves does increase, it would not necessarily lead to higher costs as some of the following reserve could be obtained from non-spinning and quick-start resources which cost little to have on standby for such purpose.
- Based on the information provided by PacifiCorp, the methodology used in the wind integration study appears to be reasonable. Based on the draft study report, the findings and conclusions

appear sound. The findings appear to be useful to inform the Integrated Resource Planning process.

Recommendations for Future Work

Wind Integration modeling presented is unique in how it is integrated with the operating process at PacifiCorp. There are some sensitivity studies which could be done to shed additional light on the results and provide some useful insights:

- Future work should explore balancing area cooperation between PACE and PACW under the EIM framework.
- Regulating margin implies reserve capacity available on very short notice (ten minute or less). The ramping and following reserve categories do not all require fast response. Future sensitivity studies could be done to compare the results from PaR to use of the RSS formula.
- It might be useful to perform some additional sensitivities on natural gas price. For example, integration costs would be expected to increase with gas prices, yet at higher gas prices PAC would be getting a larger benefit from wind energy.
- A sensitivity analysis with carbon tax assumptions could also provide some useful insight and results.

Concurrence provided by:

Andrea Coon – Director of WREGIS, WECC

Matt Hunsaker - Manager, Operations, WECC

Michael Milligan - Principal Researcher, Transmission and Grid Integration Team, NREL

J. Charles Smith - Executive Director, UVIG

Robert Zavadil - Executive Vice President, EnerNex

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/903 to Cross-Examination Statement

Testimony of Bradly G. Mullins Filed with the Washington Utilities and Transportation Commission in Docket UE-140762 (Oct. 10, 2014)

August 18, 2015

pricing" proposal falls short of isolating the costs solely attributable to Washington's renewable energy policies and should be rejected.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO OUT-OF-STATE QF RESOURCES.

A. I recommend that the Commission reject the Company's proposals to include out-of-state QF resources in Washington NPC. The Commission's current jurisdictional allocation methodology is fair, just, reasonable and in the public interest. This results in a $43.3 million reduction to WCA power costs, with $10.0 million allocated to Washington.

B. EIM Power Cost Benefits, Generally

Q. HOW DO YOU PROPOSE TO QUANTIFY EIM BENEFITS IN THE TEST PERIOD?

A. As discussed above, I propose to reflect both the costs and benefits of the EIM in the Company's revenue requirement. While the costs of joining and participating in the EIM were described above, the benefits are derived from a reduction in overall NPC. In a proceeding before the Oregon Public Utilities Commission ("OPUC"), the Company argued that a study performed by Energy and Environmental Economics, Inc. ("E3"),[56] which quantified the NPC benefits of the EIM, demonstrated that its decision to join the EIM was prudent.[57] I propose to use the same E3 study, attached as Exh. No.___(BGM-5), to quantify the NPC impacts of the EIM in the rate period. The benefits are discussed as an individual modeling adjustment below, which collectively support including EIM

56/ See Exh. No.___(BGM-5) (PacifiCorp-ISO Energy Imbalance Market Benefits, Energy and Environmental Economics, Inc. (Mar. 13, 2013)). A copy of the E3 Report can also be found at http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.

57/ See Exh. No.___(BGM-6) at 24:21-24.

benefits in NPC of $21.8 million on a WCA basis, with $5.1 million allocated to Washington.

Q. WHY SHOULD THE E3 STUDY BE USED TO ESTABLISH EIM BENEFITS IN THE TEST PERIOD?

A. The Company relied on the E3 study when it decided to join the EIM and has relied on the study results as evidence that its decision to join the EIM was prudent.[58/] Given that the Company believes the E3 study is sufficient to support the prudence of its decision to join the EIM, it should also be sufficient to establish the level of EIM benefits for ratemaking. Just as the Company relies on the 2012 Wind Integration Study to capture the wind integration costs modeled in GRID, the E3 study is an appropriate starting point to determine how test period NPC will be impacted by the operational changes associated with the EIM.

Q. WILL YOU PROVIDE AN OVERVIEW OF THE E3 STUDY?

A. The E3 study was issued jointly by the Company and the Cal-ISO on March 13, 2013. It was commissioned to examine the benefits of a potential EIM between the Company and the Cal-ISO. The study, which developed a range of benefits based on several uncertain parameters, evaluated benefits attributable to the following categories:

> 1. Interregional dispatch savings, by realizing the efficiency of combined 5-minute dispatch, which would reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
>
> 2. Intraregional dispatch savings, by enabling PacifiCorp generators to be dispatched more efficiently through the [Cal-

58/ Id.

ISO's] automated system (nodal dispatch software), including benefits from more efficient transmission utilization;

3. Reduced flexibility reserves, by aggregating the two systems' load, wind, and solar variability and forecast errors; and

4. Reduced renewable energy curtailment, by allowing [Balancing Authorities] to export or reduce imports of renewable generation when it would otherwise need to be curtailed.[59/]

Q. WHAT RANGE OF BENEFITS DID THE E3 STUDY FORECAST FOR THE COMPANY?

A. The range of benefits forecast for the Company was $10.5 million to $54.4 million in 2012 dollars, represented in Table 3, below.[60/]

TABLE 3
PacifiCorp EIM Benefits in E3 Study

Table 6. Attribution of EIM benefits to PacifiCorp in 2017 (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
Interregional dispatch	$7.0	$5.5	$11.2	$8.9	$11.2	$8.9
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$1.2	$6.1	$3.2	$14.9	$3.9	$22.5
Renewable curtailment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total benefits	**$10.5**	**$34.6**	**$16.7**	**$46.8**	**$17.4**	**$54.4**

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

Q. DID THE E3 STUDY INCLUDE ALL OF THE EXPECTED BENEFITS ASSOCIATED WITH THE EIM?

A. No. The E3 study was performed on an hourly basis and excluded within-hour dispatch benefits.[61/] The within-hour dispatch benefits, which represent reserve savings and market optimization resulting from participation in sub-hourly markets, have been

[59/] Exh. No.___(BGM-5) at 6-7.
[60/] Id. at 35.
[61/] Id. at 37.

demonstrated to be material. For example, a study performed by National Renewable Energy Laboratory ("NREL") included within-hour dispatch benefits and forecast PacifiCorp benefits of \$180 million,[62] more than three times the amount of benefits forecast in the E3 study. While it was performed to analyze an EIM that encompassed the entire western interconnection, the NREL study is an indication that the inter-hour dispatch benefits likely represent a material portion of the EIM benefits the Company will be capable of achieving.

Q. ARE THE E3 STUDY BENEFITS REPRESENTATIVE OF BENEFITS THAT WILL BE ACHIEVED IN THE RATE PERIOD?

A. Yes. Members of the Southwest Power Pool Regional Transmission Organization ("SPP") have participated in an EIM since February 2007. Following the implementation of its EIM, the SPP commissioned a study to determine the benefits achieved in the first year of operations.[63] According to the report, the first-year benefits associated with the SPP EIM were approximately 20 percent higher than the benefits estimated by the studies performed prior to the start of the market.[64] This suggests that the benefits achieved in the rate period could be even greater than the benefits presented in the E3 study.

62/ Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection, NREL (Mar. 2013). For the \$180 million figure, see NREL/Plexos Analysis of the Proposed EIM in the Western Interconnection: Individual BA Results, NREL at 39 (July 24, 2012). Copies of these reports are available online at http://westernenergyboard.org/energy-imbalance-market/documents/.

63/ SPP, Market Monitoring Unit and External Market Advisor, Report to SPP Board of Directors/Members Committee, Estimation of Net Trade Benefits from EIS Market at 1 (Apr. 22, 2008). A copy of the report is available at http://www.spp.org/publications/EIS%20Trade%20benefit%20report.pdf.

64/ Id.

Q. BASED ON THE RANGE PRESENTED IN THE E3 STUDY, HOW HAVE YOU DETERMINED THE LEVEL OF BENEFITS TO APPLY IN THE RATE PERIOD?

A. I have used the E3 study as a starting point to determine how to modify the Company's GRID modeling of NPC to reflect the operational benefits that will accrue in the rate period as a result of joining the EIM. The modeling has been modified to capture each of the benefits categories presented in the E3 study. My analysis also includes an adjustment to account for within-hour dispatch benefits which, as discussed above, were excluded from the E3 study.

C. Interregional EIM Dispatch Savings

Q. HOW DO YOU PROPOSE TO MODEL THE INTERREGIONAL DISPATCH SAVINGS ASSOCIATED WITH THE EIM IN THE TEST PERIOD?

A. The level of interregional dispatch savings expected in the rate period can be derived directly from the E3 study. Because the range of EIM benefits presented in the E3 study for each benefit category is sensitive to several key assumptions, the amount attributable to the test period can be ascertained by selecting the assumptions that most accurately represent what is known about the test period at this time. In addition, because the E3 study benefits were representative of the Company's entire system—both WCA and Eastern Control Area ("ECA")—I propose to allocate the interregional dispatch savings in proportion to the loads of the WCA and ECA. The result is an approximate $4.0 million reduction to WCA NPC, with $913,257 allocated to Washington.

Q. WHAT ARE THE STUDY PARAMETERS THAT YOU RELIED ON TO ARRIVE AT THIS LEVEL OF BENEFITS?

A. Interregional Dispatch Savings in the E3 study were sensitive to two key variables: EIM transfer capability and hydro contribution to flexibility reserves.

Q. WHAT ASSUMPTION DID YOU RELY ON FOR EIM TRANSFER CAPABILITY IN THE TEST PERIOD?

A. PacifiCorp has several interconnections and contract transmission rights with the Cal-ISO that can potentially be utilized for EIM activity. Transmission transfer capability limits the amount of imbalance energy that can flow between the Company and the Cal-ISO and impacts the amount of benefits that will be achieved. The E3 study presented a range of benefits based on three different potential interchange capabilities between the Company and the Cal-ISO, specifically 100 Megawatts ("MW"), 400 MW, and 800 MW.[65] While the EIM transfer capability was not known at the time of the E3 study, the Company subsequently stated that it "currently has long-term contract wheeling rights of 331 MW northbound and 432 MW southbound with PacifiCorp Transmission" to facilitate EIM transfers, and that it is currently in the process of negotiating additional transfer capability with BPA.[66] Accordingly, the 400 MW medium transfer capability assumption, which falls close to the Company's current southbound ownership rights, best represents the amount of transfer capability to assume in the test period.

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[65] Exh. No.___(BGM-5) at 20.

[66] Exh. No.___(BGM-6) at 27:13-22.

Q. WHAT LEVEL OF HYDRO CONTRIBUTION TO FLEXIBILITY RESERVES DID YOU ASSUME?

A. In the E3 study, flexibility reserve savings and intraregional dispatch savings benefits are both sensitive to the percent of Company hydro capacity that will be capable of providing regulation and load following reserves. The E3 study analyzed both a 12 percent and 25 percent level of hydro contribution to flexibility reserves.[67/] Because the GRID model assumes approximately 25 percent of hydro contribution to reserves, it would be inconsistent to assume a lower level of hydro reserve capability for purposes of the E3 study than is reflected in base NPC in the GRID model. Therefore, the 25 percent of hydro contribution to flexibility reserves and, thus, the low estimate for interregional dispatch savings, is assumed for this component of the EIM.

Q HOW DID YOU CALCULATE THE ADJUSTMENT TO NPC TO REFLECT INTERREGIONAL DISPATCH SAVINGS?

A. In reference to Table 3, I used the $11.2 million value included under the medium transfer capability, low-range column for interregional dispatch benefits as an offset to NPC. This system-wide benefit, originally stated in 2012 dollars, was inflation adjusted to the test period, allocated to the WCA in proportion to load, and allocated to Washington on the Control Area Generation West ("CAGW") allocation factor, as detailed in Table 4 below.

67/ Exh. No.___(BGM-5) at 21.

TABLE 4
Calculation of Washington Allocated Interregional Dispatch Benefits
($millions)

E3 Study Benefits (2012$)	11.20
Adjust to Test Period $	11.89
WCA Load %	33.28%
WCA Test Period Benefits $	3.96
Washington CAGW Factor	23.08%
Washington Allocated Benefits $	0.91

D. Intraregional EIM Dispatch Savings

Q. WHAT ARE INTRAREGIONAL DISPATCH SAVINGS?

A. Intraregional dispatch benefits represent the improved dispatch optimization that results from the Company utilizing the Cal-ISO SCED model. The Company's current dispatch practices are largely manual, often involving issuance of manual dispatch orders to request a plant to increase or decrease output. As a result of deploying the Cal-ISO SCED model on the Company's system, plant dispatch will now be automated and optimized by the model. As a result, the Company's system is now capable of operating more efficiently, reducing overall NPC.

Q. HOW WERE INTRAREGIONAL DISPATCH SAVINGS CALCULATED IN THE E3 STUDY?

A. The intraregional dispatch benefits reported in the E3 study were calculated based on the total amount of benefits achieved by Cal-ISO when it initially implemented its SCED model, prorated for the Company's load.[68/] In calculating the range of benefits, the low

[68/] Exh. No.___(BGM-5) at 23-24.

estimate in the E3 study assumed that only 10 percent of these intraregional benefits would be achieved by the Company.[69] The high estimate assumed that 100 percent of these intraregional benefits would be achieved by the Company. Based on the high estimate, the total amount of potential intraregional dispatch benefits was calculated to be \$23 million for the Company's entire system.[70]

Q. HOW DO YOU PROPOSE TO REFLECT INTRAREGIONAL DISPATCH SAVINGS IN THE GRID MODEL?

A. The GRID model contains assumptions and constraints that are designed to reflect the fact that in actual operations the Company has historically not been capable of optimizing its system to the degree that would otherwise be calculated in GRID. Market caps, for example, tie the maximum amount of sales assumed in a particular market hub to historical averages, incorporating into GRID the Company's historical, sub-optimal operations that resulted in those historical average sales. Once the Company deploys the Cal-ISO model, however, the historical averages used to develop market caps are no longer relevant. Because the Cal-ISO model is not subject to market caps, the Company will have the ability to optimize its system in actual operations in a manner that is consistent with how the GRID model optimizes its system in the absence of market caps. Accordingly, I view the value associated with the relaxation of market caps to be an accurate proxy for the benefit that the Company will achieve when it begins to operate its system using the Cal-ISO model.

69/ Id. at 24.

70/ Id.

Q. WHAT IS THE VALUE ASSOCIATED WITH THE RELAXATION OF MARKET CAPS IN THE GRID MODEL?

A. Relaxing market caps in the GRID model reduces WCA power cost by approximately $12.4 million, with $2.9 million allocated to Washington. I propose to use this level of cost reduction to be a proxy for the intraregional dispatch benefits that will be achieved from utilizing the Cal-ISO SCED model. Alternatively, I propose the market cap methodology adopted by the OPUC, discussed by Mr. Duvall, be used to account for the intraregional benefits that will accrue as a result of the EIM.[71/] Using the Oregon market cap methodology results in an approximate $4.4 million reduction to WCA power costs, with approximately $1.0 million allocated to Washington.

E. EIM Reserve Diversity Savings

Q. WHAT ARE THE FLEXIBILITY RESERVES DIVERSITY BENEFITS ASSOCIATED WITH THE EIM?

A. The flexibility reserves in the E3 study represented the load following reserve savings associated with "aggregating the two systems' load, wind, and solar variability and forecast errors."[72/] It should be noted that these reserve savings, which are representative of having a more diverse set of resources upon which to hold reserves, are distinct from the reserve savings that will accrue to the Company as a result of moving to a sub-hourly market and scheduling paradigm.

71/ Exh. No.___(GND-1CT) at 33:1-6.

72/ Exh. No.___(BGM-5) at 7.

Q. DID THE E3 STUDY QUANTIFY THE RESERVE SAVINGS THAT WILL BE ACHIEVED AS A RESULT OF THE EIM?

A. Yes. In addition to quantifying a dollar figure associated with these reserve savings, the E3 study also quantified the reduction to reserves in MW resulting from the Company's participation in the EIM, as reproduced in Table 5, below:[73/]

TABLE 5
Reserve Savings Associated with Additional Resource Diversity in E3 Study

Table 3. Estimated Total Minimum Reserve Holdings under the EIM in 2017

PacifiCorp-ISO Transfer Capability	Minimum Reserve Holdings (MW)
Standalone (no EIM)	2,011
100 MW	1,932
400 MW	1,687
800 MW	1,583

Using this data, the benefits associated with this reduced reserve requirement can be incorporated into the Company's GRID modeling, capturing the rate year benefits of this EIM component. The E3 study calculated reserve savings for each EIM transfer scenario—100 MW, 400 MW, and 800 MW—and, for reasons discussed above, the 400 MW scenario, and, thus, 324 MW of flexibility reserve savings, best represents the reserve savings that can be achieved in the rate period.

Q. HOW DID YOU QUANTIFY THE RESERVE REDUCTIONS ATTRIBUTABLE TO THE WCA IN THE TEST PERIOD?

A. The following table details how the reserve reductions presented in the E3 study have been modeled in the test period. The reserve savings were pro-rated in proportion to the amount of reserves required under the no EIM transfer capability scenario, which is

73/ Id. at 26.

consistent with how the E3 study attributed reserve savings between the Company and the Cal-ISO.[74/]

TABLE 6
Calculation of WCA Reserve Savings from E3 Study

	Reserve Requirement (MW)		
	PacifiCorp	Cal-ISO	Total
No EIM Transfer Capability	608	1,403	2,011
400 MW EIM Transfer Capability	510	1,177	1,687
Reserve Savings	98	226	324
WCA Load %	33.28%		
WCA Reserve Savings	33		

Q. WHAT IS THE IMPACT OF MODELING THESE RESERVE SAVINGS IN THE GRID MODEL?

A. Modeling this level of reserve savings in the GRID model results in a $2.1 million reduction to WCA power costs, with $492,724 allocated to Washington. This amount represents a conservative estimate of the flexibility reserve savings that will result from combining the Company's system with the Cal-ISO through the EIM.

F. Within-hour EIM Dispatch Benefits

Q. HOW HAVE YOU QUANTIFIED THE WITHIN-HOUR DISPATCH BENEFITS ASSOCIATED WITH THE EIM?

A. I quantified these benefits based on a sensitivity performed in the Company's 2012 Wind Integration Study that analyzed the regulating reserve savings associated with 30-minute balancing.[75/] Because the EIM is a five-minute market, the 30-minute balancing reserves represent a conservative estimate of within-hour dispatch benefits that will be achieved as a result of joining the market. The 30-minute balancing reserves calculated in the 2012

74/ See id. at 34 ("Benefits were allocated to PacifiCorp and ISO in proportion to their standalone need, resulting in a roughly 30/70 split, respectively.").

75/ See PacifiCorp, 2013 Integrated Resource Plan, Volume II, Appendix H at 122-23 (Apr. 30, 2013).

Wind Integration Study were modeled in GRID using the same methodology employed by the Company to model reserves for load and wind in its filing.

Q. WHAT AMOUNT OF WCA RESERVE SAVINGS DID THE 2012 WIND INTEGRATION STUDY ASSOCIATE WITH 30-MINUTE BALANCING?

A. The 2012 Wind Integration Study calculated that the WCA regulation reserve requirement would decline by approximately 30 percent as a result of moving to 30-minute balancing.[76/] Moving to 5-minute balancing, as is accomplished in the EIM, will likely result in an even greater level of reserve savings.

Q. DO THE WITHIN-HOUR DISPATCH BENEFITS OVERLAP WITH FLEXIBILITY RESERVE DIVERSITY?

A. No. The E3 study was clear when it stated: "Production simulation analysis [was] modeled at [an] hourly level, omitting potential benefits of sub-hourly dispatch (other studies indicate that these benefits could be substantial)."[77/] In addition, because the various EIM benefit components have been modeled in GRID, the final balancing adjustment detailed in Table 2 removes any overlaps between components.

Q. WHAT IS THE IMPACT OF MODELING THE RESERVE REDUCTIONS ATTRIBUTABLE TO 30-MINUTE BALANCING PRESENTED IN THE 2012 WIND INTEGRATION STUDY?

A. Modeling the approximate 30 percent reduction to regulation reserves in the GRID model study resulted in a \$3.3 million reduction to WCA NPC, with \$765,951 allocated to Washington. This amount represents a conservative provision for the savings associated with within-hour EIM dispatch benefits.

76/ Id. at 123.

77/ Exh. No.___(BGM-5) at 37.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/904 to Cross-Examination Statement

Testimony of Bradley G. Mullins Filed with the Public Service Commission of Wyoming in Docket No. 20000-469-ER-15 (July 28, 2015)

August 18, 2015

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY OF A GENERAL RATE INCREASE IN ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING OF $32.4 MILLION PER YEAR OR 4.5 PERCENT	)))))))	DOCKET NO. 20000-469-ER-15 (Record No. 14076)

NON-CONFIDENTIAL DIRECT TESTIMONY

AND EXHIBITS

OF

BRADLEY G. MULLINS

On Behalf of

Wyoming Industrial Energy Consumers

July 28, 2015

EXHIBIT No. 301

at the Federal Energy Regulatory Commission ("FERC") to begin recovering for its Wyoming and other retail customers the full integration cost associated with non-owned wind resources. These NPCs are caused by wholesale customers, and due to the Company's inaction at the FERC, Wyoming retail ratepayers continue to subsidize these costs. Because the Commission expressly requested the Company seek recovery of these costs from wholesale ratepayers at the FERC, and the Company has failed to do so, I propose an adjustment to remove the wind integration costs associated with these resources in the 2016 test period.

(6) **Hermiston Point-to-Point Transmission**: The Company includes in NPC the transmission costs necessary to deliver the full output of the Hermiston power plant onto its system. A portion of these costs, however, will no longer be used and useful when the Hermiston Purchase contract expires in July of 2016. Accordingly, I recommend that the Commission remove from NPC the unused portion of the Hermiston point-to-point transmission contract following the expiration of the Hermiston Purchase Contract.

(7) **Outage Modeling:** The Company has developed a new outage modeling methodology that should be studied further before being adopted over the long-term. However, for purposes of this case I propose to accept the Company's approach with one modification. Specifically, the Company has proposed a slightly different methodology in Oregon that normalizes some of the impacts of highly unusual long-term outages. There is no reason to use a different approach in Wyoming to the approach used in Oregon that is more fair to ratepayers. Therefore, I recommend that the Commission require the Company to use the same methodology that the Company has recently proposed in Oregon.

(8) **Avian Protection:** The Company has proposed to reduce the output from several Wyoming wind resources to account for avian protection curtailments, increasing modeled NPC due to lost generation output from those resources. However, under the September 14, 2011 Stipulation in Docket No. 20000-389-EP-11, the Company agreed not to change the modeled output from owned wind resources through the pendency of the current Energy Cost Adjustment Mechanism, except in instances of force majeure. I disagree that the requirement to curtail output from wind resources to prevent eagle impact constitutes force majeure because the Company's ability to interpret the law at the time of the stipulation was within its control and a force majeure event must be material in terms of impact—which this adjustment is not. Accordingly, I recommend that the Commission reject this modeling adjustment.

Order in the 2014 GRC to the end of the 2015 test period. To calculate the level of this adjustment, rather than removing these facilities from the Company's complicated hourly reserve requirement calculations, I propose a simple adjustment methodology based on the 2014 WIS as detailed in Table BGM-6, below.

TABLE BGM-6
Non-owned Wind Integration Adjustment (Calendar Year 2016, total-Company)

ln		
1	Non-owned Wind Generation (MWh)	815,641
2	2014 WIS Rate ($/MWh)	2.35
3	Non-owned Wind Integration Cost	$1,916,757

VIII. HERMISTON POINT-TO-POINT TRANSMISSION CONTRACT

Q. PLEASE PROVIDE AN OVERVIEW OF THE HERMISTON PURCHASE CONTRACT.

A. The Company is a 50% owner of the Hermiston power plant, which consists of two 245 MW 1x1 Combined Cycle Combustion Turbines totaling 490 MWs of capacity, located in Umatilla County, Wyoming. The remaining 50% is owned by the Hermiston Generating Company ("HGC"), which is also the operator of the facility. In addition to its ownership share, the Company currently purchases HGC's 50% of share of Hermiston under a long term PPA, the Hermiston Purchase contract, that expires on July 1, 2016. Pursuant to the PPA, however, the Company had the option to extend the PPA [redacted][63] [redacted]

[63] The Company's Confidential Response to WIEC DR 9.4

[redacted].[64]

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE HERMISTON POINT-TO-POINT TRANSMISSION CONTRACT?

A. The Company currently has rights to 490 MWs of point-to-point transmission on the Bonneville Power Administration's system to deliver power from the Hermiston power plant, including the capacity associated with the Hermiston Purchase Contract, onto its system. Based on the Company's workpapers, the total cost of this transmission in the test period was forecast to be $[redacted] million. I recommend eliminating the portion of the cost associated with this transmission contract that was related to the expired Hermiston Purchase contract. Over the six months in the test period following the expiration of the Hermiston Purchase contract, eliminating the unused transmission capability his will result in a reduction to NPC of $2.6 million on a total-Company basis, with approximately $0.4 million allocated to Wyoming.

Q. WHY DO YOU PROPOSE TO REMOVE THIS AMOUNT RELATED TO THE HERMISTON PURCHASE CONTRACT?

A. According to the Company's workpapers, the Hermiston point-to-point transmission contract—which provides the Company with transmission capability equal to the full 490 MW of capacity from the Hermiston power plant—[redacted] But, because the Company will no longer have rights to the full 490 MW of capacity from the Hermiston power plant, half of the capacity under the transmission contract will no longer be used and useful beginning on July 1, 2016. Therefore, that

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64 *Id.*

excess capacity that is not used and useful should be excluded from rates. In addition, because the Company appears to have renewed the full amount of capacity from this contract after the decision had been made not to extend the Hermiston Purchase contract, the unneeded portion of the point-to-point transmission contract is also not prudent. For these reasons, I believe it is appropriate to eliminate one-half of cost of this transmission contract from rates beginning on July 1, 2016, the expiration date of the Hermiston Purchase contract.

Q. SHOULD THE COMPANY REMOVE THE MODELED CONTRACT CAPACITY FROM THE GRID MODEL TOPOLOGY IN ITS FINAL NPC RUN?

A. Yes. Removing the capacity associated with the portion of the PTP contract attributable to the Hermiston purchase contract will result in an increase to NPC modeled in GRID, which should be applied as an offset to this adjustment in the Company's final GRID model runs. My GRID modeling does not reflect this offset.

IX. OUTAGE MODELING

Q. HOW HAS THE COMPANY PROPOSED TO CHANGE ITS OUTAGE MODELING METHODOLOGY IN THIS PROCEEDING?

A. In response to the Commission Order in the 2014 GRC, the Company has proposed to model outages dynamically based on discrete outage events over a historical, four-year base period.[65] Based on the historical data, the Company developed an hourly schedule of outages for each plant, which it modeled in GRID in the test period.[66] The impact of the Company's new methodology is a \$2.1 million increase to NPC on a total-Company basis, relative to the methodology approved by the Commission in the 2014 GRC.

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65 Exhibit RMP___(Direct Testimony of Gregory N. Duvall) at page 19, line 9 through page 22, line 6.

66 *Id.*

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED METHODOLOGY?

A. While there may be some merit in modeling a schedule of forced outages, a number of additional issues need to be resolved in the Company's modeling methodology. For example, because the Company has developed the outage schedule based on an average over the four-year base period, its proposed methodology results in a pattern of frequent, short outages that is not representative of the pattern of outages experienced in actual operations. Frequent and short outages typically increase NPC more than longer, less frequent outages. This is because it is expensive for a resource to commit up and down as a result of an outage. In addition, as outages become increasingly short and frequent, it becomes more expensive for the overall resource portfolio to respond to the outages, having to ramp up and down in more frequent intervals than in actual operations.

There is also an issue regarding bias in the timing of outages. For example, the Company had several plants located in the Northwest that were on extended forced outage during the 2013-2014 winter peak months. Modeling a similar pattern in the test period may result in a skewed outage schedule that is not representative of normalized operations.

Q. HAS THE COMPANY MADE SIMILAR PROPOSALS IN OTHER STATES?

A. Yes. In Oregon, the Company has proposed a similar outage modeling methodology, with a few exceptions. The primary difference between what the Company has proposed in Oregon and what it has proposed in this proceeding is that in Oregon the Company has proposed to cap lengthy individual outages at 28 days.[67] While the Oregon Public Utility Commission has historically imposed restrictions the outage rates used for coal plants, I

[67] *In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Or.PUC Docket 296, Direct Testimony of Brian Dickman (PAC/100) at page 34, lines 5-12.

am not aware of any explicit requirement in Oregon to cap the length of outages at 28 days.

Q. WHAT DO YOU PROPOSE IN THIS PROCEEDING?

A. While I believe there are a number of issues that need to be resolved with the Company's methodology in future rate case after more study, for purposes of this case I recommend that the Commission accept the Company's methodology with one change. Specifically, the Commission should require the Company use the same methodology in Wyoming that it has proposed in Oregon, including its proposal to cap lengthy individual outages at 28 days. There is no basis for the Company to use one methodology in Oregon and a different methodology, less reasonable and less favorable to ratepayers, in Wyoming. In addition, I propose that the Commission require the Company to further study the issues identified above to the extent that this modeling methodology is used in a future proceeding.

Q. WHY IS IT APPROPRIATE TO CAP OUTAGES AT 28 DAYS UNDER THE COMPANY'S PROPOSED METHODOLOGY?

A. Normalized NPC should be established under the assumption that no catastrophic outage event occurs in the test period, as the recovery of costs associated with catastrophic outages are most properly reflected in the ECAM, subject to prudency reviews. As an example, Colstrip Unit 4 was on an extended, six month outage in second half of 2013. Under the Company's proposal in Wyoming (but not in Oregon) it would model a discrete extended outage for Colstrip Unit 4 in normalized NPC as a result of this outage history. The costs associated with the extended outage at Colstrip Unit 4, however, were previously reflected in the Company's 2014 ECAM filing. Thus, allowing the Company to include the same outage in normalized NPC in this proceed will result in double recovery of the same outage costs. Accordingly, it is good policy for this Commission to utilize the methodology proposed by the Company in Oregon, applying a 28 day cap these sorts of catastrophic outages.

Q. WHAT IS THE IMPACT OF USING THE OUTAGE METHODOLOGY PROPOSED IN OREGON?

A. Based on a 2016 test period, the impact of using the methodology that the Company proposed in Oregon is a reduction to 2016 NPC of about \$3.7 million on a total Company basis, with \$0.6 million allocated to Wyoming. Because the Company did not prepare an outage schedule based on the Oregon methodology for 2015, I applied the 2016 outage schedule used in Oregon to the respective days in 2015 in my 2015 GRID model runs. Based on this approach, the impact of using the methodology that the Company proposed in Oregon is a reduction to 2015 NPC of \$2.6 million on a total Company basis, with \$0.4 million allocated to Wyoming.

X. AVIAN PROTECTION CURTAILMENTS

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING MODELING OF AVIAN PROTECTION COSTS?

A. The Company has proposed to reduce the generation output from several Wyoming wind resources to reflect a small amount of energy expected to be lost as a result of avian protection curtailments.[68] The Company alleges that the requirement to curtail the output of facilities in order to reduce the risk of eagle interaction constitutes force majeure and therefore, falls outside of the scope of the Company's agreement in Docket No. 20000-

68 Exhibit RMP___(Direct Testimony of Gregory N. Duvall) at page 34, line 6 through page 35, line 20

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/905 to Cross-Examination Statement

Testimony of Bradley G. Mullins Filed with the Public Utility Commission of Oregon in Docket No. UE 294 (May 28, 2015)

August 18, 2015

CONFIDENTIAL TABLE 1
Summary of Recommended Net Variable Power Cost Adjustments
($000)

		ln
Initial Filing (Feb 12)	**555,914**	1
Adjustments & Updates:		
1. California-Oregon Border Margins	[redacted]	2
2. Load Net of Wind Reserves	(661)	3
3. Super Peak Purchase	(407)	4
4. Pipeline Capacity Release Credits	[redacted]	5
5. Company's April Update	*(5,608)*	6
Total	[redacted]	7
Recommended	[redacted]	8

Q. TO THE EXTENT YOUR OPENING POWER COST TESTIMONY DOES NOT ADDRESS A PARTICULAR ISSUE, SHOULD THAT BE INTERPRETED AS YOUR ACCEPTANCE OF THAT ISSUE?

A. No.

II. CALIFORNIA-OREGON BORDER MARGINS

Q. WHAT IS YOUR RECOMMENDATION RELATED TO ECONOMIC MARGINS REALIZED AT COB?

A. The MONET model calculates system dispatch based on a single market hub—the Mid-C market. In actual operations, however, the Company participates in several different markets, with COB being the predominant market other than Mid-C where the Company makes market transactions. Through its ability to transact at both Mid-C and COB, the Company realizes substantial economic benefits, which are derived from monetizing the spreads between Mid-C and COB prices. Customer base rates currently include the cost of the transmission assets on the California-Oregon Intertie ("COI") that facilitate these economic transactions at the COB market, and it follows that customers should also recognize the incremental economic benefits, not currently reflected in the MONET model, associated with the Company's trading activities at this market. Based on the actual economic margins earned by the Company between 2012 and 2014, I recommend a $[redacted] adjustment to net variable power costs to reflect these incremental economic benefits derived from the COB market.

Q. HOW ARE MARKET SALES AND PURCHASES MODELED IN MONET?

A. The mechanics of the MONET model were described by the Company in PGE/400 at 5:1-10. As discussed in that testimony, the MONET model calculates economic dispatch based on a comparison of the hourly dispatch cost of each resource to a single electric market price,[3/] which is the Mid-C market. After dispatch has been determined, the MONET model will balance the Company's overall load and resource position by making sales in hours when the amount of dispatched resources is greater than the Company's loads and by making purchases in hours when the amount of dispatched resources is less than the Company's load.[4/] All of these market sales and purchases are assumed to occur at the Mid-C market, and in no hour will the MONET model make purchases or sales at the COB market, even though it is common for the Company to make such purchases and sales at COB in actual operations. This is in contrast to other power cost models, such as PacifiCorp's GRID model, that forecast economic dispatch based on multiple markets and based on a transmission constrained network topology.

Q. WHAT ARE THE OTHER MARKETS WHERE THE COMPANY MAKES POWER TRANSACTIONS?

A. In contrast to MONET's assumptions, in actual operations, the Company is capable of making power transactions at several different markets, which result in lower overall dispatch costs

3/ Id. at 5:2-5.
4/ Id. at 5:5-10.

compared to those calculated in the MONET model. Confidential Exhibit ICNU/102 details the quantity and volume of power transactions made by the Company by market in calendar years 2012, 2013 and 2014. A summarized version of this analysis is presented in Confidential Table 2, below.

CONFIDENTIAL TABLE 2
Company Transactions by Market Hub

[redacted]

As noted from Confidential Table 2, Mid-C was the predominant market where the Company entered into power transactions between 2012 and 2014. However, the Company also made material amounts of transactions at power markets other than Mid-C over the period. Sales transactions at the COB market, for example, constituted approximately [redacted]% of all sales transactions made by the Company over the period and approximately [redacted]% of total sales volumes. For purposes of this analysis, as well as the following analyses, transactions at the Nevada-Oregon Border were included in the definition of the COB market. In addition, the

Company has also been making an increasing number of sales transactions at other extra-regional markets, such as Palo Verde, Mona, Mead and Four Corners. While my recommendation does not address the economics of these extra-regional markets, the Company, through its participation in these markets, is likely earning additional economic benefits that are not reflected in the MONET model nor in my proposed adjustment.

Q. HOW MUCH POWER CAN THE COMPANY BUY AND SELL AT THE COB MARKET?

A. The Company's merchant function currently has approximately 296 MW of north-to-south transmission rights on the COI,[5/] enabling it to sell up to 296 MWh of energy at the COB market in any hour of the year. In addition, the Company has approximately 450 MW of south-to-north transmission rights on the COI,[6/] enabling it to purchase up to 450 MWh of energy at the COB market in any hour of the year. The ultimate amount that the Company can transmit on the COI, however, is at times limited by the Bonneville Power Administration, which, as the path operator, will derate the total transmission capacity available on the COI for reliability purposes.

Q. DO CUSTOMERS PAY FOR THESE MERCHANT TRANSMISSION RIGHTS TO THE COB MARKET?

A. Yes. Customers currently pay in base rates for the revenue requirement associated with all of the Company's owned transmission assets on the COI that provide access to the COB market. The Company is an owner of approximately 950 MW of bi-directional transmission assets on the COI. It invested in these assets as a participant in the Pacific AC Intertie project, a regional effort in the late 1960s to integrate the power systems in the Northwest with increasing loads in

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5/ See Confidential ICNU/103 (the Company's Response to ICNU Data Request ("DR") No. 85).
6/ Id.

Northern and Southern California.[7] While the assets are included in rate base, a portion of the revenue requirement of these legacy assets is offset by Open Access Transmission Tariff ("OATT") wheeling revenues, as the majority of the Company's COI transmission capability is currently resold to third parties. The total amount that customers pay, therefore, is the net amount of revenue requirement associated with these assets, an amount that is representative of the cost of rights reserved by the Company's merchant function detailed above.

Q. IS IT FAIR TO REQUIRE CUSTOMERS TO PAY FOR TRANSMISSION TO COB, WITHOUT RECEIVING THE CORRESPONDING BENEFITS OF THAT MARKET?

A. No. Customers are currently paying the cost associated with transmission access to the COB market; therefore, it does not appropriately match costs and benefits to require customers to forgo the economic benefits derived by the Company as a result of its ability to make transactions at the COB market.

Q. HOW DOES THE COMPANY REALIZE ECONOMIC BENEFITS AS A RESULT OF ITS ACCESS TO THE COB MARKET?

A. With its transmission access to the COB market, the Company is capable of earning a margin on the differences between Mid-C and COB market prices. In hours when COB market prices are greater than Mid-C market prices, the Company can purchase from the Mid-C market and sell into the COB market, earning an economic margin on the difference between the two prices. In hours when COB market prices are less than Mid-C market prices, the Company can purchase from the COB market and sell into the Mid-C market, also earning economic margins on the difference between the two prices.

[7] See Gene Tollefson, BPA & The Struggle for Power at Cost, 336-338 (1987).

Q. HOW MUCH ECONOMIC BENEFIT HAS THE COMPANY HISTORICALLY REALIZED AS A RESULT OF ITS ACCESS TO THE COB MARKET?

A. As an owner of both south- and north-bound transmission rights on the COI, the Company has realized substantial economic benefits by being able to make sales and purchases at both the Mid-C and COB markets. Based on my review of actual transactions the Company has executed at the COB market, these economic benefits have ranged from $[redacted] to $[redacted] per year over the period 2012 through 2014. Confidential Table 3, below, details the results of my analysis and the actual benefits that the Company has realized associated with its access to the COB market.

CONFIDENTIAL TABLE 3
Historical Margins on COB Sales and Purchases

[redacted]

Q. PLEASE PROVIDE AN OVERVIEW OF HOW THE FIGURES IN CONFIDENTIAL TABLE 3 WERE CALCULATED.

A. The figures in the above table were calculated based on the actual power transactions, both sales and purchases, made by the Company at the COB market in calendar years 2012 through 2014. The calculations were performed using trade data provided in response to ICNU DR Nos. 84 and 91.[8/] For each transaction that the Company made at the COB market, I compared the transaction price to the actual hourly Mid-C market price to determine the economic margin actually earned on each COB transaction. I then aggregated the economic margins associated with each transaction by year, separately for sales and purchases, to develop the annual economic benefit associated with the Company's participation at the COB market, presented in Confidential Table 3, above.

Q. HOW DO THESE BENEFITS CORRESPOND TO THE AMOUNT OF BENEFITS EXPECTED IN THE TEST PERIOD?

A. The historical economic benefits derived from COB market transactions, relative to the Mid-C market, are a fair estimate of the level of economic benefits attributable to COB market activity expected in the test period. Because these economic benefits are driven by the difference in market prices between the two markets, rather than the overall level of market prices, the Company will be able to derive economic benefits from the spreads between the two markets, regardless of market conditions. For example, the historical relationship between the two markets—where COB market prices have typically exceeded Mid-C market prices by several dollars—could reverse in its entirety, and the Company would still have an opportunity to recognize a similar amount of economic benefit by predominantly making purchases, rather than sales, at the COB market. Notwithstanding, there is no indication that the economic

8/ See Confidential ICNU/103.

factors underlying the market spreads between the Mid-C and COB markets, such as the load and resource characteristics of southern California, will change materially in the test period, so the historical spreads between the two markets, and underlying economic benefits detailed above, are not expected to change materially in the test period.

Q. HOW DO YOU PROPOSE TO REFLECT THE BENEFITS OF THE COB MARKET IN THE NET VARIABLE POWER COST FORECAST?

A. Because the historical benefits detailed above are a fair representation of the economic benefits expected in the test period, my proposal is to use the average actual economic benefits associated with the Company's trading activities at the COB market, as detailed in Confidential Figure 3, as an adjustment to net variable power costs in this proceeding.

Q. IS THIS ISSUE A FACTOR THAT HAS LED TO THE COMPANY OVER-FORECASTING POWER COSTS IN RECENT YEARS?

A. In 3 of the last 4 years, the Company has over-forecast its power costs in amounts ranging from \$12.3 million to \$34.2 million, detailed in Table 4 below.

TABLE 4
Power Cost Variance in PCAM
Over / (Under) Collection (\$000)

2010	2011	2012	2013
12,353	34,256	16,929	(11,015)

As noted, the only recent year when the Company did not over-forecast power costs was 2013, and the Company's under-collection in that year was likely driven by the major six-month outage that occurred at Colstrip Unit 4.[9] While there are many factors that lead to over- and under-forecasting of net variable power costs, the lack of consideration for the transactions

9/ See Docket No. UE 283, PGE/800 at 11:7-12:14 for a discussion of the Colstrip Unit 4 outage.

at COB and other extra-regional markets in the MONET model may be one factor that has led to this pattern of over-forecasting.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Because the MONET model does not account for transactions at the COB market, the Company's net variable power costs forecast is currently overstated. As demonstrated in Confidential Table 3, these transactions produce material economic benefits and should be reflected in the Company's net variable power cost forecasts. Customers already pay for the cost of transmission to the COB market and should also receive the corresponding benefits associated with the Company's trading activities at the COB market. Based on the analysis of the actual economic benefits associated with COB transactions presented above, I recommend an adjustment of approximately $[redacted] to properly account for these benefits.

III. LOAD NET OF WIND RESERVES

Q. WHAT CORRECTION ARE YOU PROPOSING RELATED TO THE COMPANY'S CALCULATION OF LOAD- AND WIND-FOLLOWING RESERVES?

A. The Company uses incorrect mathematics to combine the reserve requirements associated with load and wind. These reserve requirements must be combined using a root-sum-of-squares ("RSS") formula, rather than the arithmetic sum used by the Company. This RSS formula is the standard industry practice for combining load and wind errors for purposes of estimating reserve requirements and wind integration costs. The impact of this correction is a $660,900 reduction to net variable power costs.

Q. PLEASE DESCRIBE HOW THE COMPANY MODELED FOLLOWING RESERVES.

A. The Company filing includes new logic in the MONET model to account for hourly following reserves for both load and wind resources. These following reserves represent the capacity that must be withheld in order to assure that the Company will be capable of responding to changes

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/906 to Cross-Examination Statement

***APS Energy Imbalance Market Participation: Economic Benefits Analysis*, Energy and Environmental Economics (April 2015)**

August 18, 2015

APS Energy Imbalance Market Participation: Economic Benefits Assessment

April 2015

Energy+Environmental Economics

APS Energy Imbalance Market Participation: Economic Benefits Assessment

April 2015

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- Andrew Schroeder, APS
- Paul Smith, APS
- Subba Nishtala, APS
- Justin Thompson, APS
- Joshua Lind, APS
- Mattea Dibble, APS
- Marcus Schmidt, APS
- Don Fuller, California ISO
- Mark Rothleder, California ISO
- Jim Price, California ISO
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Acronyms

APS	Arizona Public Service Company
BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business-as-usual
ISO	California Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
LMP	Locational Marginal Price
NVE	NV Energy
PAC	PacifiCorp
WECC	Western Electric Coordinating Council
AB32	Assembly Bill 32 – California Global Warming Solutions Act

Executive Summary

This report examines the benefits of Arizona Public Service Company's (APS) participating in the energy imbalance market (EIM) operated by the California Independent System Operator (ISO). The ISO's EIM is a regional 15- and 5-minute balancing energy market, including real-time unit commitment capability, which began operating in November 2014 with the ISO and PacifiCorp as initial participants. NV Energy will also begin participating in the EIM in Fall 2015.[1] The ISO, PacifiCorp, and NV Energy are referred to in this study as "current EIM participants"; because they are assumed to be already participating in the EIM before APS becomes a participant.[2]

This report estimates the benefits of APS's participation under a primary scenario, as well as under a range of alternative scenarios and sensitivity cases that explore how different resource changes and fuel prices could impact EIM benefits to APS. For the year 2020, participation in the EIM is estimated to create dispatch efficiency and flexibility reserve savings of $7.0 to $18.1 million per year for APS.[3] Dispatch efficiency savings were $8.9 million per year in the primary scenario, and

[1] Puget Sound Energy (PSE) also announced in March 2015 that it intends to begin participating in the EIM in Fall 2016. The majority of this analysis for APS was completed prior to PSE's announcement, so PSE is not included as an EIM participant in this study.

[2] Throughout this report, Balancing Authorities (BAs) that participate in the EIM are described as "EIM participants". These participating BAs are referred to in the ISO's EIM Business Practice Manual and tariff as "EIM Entities."

[3] All benefits are reported in 2014 dollars.

ranged from $5.9 million to $14.9 million per year across ten alternative scenarios. Flexibility reserves savings ranged from $1.0 to $3.2 million per year.[4]

In addition, across the range of scenarios modeled, APS's participation in the EIM is estimated to produce a range of $2.2 to $8.1 million per year in incremental savings for the current EIM participants as a result of improved dispatch efficiency and reduced flexibility reserve requirements. In the primary scenario, benefits savings to current EIM participants ranged from $3.0 to $6.5 million. All incremental costs from APS's participation is expected to be recovered from APS through fixed and administrative charges, resulting in no incremental implementation costs for the current EIM participants.

To be conservative, this study's simulation modeling does not quantify potential benefits from improved dispatch in the hour-ahead (HA) and day-ahead (DA) market. We expect that information produced by participation in the real-time EIM could create learning and additional cost efficiencies in the DA and HA market for APS over time, but have not quantified those potential savings. Additionally, APS's participation in the EIM could allow APS to avoid transaction costs related to buy-sell price spreads currently incurred for market purchases and sales in bilateral 15-minute or HA trading.

This study also does not quantify potential reliability benefits tied to the increased awareness and resource control that the EIM creates. Although reliability benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits. A recent FERC staff report identified potential additional reliability benefits that may arise

[4] Individual components of low range savings do not sum to total due to rounding.

from an EIM, including enhanced situational awareness, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.[5]

EIM Benefits Quantified in This Report

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[6] By allowing BAs to pool load and generation resources, the EIM lowers total flexibility reserve requirements and minimizes curtailment of variable energy resources for the region as a whole, thus lowering costs for customers. The EIM can create value for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits (known as "Security Constrained Economic Dispatch", or "SCED"); (2) bringing this optimized dispatch down to a 5-minute interval level; (3) incorporating optimized real-time unit commitment of quick-start generation; and (4) enabling better use and compensation of flexible ramping capacity in real-time due to the diversity of loads and resources across the EIM footprint, allowing EIM participants to individually reserve a smaller amount of committed capacity for sub-hourly flexibility.

APS retained Energy and Environmental Economics, Inc. (E3) to conduct an economic study to quantify the potential benefits to APS from participation in the EIM. Energy Exemplar provided technical support to this study by running

[5] See FERC (2013).
[6] For more information regarding the EIM, see CAISO (2014c).

sub-hourly production simulations cases using the PLEXOS production simulation modeling tool to calculate EIM benefits from dispatch cost savings. This report describes the findings of the E3 and Energy Exemplar study team.

The study evaluates benefits using an approach that builds upon E3's EIM analyses for the ISO, PacifiCorp, NV Energy, and Puget Sound Energy.[7] The analysis focuses on the incremental benefits related to APS's participation in the EIM, while assuming that the ISO, PacifiCorp and NV Energy are already "current EIM participants" in the base case. This study incorporates additional system details provided by APS to improve the accuracy of APS's generation and transmission represented in the production cost simulation.

The primary scenario in this report quantifies two categories of potential cost savings from expanding the EIM to include APS:

+ *Sub-hourly dispatch benefits*, by realizing the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment across APS and the current EIM footprint, compared to bilateral transactions typically done on an hourly basis under business-as-usual (BAU) practice for APS; and
+ *Reduced flexibility reserves*, by reflecting the diversity of load, wind and solar variability and uncertainty across APS and the footprint of current EIM participants.

E3's PacifiCorp-ISO EIM study included a separate benefit category, intraregional dispatch savings, which arises from PacifiCorp generators being able to be dispatched more efficiently through the ISO's automated nodal

[7] See E3 (2013), E3 (2014), and E3 (2015).

dispatch software, reducing transmission congestion within the PacifiCorp BAAs. Based on APS's experience that there is little internal congestion within the APS system, we assumed this benefit would be small and therefore did not include it in this analysis. The PLEXOS scenarios also resulted in a reduction in renewable curtailment in the ISO region as a result of APS's participation in the EIM. Savings for this reduced renewable curtailment have been included as part of the modeled sub-hourly dispatch benefits to the current EIM participants. Renewable curtailment in the APS BA was negligible in the cases, and APS does not currently experience significant curtailment needs in its own BA.

Sub-hourly Dispatch Savings Results

We estimated the production cost benefits of APS's participation in the EIM using the PLEXOS production cost modeling software to simulate operations in the Western Interconnection for the calendar year 2020 with and without APS as an EIM participant.

As a starting point, this study used the PLEXOS database developed by PNNL for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[8] and revised and as part of the NWPP Phase 1 EIM study from 2012-13.[9] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis. The real-time stage is simulated with a 10-minute time step and incorporates the

[8] See Hunsacker, M., et al. (2013).
[9] See Samaan, NA, et al. (2013)

within hour variability associated with load, wind, and solar. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS sub-hourly dataset) produces EIM benefits results that we expect may be somewhat conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM can provide. Overall, however, we expect the 10-minute time step to capture much of the real-time dispatch efficiency savings.

Based on input from APS staff, we updated the database input data for the APS BAA to improve the accuracy of system generation and transmission details in Arizona. We also implemented updates to input data for California. The primary case used updated gas prices consistent with the WECC's latest Transmission Expansion Planning Policy Committee (TEPPC) case data,[10] and the analysis also incorporates California's greenhouse gas regulations and the associated dispatch costs.

Sub-hourly dispatch savings are quantified by (1) running a real-time BAU case that holds APS net interchange (imports minus exports) with all other BAs equal to the HA interchange schedule, and (2) running an APS EIM case (starting from the same HA case) that allows APS to trade with the other EIM participants within the hour. The difference in total production cost between the two real-

[10] See WECC, Transmission Expansion Planning (TEP) Department (2015). TEPPC data is provided for 2024. This study used gas values for the 2020 study year from the gas pricing model used to produce TEPPC data.

time cases represents the sub-hourly cost savings for all EIM participants, including APS.

Benefits are then attributed to APS and the other EIM participants based on the change in their generation cost and their net purchases and sales in real-time, priced at the transaction-weighted LMP from the model.

The dispatch savings were evaluated under a primary case and ten alternative scenarios with different assumptions regarding RPS levels in California, gas prices in the WECC, coal retirements, CO_2 prices, and EIM wheeling charges applied to real-time transactions. Scenarios were designed to test the robustness of EIM savings. They were developed based on input from APS staff to respond to categories of changes that APS believed may be plausible to occur. The table below summarizes the assumptions under each scenario. The shaded values in the table represent an assumption used for a scenario that differs from the primary scenario assumptions.

Table 1: Key Assumptions for EIM Dispatch Savings Scenarios

Scenario	CA RPS	CA CO_2 price level ($/ton)	Rest of WECC CO_2 price level ($/ton)	APS natural gas price ($ per MMBTU)	Incremental coal retirement	EIM wheeling rate ($ per MWh)
0. Primary Scenario	**33%**	**$18**	**$0**	**$4.4**	**Base**	**$0**
1. CA 40% RPS	40%	$18	$0	$4.4	Base	$0
2. WECC-wide CO_2 ($18/ton)	33%	$18	$18	$4.4	Base	$0
3. Significant WECC Coal Retirement	33%	$18	$0	$4.4	Large	$0
4. Moderate WECC coal retirement	33%	$18	$0	$4.4	Moderate	$0
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	33%	$40	$40	$4.4	Moderate	$0
6. 30% Higher Gas Prices	33%	$18	$0	$5.7	Base	$0
7. 30% Lower Gas Prices	33%	$18	$0	$3.1	Base	$0
8. EIM wheeling cost $1/MWh	33%	$18	$0	$4.4	Base	$1
9. High CA RPS, high gas, moderate coal retirement	40%	$18	$0	$5.7	Moderate	$0
10. High CA RPS, low gas, moderate coal retirement	40%	$18	$0	$3.1	Moderate	$0

The resulting sub-hourly dispatch savings are provided in the table below. Benefits to APS resulting from participation in the EIM range from $5.9 million per year (in Scenario 7, which assumes low natural gas prices in APS and through the WECC) to $14.9 million (in Scenario 9, which includes high gas prices, a 40% RPS in California, and moderate incremental coal retirements). The primary case dispatch savings to APS were $8.9 million. Comparing scenarios indicates that a higher RPS in California, and higher gas prices tend to have a positive impact on EIM benefits. In contrast, lower gas price assumptions (such as in Scenarios 7 and 10) reduce EIM dispatch benefits to APS because they lower the value of savings that results when the EIM improves the dispatch efficiency of gas generators. A range of coal retirement scenarios were developed to test whether EIM savings would change significantly if coal dispatch was reduced across the WECC as a result of the U.S. Environmental Protection Agency's Clean Power Plan Proposed Rule or other federal regulations restricting electric sector CO_2 emissions. These cases show slightly lower EIM savings for APS relative to the primary scenario, with the differences for these scenarios relative to the primary case typically being less than $1 million per year.

Table 2. Sub-hourly Dispatch Savings for 2020 by Scenario (2014$ million)

Scenario	Savings to APS	Savings to current EIM participants	Total sub-hourly dispatch savings
0. Primary Scenario	**$8.9**	**$1.4**	**$10.3**
1. CA 40% RPS	$12.9	$0.6	**$13.5**
2. WECC-wide CO2 ($18/ton)	$10.7	$2.9	**$13.6**
3. Significant WECC Coal Retirement	$8.3	$0.9	**$9.2**
4. Moderate WECC coal retirement	$8.0	$0.8	**$8.8**
5. WECC-wide CO2 ($40/ton) plus moderate coal retirement	$8.5	$3.0	**$11.5**
6. 30% Higher Gas Prices	$11.9	$2.2	**$14.1**
7. 30% Lower Gas Prices	$5.9	$1.9	**$7.9**
8. EIM transfer cost $1/MWh	$8.4	$2.1	**$10.6**
9. High CA RPS, high gas, moderate coal retirement	$14.9	$1.4	**$16.4**
10. High CA RPS, low gas, moderate coal retirement	$8.9	$0.7	**$9.6**

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

Dispatch savings to current EIM participants range from $0.6 million to $3.0 million per year. Dispatch savings to current EIM participants include the value of a small reduction in renewable curtailment in the California ISO portion of the EIM footprint, based on an estimated replacement cost of $100/MWh for renewable energy to meet future procurement targets. This reduction to curtailment ranged from 8 to 20 GWh in across the different scenarios.

Flexibility Reserve Savings Results

This study modeled flexibility reserve benefits by analyzing coincident sub-hourly load, wind, and solar generation for each of the EIM members. Within the model, BAs not participating in the EIM are required to maintain flexibility reserves to meet 95% of the upward and downward deviations of their individual BAA's 10-minute real-time net load compared to their HA forecast. EIM participants are instead allowed to collectively meet a joint flexibility reserve requirement, which due to load and resource diversity is lower than the sum of individual BAA reserve requirements without EIM participation. APS's participation in the EIM is expected to reduce APS's flexibility reserve requirement as well as to enable an incremental reduction in flexibility reserve requirements for the current EIM participants.

In the ISO, the flexible ramping constraint provides an estimate of the market price for this ramping capability. We valued the quantity reduction in flexibility reserve requirements based on a range of historical ISO flexible ramping constraint shadow prices that were present in 2013 and 2014. The low value case uses the 2014 average price of $2.23/MWh, and the high value case uses the 2013 average flexible ramping shadow price of $6.98/MWh.

The table below summarizes the flexibility reserve savings estimated in this analysis. The results include both savings to APS as well as incremental reserve savings to the current EIM participants as a result of additional load and resource diversity of the larger EIM footprint that includes APS.

Table 3: Flexibility Reserve Savings

	Quantity reduction in flexibility reserve requirements (average MW)	Value of Flexibility Reserves Savings ($MM per year)	
		Low Case	High Case
Savings To APS	52.2	$1.0	$3.2
Incremental Savings To Current EIM Participants	83.4	$1.6	$5.1
Total Incremental Savings	135.6	$2.6	$8.3

In an average hour over the year, APS's participation in the EIM is estimated to reduce upward flexibility reserve requirements by a total 135.6 MW, a 12% reduction compared to the sum of requirements for the current EIM plus APS's individual requirement as a non-participating BA. The reduction is attributed to each EIM participant based on their relative share of standalone reserve requirements under a scenario without the EIM. For APS, the attributed diversity benefit of 52.2 MW on average represents a 28% reduction in flexibility reserves requirements compared to APS's requirements as a non-participant in the BAU case. Over the entire year, this flexibility reserve reduction produces savings to APS of $1.0 million in the low flexibility reserve value level, and $3.2 million when assuming the high flexibility reserve value.

The remaining reserve reduction of 83.4 MW is attributed to the current EIM participants, an 8% reduction relative to their requirements under the current EIM, resulting in an annual savings range of $1.6 to $5.1 million. APS is attributed a large share of total incremental savings shown in the table because the current

EIM participants are assumed to have already realized reductions in reserve requirements through the existing EIM. Thus, the table shows only the flexibility reserve reductions to those current participants that are incremental as a result of APS's participation. By contrast, the flexibility reserve savings to APS represents a full savings compared to a BAU scenario in which APS does not participate and therefore must procure reserves based on its individual BAA flexibility requirements as a standalone entity.

Summary

The estimated sub-hourly dispatch savings and flexibility reserve savings from EIM participation are together expected to be material for APS, totaling $9.9 to $12.1 million in the primary scenario. These savings to APS remain significantly positive under a robust set of fuel price levels and assumptions about renewable additions, coal retirements, and CO_2 prices. Total quantified APS EIM benefits ranged from $7.0 million to $18.1 million per year across all the scenarios evaluated. [11] This total excludes additional benefits from improved transactional efficiency in the DA or HA markets and from improved reliability, which were not quantified here but could be substantial.

[11] Individual components of low range savings do not sum to total due to rounding.

1 Introduction

Arizona Public Service Company (APS) retained Energy and Environmental Economics, Inc. (E3) to estimate the economic benefits of APS's participation in the energy imbalance market (EIM) operated by the ISO. Energy Exemplar provided technical support by running sub-hourly production simulations cases using the PLEXOS production simulation modeling tool to calculate the dispatch cost savings category of benefits. Throughout the study process, the study team of E3 and Energy Exemplar worked closely with APS staff to refine scenario assumptions and data inputs to more accurately represent current operations on the APS system. This report details our approach for quantifying the benefits of APS's participation in the EIM and summarizes the findings of our analysis.

1.1 Structure of the Report

The remainder of this report is organized as follows:

+ **Section 2** describes the methodologies and assumptions used to estimate the benefits of APS's participation in the EIM;
+ **Section 3** presents the main results of the study;
+ **Section 4** provides the conclusions of the study.

2 Study Assumptions and Approach

2.1 Overview of Approach

The EIM, which began operating in November 2014 with the ISO and PacifiCorp as initial participants, allows Western BAs to voluntarily participate in the ISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances using security constrained economic dispatch (SCED), as well as commit quick-start generation every 15 minutes using security constrained unit commitment (SCUC). Each BA participating in the EIM is still responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices in advance of real-time.

APS's participation in the EIM is expected to produce two principal benefits resulting from changes in system operations for APS and the current EIM participants:

1. **Sub-hourly dispatch benefits**. Today, each BA outside of the EIM dispatches its own generating resources to meet imbalances within the hour, while holding schedules with neighboring BAs constant. The EIM nets energy imbalance across participating BAs, and economically

dispatches generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. APS's participation in the EIM enables incremental dispatch efficiency improvements relative to the current EIM.

2. **Flexibility reserve reductions**. BAs hold flexibility reserves to balance discrepancies between forecasted and actual net load within the hour. *Load following flexibility reserves* (referred to in this report as simply "*flexibility reserves*") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.[12] By pooling load, wind, and solar output across the EIM footprint, the EIM allows participants to benefit from greater geographic diversity of forecast error and variability by reducing the quantity of flexibility reserves they require. APS's participation in the EIM would bring added load and resource diversity to the current EIM footprint, resulting in additional reserve savings.

Our general approach to estimating the benefits of APS's participation in the EIM is to compare the total cost under two cases: (1) a "business-as-usual" (BAU) case in which APS is not an EIM participant, and the operational efficiencies of the "current EIM" (including the ISO, PacifiCorp, and NV Energy)[13]

[12] Regulating reserves, which address the need for resources to respond to changes on a sub-5 minute interval basis, are sometimes categorized in operational studies as a second type of flexibility reserve product. Since the EIM operates with 5-minute intervals, it is does not directly affect regulating reserve requirements. To be concise, all references to *flexibility reserve* in this report are related to load following reserves; *regulating reserves*, where referenced, are explicitly described by name.

[13] The ISO, PacifiCorp, and NV Energy are referred to in this study as "current EIM participants" because they are assumed to be already participating in the EIM before APS becomes a participant. NV Energy will also begin participating in the EIM in Fall 2015. Puget Sound Energy (PSE) also announced in March 2015 that it intends to begin participating in the EIM in Fall 2016. The majority of this analysis for APS was completed prior to PSE's announcement, so PSE is not included as an EIM participant in this study.

is already reflected; and (2) an "APS EIM" case in which the APS BA also participates in the EIM. The cost difference between the BAU and APS EIM cases represents the total incremental benefits of APS's participation in the EIM.

We estimate sub-hourly dispatch benefits using production simulation modeling of DA, HA, and real-time operations. The difference in WECC-wide production costs between the APS EIM simulations and the BAU simulation represents the incremental dispatch benefit for all EIM participants, including APS, as a result of APS's participation. To estimate cost savings from reduced flexibility reserve requirements, we used statistical analysis to determine the quantity of incremental flexibility reserve diversity that APS's participation would bring to the EIM, and then applied that quantity to historical flexible ramping constraint shadow prices from the ISO.

2.2 Key Assumptions

Four key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; (3) hurdle rates; and (4) flexibility reserves.

2.2.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, which require long lead times between scheduling the transaction and actual dispatch.[14] Within the hour, each BA resolves imbalances by manually dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real-time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in the PNNL report, as well as Section 2.3 below.

A PLEXOS simulation was run with hourly intervals in a DA stage, and then in an HA stage, using DA and HA forecasts of expected load, wind, and solar output. In the final stage, a real-time PLEXOS simulation is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are at a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM benefits results that we expect may be somewhat conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM can provide. Overall, however, we expect the 10-minute time step to capture much of the real-time dispatch efficiency savings.

[14] The ISO and AESO are the exceptions.

During the real-time simulation, BAs not participating in the EIM must maintain a net exchange with neighboring BAs that is equal to the HA exchange level. EIM participants, on the other hand, can re-dispatch generation and exchange power with the rest of the EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.2.2 below.

In E3's prior analyses assessing the benefits of PacifiCorp and NV Energy participating in the ISO EIM, we used GridView, an hourly production cost model with input data largely based on TEPPC's 2022 Common Case. The 10-minute time-step capability of PLEXOS allows us to better represent the EIM's 5-minute dispatch interval relative to GridView's hourly time-step capability.[15]

2.2.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real-time between EIM participants.

For the BAU case, we adopted real-time transmission transfer capability assumptions between current EIM participants from earlier EIM benefit analyses. All scenarios modeled 400 MW of capability between PacifiCorp and the ISO, and 1,500 MW of capability between the ISO and NV Energy.[16] For the APS EIM simulation, we allowed the physical limits on transmission capability

[15] The WECC GridView database is currently developing a sub-hourly modeling capability, but this functionality and the sub-hourly data required were not available at the time of this analysis.
[16] These values are informed by capacity rights owned or controlled by the current EIM participants. Total maximum and minimum flow levels between zones in the model (including HA flow plus incremental changes in real-time) are also subject to physical transmission constraints on rated paths.

between APS and other EIM participants to constrain the maximum total transfer between these BAs for HA flow plus real-time EIM transfers. In the model, these transmission limits included over 2,500 MW of connectivity between APS and the ISO and 600 MW between APS and PacifiCorp. The transmission topology did not include a separate trading hub zone and did not include any direct interties between APS and NV Energy, so APS to NV Energy EIM transfers would need to pass through the ISO or PacifiCorp.

2.2.3 HURDLE RATES

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 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" DA trading products defined by the Western Systems Power Pool, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", $/MWh price adders applied to interfaces between BAAs. Hurdle rates inhibit power flow over transmission paths that cross BAA boundaries, and reduce economic energy exchange between BAAs.

An EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates between EIM participants during the real-time simulations, while maintaining hurdle rates between non-participants. In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants.[17] We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we would expect that BAs would adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

Based on guidance from APS staff indicating that APS can typically send power to the ISO through the Palo Verde trading hub without incurring wheeling

[17] This approach—to maintain hurdle rates for the DA and HA simulation and remove them in the real-time simulation run—is consistent with the methodology used by PNNL in the NWPP's MC Phase I EIM Benefit study.

charges, this study applied a hurdle rate of $0/MWh on transactions from APS to the ISO for the DA, HA, BAU and APS EIM cases. Charges for CO_2 import fees related to AB32 are still applied to energy transfers from APS to California.

For interties between the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM scenarios. The removal of hurdles rates in real-time between current EIM participants in this analysis is consistent with the FERC-approved ISO tariff amendment associated with the EIM. One sensitivity case is used to test the impact of this assumption, by adding back in a $1/MWh wheeling charge to real-time transfers between EIM participants in the simulation. As described in the next chapter, this change has only a small downward impact on the resulting EIM benefits modeled.

2.2.4 FLEXIBILITY RESERVES

BAs hold capacity in reserve to balance discrepancies between forecasted and actual net load within the operating hour; these within-hour reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[18] Regulating reserves automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to 5 minutes. Load following reserves (referred to in this report simply as "flexibility reserves") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.

[18] This study assumes that contingency reserves would be unaffected by an EIM, and that APS would continue to participate in its existing regional reserve sharing agreement for contingency reserves.

Higher penetrations of wind and solar increase the quantity of both regulating and flexibility reserves needed to accommodate the uncertainty and variability inherent in these resources, while maintaining acceptable BA 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.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participating in the EIM—savings are exclusively related to flexibility reserves that are needed for net load variations between the hourly and 5-minute level.

For this study, we used statistical analysis to estimate the reduction in flexibility reserves that would occur if APS participates in the EIM. Flexibility reserve requirements for each BA were modeled as a function of the difference between the 10-minute net load in real-time versus the HA net load schedule.

While there is currently no defined requirement for BAs to carry flexibility reserves, all BAs must carry a level of operating reserves in order to maintain Control Performance Standards (CPS) within acceptable limits, and reserve requirements will grow under higher renewable penetration scenarios. In December 2011, the ISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[19] Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the ISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The ISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The ISO determines flexible ramp constraint requirements for the ISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

2.3 Sub-hourly Dispatch Benefits Methodology

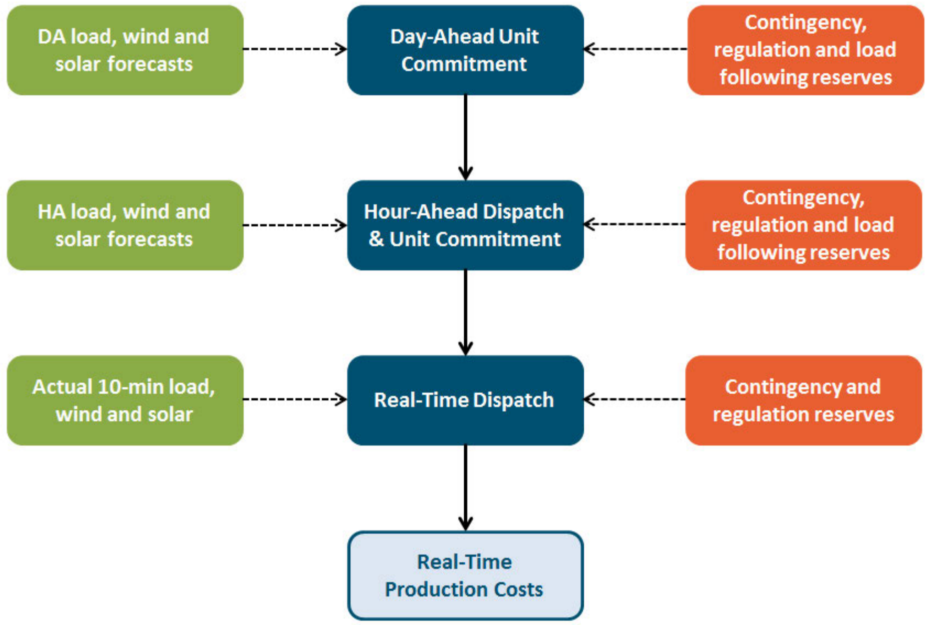
2.3.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a

[19] See CAISO (2014d and 2014e).

three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch and interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances.

The DA, HA, and real-time (DA-HA-RT) sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in an EIM. When a BA is not participating in an EIM, then: (a) hurdle rates apply during the DA, HA and real-time simulations; (b) interchange is unconstrained during the DA and HA simulations; and (c) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation. In contrast, when two or more BAs are participating in an EIM, then hurdle rates on transfers between the participating BAs are removed during the real-time stage and generation from anywhere in the footprint can solve imbalances, subject to imposed transmission constraints.

This study estimated sub-hourly dispatch benefits of APS's participation in the EIM by running pairs of production cost simulations using PLEXOS. Under each simulation scenario, there is a pair of BAU and APS EIM cases. In the BAU case, APS solves its real-time imbalances with internal generation while maintaining interchange equal to the schedule from the HA simulation. Intra-hour interchange is allowed to vary to allow economic transfers between the ISO, PacifiCorp and NV Energy, reflecting the operational efficiencies of the current EIM. The APS EIM cases simulate the operations of an EIM consisting of the ISO, PacifiCorp, NV Energy and APS BAs. Hurdle rates between the BAs are removed in real-time and intra-hour interchange is allowed up to the real-time transfer capabilities specified in each scenario. The study quantifies the EIM-wide benefit of APS's participation in the EIM by measuring the reduction in production costs from the BAU case to the APS EIM case.

2.3.2 INPUT DATA

The initial dataset used for this report is the database used in analysis for the WECC VGS analysis and updated in the NWPP's Phase 1 Economic Benefit

Assessment. This dataset was built on information originally compiled for the WECC's Transmission Expansion Planning Policy Committee (TEPPC) 2020 PC0 database.

This study made the following key updates to the case:

+ **Zonal transport model**. The transmission network in PLEXOS was modeled at the zonal level rather than the nodal level. This change was made to more accurately represent commercial behavior of two BAs scheduling transactions between each other through trading hubs. Using the zonal model also significantly reduces model run time.
+ **Topology updates**. The transmission transfer capability between APS and neighboring zones was modeled according to APS's typical monthly total transmission capability. The remaining transmission topology and hurdle rate assumptions are based on the zonal model used for the ISO's 2012 Long-Term Procurement Plan (LTPP).
+ **Combustion turbine commitment during real-time**. Quick-start combustion turbines were allowed to commit and dispatch in the real-time simulations to reflect the ISO's addition of the 15-minute real-time unit commitment process for the EIM.
+ **Hydro optimization window**. The real-time simulations optimized the dispatch of flexible hydro units across a 6-hour window.
+ **Nuclear generation**. All nuclear plants throughout the WECC were modeled as must-run at their maximum capacity to avoid any unrealistic intra-hour changes in nuclear generation.
+ **Generation updates in California**. A number of select generator updates were made in the California ISO footprint, including: (1) retiring the San Onofre Nuclear Generation Station (SONGs); (2) applying the ISO's current best estimate of retirement and repowering of once-through

cooling generators by 2020; (3) updating the ISO's share of Hoover generation to match the values in the 2012 LTPP, and (4) updating the California ISO renewable resource mix to reflect a higher share of solar PV in the renewable resource portfolio and a lower share of wind resources based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the ISO, which was not reflected in the original TEPPC model.

+ **Generation updates in APS**. APS generation in the database was updated to reflect APS planned additions of peaking units at Ocotillo, its planned retirement of a Cholla unit, as well as APS suggested revisions to operating characteristics and costs on certain APS generators. Additionally, based on information from APS indicating that APS currently does not routinely call on the Four Corners plant or its share of the Navajo plant to respond to within-hour changes, E3 held the real-time dispatch of those units equal to their hour-ahead dispatch levels during the real-time cases.

2.3.3 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under a primary scenario and ten alternative scenarios with different assumptions regarding RPS levels in California, natural gas prices, coal retirements, CO_2 prices, and EIM wheeling charges on transactions. The scenarios were developed based on input from APS staff to highlight changes that APS believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating EIM sub-hourly benefits.

In the primary scenario, the burnertip natural gas price in the APS BA is equal to $4.4 per MMBtu, and this price is adjusted by +30% and -30% in the High Gas Price and Low Gas Price Scenarios, respectively. Natural gas prices in all other BAs throughout the WECC were adjusted by a similar percentage.

Table 4. Overview of EIM Scenario Assumptions

Scenario	CA RPS	CA CO_2 price level ($/ton)	Rest of WECC CO_2 price level ($/ton)	APS natural gas price ($ per MMBTU)	Incremental coal retirement	EIM wheeling rate ($ per MWh)
0. Primary Scenario	**33%**	**$18**	**$0**	**$4.4**	**Base**	**$0**
1. CA 40% RPS	40%	$18	$0	$4.4	Base	$0
2. WECC-wide CO_2 ($18/ton)	33%	$18	$18	$4.4	Base	$0
3. Significant WECC Coal Retirement	33%	$18	$0	$4.4	Large	$0
4. Moderate WECC coal retirement	33%	$18	$0	$4.4	Moderate	$0
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	33%	$40	$40	$4.4	Moderate	$0
6. 30% Higher Gas Prices	33%	$18	$0	$5.7	Base	$0
7. 30% Lower Gas Prices	33%	$18	$0	$3.1	Base	$0
8. EIM wheeling cost $1/MWh	33%	$18	$0	$4.4	Base	$1
9. High CA RPS, high gas, moderate coal retirement	40%	$18	$0	$5.7	Moderate	$0
10. High CA RPS, low gas, moderate coal retirement	40%	$18	$0	$3.1	Moderate	$0

2.3.4 ATTRIBUTION OF BENEFITS TO EIM PARTICIPANTS

Total production cost savings represent the dispatch benefits to all EIM participants, including APS, as a result of APS's participation in the EIM. We attributed these benefits to APS and the current EIM participants by calculating the sum of the following components: (1) real-time generator production costs and (2) real-time imbalance costs, equal to imbalance times an EIM-wide market clearing price. The sum of these components for a given area, such as APS, represents a proxy for the total cost to serve load, including the production costs to run local generators and the cost of importing power (or revenues from exporting power). The net change in this sum in the APS EIM case versus the BAU case represents the incremental benefit to a given participant as a result of APS's participation.

Since the EIM does not affect HA operations, there is no change in HA net import costs between the BAU and APS EIM cases. The EIM-wide market clearing price used to calculate real-time imbalance costs is the imbalance-weighted average of the participating BAs.

2.4 Flexibility Reserve Savings Methodology

The operational cost savings from reduced flexibility reserve requirements were estimated using the following methodology. First, a statistical analysis is used to estimate the quantity of flexibility reserve reductions from APS's participation in the EIM. To produce EIM annual reserve savings, this quantity reduction of flexibility reserve requirements is valued based on historical ISO flexible ramping constraint shadow prices for 2013 and 2014.

2.4.1 FLEXIBILITY RESERVE REQUIREMENT

To determine flexibility reserve requirements, we used the real-time (10-minute) and HA schedule of load, wind, and solar data developed through the WECC VGS and PNNL study. These data are used to calculate a distribution of flexibility needs (i.e., real-time net load minus the HA net load schedule). Each

BA's flexibility reserves requirement for each month and hour are calculated using a 95% confidence interval (CI), where the 2.5th and 97.5th percentiles determine the flexibility down and up requirements, respectively.[20]

For the BAU case, the flexibility requirements for the current EIM were calculated by summing the net load profiles for the ISO, PacifiCorp and NV Energy BAs before calculating the 95% CI.[21] APS's standalone requirements are calculated as a standalone entity. In the APS EIM case, flexibility requirements are calculated for the larger EIM including APS by summing the ISO, PacifiCorp, NV Energy and APS BA net load profiles. APS's EIM participation results in a "diversity benefit" that reduces total upward flexibility requirements by 135.6 MW on average.[22]

2.4.2 AVOIDED COST OF FLEXIBILITY RESERVES

To value flexibility reserve reductions, we first examined flexible ramping constraint shadow prices in the ISO for 2013 and 2014. The ISO has applied a flexible ramping constraint in the five-minute market optimization since December 2011 to maintain sufficient upward flexibility. Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. However, if there is sufficient capacity available, the constraint is not binding, resulting in a shadow price of zero. For 2013 the average flexible ramping constraint shadow price over all

[20] Using the 95% confidence interval to calculate flexibility reserve requirements is consistent with the approach used in the NWPP EIM Phase 1 study.
[21] Due to diversity in forecast error and variability, the 95th percentile of aggregated real-time deviation from HA forecast for the entire EIM is a smaller level (relative to the size of the BAs) than it would be for the sum of individual EIM members.
[22] This reduction is subject to real-time transmission transfer capability limits, and cannot be larger than the transmission transfer levels between individual EIM participants and the rest of the EIM.

hours of the year was \$6.98/MWh, and in 2014 the shadow price was \$2.23/MWh on average.[23] Quantity reductions in *upward flexibility* requirements in 2020 are valued at the 2013 shadow price under the high flexibility reserve benefit case, and at the 2014 shadow price under the low flexibility reserve benefit case.

2.4.3 ATTRIBUTION OF FLEXIBILITY RESERVE SAVINGS

Flexibility reserve savings were attributed to APS and the current EIM participants by comparing their relative reduction in flexibility reserve requirements in the BAU case compared to the case with APS as an EIM participant. The ISO's Business Practice Manual (BPM) details how the ISO will assign flexibility reserve requirements among EIM participants. Each participating BA will be assigned a flexibility requirement equal to the BA's standalone flexibility reserve requirement (if it were not an EIM participant). This is reduced by an EIM reserve diversity factor that is equal to the combined EIM flexibility reserve requirement (which reflects diversity benefit across the EIM) divided by the sum of standalone flexibility reserve requirement quantity for all EIM participants if they were operating as standalone entities.[24]

Overall, APS's participation in the EIM provides incremental diversity to the full EIM footprint, reducing flexibility reserve requirements for current EIM participants by 83.4 MW on average, which is an 8% reduction compared to their requirements in the current EIM. APS's own flexibility reserve requirement

[23] See CAISO (2014a). Inflated here from 2013 to 2014 dollars assuming an annual inflation rate of 2%.
[24] See CAISO (2014b).

is reduced by 52.2 MW on average, a 28% reduction from its requirements as a standalone BA.

3 Results

3.1 Benefits to APS

Table 5 below presents the annual benefits of APS's EIM participation in 2020 under each scenario. Each row displays APS's EIM sub-hourly cost savings for a particular scenario modeled in the PLEXOS simulation, the flexibility reserve requirement savings range, and the total benefits, which is the sum of sub-hourly dispatch savings plus flexibility savings.

Table 5. Annual Benefits to APS by Scenario (million 2014$)

Scenario	Sub-hourly dispatch Savings to APS	Flexibility Reserve Savings Range	Total EIM savings to APS
0. Primary Scenario	**$8.9**	**$1.0 - $3.2**	**$9.9 - 12.1**
1. CA 40% RPS	$12.9	**$1.0 - $3.2 (for all scenarios)**	**$14.0 - 16.1**
2. WECC-wide CO_2 ($18/ton)	$10.7		**$11.7 - 13.9**
3. Significant WECC Coal Retirement	$8.3		**$9.3 - 11.5**
4. Moderate WECC coal retirement	$8.0		**$9.0 - 11.2**
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	$8.5		**$9.6 - 11.7**
6. 30% Higher Gas Prices	$11.9		**$12.9 - 15.1**
7. 30% Lower Gas Prices	$5.9		**$7.0 - 9.1**
8. EIM transfer cost $1/MWh	$8.4		**$9.5 - 11.6**
9. High CA RPS, high gas, moderate coal retirement	$14.9		**$16.0 - 18.1**
10. High CA RPS, low gas, moderate coal retirement	$8.9		**$10.0 - 12.1**

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

The resulting EIM sub-hourly dispatch benefits to APS shown in Table 5 range from $5.9 million per year (in Scenario 7, which assumes low natural gas prices in APS and through the WECC) to $14.9 million (in Scenario 9, which includes high gas prices, a 40% RPS in California, and moderate incremental coal retirements). The primary case savings to APS were $8.9 million. Comparing scenarios indicates that a higher RPS in California, and higher gas prices tend to have a positive impact on EIM benefits. By contrast, lower gas price assumptions (such as in Scenarios 7 and 10) reduce EIM dispatch benefits to APS because they lower the value of savings that results when the EIM improves the dispatch efficiency of gas generators. A range of coal retirement scenarios were developed to test whether EIM savings would change significantly if coal dispatch was reduced across the WECC as a result of the U.S. Environmental Protection Agency's Clean Power Plan Proposed Rule or other federal regulations restricting electric sector CO_2 emissions. These cases show slightly lower EIM savings for APS relative to the primary scenario, with the differences for these scenarios relative to the primary case typically being less than $1 million per year.

The flexibility reserve savings to APS range from $1.0 to $3.2 million per year in all scenarios. The range was produced using the 52.2 MW average reduction in APS upward flexibility reserve requirements over the full year, multiplied by the ISO historical values for flexible ramping constraint shadow prices (in $/MWh) from 2014 (low case) and 2013 (high case).

3.2 Incremental Benefits to Current EIM Participants

Table 6 below presents the incremental benefit to the current EIM participants as a result of APS's participation in the EIM. In total, APS's participation is projected to create \$3.0 to \$6.5 million per year in incremental sub-hourly dispatch and flexibility reserves benefits for the current EIM participants under the primary scenario, and a range of total benefits from \$2.2 to \$8.1 million per year under the alternative scenarios.

Table 6. Annual Benefits to Current EIM Participants (million 2014$)

Scenario	Sub-hourly dispatch Savings to Current EIM Participants	Flexibility Reserve Savings Range	Total EIM savings to Current EIM Participants
0. Primary Scenario	**$1.4**	**$1.6 - $5.1**	**$3.0 - 6.5**
1. CA 40% RPS	$0.6	**$1.6 - $5.1 (for all scenarios)**	**$2.2 - 5.7**
2. WECC-wide CO_2 ($18/ton)	$2.9		**$4.5 - 8.0**
3. Significant WECC Coal Retirement	$0.9		**$2.6 - 6.0**
4. Moderate WECC coal retirement	$0.8		**$2.4 - 5.9**
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	$3.0		**$4.6 - 8.1**
6. 30% Higher Gas Prices	$2.2		**$3.8 - 7.3**
7. 30% Lower Gas Prices	$1.9		**$3.6 - 7.0**
8. EIM transfer cost $1/MWh	$2.1		**$3.7 - 7.2**
9. High CA RPS, high gas, moderate coal retirement	$1.4		**$3.1 - 6.5**
10. High CA RPS, low gas, moderate coal retirement	$0.7		**$2.3 - 5.8**

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

3.3 Results Discussion

3.3.1 DRIVERS OF SUB-HOURLY DISPATCH BENEFITS

Sub-hourly dispatch benefits are driven by a number of factors in the different scenarios modeled. EIM participation enables APS to flexibly import and export within the hour over its interties with other EIM participants, as opposed to maintaining fixed hourly net interchange schedules as in the BAU case, and solely relying on its own resources to resolve real-time imbalances. As a result, EIM participation reduces the frequency that APS needs to start up and run its more expensive generation to respond to sub-hourly changes in load or renewable resource conditions, so APS can serve more of its load using lower cost units. Figure 2 below shows APS net exchange over a 3-day period in August for both the BAU and APS EIM case; positive values in the figure indicate outgoing energy flows from APS to other BAs. The figure illustrates how EIM participation enables APS to have a much more flexible sub-hourly net exchange than APS would have if scheduling bilaterally on a fixed hourly basis as assumed in the BAU case.

Figure 2. APS Net Exchange for Three-Day August Period

Additionally, EIM participation enables APS to import low-cost power from the other EIM participating BAAs during hours when those BAAs have lower cost generation that becomes available in a sub-hourly time interval due to lower than expected load or higher than expected wind and solar output within the hour. The ISO BAA in particular, due to the large level of solar generation present in its system by 2020, has significant within-hour ramps and at times faces very low real-time prices or even negative prices when it would need to curtail renewable generation that it cannot use in that time to serve load. As an EIM participant, APS can provide a service and also realize cost savings during these conditions, by reducing its own internal dispatch in real-time and reducing its exports to the ISO (relative to the hour-ahead interchange schedule).

3.3.2 DRIVERS OF FLEXIBILITY RESERVE SAVINGS

The additional diversity from APS's participation in the EIM would bring an incremental 135.6 MW reduction in EIM-wide flexibility reserve requirements compared to the sum of current EIM reserve requirements plus APS standalone reserve requirements in the BAU case. The EIM assigns flexibility reserve requirements and allocates the diversity reduction among EIM participants based on their relative share of the sum of standalone reserves if each were operating without an EIM. On average, throughout the year, this methodology results in a 52.2 MW reducing in average flexibility reserve requirements for APS and an incremental 83.4 MW reserve reduction attributed to the current EIM participants.

This study values these flexibility reserve reductions based on the average historical flexible ramping constraint shadow price in the ISO. The high case uses the 2013 historical average shadow price, which was $6.98/MWh; the low case uses the 2014 historical average shadow price which was $2.23/MWh.[25]

3.3.3 CONSERVATIVE ASSUMPTIONS

This study applied a number of conservative assumptions in this analysis, which could result in underestimating the benefits quantified above that would accrue to APS and to the current EIM participants. These assumptions include:

- **Reliability-related benefits were not quantified.** The study did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM will enable. Although these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.
- **HA and DA transactions held constant**. The modeling approach conservatively assumed in the DA and HA case runs that APS's participation in the EIM would not change APS dispatch or transactional decisions relative to the BAU scenario. Over time, however, we believe as an EIM participant, APS may be able to use information obtained through more transparent awareness of the real-time market to adjust its positions more optimally in the HA and DA markets. APS's participation in the EIM could also allow APS to avoid transactions costs related to buy-sell price spreads currently incurred for market purchases and sales in bilateral 15-minute or HA trading. EIM transactions for APS would avoid such costs.
- **Intra-regional dispatch savings were not quantified.** APS indicated that internal congestion on the APS system is usually small, so the analysis

[25] Adjusted from 2013 to 2014 dollars.

did not endeavor to quantify if the EIM can help reduce costs or relieve problems within APS's BAA.

- **Thermal generators were modeled with flat heat rates.** The database used in this study modeled units with a single heat rate point regardless of the unit's level of dispatch. Other databases typically use step-function incremental heat rates for thermal generators; such heat rates reflect the fact that a generator will typically have a higher average heat rate when operating at minimum dispatch levels (i.e., Pmin) compared to when operating closer to maximum output (i.e., Pmax). The EIM dispatch savings are driven by identifying efficiency opportunities to reduce dispatch of generation in one BAA and increase dispatch on a lower-cost generator located in a different participating BAA. Modeling thermal units with non-flat heat rates could produce greater variation in heat rates across generators (depending on their operating levels) and result in greater opportunities for EIM dispatch savings.

4 Conclusions

This study assessed the benefits to APS from participation in the ISO EIM, as well as the incremental savings that would accrue to the current EIM participants as a result of APS's participation. The study focused on quantifying two categories of benefits: sub-hourly dispatch savings and savings from reduced flexibility reserve requirements. The gross benefits identified are robust to a range of input assumptions regarding RPS levels in California, natural gas prices, coal retirements, CO2 prices, and EIM wheeling charges on real-time transactions. Increased RPS levels in California would likely have an upward impact on EIM savings to APS, as it would lead to more hours in which there is value to the flexibility provided by APS generators and the ability of APS to selectively reduce real-time dispatch to bring low or zero cost energy from the other portions of the EIM.

These savings do not include a quantification of potential savings to APS from improved DA or HA market efficiency as a result of access to EIM pricing data, nor from improved reliability. The modeling approach conservatively assumed in the DA and HA case runs that APS's participation in the EIM would not change APS dispatch or transactional decisions relative to the BAU scenario. Over time, however, we believe as an EIM participant, APS may be able to use information obtained through more transparent awareness of the real-time market to adjusting its positions more optimally in the HA and DA markets. In addition, APS's participation in the EIM may allow APS to avoid transactions costs related to buy-sell price spreads currently incurred for market purchases and sales in bilateral 15-minute or HA trading.

Finally, we did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM creates. Although both of these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits in addition to the savings quantified in this study.

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**BEFORE THE PUBLIC UTILITY COMMISSION
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***Benefits Analysis of Puget Sound Energy's
Participation in the ISO Energy Imbalance Market,***
Energy and Environmental Economics (September 2014)

August 18, 2015

PSE PUGET SOUND ENERGY

California ISO
Shaping a Renewed Future

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Energy+Environmental Economics

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- Joe Hoerner, PSE
- Josh Newkirk, PSE
- Zach Gill-Sanford, PSE
- Mark Rothleder, California ISO
- Jim Price, California ISO
- Don Fuller, California ISO
- Xiaobo Wang, California ISO
- Dave Timson, California ISO

Acronyms

BA	Balancing Authority
BAA	Balancing Authority Area
CAISO	California Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
NPV	Net Present Value
NVE	NV Energy
PAC	PacifiCorp
PSE	Puget Sound Energy

Executive Summary

This report examines the benefits of Puget Sound Energy's (PSE) participating in the energy imbalance market (EIM) operated by the California Independent System Operator (ISO). The ISO's EIM is a regional 15- and 5-minute balancing energy market, including real-time unit commitment capability, which will go live with binding settlements in November 2014 between the ISO and PacifiCorp, with NV Energy planning to participate starting in October 2015. In this study, the ISO, PacifiCorp, and NV Energy are referred to as "current EIM participants", and they are assumed to be already participating in the EIM before PSE's participation would commence, which is assumed to be in 2016.[1]

This report estimates the benefits of PSE's participation in the EIM for two scenarios with alternative sub-hourly transmission transfer capability levels between PSE and current EIM participants.[2] For the 2020 study year, participation in the EIM is estimated to bring sub-hourly dispatch efficiency and flexibility reserves savings to PSE in the range of $18.3 to $20.1 million per year.

Since an EIM increases operational efficiency and flexibility, it also could facilitate cost effective renewable integration. If feasible, this could allow PSE to save an

[1] Throughout this report, Balancing Authorities (BAs) that participate in the EIM are described as "EIM participants". These participating BAs are referred to in the ISO's EIM Business Practice Manual and tariff as "EIM Entities". See CAISO (2014b).
[2] All benefits are reported in 2014 dollars.

additional $9.1 million per year in wind integration costs. PSE also anticipates that, under certain conditions, EIM participation could help PSE obtain additional cost savings of up to $0.8 million per year related to avoiding curtailment of renewable energy resources if PSE were to balance all of its wind resources within its Balancing Authority Area (BAA).[3]

For the 2020 study year, PSE's participation is also expected to provide benefits of $3.5 to $4.2 million per year for the current EIM participants, and create no incremental implementation costs to those entities. All incremental costs are expected to be recovered from PSE through fixed and administrative charges.

PSE has evaluated the costs and benefits reported in this study and concluded that its participation in the EIM is likely to provide a low-risk means of achieving operational net benefits for PSE and current EIM participants. PSE staff has estimated that PSE would incur one-time EIM startup costs of $14.2 million including contingency costs, and ongoing costs of approximately $3.5 million per year. These startup costs, taken together with a 20-year series of ongoing costs and annual benefits consistent with the level identified in this report, would produce a Net Present Value (NPV) of $153.7 million to $174.4 million.[4] These results also provide further confirmation that total expected EIM benefits can

[3] A Balancing Authority Area (BAA) is the collection of generation, transmission, and loads within the metered boundaries of a BA, which is responsible entity that maintains load-resource balance within this area, integrates resource plans ahead of time, and supports Western Interconnection frequency in real-time. See NERC (2014).

[4] NPV has been estimated for the year 2014. The calculation assumes 20 years of sub-hourly dispatch and flexibility reserves benefits and annual ongoing cost from 2016 through 2035. PSE's participation in the EIM is estimated to go live in Fall 2016 with benefits and ongoing costs assumed to begin then. Startup costs are assumed to be incurred during 2015 and 2016. All values have been discounted using PSE after-tax weighted average cost of capital (WACC) of 6.7% nominal, consistent with PSE's 2013 Integrated Resource Plan (IRP), and have assumed annual inflation rate of 2%. Increasing the NPV calculation to include 30 years of benefits and ongoing costs would raise the NPV range to $190.2 to $216.3 million.

increase as additional participants join the EIM and broaden the regional diversity and footprint of the real-time market.

Two additional material benefits have not been quantified. First, the study team conservatively assumed that PSE's behavior and actions in the hour-ahead (HA) and day-ahead (DA) market would not be influenced by the continuous information flowing from participation in the EIM market; we expect that such information could create learning and additional cost savings for PSE in the HA and DA market over time, but those additional savings are not quantified in the analysis for this report. Second, the study team did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM creates. Although both of these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.

EIM Background

Changes in the electricity industry in the Western U.S. are making the need for greater coordination between Balancing Authorities (BAs) increasingly apparent. Recent studies have suggested that it will be possible to reliably operate the current Western electric grid both with greater efficiency and higher levels of variable renewable generation. Doing so will require improving and supplementing the bilateral markets used in the Western states with mechanisms that allow shorter time intervals for scheduling and more optimized coordination. The EIM provides such a mechanism.

The EIM is a balancing energy market that optimizes generator dispatch within and between participating BAAs every 15 and 5 minutes. The EIM does not replace the DA or HA markets and scheduling procedures that exist in the Western Interconnection today.

By allowing BAs to pool load and generation resources, the EIM lowers total flexibility reserve requirements and minimizes curtailment of variable energy resources for the region as a whole, thus lowering costs for customers. The EIM is complementary to Federal Energy Regulatory Commission (FERC) Order 764, which emphasizes 15-minute scheduling over interties. The EIM builds value on top of this 15-minute scheduling capability by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits (known as "Security Constrained Economic Dispatch", or "SCED"); (2) bringing this optimized dispatch down to a 5-minute interval level; (3) incorporating optimized real-time unit commitment of quick-start generation; and (4) enabling better use and compensation of flexible ramping capacity in real-time, which reflects the diversity of loads and resources across the EIM footprint, allowing EIM participants to individually reserve a smaller amount of committed capacity for sub-hourly flexibility, further reducing total operational costs to reliably serve customers.

In advance of the November 2014 go-live date for EIM operations with binding settlements, the ISO and PacifiCorp have worked with stakeholders to finalize details of the EIM's structure and functions, and have received FERC approval for tariff changes that enable EIM implementation.[5] Throughout the EIM stakeholder process, the ISO has emphasized that the EIM is being designed to

[5] For the latest details of the ISO EIM, see CAISO (2014c).

enable other BAs throughout the Western Interconnection to participate. The ISO has established an EIM Governance Transitional Committee, whose members includes stakeholders from throughout the Western Interconnection, to further lead EIM development in a manner that is beneficial for many participants in the region, and to provide participants confidence that their perspectives are reflected in this process.

This Report

PSE and the ISO worked together to jointly assess the potential benefits of PSE's participation in the EIM and retained Energy and Environmental Economics, Inc. (E3), a consulting firm, to conduct an economic study quantifying those potential benefits. To support the study, Energy Exemplar provided technical support by running sub-hourly production simulations cases using PLEXOS, a production simulation modeling tool, to calculate a portion of the benefits. This report describes the findings of E3 and Energy Exemplar, who are together referred to as "the study team" throughout the report.

The report evaluates benefits using an approach that builds upon E3's EIM analyses for the ISO, PacifiCorp, and NV Energy.[6] In addition, the study leverages the modeling improvements summarized in Pacific Northwest National Laboratory's (PNNL) Phase 1 EIM analysis for the Northwest Power Pool (NWPP).[7] This study focuses on the incremental benefits related to PSE's participation in the EIM, while assuming that the ISO, PacifiCorp and NV Energy are already EIM participants in the base case. This study incorporates additional details provided

[6] See E3 (2013 and 2014).
[7] See Samaan et al. (2013).

by PSE to improve the accuracy of PSE's generation and transmission system represented in the production cost simulations.

The primary scenarios in this report assess different categories of potential cost savings from expanding the EIM to include PSE, allowing PSE and the current EIM participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources provided by PSE. Specifically, the participation of PSE in the EIM would yield two principal benefits:

+ *Sub-hourly dispatch benefits*, by realizing the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment across PSE and the current EIM footprint, compared to bilateral transactions typically done on an hourly basis under business-as-usual (BAU) practice for PSE; and
+ *Reduced flexibility reserves*, by reflecting the diversity of load, wind and solar variability and uncertainty across PSE and the footprint of current EIM participants.

In addition, if PSE were to integrate its remote wind resources to within its BAA, the EIM could help PSE realize savings from *reduced wind curtailment*, by allowing PSE to export or reduce imports of renewable generation when they would otherwise need to curtail their own resources, as well as *additional renewable balancing cost savings* related to incremental flexibility reserves required for PSE to balance external wind plants itself.[8]

[8] The PacifiCorp-ISO EIM and NV Energy-ISO EIM analyses modeled a wide range of potential avoided curtailment in the ISO as a result of the EIM. This report assumes that PSE's incremental participation in the EIM would not

E3's PacifiCorp-ISO EIM study included a separate 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 PSE's experience that there is little internal congestion within the PSE transmission system, the study team assumed this benefit would be small and therefore did not include it in this analysis.

In addition to the quantifiable benefits described above, the EIM is expected to provide additional reliability benefits that are not quantified in this report. A recent FERC staff report identified additional reliability benefits that may arise from an EIM.[9] These include enhanced situational awareness, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.

Benefit Methodology and Scenarios

The study team estimated the benefits of PSE's participation in the EIM using the PLEXOS production cost modeling software to simulate operations in the Western Interconnection for the calendar year 2020 with and without PSE as an EIM participant. The PLEXOS software and 2020 database developed by PNNL for the NWPP Phase 1 EIM study was selected to leverage the improved characterization of transmission and generation in the Northwest, and to improve the comparability of results from PSE's perspective.

provide incremental avoided curtailment savings for the ISO, PacifiCorp and NV Energy beyond that enabled through the current EIM; thus, curtailment savings included in this study are strictly related to wind plants owned by PSE.
[9] See FERC (2013).

Like the NWPP Phase 1 EIM study performed by PNNL, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations to mirror actual power system operations. The DA and HA stages are simulated on an hourly basis. The real-time stage is simulated with a 10-minute time-step and incorporates the variability and uncertainty associated with load, wind, and solar. The study team's analysis also incorporates California's greenhouse gas regulations and the associated dispatch costs.

The study team modeled flexibility reserve benefits by analyzing coincident sub-hourly load, wind, and solar generation for each of the EIM members. Within the model, BAs not participating in the EIM are required to maintain flexibility reserves to meet 95% of the upward and downward deviations of their own BAA's 10-minute real-time net load compared to their HA forecast. On the other hand, EIM participants are allowed to collectively meet a joint flexibility reserve requirement. By pooling load, wind and solar variability across a wider geographic area, EIM participants can lower the total variability and forecast error of their net load. As a result of this net load diversity, EIM participants can reduce the amount of flexibility reserves they require compared to the sum of flexibility reserves that they would require as individual non-participants. PSE's participation in the EIM is expected to enable an incremental reduction in flexibility reserve requirements for the current EIM participants, as well as to reduce PSE's own flexibility reserve requirement. The study team valued this reduction in flexibility reserve requirements using historical flexible ramping constraint shadow prices for the ISO from 2013.

The estimated benefits are sensitive to several key assumptions regarding the expected level of real-time transfer capability available for the EIM between PSE and the current EIM participants, as well as the real-time transfer capability over COI that connects the ISO and PacifiCorp. Table 1 below summarizes the real-time transfer capability for the BAU case, in which PSE does not participate in the EIM, and two scenarios that include PSE's participation in the EIM, with different levels of real-time transfer capability between BAs participating in the EIM. These two EIM scenarios produce different levels of sub-hourly dispatch benefits relative to the BAU case.

Table 1. Overview of Scenario Assumptions

Case Name	Real-time Transfer Capability		
	PAC-PSE	CAISO-PAC	CAISO-NVE
BAU	NONE	400	1500
PSE EIM Scenarios:			
Low Transfer	300	400	1500
High Transfer	900	700	1500

Notes: Real-time transfer capability represents the maximum amount (in MW) which a BA's net transfer over a path is allowed to differ in real-time, relative to its HA schedule. PAC-PSE transfer capability utilizes a combination of PSE, PacifiCorp, and BPA transmission.

Benefit Results

Across the two PSE EIM participation scenarios, the study team estimates that PSE's participation in the EIM would produce annual savings to PSE ranging from $18.3 to $20.1 million in 2020. Table 2 shows the range of sub-hourly dispatch and flexibility reserve benefits for each scenario; all benefits shown represent cost savings relative to the BAU scenario.

Table 2. Annual Benefits to PSE by Scenario (2014$ million)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$16.7	$1.6	**$18.3**
High Transfer	$18.5	$1.6	**$20.1**

In addition to the savings shown in Table 2, participation in the EIM may enable PSE to obtain up to $9.1 million per year in incremental balancing cost savings, as well as up to $0.8 million per year in avoided curtailment costs if PSE were to balance all of its wind resources within its BAA.

The study team also estimated the benefits that accrue to the current EIM participants as a result of PSE's participation, as shown in Table 3.

Table 3. Annual Benefits to Current EIM Participants by Scenario (2014$ million)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$0.6	$2.9	**$3.5**
High Transfer	$1.2	$2.9	**$4.2**

PSE's participation provides the opportunity for current EIM participants to realize incremental dispatch cost savings of $0.6 million to $1.2 million, depending on the transmission transfer capability level assumed. PSE's participation in the EIM would also create incremental load, wind, and solar diversity for the EIM, further reducing flexibility reserve requirements for the current EIM participants. This study also estimates that the incremental diversity from PSE's participation would bring $2.9 million in flexibility reserve savings to the current EIM participants. Flexibility reserve savings are the same across both EIM scenarios, because the range of EIM transfer capability levels assumed does not constrain potential flexibility reserve requirement reductions.

Across all scenarios, the incremental sub-hourly dispatch and flexibility reserve benefits for all EIM participants, including PSE, range from $21.8 to $24.3 million per year as a result of PSE's participation in the EIM.

1 Introduction

Puget Sound Energy (PSE) and the California Independent System Operator (ISO) retained Energy and Environmental Economics, Inc. (E3) to estimate the economic benefits of PSE's participation in the energy imbalance market (EIM) operated by the ISO. This report details our approach to identify and quantify the benefits of PSE's participation in the EIM, and presents the results of our analysis. Throughout the study process, the study team of E3 and Energy Exemplar worked closely with PSE and the ISO to refine scenario assumptions and data inputs, and to estimate benefits consistent with how each entity operates today, as well as with their expectation of future operations.

1.1 Background and Objectives

Changes in the electric industry in the Western Interconnection are making the need for greater coordination among Balancing Authorities (BAs) increasingly apparent. In particular, increasing penetrations of variable energy resources is driving interest in options to cost-effectively integrate those resources. One option to improve coordination is an EIM, which has been successful in other regions, such as the Southwest Power Pool (SPP). An EIM optimizes generator dispatch to resolve energy imbalances across multiple Balancing Authority Areas (BAAs), and can capture the value of geographic diversity of load and generation resources.

Several recent studies have examined the potential benefits of an EIM in the Western Interconnection. In 2011, E3 and the Western Electricity Coordination Council (WECC) examined the benefits of an EIM throughout the Western Interconnection, excluding the ISO and Alberta Electric System Operator (AESO).[10] In 2013, the National Renewable Energy Laboratory (NREL), on behalf of the Public Utility Commissions Energy Imbalance Market (PUC EIM) Group, extended the E3-WECC analysis by using a sub-hourly production simulation model.[11] In 2013, the Northwest Power Pool (NWPP) Market Assessment Committee (MC) Initiative examined the benefits of an EIM across the NWPP footprint through a study led by Pacific Northwest National Laboratory (PNNL), and the NWPP is continuing to evaluate opportunities for better regional coordination.[12] Each of these studies identified positive dispatch cost savings attributable to implementation of an EIM.

Starting in 2012, the ISO and PacifiCorp began actively developing a regional EIM in the Western Interconnection. The proposed EIM has received Federal Energy Regulatory Commission (FERC) approval for tariff changes in June 2014. The EIM is expected to go live with binding settlements in November 2014 with the ISO, PacifiCorp East, and PacifiCorp West BAs as the initial participants. In 2014, NV Energy obtained approval by FERC and the Public Utilities Commission of Nevada (PUCN) to begin participating in the EIM in Fall 2015.[13]

PSE has been actively exploring potential benefits of all regional coordination options, including participation in the NWPP MC Initiative. PSE and the ISO also

[10] See E3 (2011).
[11] See Milligan et al. (2013)
[12] See Samaan et al. (2013)
[13] See CAISO (2014f) and PUCN (2014).

engaged E3 to assess the impact of PSE's participation in the EIM. This report summarizes the findings of our analysis, with a focus on sub-hourly dispatch benefits and savings from reductions in flexibility reserve requirements. In addition to those benefits, this report also summarizes the potential cost-savings to PSE if the EIM can enable PSE to balance its own wind plants that are currently balanced in real-time by other BAs.

1.2 Structure of the Report

The remainder of this report is organized as follows:

- **Section 2** describes the methodologies and assumptions used to estimate the benefits of PSE's participation in the EIM;
- **Section 3** presents the main results of the study;
- **Section 4** summarizes the additional potential savings if the EIM enables PSE to balance its wind resources that are currently balanced outside its BAA; and
- **Section 5** provides the conclusions of the study.

2 Study Assumptions and Approach

2.1 Overview of Approach

The EIM allows Western BAs to voluntarily participate in the ISO's real-time energy market. EIM software will automatically dispatch generation across participating BAAs every 5 minutes to solve imbalances using security constrained economic dispatch (SCED), as well as commit quick-start generation every 15 minutes using security constrained unit commitment (SCUC). Each BA participating in the EIM is still responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices in advance of real-time.

PSE's participation in the EIM is expected to result in two principal benefits resulting from changes in system operations for PSE and the current EIM participants:

1. **Sub-hourly dispatch benefits**. Today, each BA outside of the EIM dispatches its own generating resources to meet imbalances within the hour, while holding schedules with neighboring BAs constant. The EIM nets energy imbalance across participating BAs, and economically dispatches generating resources across the entire EIM footprint to

manage the imbalance, resulting in operational cost savings. PSE's participation in the EIM enables incremental dispatch efficiency improvements relative to the current EIM.

2. **Flexibility reserve reductions**. BAs hold flexibility reserves to balance discrepancies between forecasted and actual net load within the hour. *Load following flexibility reserves* (referred to in this report as simply "*flexibility reserves*") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.[14] By pooling load, wind, and solar output across the EIM footprint, the EIM allows participants to benefit from greater geographic diversity of forecast error and variability by reducing the quantity of flexibility reserves they require. PSE's participation in the EIM would bring added load and resource diversity to the current EIM footprint, resulting in additional reserve savings.

In addition, if PSE were to integrate its remote wind resources to within its BAA, then the EIM could help PSE realize wind curtailment savings and additional renewable integration cost savings. Participation in the EIM could help PSE reduce or eliminate reliability curtailments of its wind resources by using the EIM to export energy that PSE would otherwise need to curtail, or through reducing energy import in real-time compared to PSE's HA schedule. Through the EIM, PSE would also reduce incremental flexibility reserves required to

[14] Regulating reserves, which address the need for resources to respond to changes on a sub-5 minute interval basis, are sometimes categorized in operational studies as a second type of flexibility reserve product. Since the EIM operates with 5-minute intervals, it is does not directly affect regulating reserve requirements. To be concise, all references to *flexibility reserve* in this report are related to load following reserves; *regulating reserves*, where referenced, are explicitly described by name.

balance external wind plants itself. These savings are addressed separately in Chapter 4 of this report.

Our general approach to estimating the benefits of PSE's participation in the EIM is to compare the total cost under two cases: (1) a "business-as-usual" (BAU) case in which PSE is not an EIM participant, and the operational efficiencies of the "current EIM" (including the ISO, PacifiCorp, and NV Energy) is already reflected; and (2) a "PSE EIM" case in which the PSE BA also participates in the EIM. The cost difference between the BAU and PSE EIM cases represents the incremental benefits of PSE's participating in the EIM.

Sub-hourly dispatch benefits are estimated over a range of real-time transmission transfer capabilities using production simulation modeling. The difference in WECC-wide production costs between the PSE EIM simulations and the BAU simulation represents the societal benefit of PSE's participation. To estimate cost savings from reduced flexibility reserve requirements, the study team used statistical analysis to determine the quantity of incremental flexibility reserve diversity that PSE's participation would bring to the EIM, and then applied that quantity to historical flexible ramping constraint shadow prices from the ISO to calculate operational cost savings.

2.2 Key Assumptions

Five key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; (3) hurdle rates; (4) flexibility reserves; and (5) hydropower modeling.

2.2.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, which require long lead times between scheduling the transaction and actual dispatch.[15] Within the hour, each BA resolves imbalances by manually dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real-time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

The study team quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in the PNNL report, as well as Section 2.3 below.

A PLEXOS simulation was run with hourly intervals in a DA stage, and then in an HA stage, using DA and HA forecasts of expected load, wind, and solar output. In the final stage, a real-time PLEXOS simulation is run with 10-minute intervals, using actual wind, load, and solar output for each interval. During the real-time simulation, BAs not participating in the EIM must maintain a net exchange with neighboring BAs that is equal to the HA exchange level. EIM participants, on the other hand, can re-dispatch generation and exchange power with the rest of the

[15] The ISO and AESO are the exceptions.

EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.2.2 below. [16]

In E3's analyses assessing the benefits of PacifiCorp and NV Energy participating in the ISO EIM, GridView, an hourly production cost model, was used with input data largely based on TEPPC's 2022 Common Case. The 10-minute time-step capability of PLEXOS allows us to better represent the EIM's 5-minute dispatch interval relative to GridView's hourly time-step capability.[17]

2.2.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real-time between EIM participants. For this sub-hourly modeling analysis, the study team specified the maximum amount, in both the positive and negative direction, by which a BA's net transfer over a path is allowed to differ in real-time, relative to the HA scheduled transfer.[18] For example, if the HA scheduled transfer between two BAAs is 1,000 MW and there is 500 MW of real-time transfer capability modeled, then the real-time transfer over that path may range from 500 to 1,500 MW throughout the hour.

[16] While the EIM will operate down to a 5-minute level, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across COI and BPA network.

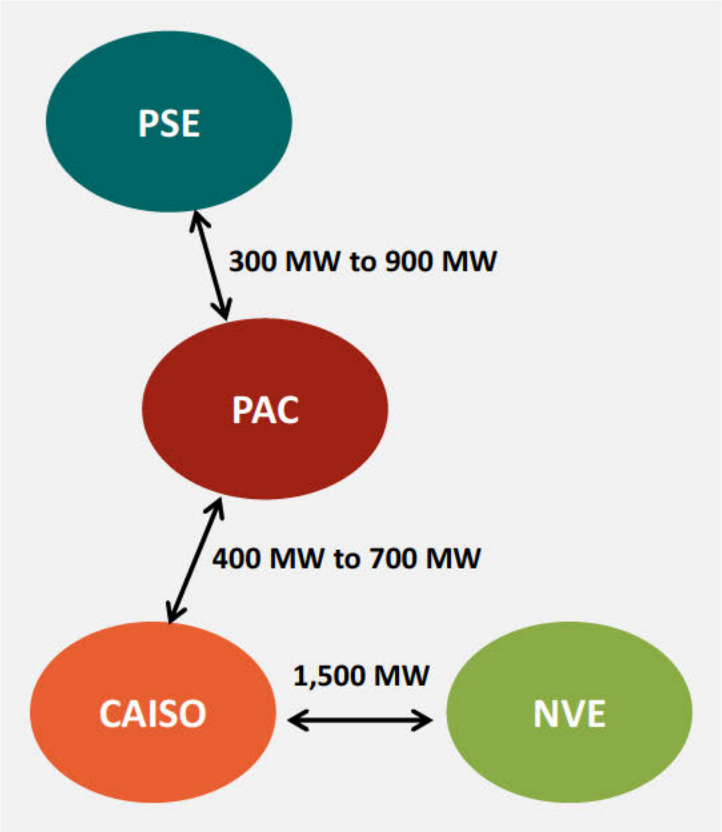
[17] The WECC GridView database is currently developing a sub-hourly modeling capability, but this functionality and the sub-hourly data required were not available at the time of this analysis.

[18] In certain studies in the Northwest, real-time transmission transfer capability has also been termed as "Transfer Variability Limit" or "TVL". See, for example, Columbia Grid (2011).

For the BAU case, the study team adopted real-time transmission transfer capability assumptions from earlier EIM benefit analyses. The study team modeled 400 MW of capability between PacifiCorp and the ISO, and 1,500 MW of capability between the ISO and NV Energy.[19] For the PSE EIM simulation, the study team modeled two scenarios where the real-time transfer capability between PSE and PacifiCorp ranged from 300 to 900 MW, and the capability between PacifiCorp and the ISO ranged from 400 to 700 MW. Figure 1 below characterizes the range of real-time transfer capabilities used in this analysis.

[19] These values are informed by capacity rights owned or controlled by the current EIM participants. Total maximum and minimum flow levels between zones in the model (including HA flow plus incremental changes in real-time) are also subject to physical transmission constraints on rated paths. The flexibility of real-time transfer capability over COI is the subject of an ongoing study by Columbia Grid. The flexibility between ISO and NV Energy is assumed to include transactions over direct interties between the two BAAs, as well as over co-owned transmission facilities. 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 transmission rights over the 500 kV lines connecting the Crystal and McCullough Substations. This study conservatively assumed that interties between NV Energy and the PacifiCorp East system will not be utilized for the EIM.

Figure 1. Real-time Transfer Capabilities across the EIM Footprint



2.2.3 HURDLE RATES

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 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" DA trading products defined by the Western Systems Power Pool, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", $/MWh price adders applied to interfaces between BAAs. Hurdle rates inhibit power flow over transmission paths that cross BAA boundaries, and reduce economic energy exchange between BAAs.

An EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates between EIM participants during the real-time simulations, while maintaining hurdle rates between non-participants.[20] In the DA and HA simulations, hurdle rates are

[20] Market participants must also acquire CO2 allowances to deliver "unspecified" energy to California BAAs (i.e., the ISO, LADWP, BANC and IID), as required by California's greenhouse gas cap-and-trade program developed in compliance with AB32. In all production simulation cases modeled, a component of the hurdle rates is used in the model to reflect the need to acquire these allowances when delivering electricity from neighboring states into California.

maintained between all BAAs, including between EIM participants.[21] The study team believes this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we would expect that BAs would adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it is realized, this learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

The removal of hurdles rates in our analysis mirrors proposed changes under the EIM. This modeling is consistent with the FERC-approved ISO tariff amendment associated with the EIM. This modeling approach is also consistent with previous analyses performed to assess the benefits of PacifiCorp and NV Energy participating in the ISO EIM.

2.2.4 FLEXIBILITY RESERVES

BAs hold excess capacity as reserves to balance discrepancies between forecasted and actual net load within the operating hour; these within-hour reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[22] Regulating reserves

[21] This approach—to maintain hurdle rates for the DA and HA simulation and remove them in the real-time simulation run—is consistent with the methodology used by PNNL in the NWPP's MC Phase I EIM Benefit study.
[22] This study assumes that contingency reserves would be unaffected by an EIM, and that PSE would continue to participate in its existing regional reserve sharing agreement for contingency reserves.

automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to 5 minutes. Load following reserves (referred to in this report simply as "flexibility reserves") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.

Higher penetrations of wind and solar increase the quantity of both regulating and flexibility reserves needed to accommodate the uncertainty and variability inherent in these resources, while maintaining acceptable BA 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 study, the study team used statistical analysis to estimate the reduction in flexibility reserves that would occur if PSE participates in the EIM. Flexibility reserve requirements for each BA are a function of the difference between the actual 10-minute net load in real-time versus the HA net load schedule. As a result of geographic diversity, the combined net load profiles for participating BAs have less variability and forecast error than the individual profiles of each BA, resulting in lower flexibility reserve requirements under the EIM.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participating in the EIM.

There are two implicit assumptions embedded in this approach: (1) that PSE and the current EIM participants would carry the calculated levels of flexibility reserves; and (2) that the EIM includes a mechanism to take advantage of increased net load diversity by reducing the quantities of flexibility reserves that would need to be carried.

With regard to the first assumption, while there is currently no defined requirement for BAs to carry flexibility reserves, all BAs must carry a level of operating reserves in order to maintain Control Performance Standards (CPS) within acceptable limits, and reserve requirements will grow under higher renewable penetration scenarios. In December 2011, the ISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[23] Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the ISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

With regard to the second assumption, while the specific design of the flexible ramping products 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 time-step.[24] It should be noted that this is a product that may not be in place by the time PSE would begin to participate in the EIM, and EIM participants may require a period of

[23] See CAISO (2014d and 2014e).
[24] For a detailed discussion of the proposed approach for determining, procuring and allocating flexibility requirements under EIM, see Section 3.4.3 of CAISO (2013).

operational experience before the full benefits of flexibility reserve savings can be achieved.

At a minimum, however, when the EIM becomes operational, the flexible ramping constraint and settlement will be implemented. The ISO will determine flexible ramp constraint requirements for the ISO and each EIM participant based on the 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 current EIM implementation. Furthermore, the EIM design will compensate resources for their contribution to meeting the flexibility constraint. As a result, the EIM will 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.

2.2.5 HYDROPOWER MODELING

Previous EIM analyses indicate that benefits are sensitive to the availability of hydropower to provide flexibility reserves.[25] Dispatchable hydroelectric resources rarely generate at levels that approach maximum nameplate capacity due to limitations on water available for power generation. On many facilities, a portion of the "unloaded" capacity — the difference between the nameplate capacity and the actual generation — can be used to provide contingency and flexibility reserves. However, this unloaded capacity varies by facility and with continually-fluctuating river conditions, making it challenging to generalize for

[25] For example, see E3 (2011) for a discussion of this issue in the context of a WECC-wide EIM excluding the ISO and AESO.

modeling purposes. This leads to uncertainty in the calculation of operating costs using production simulation models.

Generally, EIM benefits are higher when hydro's flexibility is restricted, because a higher proportion of reserves are provided by thermal resources. Conversely, there are fewer production cost savings available when hydro provides a large quantity of flexibility with zero variable costs.

PSE's share of the Mid-Columbia (Mid-C) hydroelectric generating facilities is its primary source of flexibility, and gas-fired simple- and combined-cycle plants provide the remainder. This necessitates a more accurate characterization of hydro resources in the production cost simulations.

The NWPP Analytical Team spent considerable effort improving the modeling of hydro plants in the Northwest, including: (a) specifying hydro units as following a fixed schedule or dispatching using hydro-thermal coordination (HTC); (b) limiting reserve provision from specific hydro plants; (c) correcting ramp rates; and (d) reducing hydro generating capacities to reflect O&M and head obligations.[26] These modeling improvements are particularly important given that both PSE and PacifiCorp have contractual shares of Mid-C hydro plants. This analysis uses the same modeling assumptions and input data from the NWPP EIM Phase 1 Analysis.

The study team made one modification to the approach developed by the NWPP Team for the purposes of this study, optimizing the real-time dispatch of

[26] See Section 2.4 of Samaan et al. (2013) for a detailed discussion of hydropower plant modeling in the NWPP Phase 1 EIM Analysis.

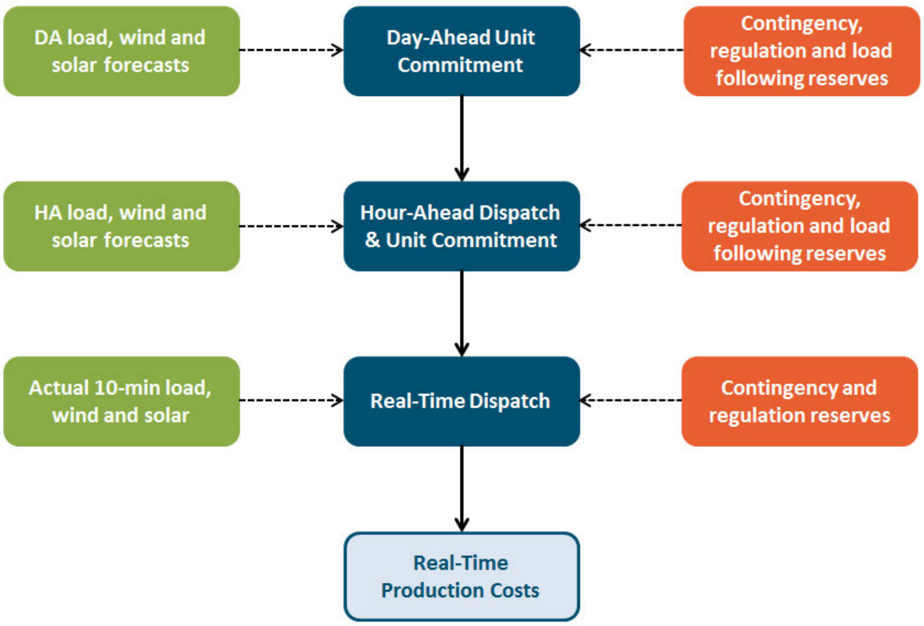
flexible hydro units in 6-hour increments rather than the 1-hour increments used in the NWPP study. This change was based on input from both PSE and the ISO, who felt that the 1-hour hydro optimization was overly restrictive of hydro flexibility. The use of 6-hour increments for hydro energy optimization results in a more conservative estimate of EIM benefits than a 1-hour hydro energy optimization window, because the 6-hour incremental reduces the amount of inefficiency in the BAU case that remains possible for an EIM to address. Importantly, this update also allowed the analysis to largely avoid the impact of hydro energy constraint violations (also termed “excess hydro”) on EIM benefits that arose during modeling for the NWPP EIM Phase 1 study.

2.3 Sub-hourly Dispatch Benefits Methodology

2.3.1 PRODUCTION COST MODELING

The study team used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 2 below.

Figure 2. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch and interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances.

The DA, HA, and real-time (DA-HA-RT) sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in an EIM. When a BA is not participating in an EIM, then: (a) hurdle rates apply during the DA, HA and real-time simulations; (b) interchange is unconstrained during the DA and HA simulations; and (c) during the real-time simulation, the

HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation. In contrast, when two or more BAs are participating in an EIM, then hurdle rates on transfers between the participating BAs are removed during the real-time stage and generation from anywhere in the footprint can solve imbalances, subject to imposed transmission constraints.

The study team estimated sub-hourly dispatch benefits of PSE's participation in the EIM by running pairs of production cost simulations using PLEXOS. Under each simulation scenario, there is a pair of BAU and PSE EIM cases. In the BAU case, PSE solves its real-time imbalances with internal generation while maintaining interchange equal to the schedule from the HA simulation. Intra-hour interchange is allowed to vary to allow economic transfers between the ISO, PacifiCorp and NV Energy, reflecting the operational efficiencies of the current EIM. The PSE EIM cases simulate the operations of an EIM consisting of the ISO, PacifiCorp, NV Energy and PSE BAs. Hurdle rates between the BAs are removed in real-time and intra-hour interchange is allowed up to the real-time transfer capabilities specified in each scenario. The study quantifies the societal benefit of PSE's participation in the EIM by measuring the reduction in production costs from the BAU case to the PSE EIM case.

2.3.2 INPUT DATA

The initial dataset used for this report is the database used in PNNL analysis for the NWPP's Phase 1 EIM benefit assessment, which was built on the Transmission Expansion Planning Policy Committee (TEPPC) 2020 PC0 database.[27] The NWPP Analytical Team made numerous modeling updates for the purposes of their study, with a particular focus on improving the representation of BAAs in the Northwest.[28] Utilizing this database allowed this study to reflect the best available compiled representation of BAAs in the Northwest, as well as leverage the hourly DA, HA forecast and sub-hourly real-time data which PNNL developed for load, wind, and solar output.

For the purposes of this study, the study team made the following key updates:

+ **Zonal transport model**. The transmission network in PLEXOS was modeled at the zonal level rather than the nodal level. This change was made to more accurately represent commercial behavior of two BAs scheduling transactions between each other through the Mid-C trading hub. Using the zonal model also significantly reduces model run time.
+ **Topology updates**. The transmission transfer capability between PSE and neighboring zones was modeled according to PSE's typical monthly total transmission capability (TTC).[29] The remaining transmission topology and hurdle rate assumptions are based on the zonal model used for the ISO's 2012 Long-Term Procurement Plan (LTPP).
+ **CT commitment during real-time**. Quick-start combustion turbines were allowed to commit and dispatch in the real-time simulations to reflect the ISO's addition of the 15-minute real-time unit commitment process for the EIM.

[27] It is based on PNNL's Base Case (1.86a) for the NWPP, which itself was modified from a data set and had been developed for use with the PLEXOS sub-hourly model for PNNL's 2012 study for the WECC Variable Generation Subcommittee (VGS).
[28] See Section 2 of Samaan et al. (2013) for a detailed discussion of the updates the NWPP Analytical Team made to improve upon the TEPPC PC0 case.
[29] See PSE (2014).

- **Hydro optimization window**. As discussed in Section 2.2.5, the simulations optimize the real-time dispatch of flexible hydro units across a 6-hour window rather than a 1-hour window.
- **Nuclear generation**. All nuclear plants throughout the WECC were modeled as must-run at their maximum capacity to avoid any unrealistic intra-hour changes in nuclear generation.
- **Generation updates in California**. A few generation updates were made to reflect anticipated system changes that PSE and the ISO believed were important to the analysis. In California, the San Onofre Nuclear Generation Station (SONGs) was taken out of service, as well as applying the ISO's current best estimate of retirement and repowering of once-through cooling generators by 2020; the ISO's share of Hoover generation was also changed to match the values in the 2012 LTPP.
- **Generation updates in PSE**. A 200 MW quick-start CT generator was added pursuant to PSE's most recent Integrated Resource Plan. The portion of the Colstrip coal plant owned by PSE was moved into the PSE BAA so that its output could be changed in real-time based on PSE's needs, because PSE indicated that they can dispatch its share of Colstrip in real-time through a dynamic transfer.

Overall, the study team's modeling assumptions seek to be consistent with projections for calendar year 2020 in terms of generation, transmission and fuel prices across the WECC. At the same time, the study team sought to limit the number of changes in input data from the information used for the NWPP Phase 1 study.

2.3.3 SCENARIOS

Table 4 summarizes the assumptions used for each case modeled using production simulation: the BAU case (where PSE is not an EIM participant), and two PSE EIM participation scenarios with different levels of real-time transfer capability between BAs participating in the EIM.

Table 4. Overview of EIM Scenario Assumptions

Case Name	Real-Time Transfer Capability		
	PAC-PSE	CAISO-PAC	CAISO-NVE
BAU	NONE	400	1500
PSE EIM Scenarios:			
Low Transfer	300	400	1500
High Transfer	900	700	1500

As noted in Section 2.2.2, the study team anticipated that the real-time transfer capability between EIM participants would affect benefits, so PSE and the ISO worked to develop a range that would characterize low and high end expectations of real-time flexibility of transfers between PSE and PacifiCorp utilizing direct connections between them through their own transmission systems and other transmission system connections. PacifiCorp provided useful descriptions about their system and operations to help develop this range. In addition, PSE believes that it should be able to use a portion of its current Dynamic Transfer Capability (DTC) over the Bonneville Power Administration (BPA) system to enable further real-time EIM transactions for PSE when economic. In total, the study team selected a real-time transfer capability of +/- 300 MW between PSE and PacifiCorp for the PSE EIM Low Transfer Case and +/- 900 MW for the PSE EIM High Transfer Case.

In the BAU and PSE EIM Low Transfer scenarios, real-time transfer capabilities between current EIM participants are consistent with the assumptions in the NVE-ISO EIM study: 1,500 MW for the ISO-NV Energy real-time transactions, and 400 MW for PacifiCorp-ISO transactions, which is also the value for the middle level of transfer capability in the PacifiCorp-ISO EIM study. In the PSE EIM High Transfer Case, the study team increased the capability between PacifiCorp and the ISO by an additional 300 MW (to 700 MW total) to investigate the impact that additional COI transfer capability for the EIM could have on benefits to PSE.

2.3.4 ATTRIBUTION OF BENEFITS TO EIM PARTICIPANTS

WECC-wide production cost savings represent the societal benefits resulting from PSE's participation in the EIM. The study team attributes these benefits to PSE and the current EIM participants by calculating the "Total Operations Cost" for both parties, which is the sum of the following components: (1) HA net import costs, equal to net imports times the zone's locational marginal price; (2) real-time generator production costs; and (3) real-time imbalance costs, equal to imbalance times an EIM-wide market clearing price. The "Total Operations Cost" represents a proxy for the total cost to serve load in a given area, including the production costs to run local generators and the cost of importing power (or revenues from exporting power). The reduction in "Total Operations Costs" under an EIM case versus the BAU case represents the EIM benefit for a given participant.

Since the EIM does not affect HA operations, there is no change in HA net import costs between the BAU and EIM cases. The EIM-wide market clearing price used to calculate real-time imbalance costs is the imbalance-weighted average of the participating BAs. Table 5 is an example of calculating the EIM-wide market clearing price for a single 10-minute interval. The EIM-wide market clearing price is only applied to imbalance transactions.

Table 5. Example of EIM-wide Marketing Clearing Price Calculation

Category	CAISO	PAC	NVE	PSE
Real-time Price ($/MWh)	73.0	56.5	61.9	59.8
HA Net Import Schedule (MW)	7,635	(2,592)	1,463	110
Real-time Net Imports (MW)	7,449	(2,769)	1,587	350
Imbalance (MW)	-186.0	-177.2	123.4	239.9
Absolute Value of Imbalance (MW)	186.0	177.2	123.4	239.9
Share of Imbalance (%)	25.6%	24.4%	17.0%	33.0%
EIM-wide Market Clearing Price ($/MWh)	62.7			

2.4 Flexibility Reserve Savings Methodology

The study team estimates the operational cost savings from reduced flexibility reserve requirements using the following methodology. First, a statistical analysis is used to estimate the quantity of flexibility reserve reductions from PSE's participation in the EIM. Next, the avoided cost of flexibility reserves is determined by observing historical flexible ramping constraint shadow prices from 2013. Finally, to estimate the total EIM reserve savings from PSE's participation, the average shadow price from 2013 is applied to the flexibility reserve quantity reductions.

2.4.1 FLEXIBILITY RESERVE REQUIREMENT

To determine flexibility reserve requirements, the study team used the actual (10-minute) and HA schedule load, wind, and solar data from the NWPP EIM study. This data is used to calculate a distribution of flexibility needs (i.e., real-time net load minus the HA net load schedule). Each BA's flexibility reserves requirement for each month and hour are calculated using a 95% confidence interval (CI), where the 2.5th and 97.5th percentiles determine the flexibility down and up requirements, respectively.[30]

For the BAU case, the study team calculates flexibility requirements for the current EIM by summing the net load profiles for the ISO, PacifiCorp and NV Energy BAs before calculating the 95% CI.[31] PSE's requirements are calculated as a standalone entity. In the PSE EIM case, flexibility requirements are calculated for the Expanded EIM by summing the ISO, PacifiCorp, NV Energy and PSE BA net load profiles. Figure 3 shows the average upward flexibility requirements in 2020 across the BAU and PSE EIM cases. PSE's EIM participation results in a "diversity benefit" that reduces upward flexibility requirements by 74.5 MW on average.[32]

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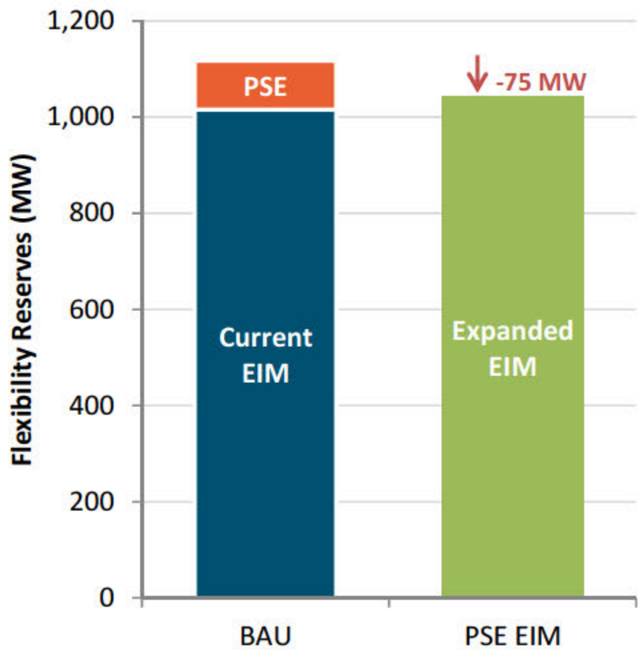
[30] Using the 95% confidence interval to calculate flexibility reserve requirements is consistent with the approach used in the NWPP EIM Phase 1 study.

[31] Due to diversity in forecast error and variability, the 95th percentile of aggregated real-time deviation from HA forecast for the entire EIM is a smaller level (relative to the size of the BAs) than it would be for the sum of individual EIM members.

[32] This reduction is subject to real-time transmission transfer capability limits, and cannot be larger than the levels between individual EIM participants and the rest of the EIM. However, the reduction levels quantified for PSE were well under the levels for the PSE Low Transfer Case, so transmission was assumed to not have a binding impact on flexibility reserve reductions for the PSE EIM scenario, and the resulting flexibility reserve savings are the same for all three PSE EIM scenarios. The reserve savings for PSE would change if PSE had a different renewable generation portfolio, which is addressed in Chapter 4.

Figure 3. Average Upward Flexibility Requirement

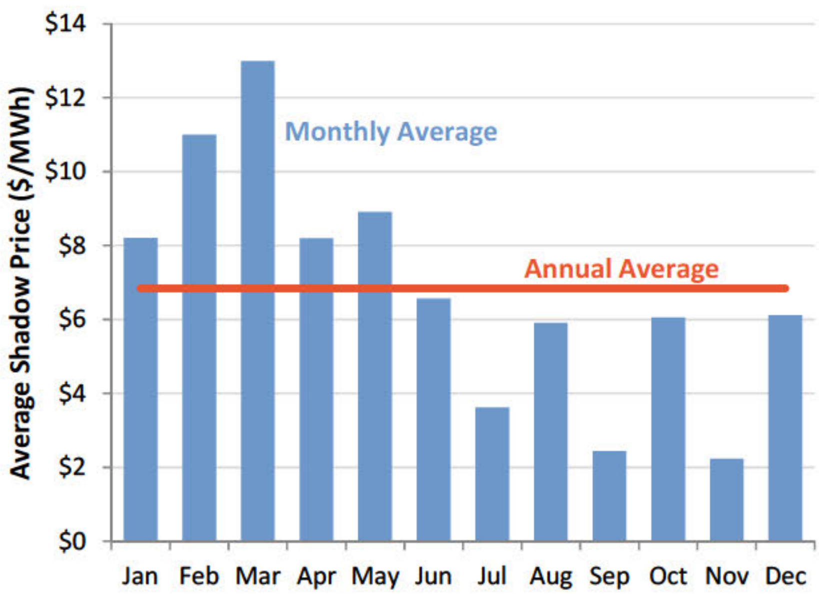


Note: Current EIM consists of the ISO, PacifiCorp and NV Energy BAs. "Expanded EIM" consists of the ISO, PacifiCorp, NV Energy and PSE.

2.4.2 AVOIDED COST OF FLEXIBILITY RESERVES

To value flexibility reserve reductions, the study team first examined flexible ramping constraint shadow prices in 2013. The ISO has applied a flexible ramping constraint in the five-minute market optimization since December 2011 to maintain sufficient upward flexibility. Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. However, if there is sufficient capacity available, the constraint is not binding, resulting in a shadow price of zero. Figure 4 shows the average shadow price for procuring upward flexible ramping capacity for each month in 2013. Reductions in *upward flexibility* requirements in 2020 are valued at the 2013 annual average flexible ramping constraint shadow price of \$6.98/MWh.[33]

Figure 4. 2013 ISO Flexible Ramping Constraint Shadow Prices



Note: Data from CAISO (2014a).

2.4.3 ATTRIBUTION OF FLEXIBILITY RESERVE SAVINGS

Flexibility reserve savings were attributed to PSE and the current EIM participants by comparing their relative reduction in flexibility reserve requirements in the BAU case compared to the PSE EIM cases. The ISO's Business Practice Manual (BPM) details how the ISO will assign flexibility reserve

[33] Inflated here from 2013 to 2014 dollars assuming an annual inflation rate of 2%.

requirements among EIM participants. Each participating BA will be assigned a flexibility requirement equal to the BA's standalone flexibility reserve requirement (i.e., if it were not an EIM participant), reduced by an EIM reserve diversity factor that is equal to the combined EIM flexibility reserve requirement (which reflects diversity benefit across the EIM), and then divided by the sum of standalone flexibility reserve requirement quantity for all EIM participants.[34]

Overall, PSE's participation in the EIM creates more diversity to the full EIM footprint, reducing flexibility reserve requirements for current EIM participants by 48.2 MW on average, which is a five percent reduction compared to their requirements in the current EIM. PSE's own flexibility reserve requirement is reduced by 26.3 MW on average, a 26% reduction from its requirements as a standalone BA.

[34] See CAISO (2014b).

3 Results

3.1 Overview of Benefits Across Scenarios

Table 6 below presents the annual benefits of PSE's EIM participation in 2020 under both transfer scenarios. Each row displays PSE's EIM cost savings in a particular transfer capability scenario relative to the BAU scenario. Annual sub-hourly dispatch and flexibility reserves benefits to PSE range from $18.3 million in the Low Transfer Case to $20.1 million for the High Transfer Case.

Table 6. Annual Benefits to PSE by Transfer Capability Scenario (million 2014$)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$16.7	$1.6	**$18.3**
High Transfer	$18.5	$1.6	**$20.1**

The PSE EIM Low Transfer case, with 300 MW of real-time transfer capability between PSE and PacifiCorp, enables $16.7 million in sub-hourly dispatch benefits for PSE. The High Transfer scenario, in which the PSE-PacifiCorp real-time transfer capability is increased to 900 MW and the PacifiCorp-ISO transfer capability is increased to 700 MW, produces $18.5 million in sub-hourly dispatch benefits for PSE, a modest $1.8 million increase in savings compared to the Low Transfer case. The small size of this incremental savings is discussed later in this chapter, which highlights that the 300 MW of PSE-PacifiCorp real-time transfer capability is sufficient to facilitate most economic real-time transactions in the majority of hours of the year for the simulation of PSE EIM participation.

For both scenarios modeled, the flexibility reserve benefit to PSE is $1.6 million. The Low Transfer scenario uses 300 MW of real-time transfer capability between PSE and the current EIM. This transfer capability is sufficient to not constrain the potential reduction to PSE's flexibility reserve requirement as an EIM participant, which in Section 2.4.3 the study team identified as 26.3 MW on average. Therefore, PSE's flexibility reserve savings are not constrained by the real-tim41e transfer capability in the Low Transfer scenario, and adding additional transfer capability in the other scenario does not produce additional flexibility reserve savings for PSE.

Table 7 below presents the incremental benefit to the current EIM participants as a result of PSE's participation in the EIM. In total, PSE's participation is projected to create $3.5 to $4.2 million per year in incremental benefits for the current EIM participants.

Table 7. Annual Benefits to Current EIM Participants (million 2014$)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$0.6	$2.9	**$3.5**
High Transfer	$1.2	$2.9	**$4.2**

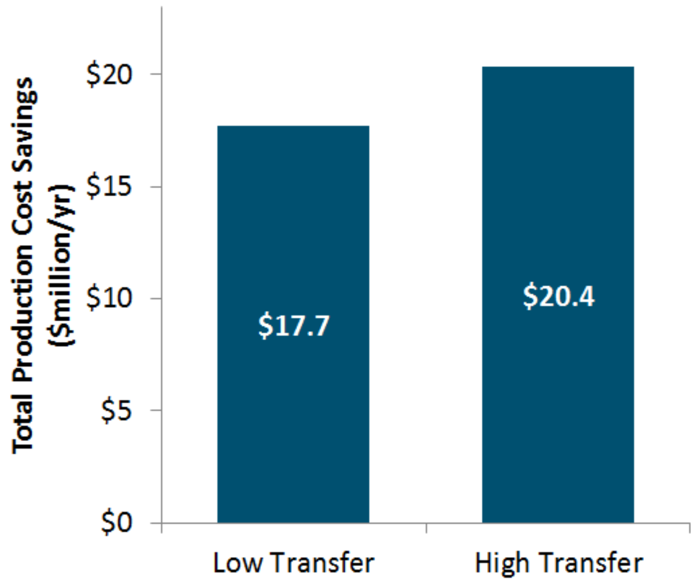
PSE's participation in the EIM provides the current participants opportunities for incremental, sub-hourly dispatch benefits ranging from $0.6 to $1.2 million per year. Under the Low Transfer scenario, current EIM participants see sub-hourly dispatch savings of $0.6 million per year, while under High Transfer scenario, benefits to current participants are $1.2 million. In both of the EIM scenarios considered, PSE's participation in the EIM would also create additional diversity, further reducing flexibility reserve requirements for the current EIM participants and producing $2.9 million in incremental savings for the current EIM participants.

3.2 Detailed Benefit Results by Category

3.2.1 SUB-HOURLY DISPATCH BENEFITS AND IMBALANCE LEVELS

Figure 5 presents the WECC-wide production cost savings under both scenarios of transfer capability between EIM participants. WECC-wide production cost savings from the dispatch analysis should aggregate all transfers between consumers and producers to present the total incremental savings from PSE EIM participation. This total was $17.7 million for the PSE EIM Low Transfer Case and $20.4 million for the PSE EIM High Transfer Case. These totals are slightly larger from the sum of dispatch benefits attributed to PSE and the current EIM participants due to small interactions with BAs outside of the EIM footprint.

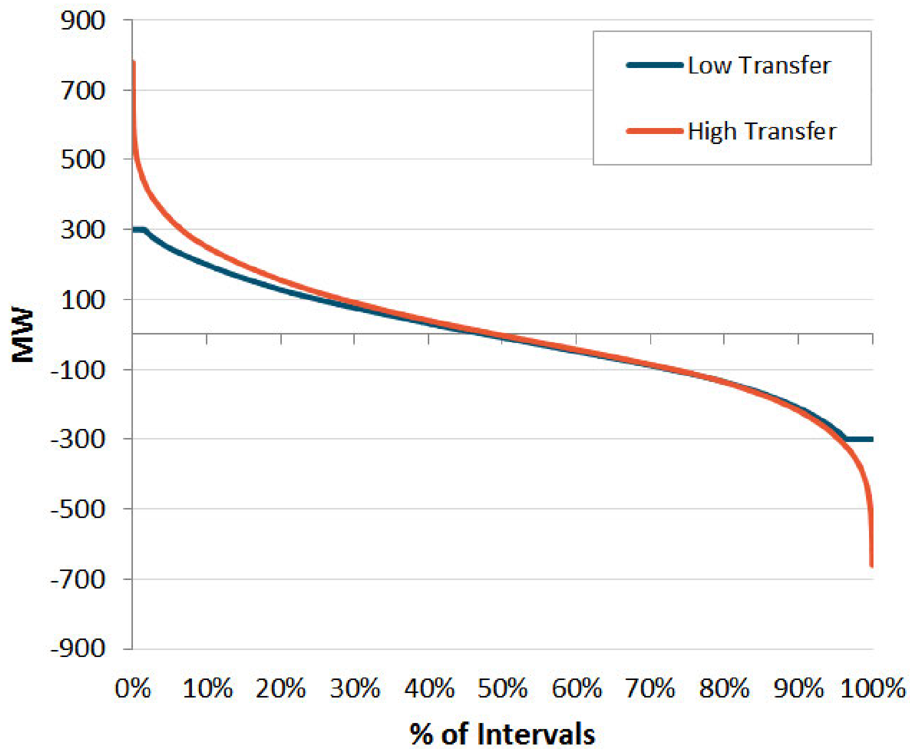
Figure 5. WECC-wide Production Cost Savings



The results presented above highlight that the overwhelming majority of potential sub-hourly dispatch benefits are captured with only 300 MW of real-time transfer capability between PSE and PacifiCorp. A threefold increase in this capability only results in a 15% increase in sub-hourly dispatch benefits. This suggests that there are very few intervals throughout the simulation year where it would be economic for PSE to either increase or decrease its generation dispatch and net exchange with other EIM participants by more than 300 MW.

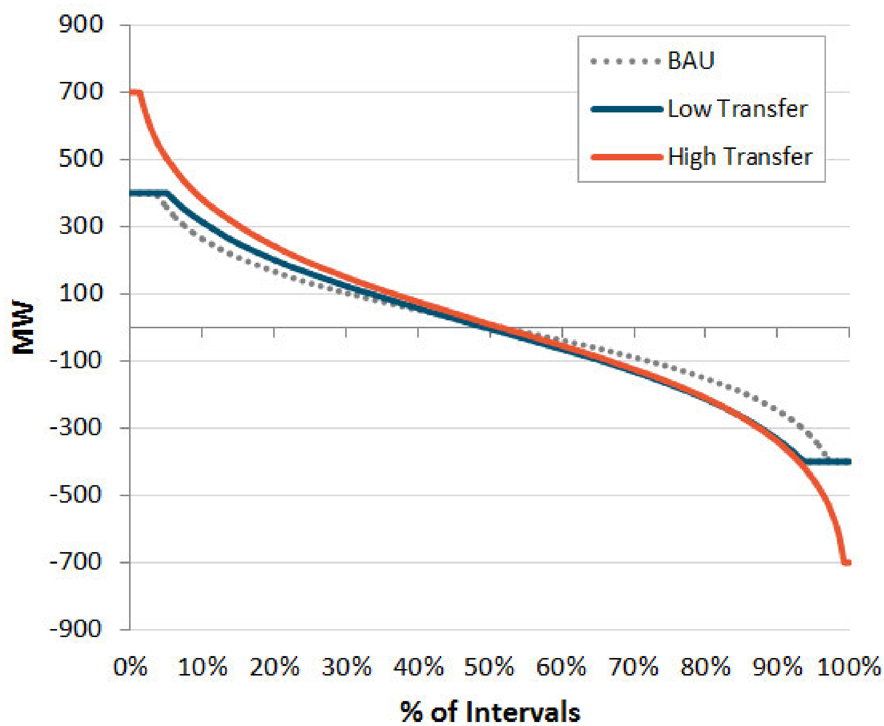
The infrequency of transfers above 300 MW is highlighted in Figure 6. The figure compares imbalance energy duration curves for PSE for the two EIM scenarios. Imbalance shown here is the difference between PSE's real-time (10-minute) net imports and the HA net import schedule produced from the HA simulation. Positive imbalances represent intervals when PSE is importing more in real-time relative to their HA schedule (or exporting less than in the HA schedule), and vice versa. In the PSE EIM Low Transfer case, imbalances are exactly equal to +300 MW or -300 MW in fewer than 2% of the intervals across the year, suggesting that the transfer capability is rarely a binding constraint on EIM transactions. In the High Transfer case, PSE's imbalance exceeds +/-300 MW in 11% of the intervals, with imbalances never reaching 900 MW.

Figure 6. PSE Imbalance Duration Curve



PSE's participation in the EIM also results in incremental increases in the EIM transaction volume over COI relative to the current EIM (in both positive and negative directions for certain sub-hourly intervals). This impact is illustrated in Figure 7 below, where the BAU duration curve represents the PacifiCorp-only EIM transactions over COI, and the remaining curves reflect PSE plus PacifiCorp real-time imbalance over the COI for the two PSE EIM cases analyzed. Positive imbalance represents south to north flow, and negative imbalance represents north to south flow. The 400 MW of real-time transfer capability between PacifiCorp and the ISO modeled in the BAU and Low Transfer scenarios is only binding during a small percentage of real-time intervals. Therefore, increasing this capability from 400 to 700 MW in the High Transfer scenario produces a small marginal increase in EIM dispatch benefits.

Figure 7. PSE plus PacifiCorp Imbalance Duration Curve



3.2.2 DRIVERS OF SUB-HOURLY DISPATCH BENEFITS FOR PSE

The study team reviewed detailed outputs on generation dispatch from each of the simulations to identify key drivers of PSE EIM dispatch benefits. The most significant sources of dispatch saving for PSE was the result of the EIM enabling more efficient use of PSE's internal generation and allowing flexibility in the ability to increase or decrease net imports in real-time. In the BAU case, forecast errors and variability of load and wind in real-time resulted in the need for PSE to commit internal peaking generators in real-time during certain periods when PSE required more energy, but was unable to adjust real-time exchanges scheduled with neighboring BAs. By comparison, under both PSE EIM scenarios, participation in the EIM enables PSE to adjust net exchanges with the other EIM participants in real-time. This capability allowed PSE to frequently avoid the need to commit additional internal peaking generators to address real-time generation shortfalls, and, as a result, PSE is able to produce a higher percentage of energy to serve its load with lower-cost base load generation. The EIM also allows PSE to dispatch its lowest-cost generators for export sales to the other EIM participants in intervals when these units have available capacity in real-time and it is economic to do so.

Figure 8compares PSE's real-time net imports in the BAU and PSE EIM Low Transfer scenarios for a three-day snapshot period in December 2020. In the BAU scenario (shown in blue), net imports are fixed to the HA schedule. In contrast, net imports in the EIM Low Transfer scenario (shown in orange) are allowed to vary by the real-time transfer capabilities discussed above, resulting in more variable real-time net imports that are both higher and lower than the HA schedule. This net import flexibility allows PSE to optimize the use of its own generation to resolve imbalances. The flexibility of real-time exchange facilitated by the EIM is further illustrated in Figure 9, which displays the level of imbalance for each participating BA across the same three-day snapshot.

Figure 8. PSE Real-Time Net Imports for Three-Day December Period

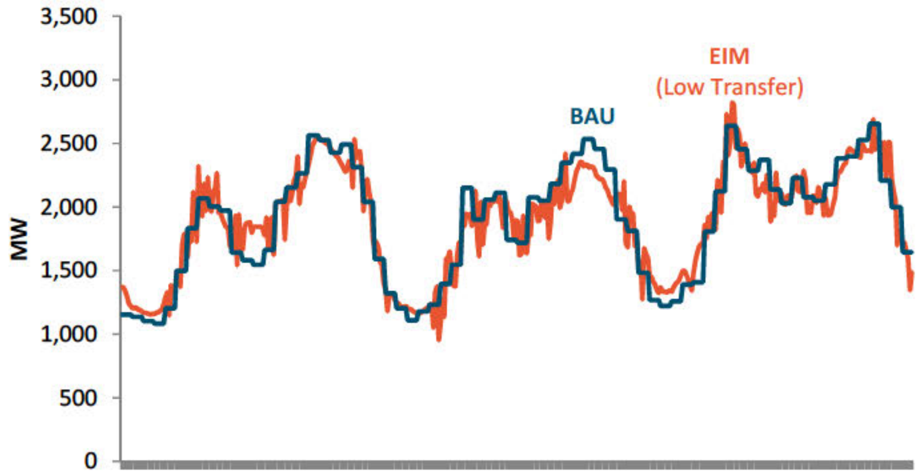
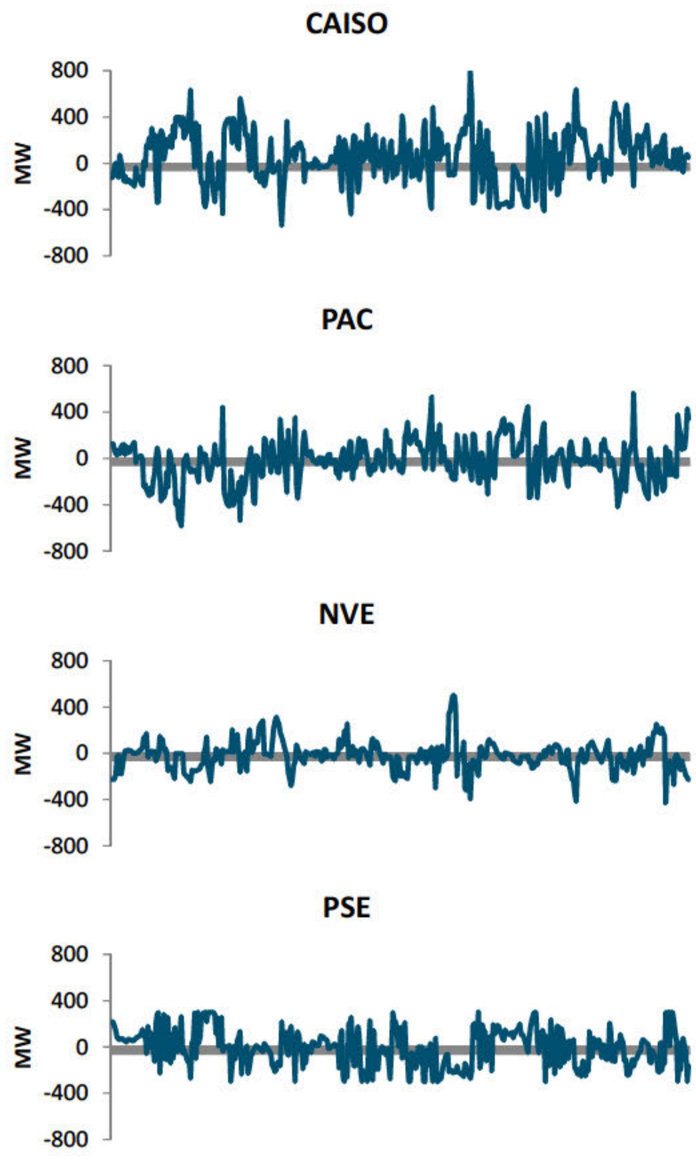


Figure 9. Real-Time Imbalance for EIM Participants for Three Day December Period, Low Transfer Case



Note: sum of imbalances across the four EIM participants is equal to zero for every 10-minute interval.

Table 8 below shows the calculations used to attribute EIM benefits to PSE and the current EIM participants by estimating the "Total Operations Cost" for PSE and the current EIM under the BAU case and both PSE EIM scenarios. Each component is calculated according the methodology described in Section 2.3.4.

Table 8. Total Operations Cost by Component across Scenarios (2014 $ million/year)

	Current EIM (ISO-PAC-NVE)		PSE	
BAU				
HA Net Import Cost	$	2,806.9	$	489.4
Real-time Imbalance Cost	$	0.1	$	(0.0)
Real-time Generation Cost	$	7,727.9	$	216.4
Total	**$**	**10,534.9**	**$**	**705.8**
PSE EIM: Low Transfer				
HA Net Import Cost	$	2,806.9	$	489.4
Real-time Imbalance Cost	$	1.6	$	(1.5)
Real-time Generation Cost	$	7,725.8	$	201.3
Total	**$**	**10,534.3**	**$**	**689.1**
PSE EIM: High Transfer				
HA Net Import Cost	$	2,806.9	$	489.4
Real-time Imbalance Cost	$	(5.2)	$	5.3
Real-time Generation Cost	$	7,732.0	$	192.7
Total	**$**	**10,533.7**	**$**	**687.3**

The resulting incremental EIM savings for each participating BA is based on the reduction in total operations cost for that BA in a particular PSE EIM scenario compared to the BAU case. These savings are shown by component in Table 9 below.

Table 9. EIM Savings (Cost) by Scenario (2014 $ million/year)

	Current EIM (ISO-PAC-NVE)		PSE	
PSE EIM: Low Transfer				
HA Net Import Cost	$	-	$	-
Real-time Imbalance Cost	$	(1.5)	$	1.5
Real-time Generation Cost	$	2.1	$	15.2
Total	**$**	**0.6**	**$**	**16.7**
PSE EIM: High Transfer				
HA Net Import Cost	$	-	$	-
Real-time Imbalance Cost	$	5.3	$	(5.3)
Real-time Generation Cost	$	(4.1)	$	23.8
Total	**$**	**1.2**	**$**	**18.5**

3.2.3 FLEXIBILITY RESERVE SAVINGS

As noted in Section 2.4, the additional diversity from PSE's participation in the EIM would bring an incremental 74.5 MW reduction in EIM-wide flexibility reserve requirements compared to the sum of current EIM reserve requirements plus PSE standalone reserve requirements in the BAU case. The EIM assigns flexibility reserve requirements and allocates the diversity reduction among EIM participants based on their relative share of the sum of standalone reserves if each were operating without an EIM. On average, throughout the year, this methodology results in a 26.3 MW flexibility reserve reduction attributed to PSE and an incremental 48.2 MW reserve reduction attributed to the current EIM participants.

This study values these flexibility reserve reductions based on the average historical flexi-ramp value in the ISO for 2013, which was $6.98/MWh.[35] This value results in total flexibility savings for the year 2020 of $4.6 million, of which $1.6 million is for PSE and $2.9 million is for the current EIM participants.

3.3 Results Discussion

The study team applied a number of conservative assumptions in this analysis, which could results in the benefits quantified above to be lower than the actual savings that would accrue to PSE and to the current EIM participants. These assumptions include:

+ **Reliability-related benefits were not quantified.** The study team did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM will enable. Although these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.
+ **Intra-regional dispatch savings were not quantified.** PSE indicated that internal congestion on the PSE system is usually small, so the analysis did not endeavor to quantify if the EIM can help reduce costs or relieve problems within PSE's BAA.
+ **Average hydro conditions and current renewable generation policy targets.** The analysis evaluated an average hydro year and renewable generation levels equal to current policy targets. It is possible that high hydro runoff in the Pacific Northwest or higher RPS targets in the ISO could lead to greater BAU scenario renewable energy curtailment. In

[35] Adjusted from 2013 to 2014 dollars.

such conditions, PSE's participation in the EIM may be able to produce larger savings than the levels included here. In addition, low hydro conditions could reduce PSE's ability to call on its hydro resources for flexibility, which would lead to greater incremental savings from EIM participation.

+ **Thermal generators were modeled with flat heat rates.** According to the WECC VGS study and PNNL NWPP Phase 1 EIM analysis, each thermal generator in the PLEXOS database was assigned a single heat rate regardless of the unit's current level of dispatch. Other models such as the WECC TEPPC model in GridView typically use step-function incremental heat rates for thermal generators; such heat rates reflect the fact that a generator will typically have a higher average heat rate when operating at minimum dispatch levels (i.e., Pmin) compared to when operating closer to maximum output (i.e., Pmax). The EIM dispatch savings are driven by identifying efficiency opportunities to reduce dispatch of generation in one BAA and increase dispatch on a lower-cost generator located in a different participating BAA. Modeling thermal units with non-flat heat rates could produce greater variation in heat rates across generators (depending on their operating levels) and result in greater opportunities for EIM dispatch savings.

+ **Hydro energy optimization was modeled with a 6-hour horizon**. In the real-time simulation runs with sub-hourly intervals, PLEXOS models dispatchable hydro plants by first allocating each plant's total monthly hydro energy budget to a single hour, or to a window of consecutive hours. The simulation then optimizes overall real-time system dispatch while using the capability to move the hydro energy available during a single hour (or window of hours) among 10-minute intervals within that hour. The simulation uses the hour's available hydro energy during intervals when hydro dispatch has the most value, subject to constraints on generator ramp rates and maximum and minimum output levels for the hydro plant. This allocation procedure limits the ability of a BA to move hydro energy across a wide time period in the real-time simulation to respond to differences in system need across a day or group of days. In actual practice, hydro operators do not have perfect forecasts of load and variable energy, and they similarly must budget available hydro energy under uncertainty, subject to hydrological and environmental constraints. The PNNL EIM Benefit Phase 1 for the NWPP used a 1-hour hydro optimization window, which prevented BAs in the model from shifting real-time hydro energy forward from one hour to the next and contributed to the hydro energy constraint violation included in that analysis. Based on feedback from PSE regarding its own hydro dispatch capabilities, the study team extended the hydro optimization horizon to a 6-hour window. By simulating a longer hydro energy optimization window this study allows the available hydro energy to be used more optimally and flexibly to address intra-hour dispatch challenges. This assumption results in a more conservative EIM dispatch savings estimate because the hydro improves the efficiency of the dispatch in the BAU case, leaving a smaller remaining opportunity for incremental improvement under an EIM.

4 Additional Wind Balancing Cost Savings

In addition to the savings described in Chapter 3, an EIM may enable PSE to realize incremental savings related to wind resource balancing and reduced curtailment. Under current conditions (i.e., without EIM participation), limitations of PSE's internal reserve capability motivate PSE to contract with other BAs to provide reserves and balancing services for current and future wind plants in PSE's generation portfolio.

4.1 Renewable Balancing Cost Savings

Currently, PSE has 500 MW of wind generation located in an external BAA and the energy from that generation is scheduled in hourly block transfers to PSE. PSE expects that it will also need assistance to balance 300 MW of additional wind generation planned by 2020. PSE must pay the external BA for the balancing services it provides, and, based on current balancing service rates, PSE would expect to incur annual costs of $11.5 million to balance the total of 800 MW of external wind resources.

As an EIM participant, PSE would have a lower local flexibility reserve requirement and more opportunities for balancing load and wind variability in sub-hourly intervals. This helpful impact of the EIM would allow PSE to instead provide its own flexibility reserves (with the assistance of the EIM diversity benefit) to balance the PSE wind resources currently integrated by the external BA and thereby avoid all or a substantial portion of the balancing charges it currently incurs each year.

If feasible, this operating change could allow PSE to avoid balancing charges but would require PSE (as an EIM participant) to maintain a higher internal flexibility reserve requirement than it otherwise would as an EIM participant if the 800 MW of remote wind was still balanced outside of the PSE BAA. Using the flexibility reserve methodology described above, the study team estimates that PSE would need to maintain an incremental 22 MW of flexibility reserves, on average, to balance the remote wind as an EIM participant.[36] Based on the ISO's average 2013 flexible ramping constraint shadow price of $6.98/MW-hour, which was used in Chapter 3 of this report to value flexibility reserve requirement savings, the 22 MW increase in average flexibility reserves requirements to balance its remote wind would create $1.3 million in additional cost to PSE. PSE would also need to hold a higher amount of regulating reserves to manage the greater wind variability on a sub-5-minute timescale. Based on previous analysis by PSE, balancing the remote wind internally would also be expected to require PSE to hold an incremental 15 MW of regulating up and 15 MW of regulating down reserves on average. Using the ISO's historical average prices from 2013 of $5.34/MW-hour for regulating up and $3.32/MW-hour for

[36] It is important to note that this incremental amount is 48 MW lower than the amount of flexibility reserves that PSE would require if it were to attempt to balance the remote wind as a standalone entity.

regulating down as a proxy for PSE regulating costs,[37] the incremental regulating requirement would create $1.1 million in incremental regulating costs for PSE.

The annual net cost savings of PSE balancing these remote wind plants locally with the support of the EIM is $9.1 million per year.[38] This benefit is in addition to the cost savings reported in Section 3.1.

4.2 Renewable Curtailment Savings

Renewable curtailment savings estimates were provided by PSE based on historical curtailment of its wind resources both within and external to its BAA. Wind resources external to the PSE BAA are subject to reliability curtailments from the source BA. In addition, under current operational practice, PSE may need to curtail output of wind plants located in its own BAA during periods of elevated reliability concern, such as spring runoff conditions. If PSE were to internally integrate its remote wind plants, then PSE's historical backcast approach estimates renewable curtailment cost savings for its total wind portfolio range from $0 to $0.8 million per year, depending on a combination of local and regional system conditions. PSE expects that the EIM could help reduce a portion or eliminate all of this curtailment if all of the wind plants were in PSE's BAA. To cover this range, EIM renewable curtailment related savings for PSE have been assessed as a range of annual benefits from $0 to $0.8 million.

[37] See Section 6.3 of CAISO (2014a). It is not expected that the ISO would provide regulating reserves to PSE under the EIM; rather the ISO's regulating reserve prices were used as a transparent ancillary services market value as a proxy for potential costs that PSE would incur to meet a higher regulating requirement.
[38] This net savings is calculated by taking the difference of $11.5 million in avoided balancing service charges, less $1.3 million in incremental flexibility reserve costs for PSE and $1.1 million in incremental regulating reserve costs for PSE.

The PacifiCorp-ISO and NV Energy-ISO EIM studies included benefits related to the EIM's assistance in reducing renewable energy curtailment inside the ISO. Due to the renewable energy curtailment benefits already captured by PacifiCorp and NV Energy's participation in the EIM, this study conservatively assumes that PSE's participation in the EIM would not enable any additional avoidance of renewable energy curtailment for current EIM participants.

5 Conclusions

This report assessed the incremental benefits of PSE's participation in the ISO EIM. The study team estimated the benefits for PSE as well as current EIM participants. The gross benefits identified to PSE are substantial, even under the low real-time transmission transfer capability scenario, which includes 300 MW of real-time transfer capability between PSE and PacifiCorp. In addition, if the EIM enables PSE to locally balance its remote wind resources and avoid wind balancing service charges, significant additional cost savings could be possible.

Two additional material benefits have not been quantified. First, the study team assumed that PSE's behavior and actions in the DA and HA market would not be influenced by the continuous information flowing from participation in the EIM market. We believe that over time, PSE may be able to obtain additional benefits, which were not captured in this study, by adjusting its positions more optimally in the HA and DA markets based on information obtained through more transparent awareness of the real-time market as a result of EIM participation.

Second, the study team did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM creates. Although both of these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.

Relative to the EIM startup and ongoing participation costs estimated by PSE staff, the gross benefits presented in this study are significant. The benefits and costs from PSE's participation in the EIM quantified in this report would produce a positive net present value ranging from $153.7 million to $174.4 million for PSE over a 20-year period. [39]

[39] NPV has been estimated for a project start year of 2014. The calculation assumes 20 years of sub-hourly dispatch and flexibility reserves benefits and annual ongoing costs. PSE's participation in the EIM is estimated to go live in Fall 2016, and startup costs are incurred in 2015 and 2016. All values have been discounted using PSE's after-tax weighted average cost of capital (ATWACC) of 6.7% nominal, consistent with PSE's 2013 IRP, and assumed annual inflation rate of 2%. Increasing the NPV calculation to include 30 years of benefits and ongoing costs results in an NPV ranging from $190.2 to $216.3 million.

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BEFORE THE PUBLIC UTILITY COMMISSION
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PACIFICORP

PAC/908 to Cross-Examination Statement

***NV Energy-ISO Energy Imbalance Market Economic Assessment*,**
Energy and Environmental Economics (March 25, 2014)

August 18, 2015

NV Energy-ISO Energy Imbalance Market Economic Assessment

March 25, 2014

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

[1] A balancing authority (BA) is an entity responsible for integrating resource plans in advance of real-time balancing needs, maintaining load-interchange-generation balance within a balancing authority area, and supporting interconnection frequency in real time. A balancing authority area (BAA) is the collection of generation, transmission, and loads within the metered boundaries of a BA.

incremental savings for current EIM participants, and is expected to create no incremental implementation costs for current EIM participants beyond those that are recovered from NV Energy through ISO fixed and administrative charges. Thus, NVE Energy participation in the EIM is expected to produce positive incremental net benefits for all EIM participants collectively, including NV Energy.

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

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

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

[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.

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.*

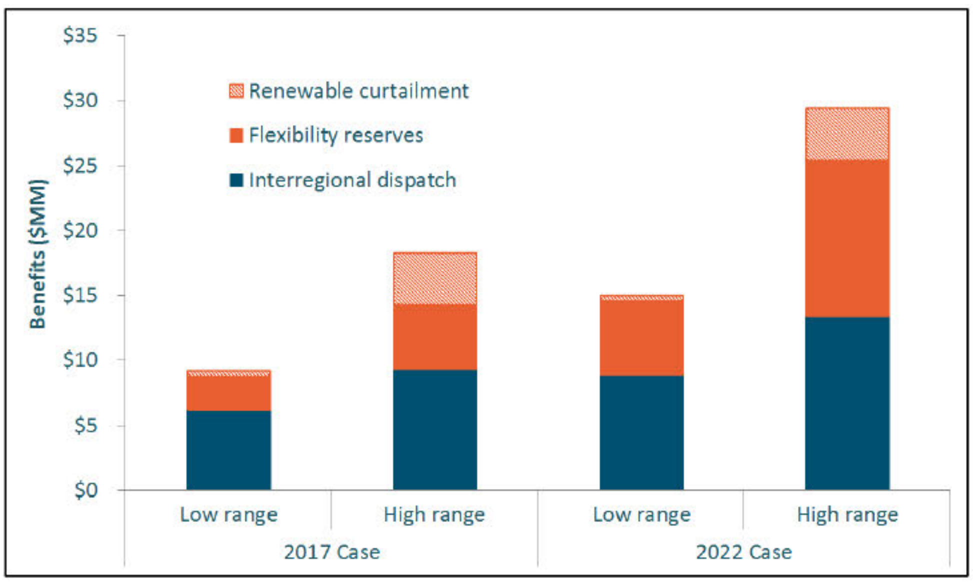
Across these scenarios, the study team estimated that NV Energy participation in the EIM generates total annual cost savings to all participants (in 2013$) of $9.2 to $18.2 million in 2017, and $15.0 to $29.4 million in 2022. These benefits are incremental to those estimated for the creation of the initial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



Note: Figure represents total incremental benefits to all EIM participants as a result of NV Energy's participation in the EIM.

The study team's attribution of these benefits between the NV Energy balancing authority (BA) and the current EIM participants is shown in Tables 3 and 4 below, and indicate that NV Energy's participation could deliver operational savings to both parties.

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

Benefit Category	2017 Low range	2017 High range	2022 Low range	2022 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 annual 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:		**$11.2**
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 $11.2 million in one-time setup costs and fees plus $2.6 million in annual operating costs and usage charges, for a total 20-year present value cost of $41.8 million.[11] The present value gross benefits to the NV Energy BA over this time period range from $82.1 million to $129.4 million,[12] resulting in 20-year NPV benefits of between $40.3 million and $87.6 million.

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

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

[12] The present value benefit calculations assume that gross benefits in the project start year of 2016 are equal to the 2017 estimate. Annual benefits for the years 2018-2021 were interpolated from the 2017 and 2022 benefit estimates; benefits for 2022 through 2035 were conservatively assumed to grow at the rate of inflation. Results from the GridView model are inflated from 2012$ to 2013$ at 1.5%.

Summing the estimated NPV benefits for all EIM participants — $40.3 to $86.7 million for NV Energy and $68.9 to $166.9 million for current participants — leads to an estimate of total incremental NPV benefits to all participants of $109.2 million to $254.5 million that result from NV Energy's participation in the EIM.

1 Introduction

1.1 Background and Goals

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

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

1.2 Structure of this Report

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

2 EIM Analysis

2.1 Key Assumptions

2.1.1 WHAT IS AN EIM AND WHAT WOULD IT DO?

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

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

+ **More efficient interregional dispatch.** The EIM would allow more efficient use of generators and transmission systems by reducing "transactional friction" and structural impediments between NV Energy and ISO BAAs,[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 $11.2 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:		**$11.2**
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. If utilized by the EIM, these paths may create additional savings from dispatch efficiency improvements that are not captured in this analysis. Even without utilization of those paths, NV Energy's participation in the EIM could still provide incremental efficient dispatch opportunities and flexibility diversity through each participant's EIM interaction over ties shared with ISO.

2.1.3.5 Limits on hydropower contributions to flexibility reserves

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

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

[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.

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

[24] FERC Order 764 policy directs transmission operators to permit system users to submit schedules on a 15-minute basis. The proposed EIM, however, would provide significant additional cost savings over sub-hourly bilateral scheduling by providing automated, optimized software for facilitating cost-effective transactions on a time scale that may not be feasible through bilateral trading alone. ISO has incorporated real-time unit commitment into the EIM functionality to provide further opportunities for improved efficiency.

expectation of EIM market demands and prices. Convergence bidding in the ISO market can also help to link market decisions in real-time and at day-ahead.

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

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

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

2.1.3.8 Attribution of EIM benefits

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

This assumption is balanced by offsetting limitations in GridView. GridView determines dispatch and power flows based on transmission system impedances, which creates two types of modelling deficiencies. First, the model tends to under-predict that actual flow that would be created between the direct EIM participants. In actual operations, these flows are partially dictated through contract path, which would allow for more transactions that produce savings to be concentrated within participating jurisdictions than can be simulated in GridView.

Second, a portion of the generation changes that produce the dispatch savings reported here occur in other WECC regions, such as LADWP and WAPA and APS in the desert southwest. In practice, NV Energy participation in the EIM may bring indirect benefits to certain entities as they respond to greater efficiencies in regional dispatch; such efficiency improvements outside of the EIM footprint are expected to result in savings for EIM participants through lower cost purchases. We have assumed that the impact of these modeling limitations is well within the range of the high and low scenario savings levels modeled.

2.2 Methods

2.2.1 INTERREGIONAL DISPATCH SAVINGS

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

The NVE BAU Case simulates status quo operational arrangements, and includes wheeling rates based on point-to-point transmission tariffs to conservatively represent barriers to trade across BAA boundaries. The NVE EIM Dispatch Case eliminates the wheeling rates charged on power flows between NV Energy and ISO, resulting in more efficient dispatch and lower production costs. In eliminating the wheeling rates, the study team implicitly assumed that no variable transmission costs are incurred for EIM transactions. An additional charge was also applied to imports to California BAAs (ISO, LADWP, Balancing Area of Northern California, and Imperial Irrigation District) to simulate the need for market participants to acquire 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).

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

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

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.

[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.

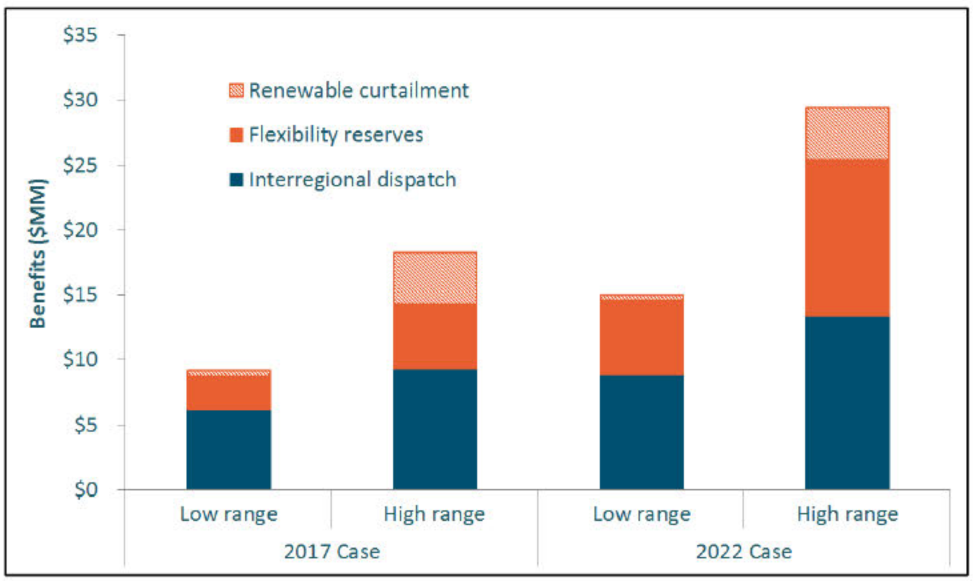
Table 8. Low and high range assumptions for 2017 and 2022 cases

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
Caclulation 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 annual benefits to all participants from NV Energy Participation in EIM (2013$)



Note: Figure represents total incremental benefits to all EIM participants as a result of NV Energy's participation in the EIM

Table 9. Low and high range annual benefits to all participants for 2017 and 2022 (million 2013$)

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.

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 annual 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 annual 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.

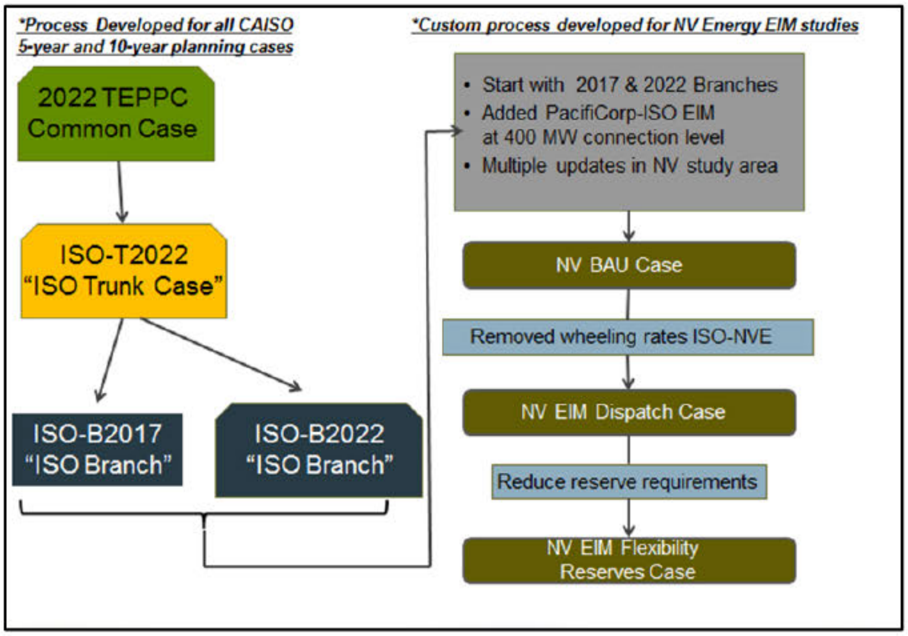
[1] For more on GridView, see http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

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$)

	2017		2022	
Scenario	Low Range	High Range	Low Range	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

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 296

PACIFICORP

PAC/909 to Cross-Examination Statement

***PacifiCorp-ISO Energy Imbalance Market Benefits*,**
Energy and Environmental Economics (March 13, 2013)

August 18, 2015

PacifiCorp-ISO Energy Imbalance Market Benefits

March 13, 2013

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Executive Summary

This report examines the benefits of an energy imbalance market (EIM) between PacifiCorp and the California Independent System Operator (ISO). This report focuses on estimated potential EIM benefits with the low range reflecting a scenario in which assumptions were chosen to be conservative. The full range of estimated EIM benefits in this report for the year 2017 is \$21 million to \$129 million (2012\$). Preliminary cost estimates (based on previous studies) of setting up the EIM range from \$3 million to \$6 million, with an estimated annual cost of \$2 million to \$5 million.

The report supports the conclusion that the two-party EIM provides a low-cost, low-risk means of achieving operational savings for both PacifiCorp and ISO and enabling greater penetration of variable energy resources. The report further supports that the benefits of the EIM would increase to the extent that: (1) operational changes can be made to support the EIM, such as increased transmission transfer capabilities between PacifiCorp and ISO; and (2) additional entities join the EIM, thus bringing incremental load and resource diversity, transfer capability, and flexible generation resources that would further reduce costs for customers.

Changes in the electricity industry in the Western U.S. are making the need for greater coordination among balancing authorities (BAs),[1] such as through an EIM, increasingly apparent. Renewable portfolio standards already enacted in Western states are expected to result in some 60,000 MW of wind, solar, geothermal, and other renewable generation in the Western Interconnection by 2022, comprising approximately 15% of total electric energy.[2]

Recent studies have suggested that it will be possible to reliably operate the current western electric grid with high levels of variable generation, but doing so may require supplementing the hourly bilateral markets used in the West toward shorter scheduling timescales and greater coordination among western BAs. Greater coordination would allow BAs to pool load, wind, and solar variability and reduce flexibility reserve requirements, and would increase flexibility and reduce renewable curtailment.

In response, several regional initiatives, studies, and groups have emerged to explore innovations for scheduling and coordination. These include reforms being assessed as part of the Western Electric Coordinating Council's Efficient Dispatch Toolkit (EDT) initiative, an effort by a group of public utility commissions to explore an EIM for the West, and an ongoing Northwest Power Pool initiative to analyze the benefits of an EIM or other forms of regional coordination for the Pacific Northwest region.

As an extension of these efforts, in February 2013 PacifiCorp and ISO signed a memorandum of understanding to pursue an EIM. Energy and Environmental Economics,

[1] A balancing authority (BA) is a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports Interconnection frequency in real time. A balancing authority area (BAA) is the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, which maintains load-resource balance within this area.

[2] These renewable capacity and energy projections are from the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case; see http://www.wecc.biz/Lists/Calendar/Attachments/4057/2022 20Common%20Case%20-%20Webinar%205.pdf.

Inc. (E3), a consulting firm, was retained by ISO to assess the EIM's potential benefits. This report documents E3's findings.

The EIM under consideration is a balancing market that optimizes generator dispatch within and between balance authority areas (BAA)[3] every five minutes by leveraging the existing ISO real-time dispatch market functionality. It does not replace the day-ahead or hourly markets and scheduling procedures that exist today. The ISO outlined the structure of such an EIM in a recent proposal to the Western Governors Association and the Public Utilities Commissions Energy Imbalance Market (PUC-EIM) Task Force.[4]

An EIM covering PacifiCorp and ISO would allow both parties to improve dispatch efficiency and take advantage of the diversity in loads and generation resources between the two systems, reducing production costs, operating reserve requirements, and renewable generation curtailment. Specifically, the creation of a PacifiCorp-ISO EIM would yield the following four principal benefits:

+ *Interregional dispatch savings*, by realizing the efficiency of combined 5-minute dispatch, which would reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
+ *Intraregional dispatch savings*, by enabling PacifiCorp generators to be dispatched more efficiently through the ISO's automated system (nodal dispatch software), including benefits from more efficient transmission utilization;

[3] See footnote #1
[4] See CAISO, "CAISO Response to Request from PUC-EIM Task Force," March 29, 2012, http://www.westgov.org/PUCeim/documents/CAISOcewa.pdf; CAISO, "Energy Imbalance Protocols (Revised to Support CAISO Cost Estimate for PUC-EIM)", January 24, 2013, http://www.westgov.org/PUCeim/documents/CAISOrcp.pdf.

+ *Reduced flexibility reserves*, by aggregating the two 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 it would otherwise need to be curtailed.

These benefits are indicative but not exhaustive. A recent report by staff to the Federal Energy Regulatory Commission identifies non-quantified reliability benefits that will also arise. These include enhanced situational awareness, security constrained dispatch, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.[5]

E3 estimated benefits from a PacifiCorp-ISO EIM using the GridView[6] production simulation software to simulate operations of the Western Interconnection with and without the EIM in the year 2017. This year was selected to represent likely system conditions within the first several years after the EIM becomes operational. E3's analysis incorporated California's greenhouse gas regulations, and the associated dispatch costs.

The GridView results are sensitive to several key assumptions and modeling parameters. These include: limits on the transmission transfer capabilities between PacifiCorp and ISO, and the extent to which unloaded hydroelectric capacity is allowed to contribute toward contingency and flexibility reserve requirements. E3's analysis of EIM benefits is also sensitive to the assumed level of savings from moving to nodal dispatch in PacifiCorp and the amount of renewable energy curtailment that could be reduced through the EIM.

[5] Staff of the Federal Energy Regulatory Commission, 2013, "Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market," February 26.
[6] GridView is ABB's production simulation software.

E3 developed several scenarios to address key uncertainties in the modeling of EIM benefits. These scenarios explore a wide range of potential benefit levels to reflect both the limitations of existing tools to characterize all of the changes to system operations that would occur under an EIM, particularly in the modeling of hydropower, reserves, and renewable curtailment, greenhouse gas regulation, and uncertainties about the extent to which future industry developments would allow cost savings to occur both with and without an EIM. The scenarios were developed around three assumptions of transfer capability between PacifiCorp and ISO: low (100 MW), medium (400 MW), and high (800 MW). Within each scenario, E3 modeled a low and high range of benefits. The assumptions for the low and high range estimates are shown in Table 1.

Table 1. Low and high range assumptions under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios

Assumption	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Maximum hydropower contribution to contingency and flexibility reserves*	25%	12%	25%	12%	25%	12%
Share of intraregional dispatch savings achieved	10%	100%	10%	100%	10%	100%
Share of identified renewable energy curtailment avoided	10%	100%	10%	100%	10%	100%

** Percent of nameplate capacity for each project*

Across these scenarios, E3 estimated that a PacifiCorp-ISO EIM would generate total annual cost savings (in 2012 $) of $21-129 million in 2017, with PacifiCorp and ISO both benefitting. Table 2 shows the range of benefits by category for each scenario.

Table 2. Low and high range annual benefits under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Interregional dispatch	$14.1	$11.0	$22.3	$17.7	$22.4	$17.8
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$4.0	$20.8	$11.0	$51.3	$13.4	$77.1
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$21.4**	**$65.6**	**$36.7**	**$102.8**	**$39.2**	**$128.7**

Notes: Individual estimates may not sum to total benefits due to rounding. Section 2.4 describes why interregional dispatch savings are lower in the high range than the low range.

The benefit estimates described in this report are gross benefits and are not net of estimated costs. Because the EIM would make use of ISO's existing dispatch software, the initial cost is expected to be low when compared to these benefits. E3 did not conduct an independent analysis of the cost of establishing and operating an EIM. Based on ISO's estimates of market operator costs, PacifiCorp would incur a one-time fixed charge of approximately $2.1 million.[7] A separate study of a WECC-wide EIM estimated that each EIM market participant would also incur one-time capital costs of $1-4 million for software, hardware, and other related investments.[8] Annual costs to operate the PacifiCorp-ISO EIM are estimated to be on the order of $2-5 million.[9]

[7] Based on estimates from CAISO staff.

[8] WECC, 2011, "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," WECC White Paper, p. 62, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

[9] This estimate is comprised of CAISO estimate of $1.35 million per year in administrative charges to PacifiCorp plus additional PacifiCorp costs of $1-4 million per year in staffing and other operating costs for an EIM market participant.

1 Introduction

1.1 Background and Goals

PacifiCorp and ISO have been active participants in an ongoing regional effort to enhance bulk power operations to achieve cost savings for customers and facilitate the integration of higher levels of renewable generation. In response, PacifiCorp and ISO have been funding, participating in, and observing a number of regional and national initiatives, studies, and groups aimed at enhancing access to needed flexible resources, application of automated tools to manage resources and products that balance variable generation, and more effective utilization of existing and new transmission facilities. These efforts include:

+ The 2008 Western Executive Industry Leaders (WEIL) study, which identified economic opportunities to lower renewable procurement costs across the Western Interconnection;[10]
+ Two recent (2011 and 2012) studies of an EIM covering all of the Western Interconnection except for ISO and the Alberta Electric System Operator, one coordinated by WECC and another by the PUC-EIM Group (see Section 3.2);
+ Two studies examining intra-hour scheduling in the Western Interconnection, one for the WECC's Variable Generation Subcommittee and another for the Northwest Power Pool (see Section 3.2);

[10] See http://www.weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf for the full report.

+ A Joint Initiative among Columbia Grid, Northern Tier Transmission Group, and WestConnect on a dynamic scheduling system, an intra-hour transaction accelerator platform, and intra-hour transmission scheduling;[11] and
+ The North American Electric Reliability Corporation's (NERC's) ongoing Integration of Variable Generation Task Force (IVGTF).[12]

Building on their involvement in these efforts, PacifiCorp and ISO undertook a joint study to evaluate the potential benefits of an EIM covering their service areas. E3 was retained to identify and quantify the benefits of this potential EIM, and to examine the allocation of benefits between PacifiCorp and ISO.

This report describes E3's methods and findings. Throughout the study process, E3 worked closely with both PacifiCorp and ISO to develop scenario assumptions, validate the approach, and 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 report also contains a technical appendix that describes modeling assumptions and methods in more detail.

[11] For documents related to this process, see http://www.columbiagrid.org/ji-nttg-wc-documents.cfm.
[12] For task force materials, see http://www.nerc.com/filez/ivgtf.html.

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 PacifiCorp West, PacifiCorp East, and ISO BAAs. EIM software would automatically dispatch imbalance energy from generators voluntarily offering their resource for dispatch 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 EIM would complement PacifiCorp's existing procedures for transacting in the ISO's hour-ahead and day-ahead markets. This study assumes that the ISO hour-ahead and day-ahead markets will remain unchanged and that PacifiCorp will continue its existing operational plans to serve its load, arrangements for unit commitment, contingency reserves, regulation, regional reserve sharing agreements, and other BA responsibilities.

The EIM is expected to lead to four principal changes in system operations for PacifiCorp and ISO:

+ **More efficient interregional dispatch.** The EIM would allow more efficient use of generators and the transmission systems in PacifiCorp and ISO by removing transmission rate and structural impediments between BAAs, eliminating within-hour limitations, and enabling more efficient dispatch between the two systems relative to hourly scheduling.

+ **More efficient intraregional dispatch in PacifiCorp.** The EIM's nodal dispatch software would improve the efficiency of PacifiCorp's system dispatch by better reflecting transmission constraints and congestion within PacifiCorp.

+ **Reduced flexibility reserve requirements in PacifiCorp and ISO.** By pooling variability in load and wind and solar output, PacifiCorp and ISO would each reduce the quantity of reserves required to meet flexibility needs.

+ **Reduced renewable energy curtailment in ISO.** By allowing generators in PacifiCorp's BAAs to reduce output when ISO faces an "over-generation" situation, an EIM would reduce the amount of renewable energy ISO would otherwise need to curtail.

This study calculates the benefits associated with these changes by comparing the total cost of operating the combined ISO and PacifiCorp systems under two cases: (1) a Benchmark Case, representing continuation of current scheduling and operating practices under "business-as-usual," and (2) an EIM Case, in which an EIM is established encompassing the PacifiCorp and ISO BAAs. The cost difference between the Benchmark Case and the EIM Case represents the total benefits of an EIM. The study also provides a high-level estimate of how these benefits might be apportioned among the ISO and PacifiCorp systems.

2.1.2 EIM COSTS

The costs of an EIM include those borne by the market operator to set up and operate the EIM, and those borne by market participants to participate in the EIM. The EIM requires some expansion of ISO's modeling and software capabilities, but by using ISO's existing software, initial costs are significantly reduced relative to what they would be if new software development were needed.

Additional hardware and organizational costs may also be required. For instance, PacifiCorp may need to purchase some new metering or communications hardware to enable effective communication between parties. PacifiCorp may also seek some amount of staff training and organizational development to more fully take advantage of the market opportunities offered by the EIM.

ISO has estimated the costs of setting up and operating an EIM, as part of its engagement with ongoing regional EIM initiatives. 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 covers the cost of making the modeling, systems, and other preparations to include an entity in the EIM, and depends on the size of the BAA. 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 a PacifiCorp-ISO EIM, ISO estimates that PacifiCorp would incur a one-time fixed charge of approximately $2.1 million and $1.35 million per year in administrative charges.[13]

Independent estimates of market participant costs were not developed for this study. A WECC-sponsored study of EIM costs estimated that each market participant would incur total capital startup costs of $1-4 million and operating costs of $1-4 million per year.[14]

[13] Based on estimates from CAISO staff. Administrative charges per participant will likely fall as the number of participants grows. Other cost and risk allocation issues associated with the EIM, and the rules to address these issues, will be considered in a 2013 stakeholder process.

[14] WECC, 2011, "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," WECC White Paper, p. 62, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

In this case, PacifiCorp is assumed to be the only incremental market participant and no incremental costs would be required for existing ISO market participants.

Using these preliminary estimates of market operator and market participant costs, total fixed and operating costs for the PacifiCorp-ISO EIM would be on the order of $3-6 million (one-time startup costs) and $2-5 million per year (annual operating costs), respectively. PacifiCorp and ISO are actively working to develop specific start up and operating costs as part of initial efforts under the memorandum of understanding.

2.1.3 KEY MODELING ASSUMPTIONS

Five key modeling assumptions are important for understanding the results in this study: 1) the use of hurdle rates, (2) hourly dispatch, (3) the treatment of flexibility reserves, (4) transfer capability limits between PacifiCorp and ISO, and (5) limits on hydropower contributions to reserves. This section provides a brief overview of the rationale for these assumptions.

2.1.3.1 Hurdle rates

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 some cases, for market participants to acquire point-to-point transmission service in order to schedule transactions from one BAA to another;
+ The current practice of some transmission providers 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" losses requirements; and

+ Inefficiencies due to illiquid 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, among others.

In production simulation modeling, these impediments to trade are typically represented by "hurdle rates," $/MWh price adders that inhibit power flow over transmission paths that cross BAA boundaries. In this analysis, E3 used hurdle rates that were benchmarked to historical data, so that hourly power flows on major WECC paths in the simulation approximate the historical flow levels on those paths during a historical test year.[15]

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 at the 5-minute timestep. This is represented in production simulation modeling by the removal of hurdle rates, which allows for more efficient (i.e., lower cost) dispatch.

2.1.3.2 Hourly dispatch

While a PacifiCorp-ISO EIM would likely operate on a 5-minute timestep, E3 used GridView simulation runs with an hourly timestep to estimate the change in operating costs associated with an EIM. This was done in order to simplify the computational process and reduce model runtime, and because of the limited quantity of high-temporal resolution data available for the Western Interconnection.

[15] This analysis used benchmarked hurdle rates from the WECC EIM study. See http://www.wecc.biz/committees/ EDT/ Documents/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2[1].pdf, pp 41-43.

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 an 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: (1) savings due to more efficient dispatch of resources to meet net load variations inside the operating hour; and (2) savings from reductions in costs to meet potential intra-hour ramping shortages. Other studies have indicated that sub-hourly dispatch benefits may be substantial. Those benefits would be additive to the benefits reported here.

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.[16] 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 and variability inherent in these resources while maintaining acceptable balancing area control

[16] This study assumes that contingency reserves would be unaffected by an EIM and that PacifiCorp would continue to participate in its existing regional reserve sharing agreement for contingency reserves in all scenarios.

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 study, E3 performed statistical calculations of the quantity of flexibility reserves that would be required in both the Benchmark Case and the EIM Case. 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, E3 assumed that the diversity benefit from an EIM results in savings from reduced load following reserves, but not regulation reserves. Other contingency reserves (spin and non-spinning reserves) were assumed not to change under the EIM operation.

There are two implicit assumptions embedded in this approach: (1) that PacifiCorp and ISO would carry the calculated levels of flexibility reserves in the Benchmark Case, and (2) the EIM would include a mechanism to take advantage of increased net load diversity by reducing the quantities of flexibility reserves that would need to be carried. 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 is in the process of introducing a “flexi-ramp” product for this purpose.

With regard to the second assumption, while the specific design of a potential PacifiCorp-ISO EIM has not been finalized, it is logical to assume that ISO’s flexi-ramp requirements 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. However, it should be noted that this mechanism may not be in place at the time EIM becomes operational, and the ISO and PacifiCorp may require a period of operational experience before the full benefits of flexibility reserve savings can be achieved.

2.1.3.4 Transmission transfer capability

PacifiCorp has several interconnections and contract transmission rights between the ISO and both the PacifiCorp East and PacifiCorp West BAAs that can potentially be utilized for EIM activity. Each interconnection has unique capabilities to facilitate beneficial interchange based upon existing facilities, path operators, legacy agreements, and incremental costs. Initiatives are underway to maximize the potential at each interconnection for the EIM.

Transmission transfer capability limits between PacifiCorp and ISO will constrain EIM benefits. These limits can be physical or contractual. If the transmission paths connecting PacifiCorp and ISO are congested, generators in PacifiCorp will not be able to provide additional imbalance energy to ISO, and vice versa. PacifiCorp and ISO anticipate initially relying on PacifiCorp transmission contract rights to the ISO to facilitate EIM transactions, as opposed to a "flow-based" transmission optimization, similar to those in use in the ISO and other organized markets, that would be unconstrained by contract limitations.

While reliance on existing contract path scheduling mechanisms will prevent achievement of full benefits at EIM startup, transmission transfer capability and associated EIM benefits would increase through potential contractual changes, new transmission construction, operational changes such as WECC-wide 15-minute scheduling, and the addition of other EIM participants. In particular, as additional market participants join the EIM and a larger contiguous EIM area is formed, flow-based transmission usage will be explored, along with methods to limit impact to non-participating transmission systems. Flow-based transmission usage is expected to increase benefits to EIM market participants. In addition, a mechanism to increase the flexibility of existing transmission for intra-hour use could be pursued to increase the transfer capabilities and increase the value of EIM.

This report provides a range of benefits based, in part, on three different potential interchange capabilities between PacifiCorp and ISO, specifically 100, 400, and 800 MW.[17] The two parties have agreed in the memorandum of understanding to conduct an initial review of contracts. The findings from the ongoing review, collaboration with neighboring transmission path operators, and additional certainty on market design will inform total interconnection capabilities in the short-term as well as specific opportunities to add to those capabilities over time. The model also incorporates a 200 MW limit on east to west transfers between the PacifiCorp East and PacifiCorp West BAAs. For reduced renewable curtailment, E3 assumed that this transfer capability would not pose a constraint, given the relatively small quantity of curtailed energy in question.

[17] For simplicity of modeling, transmission transfer capabilities are modeled at the California-Oregon Intertie (COI). This is a proxy used to demonstrate a general level of increased benefit with increasing interconnection capabilities, which may occur on other paths.

2.1.3.5 Limits on hydropower contributions to flexibility reserves

Cost savings from reduced flexibility reserves are sensitive to assumptions about the availability of hydropower to provide reserves. Dispatchable hydroelectric resources only rarely generate at levels that approach maximum nameplate capacity due to limitations on water available for power generation. On many facilities, a portion of the "unloaded" capacity — the difference between the nameplate capacity and the actual generation — can be used to provide contingency and flexibility reserves. However, this unloaded capacity varies by facility and with continually-fluctuating river conditions, making it challenging to generalize for modeling purposes. This leads to uncertainty in the calculation of operating costs using production simulation models.

In order to address this uncertainty, E3 developed a range regarding the ability of hydro to provide flexibility reserves, which affect a significant component of potential EIM savings. In the high range, E3 assumed that up to 12% of the total nameplate capacity of hydropower generation is available to provide flexibility reserves, while in the low range, E3 assumed that up to 25% of hydropower nameplate capacity is available to provide flexibility reserves.[18] EIM benefits are higher in the case where hydro'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. Conversely, there are fewer cost savings available in the case where hydro provides a larger quantity of flexibility reserves with little, if any, variable cost.

[18] The two scenarios used here reflect the low and high ends of a plausible range of values based on CAISO and PacifiCorp experience.

2.2 Methods

2.2.1 INTERREGIONAL DISPATCH SAVINGS

An EIM would reduce transactional friction between PacifiCorp and ISO and thus enable improved resource dispatch efficiency and reduced cost to serve load in both systems. E3 estimated these interregional dispatch savings by running parallel production cost simulations using GridView: one with a PacifiCorp-ISO EIM (EIM Dispatch Case) and one without the EIM (Benchmark Case).

The Benchmark Case simulates status quo operational arrangements, and includes hurdle rates to represent economic and non-economic barriers to trade, such as transmission tariff rates, losses, and lack of market liquidity. The EIM Dispatch Case simulates operations with an EIM in place by eliminating these hurdle rates between PacifiCorp and ISO, resulting in more efficient energy dispatch and lower production costs.[19] Interregional dispatch savings from an EIM are measured as the difference in production costs between the Benchmark and EIM Dispatch Cases. In eliminating hurdle rates, E3 implicitly assumed that no variable transmission costs are incurred for EIM transactions.

To calculate the interregional dispatch savings, E3 developed GridView production cost estimates for two cases. The first, a Benchmark Case, assumes hurdle rates are in place. The second, an EIM Dispatch Case, assumes alternately that there is 100, 400, and 800 MW of transmission transfer capability between the PacifiCorp and ISO systems, and that EIM transactions using this capability pay no hurdle rates. E3 scaled the

[19] Only hurdle rates between PacifiCorp –West and ISO have been adjusted from the benchmark case. Hurdle rates were also used to simulate the need for market participants to acquire CO_2 allowances when delivering "unspecified" electric energy into California. These CO_2-related hurdle rates were kept in place for both the Benchmark and the EIM Dispatch Cases.

interregional dispatch savings for lower levels of transmission transfer capability (100 MW and 400 MW) by assuming that the benefits are proportional to the change in intertie flows resulting from the EIM at each level of transfer capability.[20]

2.2.2 INTRAREGIONAL DISPATCH SAVINGS

In bilateral markets, load serving entities (LSEs) like PacifiCorp seek to minimize the cost of serving their loads through a combination of dispatching their own resources and trading energy subject to the physical limitations of the transmission system. This can result in significant additional dispatch costs to manage transmission congestion within the LSE's own service territories. In a nodal market, all transmission constraints are considered when determining optimal commitment[21] and dispatch of generators, and the efficient use of the transmission system.

While ISO currently uses nodal dispatch, PacifiCorp's unit commitment and dispatch do not take full advantage of all sub-hourly cost saving opportunities. A PacifiCorp-ISO EIM would provide 5-minute nodal price signals to generation resources throughout the EIM area, thus enabling more optimal generation and transmission dispatch in the PacifiCorp area. These efficiency improvements cannot be captured using the GridView software, which assumes perfectly efficient operations within each area.

To quantify the cost savings from using ISO's nodal dispatch software within PacifiCorp's BAAs, E3 assumed these savings would be proportional to the estimated savings from

[20] Scaling factors of 0.617 (12% hydropower reserve cap) and 0.628 (25% hydropower reserve cap), applied to the 800 MW results, were used for the 100 MW transfer capability scenario, based on estimated changes in intertie flows. A 0.997 scaling factor, applied to the 800 MW results, was used in the 400 MW case for both hydropower assumptions.

[21] Under an EIM, commitment would remain the responsibility of the BA. An EIM would provide optimal real-time dispatch, but would not address commitment.

ISO's own transition to nodal pricing that occurred in 2009.[22] By assuming estimated cost savings scale with peak load, the benefits from nodal dispatch in PacifiCorp for 2017 would be:

$$PacifiCorp\ 2017\ savings = CAISO\ 2009\ savings * \frac{PAC\ 2017\ peak\ load}{CAISO\ 2009\ peak\ load}$$

or

$$PacifiCorp\ 2017\ savings = \frac{\$105\ MM}{yr} * \frac{10{,}079\ MW}{45{,}486\ MW} = \frac{\$23\ MM}{yr}$$

Because there is some uncertainty about the extent to which ISO's nodal dispatch software will produce dispatch cost savings from PacifiCorp's generation, this study examines alternative low and high scenarios. In the low range scenario, the EIM is assumed to achieve 10% of the total $23 million of available cost savings, which were calculated based on an hourly analysis. This assumption stems from the ISO's experience that its balancing market clears transactions totaling approximately 10% of total load. In the high range scenario, the EIM is assumed to achieve 100% of the total $23 million of available cost savings. This scenario implicitly assumes that 5-minute EIM prices will inform market transactions that occur on an hourly basis, allowing more savings than would occur based only on the amount of imbalance energy clearing in the 5-minute market. As the non-EIM forward market becomes better informed by the EIM market, E3 would expect that the real-time nodal market applied to PacifiCorp would result in more than 10% savings.

[22] See Frank A. Wolak, 2011, "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, *American Economic Review* 101: 247-252. The estimates in this study are estimated annual cost reductions that resulted from the introduction of nodal pricing in California.

2.2.3 REDUCED FLEXIBILITY RESERVES

Currently, PacifiCorp and ISO meet their operating reserve requirements by procuring and utilizing existing generating capacity within their respective BAAs. An EIM would lower the total cost of procuring and utilizing flexibility reserves for both entities in two ways: (1) reducing flexibility reserve requirement quantities by combining PacifiCorp and ISO's forecast error for load and variable generation; and (2) enabling flexibility reserves to be procured from thermal or hydro resources anywhere in the EIM footprint, subject to transmission constraints. The result is that the combined cost of procuring flexibility reserves with an EIM is less than it would be if each entity procured them independently.

E3 estimated the cost savings from reduced flexibility reserves using the following three steps. First, flexibility reserve requirements were calculated for PacifiCorp and ISO as separate areas (Benchmark Case) and then again as a combined area (EIM Flexibility Reserve Case).[23] Flexibility reserve requirements were calculated separately for each hour using three years of 10-minute load, wind, and solar data for PacifiCorp and ISO. Calculations in the EIM Flexibility Reserve Case were constrained so that reductions in flexibility reserve requirements were less than or equal to the assumed transfer capability between PacifiCorp and ISO.

Next, E3 applied the flexibility reserve requirement calculations from above to production cost simulation runs for each case, using GridView. In the Benchmark Case and EIM Dispatch Cases, PacifiCorp and ISO must procure flexibility reserves from capacity located in their respective BAs to meet the requirements calculated for each

[23] 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.

entity. In the EIM Flexibility Reserve Case, all PacifiCorp and ISO generation is eligible to meet the single flexibility reserve requirement for the EIM footprint, subject to transfer constraints.

Table 3 shows E3's estimates of the combined minimum reserve requirements for PacifiCorp and ISO under the EIM. The standalone case represents no transfer capability between PacifiCorp and ISO, and is comprised of 608 MW of required reserves in PacifiCorp and 1,403 MW in ISO. As the Table shows, increasing transfer capability allows for greater diversity benefits, reducing minimum reserve holdings.

Table 3. Estimated Total Minimum Reserve Holdings under the EIM in 2017

PacifiCorp-ISO Transfer Capability	Minimum Reserve Holdings (MW)
Standalone (no EIM)	2,011
100 MW	1,932
400 MW	1,687
800 MW	1,583

As a final step, E3 calculated the difference in production costs between the EIM Dispatch Case and EIM Flexibility Reserve Case to estimate the annual benefit of reduced flexibility reserves, over and above the dispatch benefits. This yields the incremental savings associated with flexibility reserve reductions between the two cases. E3 benchmarked the cost savings using market prices for ancillary services in ISO, to ensure that these estimates were reasonable (See Technical Appendix).

Since the PacifiCorp-ISO EIM would be a 5-minute energy market, only the portion of savings associated with reductions in load following reserves (5-minute to hourly timescale) would accrue under an EIM. Each area would continue to procure and deploy regulation reserves independently. Since load following accounts for approximately 80%

of total flexibility reserve needs (load following plus regulation) in E3's calculations, E3 assumed that a PacifiCorp-ISO EIM could achieve 80% of total savings from reduced flexibility reserve requirements.

2.2.4 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 located exclusively 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, 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. An EIM could potentially avoid over-generation situations since it could enable ISO to reduce imports in real time from PacifiCorp rather than curtail renewables during minimum generation or ramp-constrained intervals.

E3 calculated the benefits of reduced energy curtailment in ISO 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 PacifiCorp has generation available to back down during these situations.

To estimate the level of renewable energy curtailment in ISO, E3 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 ISO in 2022.

This is likely a conservative estimate of the level of renewable energy curtailment. Production simulation models are designed to utilize normative assumptions regarding load, hydro conditions, thermal resource outages, and other variables in order to produce reasonable, mid-range estimates of resource dispatch and prevailing power flows. However, renewable curtailment occurs during extreme events such as very high output of wind, solar and hydro 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.

E3 used a $90/MWh value of avoided renewable energy curtailment as the sum of three components: (1) renewable energy certificate (REC) value, assumed to be $50/MWh; (2) production tax credit (PTC) value of $20/MWh; and (3) the avoided production cost of the thermal unit that an EIM enables to dispatch down, estimated to be $20/MWh.

E3 used the simulated renewable curtailment results to develop two scenarios for renewable energy curtailment in 2017. As a lower end estimate, E3 assumed that ISO renewable energy curtailment is 10% of the simulated value, or 12 GWh. As a higher end estimate, E3 assumed that renewable curtailment is 100% of the simulated value, or 120

GWh. This range of curtailment estimates was then multiplied by the value of avoided renewable energy curtailment to calculate lower end and higher end estimates of $1.1 million (= 12 GWh * 90/MWh) to $10.8 million (= 120 GWh * $90/MWh) in benefits for reduced renewable energy curtailment in 2017.

2.3 EIM Scenarios

E3 estimated EIM benefits based on study year 2017. E3 chose this year, in consultation with ISO and PacifiCorp, to represent a period after the EIM was already operational but prior to any significant changes in load, generation, and transmission. In particular, E3's modeling analysis excludes: (1) a portion of the full build out of renewable resources necessary to meet California's 33% RPS; (2) 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 that have the potential to provide a substantial expansion of the quantity of flexible resources that would be able to participate in a 5-minute market.

E3 used scenario assumptions to inform how sensitive benefits are to: (1) the transmission transfer capability between ISO and PacifiCorp, which limits savings both from interregional dispatch and reduced flexibility reserves; (2) the amount of hydropower capacity that can provide flexibility reserves; (3) the extent to which nodal prices from an EIM would change PacifiCorp's dispatch and produce associated efficiency improvements; and (4) the extent of renewable energy curtailment that can be avoided through an EIM. These scenarios are designed to explore a wide range of potential benefit levels 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 hydropower, reserves, and renewable curtailment. In addition, 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 4. Low and high range assumptions under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios

Assumption	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Maximum hydropower contribution to contingency and flexibility reserves*	25%	12%	25%	12%	25%	12%
Share of intraregional dispatch savings achieved	10%	100%	10%	100%	10%	100%
Share of identified renewable energy curtailment avoided	10%	100%	10%	100%	10%	100%

** Percent of nameplate capacity for each project*

The scenarios are organized around low, medium, and high scenarios for transmission transfer capability between PacifiCorp and ISO, with 100, 400, and 800 MW, respectively, in each case. Within each scenario, E3 calculated a low and high range of benefits (Table 4). The low range assumes: hydropower can contribute up to 25% of nameplate capacity toward flexibility reserves; PacifiCorp achieves 10% of estimated nodal dispatch savings; and the value of renewable energy curtailment is 10% of the full estimated value. The high range assumes: hydropower can contribute up to 12% of nameplate capacity toward contingency and flexibility reserves; PacifiCorp achieves 100% of estimated nodal dispatch savings; and the value of renewable energy curtailment is 100% of the full estimated value.

2.4 EIM Benefits

Figure 1 and Table 5 show the low and high range of EIM benefits for the low (100 MW), medium (400 MW), and high (800 MW) transfer scenarios, and the amount attributed to each component. Total annual benefits in 2017 range from $21 million in the low range of the 100 MW transfer capability scenario, to $129 million in the high range of the 800 MW transfer capability scenario (2012$).

Figure 1. Low and high range benefits under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios (2012$)

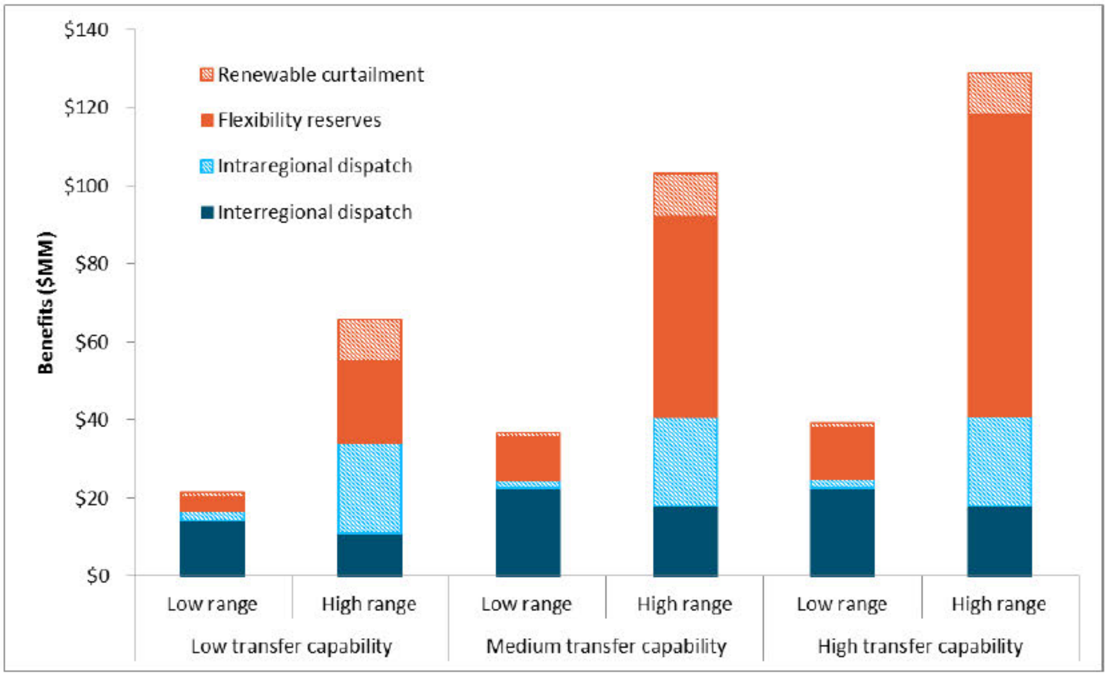


Table 5. Low and high range annual benefits in 2017 under low, medium, and high PacifiCorp-ISO transfer capability scenarios (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Interregional dispatch	$14.1	$11.0	$22.3	$17.7	$22.4	$17.8
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$4.0	$20.8	$11.0	$51.3	$13.4	$77.1
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$21.4**	**$65.6**	**$36.7**	**$102.8**	**$39.2**	**$128.7**

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

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

+ Interregional dispatch savings range from $14 million to $22 million per year. Increasing PacifiCorp-ISO transfer capability from 100 MW in to 400 MW drives significant additional cost savings. However, the marginal benefit of additional transfer capability beyond 400 MW appears to be small.

+ Interregional dispatch savings are somewhat lower under the high range scenarios than under the low range scenarios because of interactions that occur between the hurdle rate and operating reserve aspects of the modeling. When the ability of hydropower to provide reserves is restricted, total production costs increase because more thermal generators are committed to provide reserves. These additional thermal generators tend to be higher-cost units, which may be operated at or near their minimum operating levels. This restricts the dispatch efficiency gains that are available due to the elimination of hurdle rates, because these higher-cost generators are less able to reduce their output when a lower-cost unit is available in a neighboring system.

+ Annual cost savings from reduced flexibility reserves range from $4 million to $77 million. These are driven largely by constraints on the ability of hydropower to provide contingency and flexibility reserves. This is a source of considerable uncertainty, and more research is needed to understand hydro's ability to contribute toward flexibility reserve requirements under high penetrations of wind and solar. Transfer capability is also an important constraint, as benefits increase from $4 million per year with 100 MW to $13 million per year with 800 MW of transfer capability in the scenario where hydropower can contribute to up to 25% of flexibility reserves.

+ Annual cost savings from intraregional dispatch savings and reduced renewable energy curtailment range from $3 million to $34 million, suggesting that, although they are uncertain, both categories could be important contributors to EIM benefits. Because an EIM would provide an automated mechanism for facilitating wind 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 described here confirm that, even under conservative assumptions regarding the use of hydro for imbalance energy and the availability of transmission transfer capability, the incremental benefits of an EIM between PacifiCorp and ISO are likely to be larger than the preliminary estimates of the costs to implement and operate this market. The results also confirm that the benefits of an EIM can be quite substantial as participation grows, allowing more resources to participate and lowering the costs of both imbalance energy and the costs of providing adequate dynamic reserves.

2.5 Attribution of EIM Benefits

E3 assumed that the benefits of an EIM would be attributed to PacifiCorp and ISO as follows:

- **Interregional dispatch savings.** Savings were split evenly between PacifiCorp and ISO to reflect: (1) the reduced cost to serve ISO load, since expensive internal generation is displaced by low-cost imports from PacifiCorp; and (2) additional revenues for PacifiCorp, since it exports additional power to ISO.
- **Intraregional dispatch savings.** The savings were scaled to the PacifiCorp service area from a study of the ISO's nodal market, thus all benefits were attributed to PacifiCorp.
- **Reduced flexibility reserves.** Benefits were allocated to PacifiCorp and ISO in proportion to their standalone need, resulting in a roughly 30/70 split, respectively.
- **Reduced renewable energy curtailment.** All benefits of reduced curtailment were attributed to ISO, because the reduced curtailment would take place within the ISO footprint.

This simple approach allocates the total cost savings between the two parties 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 PacifiCorp and ISO systems might be different from the assumptions used here.

The attribution of benefits from a PacifiCorp-ISO EIM in 2017 is summarized in Tables 6 and 7. PacifiCorp achieves annual cost savings of $10-54 million, with the range dependent on the extent to which PacifiCorp generators participate in the EIM and its nodal market, transfer limits, and the extent to which hydropower can provide flexibility reserves. Annual cost savings to ISO are $11-74 million by 2017, with the range dependent on transfer limits, the extent to which hydropower can provide flexibility reserves, and the extent of renewable curtailment.

Table 6. Attribution of EIM benefits to PacifiCorp in 2017 (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
Interregional dispatch	$7.0	$5.5	$11.2	$8.9	$11.2	$8.9
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$1.2	$6.1	$3.2	$14.9	$3.9	$22.5
Renewable curtailment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total benefits	**$10.5**	**$34.6**	**$16.7**	**$46.8**	**$17.4**	**$54.4**

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

Table 7. Attribution of EIM benefits to ISO in 2017 (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
Interregional dispatch	$7.0	$5.5	$11.2	$8.9	$11.2	$8.9
Intraregional dispatch	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Flexibility reserves	$2.8	$14.7	$7.8	$36.4	$9.5	$54.6
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$10.9**	**$31.0**	**$20.0**	**$56.0**	**$21.8**	**$74.3**

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

3 Interpreting the Results

3.1 Conservative Nature of the Results

Because of the difficulties in modeling the operational complexities of an EIM, E3'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 8 provides a high-level overview of the nature of assumptions (conservative, moderate, aggressive) used for each of the five identified categories of benefits, and an explanation of why the assumptions were considered to be conservative or moderate.

Table 8. Categorization of assumptions used in this study

Benefit Category	Assumptions (conservative, moderate, aggressive)	Rationale
Interregional dispatch	Conservative-Moderate	• E3 limited PacifiCorp-ISO transmission transfer capability in the low transfer capability scenario to 100 MW, which limited EIM benefits • E3 used hurdle rates to inhibit interregional trade in Benchmark Case (moderate assumption) • 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 understated EIM benefits
Intraregional dispatch	Conservative-Moderate	• E3 calculated nodal dispatch savings by scaling estimated ISO peak load-normalized savings by PacifiCorp peak load (moderate assumption); E3 assumed only 10% of these savings materialize for low range (conservative assumption)
Flexibility reserves	Conservative	• E3 limited PacifiCorp-ISO transmission transfer capability in the low transfer capability scenario to 100 MW, which limited EIM benefits • E3 included operating cost only; no capacity cost savings are included, which limited EIM benefits • E3 allowed 25% of total hydropower capacity to contribute to flexibility reserves in the low range estimates, which limited EIM benefits • E3 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 curtailment	Conservative	• E3 did not evaluate renewable curtailment for PacifiCorp, which limited EIM benefits • In low range estimate, E3 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:

+ **WECC EIM Analysis (completed in 2011)** — examined the benefits of an hourly EIM in parts of the WI region; undertaken by E3 for WECC;[24]
+ **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;[25]
+ **WECC VGS (draft completed in 2012)** — examined the benefits of 10-minute bilateral scheduling for the entire WECC region; undertaken by the Pacific Northwest National Laboratory (PNNL) for WECC as part of the WECC Variable Generation Subcommittee (VGS);[26]
+ **NWPP EIM (ongoing)** — 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.

The above studies can be broadly categorized into two different approaches. The first two studies, the WECC EIM and PUC Group EIM analyses, 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

[24] 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.
[25] See http://www.westgov.org/PUCeim/ for the PUC EIM website and link to the NREL final report.
[26] The draft final report, "Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection," is not yet publicly available.

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 approach used in this study is consistent with the WECC EIM and PUC Group EIM analyses. It does benefit, however, from the NWPP EIM study assumption used to limit the amount of hydropower that would qualify and be available to provide contingency and flexible reserves. Table 9 (next page) provides a high-level comparison between the benefit estimates in this study and the four 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 PacifiCorp and 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 9. 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
PacifiCorp-ISO EIM study	$21-$129 in 2017	PacifiCorp and ISO	
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)	$349 in 2020	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 (PNNL)	Pending	Entire WECC	• WECC VGS study had larger EIM footprint than this study • VGS study modeled 10-minute bilateral scheduling, not EIM • In VGS study, no savings due to reduced reserves or reduced transactional friction, which means all savings due to within-hour efficiency gains; this study includes savings from reduced reserves or transactional friction
NWPP EIM (PNNL)	Pending	NWPP	• Similar approach to WECC VGS study • Detailed results pending

Technical Appendix

Technical Appendix

Overview

This technical appendix provides a detailed description of the methods and assumptions used in calculating the benefits of more efficient interregional dispatch and reduced flexibility reserves from a PacifiCorp-ISO EIM. Following this overview, this appendix includes three sections. The first describes methods for calculating inputs to the Benchmark Case, including hurdle rates and statistical calculations used to estimate flexibility reserve requirements in the Benchmark Case. The second section describes the change in hurdle rates used in an EIM Dispatch Case. The third section describes the statistical calculations used to estimate a comparative benchmark for reserves in an EIM Flexibility Reserves Case and how transmission constraints were addressed in these calculations.

E3 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]

E3 modeled three cases:

- **Benchmark Case**, reflecting a business as usual scenario that includes continued obstacles to interregional dispatch between PacifiCorp and ISO and separate procurement of flexibility reserves;
- **EIM Dispatch Case**, in which obstacles to more efficient interregional dispatch are removed but flexibility reserves are still procured separately; and
- **EIM Flexibility Reserve Case**, in which obstacles to more efficient interregional dispatch are removed and PacifiCorp and ISO pool flexibility reserves.

The Benchmark 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 to improve accuracy inside of California. Load forecasts, fuel price forecasts, generators, and transmission were also adjusted to reflect anticipated values and availability in 2017. The EIM Dispatch Case and EIM Flexibility Reserve Case were used to isolate the benefits of more efficient interregional dispatch and reduced flexibility reserves, respectively, relative to the Benchmark Case.

In the EIM Dispatch Case, E3 modeled the incremental benefits of more efficient interregional dispatch by eliminating the hurdle rates between PacifiCorp and ISO that are used to reflect impediments to regional electricity trades in the Benchmark Case.[2] In the EIM Flexibility Reserve Case, E3 modeled the

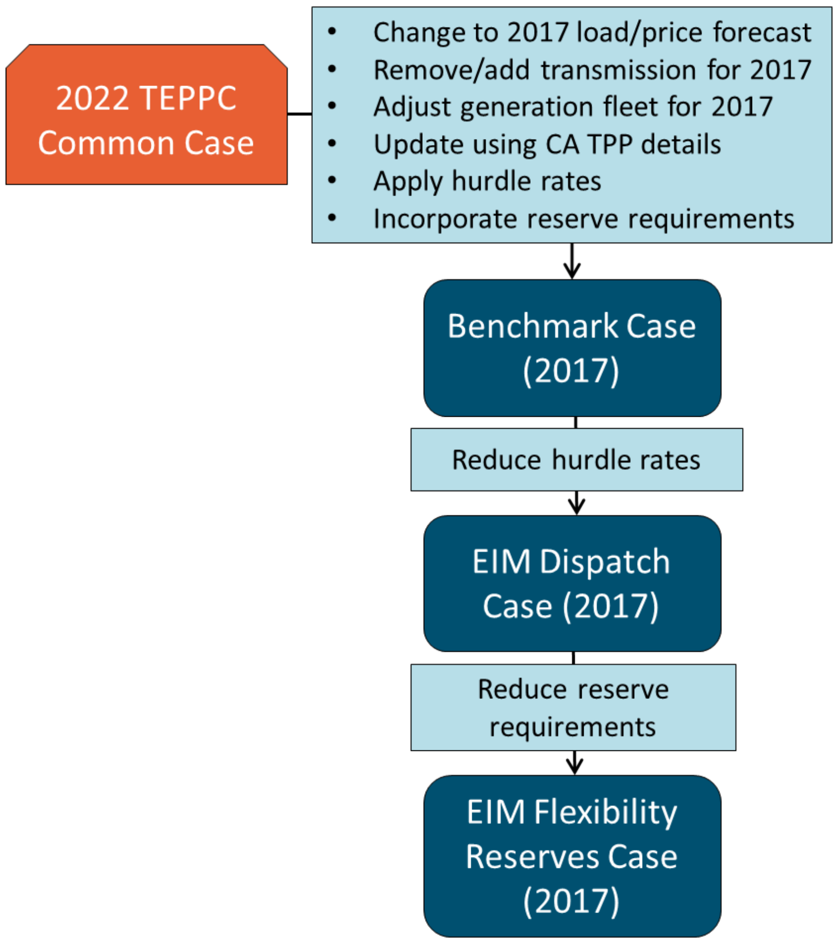
[1] For more on GridView, see http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

[2] A component of hurdle rates that reflects to 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.

incremental benefits of reduced flexibility reserves by calculating the reduction in flexibility reserves that results from pooling load, wind, and solar variability between PacifiCorp and ISO, and then by reducing the amount of required reserves in GridView runs.

As described in the main report, within the EIM Dispatch Case and EIM Flexibility Reserve Case, E3 modeled the year 2017, to provide an estimate of near-term benefits from an EIM. Figure 1A illustrates E3's modeling approach.

Figure 1A. Modeling approach for calculating interregional dispatch and reduced flexibility reserve benefits



The modeling was organized around three scenarios of interchange transfer capability between PacifiCorp and ISO: 100, 400, and 800 MW. Within each transfer capability scenario, E3 modeled low and high benefit ranges. In the low range scenario, E3 limited hydropower's ability to contribute to contingency and flexibility reserves to 25% of nameplate capacity. In the high range scenario, E3 assumed that 12% of hydropower nameplate capacity can contribute to contingency and flexibility reserves. Production cost results for the interaction of all of these scenarios are described in this Appendix.

Benchmark Case

The Benchmark 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.[3]

Adjustments to the TEPPC Common Case

In developing its 2017 TPP Case, ISO staff made adjustments to the TEPPC 2022 Common Case to improve transmission and generation modeling accuracy within California. E3 incorporated those adjustments and made further modifications to the TEPPC 2022 Common Case 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.[4] Table 1A shows fuel prices by region, for the TEPPC regions within the ISO and PacifiCorp BAAs.

Table 1A. Average annual burnertip gas price (2012$/MMBtu)

Area	2017
PACE_ID	$ 3.99
PACE_UT	$ 3.81
PACE_WY	$ 3.95
PACW	$ 3.91
PG&E_BAY	$ 4.09
PG&E_VLY	$ 4.09
SCE	$ 4.18
SDGE	$ 3.86

Load forecast

A load forecast for 2017 was provided directly by PacifiCorp for the PacifiCorp East and PacifiCorp West BAAs. For all other load areas, monthly peak and energy values were interpolated between 2006 historical data (provided by TEPPC by BA) and the 2022 forecasted value from TEPPC's Data Working Group (DWG) based on the most recently available WECC Load-Resource Subcommittee (LRS) data submittals.

[3] 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.

[4] A small adjustment was also implemented to use the same fuel prices for PG&E Bay and PG&E Valley load areas.

Generation and transmission

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 PacifiCorp. For modeling purposes, generation in 2017 was assumed to precede the majority of expected OTC-related retirements and replacements in California.

Hurdle rates

The Benchmark Case utilized hurdle rates from the WECC EDT Phase 2 EIM Benefits Analysis, which were developed by calibrating simulation output to historical flow levels on WECC paths.[5] These historically-calibrated hurdle rates are adjusted to reflect the impact of anticipated CO_2 allowance cost on unspecified power imports into California in 2017. For power flows from PacifiCorp-West (PACW) to ISO, E3 used a value of \$21.07/MWh, which included a \$10.76/MWh cost for CO_2 allowances on PacifiCorp exports to ISO (Table 2A). This \$10.76/MWh adder was based on a default CO_2 emissions factor for a CCGT from the California Air Resources Board and a CO_2 price of \$24.66 (2012\$) per short ton of CO_2. For power flows from ISO to PACW, E3 used a hurdle rate of \$3.97/MWh. E3 assumed no direct interties between ISO and PACE.

Table 2A. Hurdle rates used in the Benchmark Case

Case	Hurdle Rate (\$/MWh)			
	PACW → ISO			ISO → PACW
	CO_2-related	Non-CO_2 related	Total	
Benchmark Case	\$10.76	\$10.31	\$21.07	\$3.97*

**No CO_2-related hurdle rate is applied to ISO exports to PACW 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 Benchmark Case, E3 calculated load following and regulation reserve requirements, summed the two, and then set the total as a constraint in 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.

Load following and regulation reserves were calculated using a common methodology based on the North American Electricity Reliability Corporation (NERC) Control Performance Standard 2 (CPS2).[6] CPS2 is designed to ensure that a BA maintains its area control error (ACE) – the difference between actual and scheduled power flows across interties to neighboring BAs – within reasonable bounds. Spinning

[5] See http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf. The WECC Analysis reported hurdle rates in 2010\$, and those rates were adjusted to 2012\$ for this analysis.
[6] For more on NERC CPS, see http://www.nerc.com/docs/oc/ps/tutorcps.pdf.

reserve requirements) were set to equal 3% of load, which represents one-half of total operating reserves requirements (spinning plus non-spinning). Non-spinning reserve needs were not explicitly modeled because the simulation addresses reserve needs by increasing the level of generator commitment required, but is assumed for modeling that non-spinning reserve needs would typically be met with resources that do not require day-ahead unit commitment.

By benchmarking against ISO's current regulation procurement, wind integration studies performed by PacifiCorp, and in consultation with ISO and PacifiCorp, E3 chose to model a CPS2 compliance target which requires BAAs to secure load following reserves to meet 97% of forecasted load following demand, equivalent to 1.5% of the left-hand and right-hand tails of a distribution of load following needs (i.e., 10-minute forecasted net load minus hourly unit commitment). For regulation under this target, BAAs also secure regulation reserves to meet 94% of forecasted regulation demand, equivalent to 3% of the left-hand and right-hand tails of a distribution of regulation needs (i.e., 10-minute actual load minus 10-minute forecasted net load). This approach allows regulation reserves to meet load following needs, but not vice versa.

The regulation requirement percentage is lower than load following because regulation can be used to meet load following requirements. In the 3% of time periods with an unmet load following requirement, the residual load following error is added to the time-series regulation requirement. During these hours, if the system had unutilized regulation capacity or if regulation needs were in the opposite direction of the load following residual error, generator flexibility procured for regulation may be able to still satisfy the CPS2 requirement for that time period even though the system were short on load following resources.

Key steps in this analysis are shown graphically in Figure 2A.

- Step 1: Calculate a distribution of load following requirements. E3 used historical 10-minute wind, solar, and load data to forecast 10-minute net load and hourly unit commitment based on hourly net load. Forecasted hourly net load was then calculated for each 10-minute time period, using a linear 20-minute ramp across the top of the hour (see upper rightmost part of Figure 2A). A distribution of load following requirements was calculated as the difference between the 10-minute and hourly net load forecasts in each 10-minute period.
- Step 2: Calculate load following up and down needs. These were calculated using the 1.5 and 98.5 percentiles of these distributions, respectively, consistent with the chosen CPS2 compliance target. Figure 3A shows an example of the distribution for load following requirements and the points associated with the 1.5 and 98.5 percentiles.
- Step 3: Calculate a distribution of regulation requirements. A distribution of regulation requirements was calculated as the difference between the 10-minute net load forecast and 10-minute actual net load values. Residual load following errors were added to the regulation distributions to allow for the fact that regulation reserves can also be used for load following.
- Step 4: Calculate final regulation requirements as the 3rd and 97th percentiles of this distribution, representing regulation down and up needs, respectively.

Figure 2A. Flexibility reserve calculation steps

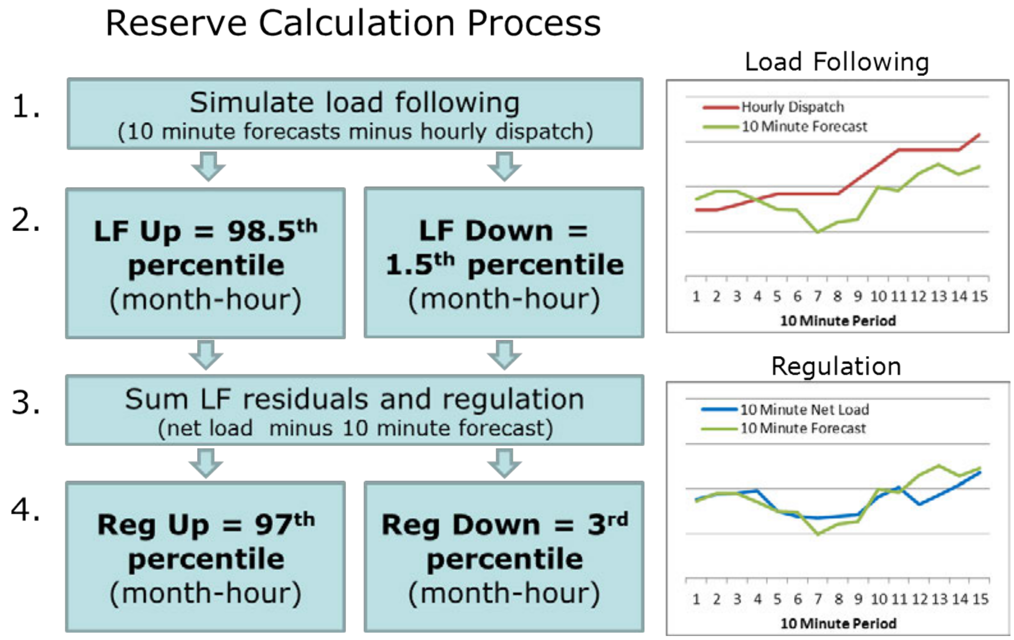
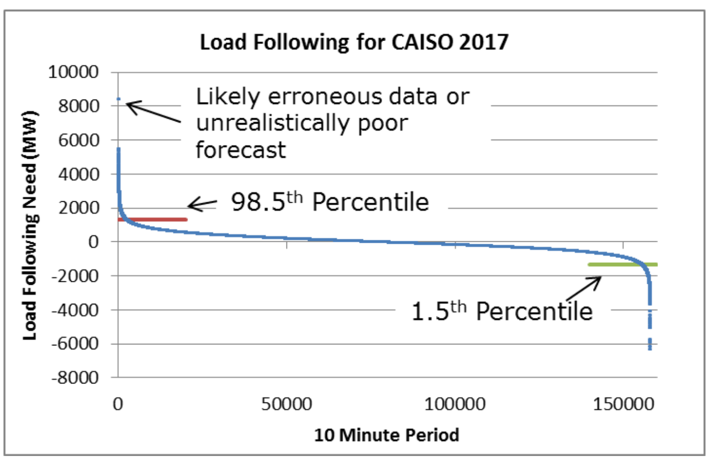


Figure 3A. Load following needs associated with the 1.5 and 98.5 percentiles



To calculate net load, E3 used three years of 10-minute load and modeled renewable production data. Years 2004 to 2006 were used in the analysis because of data availability in the Western Wind Integration Dataset. Solar PV was modeled using data from Solar Anywhere and 10-minute load data was provided by PacifiCorp and ISO. The load data provided was scaled to 2017 by both annual energy and peak load to account for load growth. Forecasts for 10-minute wind, solar, and load were created using linear regression and were extensively benchmarked. The following table shows renewable assumptions used for 2017.

Table 3A. Renewable assumptions for 2017 reserve calculations[7]

Area	Wind Installed (MW)	Solar Installed (MW)
PacifiCorp East	1,638	-
PacifiCorp West	635	-
PacifiCorp Combined	2,272	-
ISO	6,228	5,483
PacifiCorp and ISO (pooled)	8,501	5,483

In the Benchmark Case, regulation and load following were calculated separately for PacifiCorp East, PacifiCorp West, and ISO, and were implemented in GridView as separate constraints for each BAA. Table 4A shows the resulting load following up and regulation up reserve requirements for PacifiCorp East, PacifiCorp West, and ISO. The GridView modeling configuration used does not have the ability to model load following down and regulation down.

Table 4A. Estimated load following up and regulation up reserve requirements for PacifiCorp East, PacifiCorp West, and ISO in 2017

Area	Average Regulation Up (MW)	Average Load Following Up (MW)
PacifiCorp East	103	313
PacifiCorp West[8]	45	146
PacifiCorp Combined	115	357
ISO[9]	276	1,128

[7] The study did not incorporate the most current renewable resource capacity in PacifiCorp, which results in understating total installed wind capacity in PacifiCorp's BAAs by 280 MW. As of 2013 PacifiCorp will have 1,758 MW of installed wind capacity in PacifiCorp East and 795 MW of installed wind capacity in PacifiCorp West.

[8] In the Benchmark and EIM Cases, E3 assumed 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. The hourly load following requirement applied to PacifiCorp West is reduced for this transfer capability, and a separate reserve requirement is applied to the Combined PacifiCorp area which reflects diversity of wind and load variability across the two PacifiCorp BAs.

[9] The applied common methodology for determining regulation and load following results in conservative lower amount of regulation requirements used in ISO production and lower regulation and load following 20 minute requirements then has been calculated using other methodologies.

EIM Dispatch Case

In the EIM Dispatch Case, E3 modeled reduced transactional friction between PacifiCorp and ISO from the EIM by removing the non-CO_2 hurdle rates in the Benchmark Case. In this case, the PACW → ISO hurdle rate still includes the $10.76/MWh cost for CO_2 allowances on PacifiCorp flows to ISO (Table 5A).

Table 5A. Hurdle rates for the Benchmark and EIM Dispatch Cases

Case	Hurdle Rate ($/MWh)			
	PACW → ISO			ISO → PACW
	CO_2-related	Non-CO_2 related	Total	
Benchmark Case	$10.76	$10.31	$21.07	$3.97
EIM Dispatch Case	$10.76	$0.00	$10.76	$0.00*

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

Eliminating hurdle rates enables GridView to dispatch more generation in the PacifiCorp BAAs to serve needs in the ISO BAA when more efficient units are available, and vice-versa. Reduced transactional friction lowers total production costs. As described in the main text, for the EIM Dispatch Case E3 used an 800 MW static transfer limit on the California-Oregon Intertie (COI) as a proxy for transfer capability between the PacifiCorp and ISO systems.

Table 6A shows production costs in the Benchmark Case, the EIM Dispatch Case, and cost savings (Benchmark Case – EIM Dispatch Case production costs), for the 100, 400, and 800 MW transfer capability scenarios under both hydro assumptions. As described in the main body, production cost savings from the 800 MW scenario were scaled to 100 and 400 MW based on relative changes in intertie flows. Most of the savings stemming from increased flows between the Benchmark Case and the EIM Dispatch Case were captured with 400 MW of transfer capability.

Table 6A. Production cost savings in the EIM Dispatch Case for different hydropower flexibility scenarios and assumptions about transfer capability between PacifiCorp and ISO (Million 2012$)

	25% Hydro Reserve Cap			12% Hydro Reserve Cap		
Transfer Capability (MW)	100	400	800	100	400	800
EIM Dispatch Case	$14 1	$22 3	$22 4	$11 0	$17 7	$17 8

As described in this report, GridView assumes perfect, security-constrained, least-cost dispatch within both the ISO and PacifiCorp footprints. The EIM Dispatch Case thus captures the incremental benefits from more efficient dispatch between PacifiCorp and ISO assuming that PacifiCorp already uses nodal dispatch. The savings from moving to nodal dispatch in PacifiCorp are estimated separately under “intraregional dispatch savings” and described in Section 2.2.2 of this report.

EIM Flexibility Reserves Case

E3 calculated within-hour regulation and load following reserves for the EIM Flexibility Reserves Case using the same approach as in the Benchmark and EIM Dispatch Cases, except that net load profiles for each BA were summed before the calculation and transmission constraints were enforced to ensure realistic reserve sharing. By summing the net load profiles for PacifiCorp and ISO, diversity in forecast errors and net load ramps reduces the reserves that each BAA is required to hold, relative to the Benchmark Case.

Table 7A shows the pooled load following up and regulation up reserve requirements for PacifiCorp and ISO in 2017, prior to enforcing transmission constraints between BAs.

Table 7A. Pooled load following and regulation up reserve requirements for PacifiCorp and ISO in 2017

Area	Average Regulation Up (MW)[10]	Average Load Following Up (MW)
PacifiCorp and ISO (pooled)	310	1,255

Transmission limits were enforced on the results in the above table as a set of five separate constraints in the GridView cases, shown below for the scenario where 100 MW of transfer capability exists between PacifiCorp and ISO. These five constraints ensure that each BA holds the necessary reserves given transfer limits. The constraints also reflect the 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.

1. $PACW_{pooled\ reserves} \geq max(PACW_{benchmark\ case} - 200\ MW, 0)$
2. $PACE_{pooled\ reserves} \geq PACE_{benchmark\ case}$
3. $CAISO_{pooled\ reserves} \geq max(CAISO_{benchmark\ case} - 100\ MW, 0)$
4. $PacifiCorp_{pooled\ reserves} \geq max(x - 100\ MW, 0)$
5. $PAC\&CAISO_{pooled\ reserves} \geq max\left(x + CAISO_{benchmark\ case} - 100\ MW,\ PAC\&CAISO_{no\ transfer\ limit}\right)$

where: $x = max(PACW_{benchmark\ case} + PACE_{benchmark\ case},\ PacifiCorp_{benchmark\ case})$

[10] Reductions to both regulation and load following requirements were modeled in the EIM Flexibility Reserves Case, but resulting cost savings were multiplied by the share that load following reserves (80%) represent relative to total flexibility reserves (load following plus regulation), to account for the fact that the EIM will only affect reserves above a 5-minute timestep.

Table 8A shows production cost savings for the four transfer capability scenarios and two hydropower flexibility scenarios. As described in the main text, cost savings were multiplied by the share that load following reserves (80%) represent relative to total flexibility reserves (load following plus regulation), to account for the fact that the EIM will only affect reserves above a 5-minute timestep.

Table 8A. Production cost savings in the EIM Dispatch and EIM Flexibility Reserve Cases for different hydropower flexibility scenarios and assumptions about transfer capability between PacifiCorp and ISO (Million 2012$)

	25% Hydro Reserve Cap			12% Hydro Reserve Cap		
Transfer Capability (MW)	**100**	**400**	**800**	**100**	**400**	**800**
EIM Dispatch Case	$14.1	$22.3	$22.4	$11.0	$17.7	$17.8
EIM Flexibility Reserve Case	$4.0	$11.0	$13.4	$20.8	$51.3	$77.1
Total Both Cases	$18.1	$33.3	$35.8	$31.8	$69.0	$94.9

E3 benchmarked the results from the EIM Flexibility Reserve Case by multiplying reductions in hourly load following component of flexibility reserve quantities by ISO regulation prices. Annual savings from reduced flexibility reserves were calculated as the difference between reserve costs with no transfer capability (i.e., 0 MW) and reserve costs with transfer capability (i.e., 100, 400, or 800 MW) between PacifiCorp and ISO. 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.

The results of this benchmarking exercise (AS price-based results) are shown in Table 9A, using ISO AS market prices from 2010, 2011, and an average of the two years. Given that PacifiCorp is more dependent than ISO on thermal resources to provide flexibility reserves, the benchmarking results in the below table are conservatively low (i.e., ISO AS prices are likely to be lower than implied AS prices in PacifiCorp because hydropower provides a significant amount of AS in ISO). With this in mind, the EIM Flexibility Reserve Case results (Table 8A) appear reasonable compared to the benchmarking results below.

Table 9A. Results from flexibility reserve benefits benchmarking analysis (Million 2012$)

Transfer Capability	2010 AS Prices	2011 AS Prices	Average 2010/2011 AS Prices	EIM Flex. Reserve Case (25% Hydro Reserve Cap)	EIM Flex. Reserve Case (12% Hydro Reserve Cap)
100 MW	$7.3	$4.5	$5.7	$4.0	$20.8
400 MW	$24.3	$14.8	$18.8	$11.0	$51.3
800 MW	$29.6	$17.6	$22.7	$13.4	$77.1