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August 25, 2016

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2017 Transition Adjustment Mechanism
Docket No. UE 307

Dear Filing Center:

Please find enclosed the Cross-Examination Exhibits of the Industrial Customers of Northwest Utilities in the above-referenced docket.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of	)	
	)	CROSS-EXAMINATION EXHIBITS OF
PACIFICORP, dba PACIFIC POWER	)	THE INDUSTRIAL CUSTOMERS OF
	)	NORTHWEST UTILITIES
2017 Transition Adjustment Mechanism	)	
	)	

Pursuant to the Administrative Law Judge's July 8, 2016 Ruling, the Industrial Customers of Northwest Utilities ("ICNU") submits the following cross-examination exhibits in the above-referenced Docket:

Cross Examination Exhibit	Description
ICNU/300	PacifiCorp 2014 Wind Integration Resource Study
ICNU/301	Excerpt of Rebuttal Testimony of Gregory N. Duvall (Wyoming Pub. Svc. Comm'n Docket No. 20000-446-ER-14)

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Dated this 25th day of August, 2016.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

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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.

[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

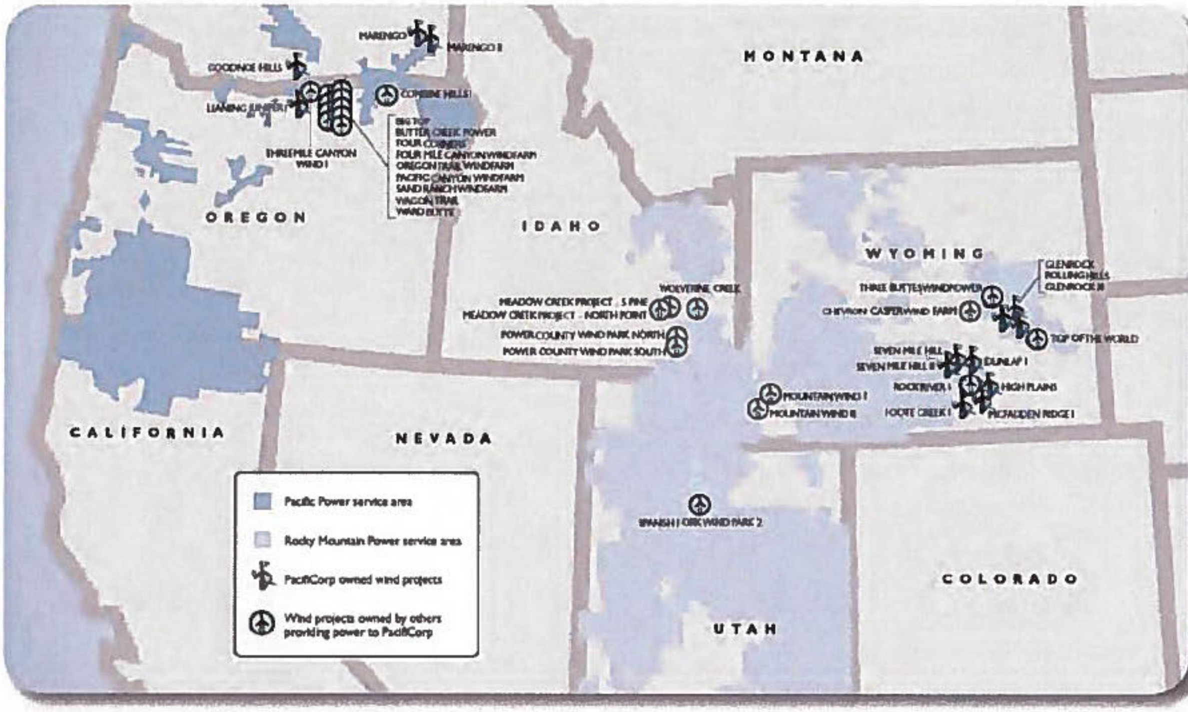
Historical Wind Generation Data

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.

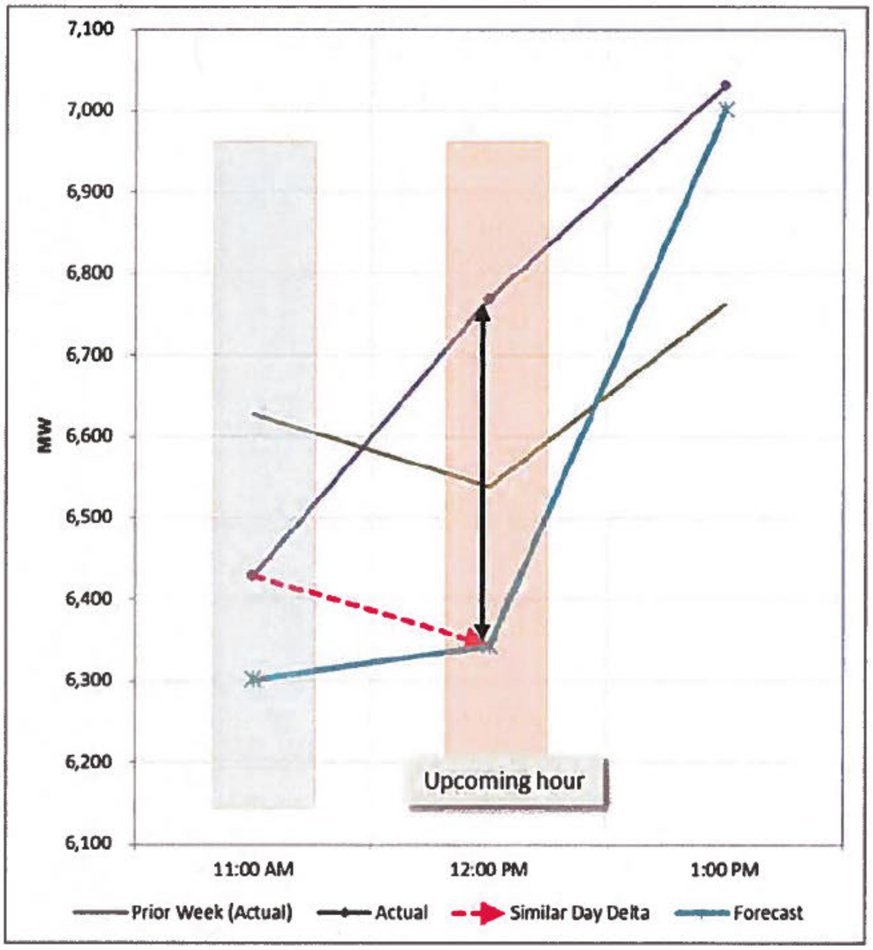
Hypothetical Load Following Operational Forecast
PacifiCorp maintains system balance by optimizing its operations to an hour-ahead load forecast every hour with changes in generation and market activity. This planning interval represents hourly changes in generation that are assessed roughly 20 minutes 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



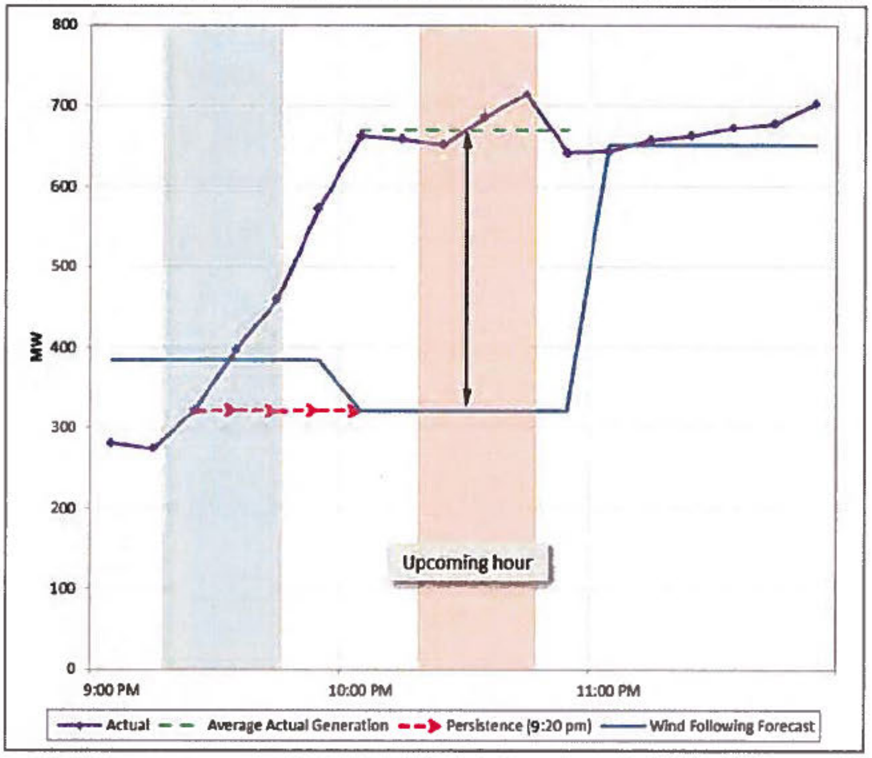
Hypothetical Wind Following Operational Forecast

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



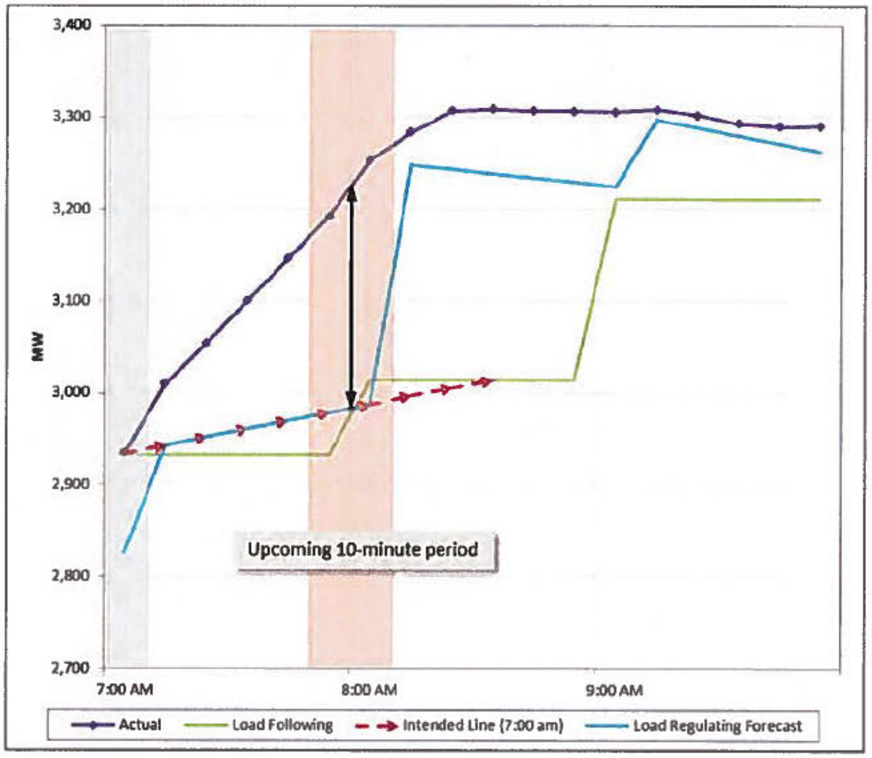
Hypothetical Load Regulating Operational Forecast

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

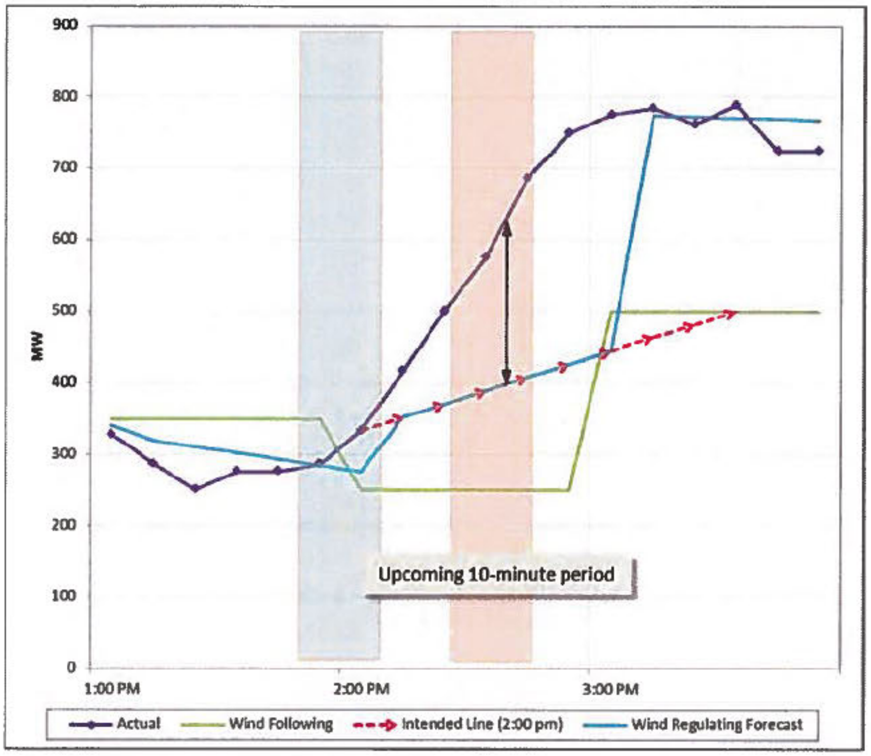
Similarly, the 10-minute wind generation variability and uncertainty was analyzed by comparing the 10-minute actual wind generation values to a line of intended schedule, represented by a line interpolated between the actual wind generation at the top of the "current" hour and the hour-ahead forecasted 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 5^{th} 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.

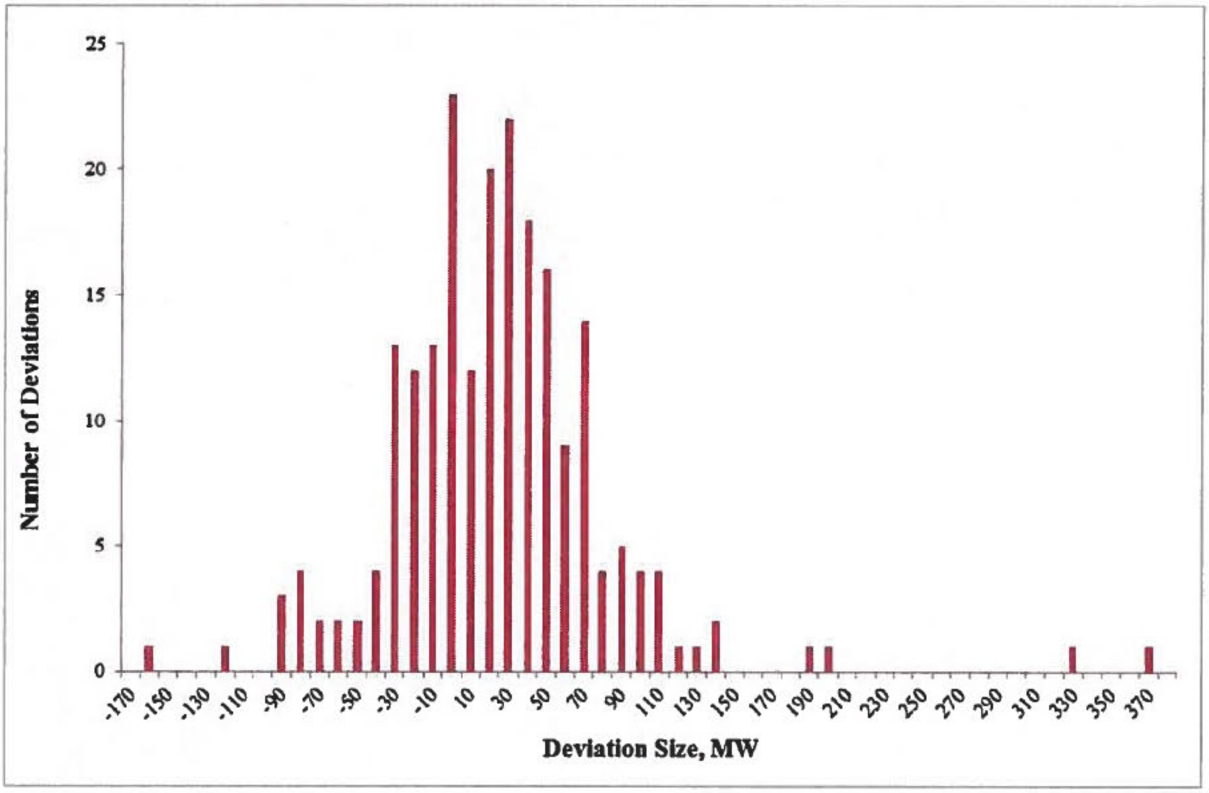
Table H.7 – Recorded Interval Load Regulating Forecasts and their Respective Deviations for June 2013 Operational Data from PACE

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**

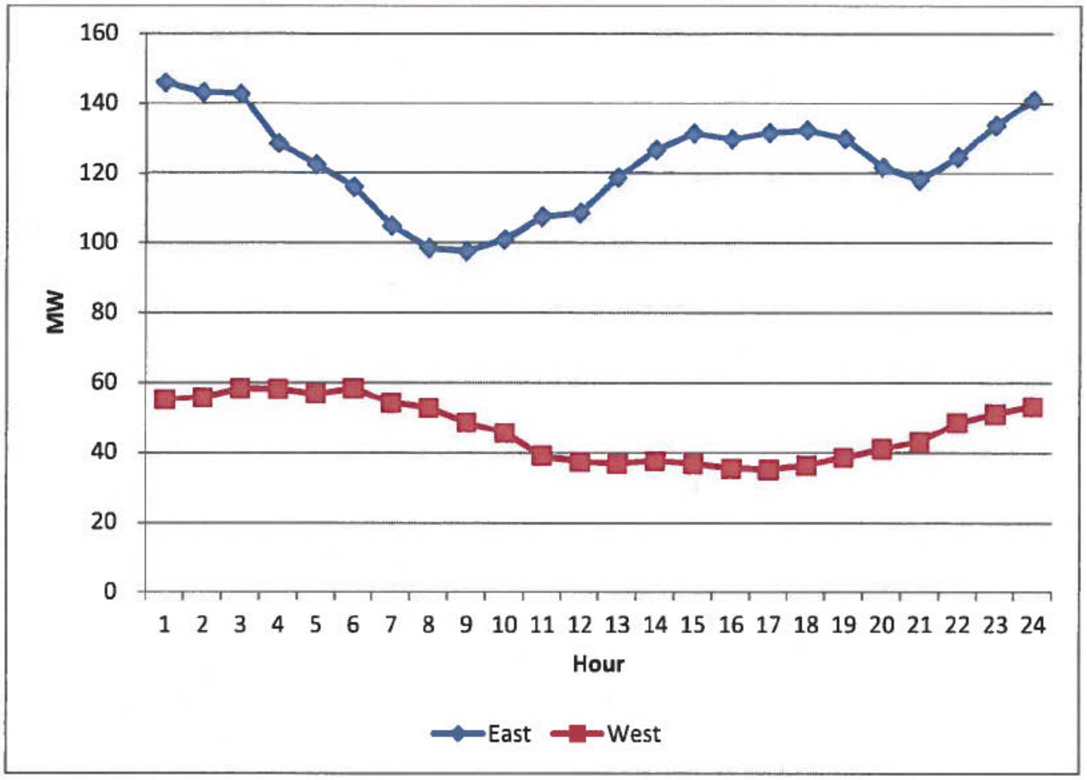
Compared to the 2012 WIS intra-hour reserve cost, the 2014 WIS intra-hour reserve cost is lower when reserves are modeled on a monthly basis in PaR. This is primarily due to the addition of a the Lake Side 2 combined-cycle plant, which can be used to cost effectively meet regulating margin requirements. 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

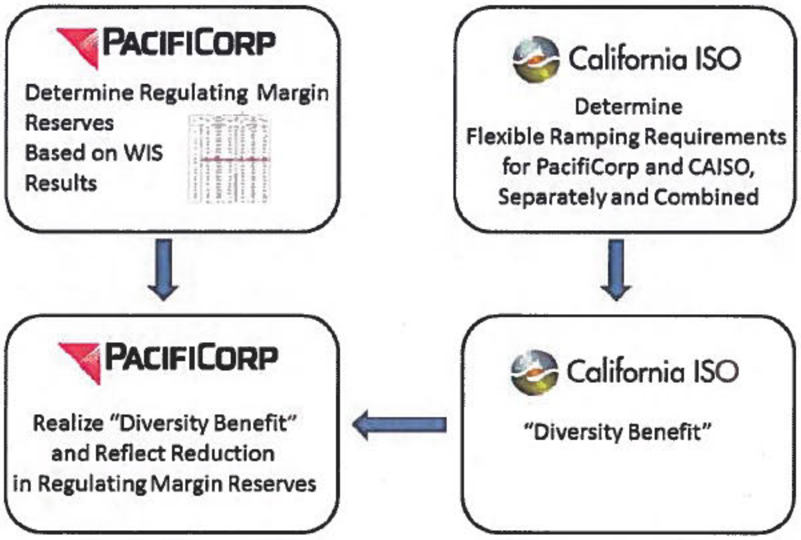
Energy Imbalance Market (EIM)

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

Docket No. 20000-446-ER-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Gregory N. Duvall

September 2014

expensive than the Company's then current forward price curve at the time they were entered, the lower-of-cost-or-market value is already reflected in the Company's forecast and no adjustment is warranted.

Second, Mr. Mullins wants to apply current settlement prices as "market" in the lower-of-cost-or-market calculation, effectively only allowing recovery by the Company to the extent the transaction price is lower than the settlement prices.

Q. What treatment do you propose for the transactions highlighted by WIEC?

A. The Company disagrees that the two long-term natural gas swaps done with J. Aron & Company fall into the category of affiliated transactions that would require special pricing treatment for setting retail rates in Wyoming. The transactions were done at prices below the Company's then-current forward price curve as required by the 2012 Gas RFP and should be approved by the Commission to be included in rates according to the pricing in the contracts.

System Balancing Wind Integration (WIEC Adjustment 4)

Q. Please explain WIEC's adjustment related to system balancing wind integration.

A. WIEC argues that the new methodology for including the shape of wind generation in GRID already reflects actual hour-to-hour variability and that calculating inter-hour integration costs outside of GRID means that the Company is double-counting the inter-hour integration costs in the NPC. The adjustment to remove inter-hour wind integration results in a $2.3 million total Company or $0.36 million on a Wyoming allocated basis.

Q. Does WIEC view the Company's change in the wind modeling methodology as an overall improvement?

A. Yes. WIEC stated that the new methodology better captures the variability seen in actual operations with regard to wind generation.

Q. How does WIEC describe system balancing wind integration?

A. Mr. Mullins describes system balancing wind integration costs as the system costs associated with the hour-to-hour variability in wind output. He goes on to describe how the Company's 2012 Wind Study estimated these costs based on the difference in system dispatch cost associated with modeling forecasted wind profiles and modeling actual wind profiles.

Q. Can you please further explain what the Wind Study means with respect to system balancing wind integration?

A. The Company must commit generation resources (*i.e.*, select startup and shutdown times for the next day), based on a forecast of load and wind generation and considering wholesale market prices, but must dispatch those resources to balance the actual load and wind conditions that occur in real time. In the Wind Study, this inter-hour or system balancing cost is calculated by comparing the NPC from two studies. In the first study, the economic unit commitment is determined including the day-ahead forecast and the system is balanced around the forecast wind output. In the second study, the economic units' commitment remains based on the day-ahead forecast, but the system must balance around the actual wind output. Costs are higher in the second study because the unit commitment is optimized against wind output that is different from what actually occurs. The Wind Study determined this cost to be 36 cents (in 2012 dollars) per megawatt-hour of wind generation and this cost is added to the Company's NPC results.[6]

Q. Is the hour-to-hour variability included in the Company's wind generation forecast the same issue as measured by the Wind Study?

A. No. The Wind Study measures the impact committing generation resources considering a forecast of wind generation and then dispatching those resources when actual generation is different than forecast. The Company's filed GRID study uses the same wind shape to determine unit commitment and final dispatch, so the costs associated with less-than-optimal day-ahead unit commitment are not included within the GRID model. Clearly, Mr. Mullins' claim that the cost of using the actual wind shape during each hour in GRID, rather than using a less volatile shape, is the same as including costs borne from committing generation resources against forecasted load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time is incorrect.

Q. Is WIEC correct that in practice, the day-ahead dispatch decisions are driven by market prices and are largely independent of its day-ahead forecasts for load and wind?

A. No. While market prices are an important consideration in whether to dispatch an owned resource, the commitment of the Company's thermal resources is not

[6] PacifiCorp 2013 Integrated Resource Plan, Volume II, Appendix H - Wind Integration Study. Table H.2. available online at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf (last accessed 8/21/2014).

independent of its forecasts of load and wind. Specifically, the Company must provide adequate contingency and regulating margin reserves to maintain system reliability. The amount of reserve required on a day-ahead basis is directly impacted by the forecast for load and wind. In real time, actual load and wind, and the corresponding reserve requirement will be different. Commitment and dispatch is further complicated by a plant's operational parameters, natural gas scheduling requirements, market liquidity, and transmission constraints.

Q. Can you provide additional details on the costs of less than optimal commitment of gas units?

A. Yes. Each of the Company's combined cycle combustion turbines in Utah has a capacity larger than the Company's long-term firm transmission rights from Utah to electricity markets. If these gas plants are in-the-money compared to market price, the Company has sufficient resources to meet load, and transmission capacity is available, the output from these plants can be sold at market. If actual wind generation is higher than forecast and uses up the available transmission capacity to market, these plants will be forced to back down and will have higher heat rates and reduced opportunity to amortize their startup costs. To the extent these resources are constrained by minimum operating levels, minimum up and down times, and gas scheduling requirements, lower cost coal units may be forced to back down instead. All of these factors contribute to higher costs.

Similarly, if in-the-money gas plants are offline due to forecasted wind generation levels and actual wind is lower, replacement power will need to come from higher cost market purchases or faster-starting gas plants with higher heat rates.

Q. Does the Company's GRID model reflect the costs related to this uncertainty?

A. No. The GRID modeling forming the basis for the Company's NPC forecast includes commitment based on perfect foresight of future prices, loads, and wind conditions, and therefore does not include costs associated with uncertainty in these inputs.

Q. Is it appropriate to include both inter-hour integration costs and an hourly wind shape?

A. Yes. The Company's filed GRID study uses the same wind shape to determine unit commitment and final dispatch, so the costs associated with less-than-optimal day-ahead unit commitment are not included within the GRID model. Therefore the Company's continued application of this cost outside of the GRID model is appropriate and is in keeping with the basis for these expenses in the 2012 Wind Study.

Inter-hour Load Integration (WIEC Adjustment 5)

Q. Please explain WIEC's adjustment related to inter-hour load integration.

A. WIEC advocates for the removal of all inter-hour load integration costs from the Company's NPC. The claim is that the GRID model includes a load profile with hour-to-hour variability and thus already captures these costs. The adjustment results in a $1.2 million total Company or $0.2 million reduction in Wyoming-allocated NPC.

Q. Are inter-hour load integration costs derived in the same manner as system balancing wind integration costs?

A. Yes. Both of these costs result from the unpredictable nature of load and wind on a day-ahead basis and committing generation resources against a forecast and then dispatching generation resources under actual conditions. The Wind Study accounted for the inter-hour integration costs associated with load using the same methodology as for wind, by calculating unit commitment based on the day-ahead load forecast, and system costs based on the actual load.

Q. Mr. Mullins states that the Company "should solely be responsible for bearing the risks associated with its load forecasting." Is this reasonable?

A. No. The Company makes commercially reasonable efforts to forecast its load requirements; however, uncertainty will always remain due to variations in weather and customer behavior. The Company is obligated to provide electrical service to all of its customers in whatever amounts they require, but with few limited exceptions, retail customers have no obligation to inform the Company of their expected usage or to limit usage to predictable patterns. Customers thus receive the benefits of flexible, on-demand load service and should pay for the associated costs.

Q. Do costs caused by variations between day-ahead and actual wind and those caused by load impact the Company's system differently?

A. No. An increase in load and a decrease in wind generation in the same area both require additional generation or replacement market power, and both impact the level of reserves the Company is required to hold.

Q. Do the Company's forecasted inter-hour expenses for wind and load capture the benefits of netting variations in load and wind?

A. Yes. The Wind Study calculated the inter-hour expense associated with load, and then calculated the incremental inter-hour expense associated with wind. Thus benefits from offsetting load and wind forecast errors reduce the wind integration expense.

Q. Is this the first time inter-hour load integration charges have been included in NPC?

A. No. In the 2010 Wind Integration Study, the reported system balancing cost for wind reflected the cost of day-ahead forecast errors for both wind and load. The costs associated with both wind and load errors were divided by the wind generation in the study resulting in a total cost averaging $0.86 per megawatt-hour of wind generation.[7] This issue was identified in stakeholder comments on the 2010 Wind Integration Study, and in the 2012 Wind Study the methodology was revised to distinguish between wind and load, which resulted in the lower inter-hour wind integration cost of $0.36 per megawatt-hour. Since the 2010 Wind Integration Study results were used in the prior dockets inter-hour costs for load have already been reflected in rates in the past.

Qualifying Facility ("QF") Contracts (WIEC Adjustment 6)

Q. Please explain WIEC's adjustment related to QF contracts.

A. WIEC recommends that a three-pronged test be used to determine when a QF

[7] PacifiCorp 2013 Integrated Resource Plan, Volume II, Appendix H - Wind Integration Study. Table H.2. available online at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf (last accessed 8/21/2014).