Exhibit No.___(GND-3)
Docket UE-13____
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP dba Pacific Power & Light Company Respondent.	)	Docket UE-13____

PACIFICORP

EXHIBIT OF GREGORY N. DUVALL

2012 Wind Integration Study

January 2013

PacifiCorp

2012 Wind Integration Resource Study

DRAFT- For IRP Public Participants Review

DRAFT Version

November 15, 2012

1. Introduction

The purpose of this study is to estimate the operating reserves required to maintain PacifiCorp's system reliability and comply with North American Electric Corporation (NERC) regional reliability standards. The Company must provide sufficient operating reserves to allow the Balancing Authority to meet NERC's control performance criteria (See BAL-007-1[1]) at all times, incremental to contingency reserves which the Company maintains to comply with NERC Standard BAL-002-0[2]. These incremental operating reserves are necessary to maintain area control error[3] within required parameters, apart from disturbance events that are addressed through contingency reserves, due to sources outside direct operator control including intra-hour changes in load demand and wind generation. The study results in an estimate of operating reserve volume and estimated cost of these operating reserves required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas (BAAs).

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

[1] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf.

[2] NERC Standard BAL-002-0: http://www.nerc.com/files/BAL-002-0.pdf

[3] "Area Control Error" is defined in the NERC glossary here: http://www.nerc.com/files/Glossary_12Feb08.pdf

Technical Review Committee

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

- *Andrea Coon - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)*
- *Randall Falkenberg – President, RFI Consulting, Inc.*
- *Matt Hunsaker - Manager, Western Renewable Energy Generation Information System (WREGIS) 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*

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

1.1 Executive Summary

The 2012 Wind Integration Study (the "Wind Study") estimates the regulating margin requirement from historical load and wind generation production data. The regulating margin is required to manage variations to area control error due to load and wind variations within PacifiCorp's BAAs. The Wind Study estimates the regulating margin requirement based on load combined with wind variation and separately estimates the regulating margin requirement based solely on load variation. The difference between these two calculations, with and without the estimated regulating margin required to manage wind variability and uncertainty, provides the amount of incremental operating reserves required to maintain system reliability due to the presence of wind generation in the PacifiCorp's BAAs. The resulting regulating margin requirement was evaluated deterministically in PaR, a production cost model used in the Company's Integrated Resource Plan (IRP) to evaluate stochastic risk in selection of a preferred resource portfolio, so that the incremental cost of the regulating margin required to manage wind resource variability and uncertainty can be reported on a $ per MWh of wind generation.[4]

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

Table 1. Average annual regulating margin reserves, 2012 Wind Study (MW).

	West BAA	East BAA	Combined
Load-Only Regulating Margin	149	238	388
Incremental Wind Regulating Margin	69	130	200
Total Regulating Margin	219	369	587

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

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

Table 2. Wind integration cost (2013$ per MWh of wind generation).

Study	2010 Wind Integration Study	2012 Wind Integration Study
Wind Capacity Penetration	2046 MW	2135 MW, 2011 Operational Data
Tenor of Cost	3-year levelized, 2010$	1 year levelized, 2012$
Hourly Reserve ($/MWh)	$8.85	$1.52
Interhour/System Balancing ($/MWh)	$0.86	$0.36
Total Wind Integration ($/MWh)	$9.70	$1.89

The Company's Wind Study indicates a substantially reduced cost for wind integration relative to previous studies. The primary cause for the reduction is lower forecasted natural gas and power market prices. Table 3 compares natural gas and power price assumptions used in the 2010 Wind Integration Study to those used in the 2012 Wind Integration Study.

Table 3. Natural Gas and Power prices used in the 2010 and 2012 Wind Integration Studies.

	Palo Verde HLH Power	Palo Verde LLH Power	Opal Natural Gas
2010 Wind Study (2010$)	$51.26	$35.60	$5.36
2012 Wind Study (2013$)	$37.05	$25.74	$3.43

The effect of changing power and natural gas prices on the cost of wind integration is significant, even if the volume of wind being integrated does not change. The value of reserves is often the opportunity cost of a lost sale at a given generation station. This opportunity cost is foregone margin (which is equal to the lost revenue from the wholesale sale) less the variable cost to run the generation plant at a higher level, which is primarily the cost of fuel. In actuality, and as reflected in the PaR model cost estimation, this sale would have been made, but for the need to back the unit down to provide the required reserves.

2. Data

2.1 Overview

The calculation of regulating margin reserve requirement was based entirely on actual historical load and wind production data over the Study Term from January 2007 through December 2011. No simulated wind production data was incorporated in the Wind Study, which is a change from prior studies that did not have the benefit of a more complete historical data set. Table 4 shows that the ten-minute interval data for wind resources grew substantially during this period as wind resources came online in PacifiCorp's BAAs.

Table 4. Historical wind production and load data inventory.

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

2.2 Historical Load and Load Forecast Data

The historical hourly day-ahead load forecasts and day-ahead hourly wind forecasts used to operate the generation system through the Study Term (2007-2011) were retrieved from Company records. Historical load data for the PacifiCorp East (PACE) and PacifiCorp West (PACW) BAAs were collected for the Study Term from the PacifiCorp PI system[5]. These data were used for all the calculations involving historical load in the Study. The raw load data were reviewed for anomalies prior to further use. Data anomalies can include:

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

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

[5] 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 5. Load data anomalies and their interpolated solutions.

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

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2.3 Historical Wind Generation and Wind Generation Forecast Data

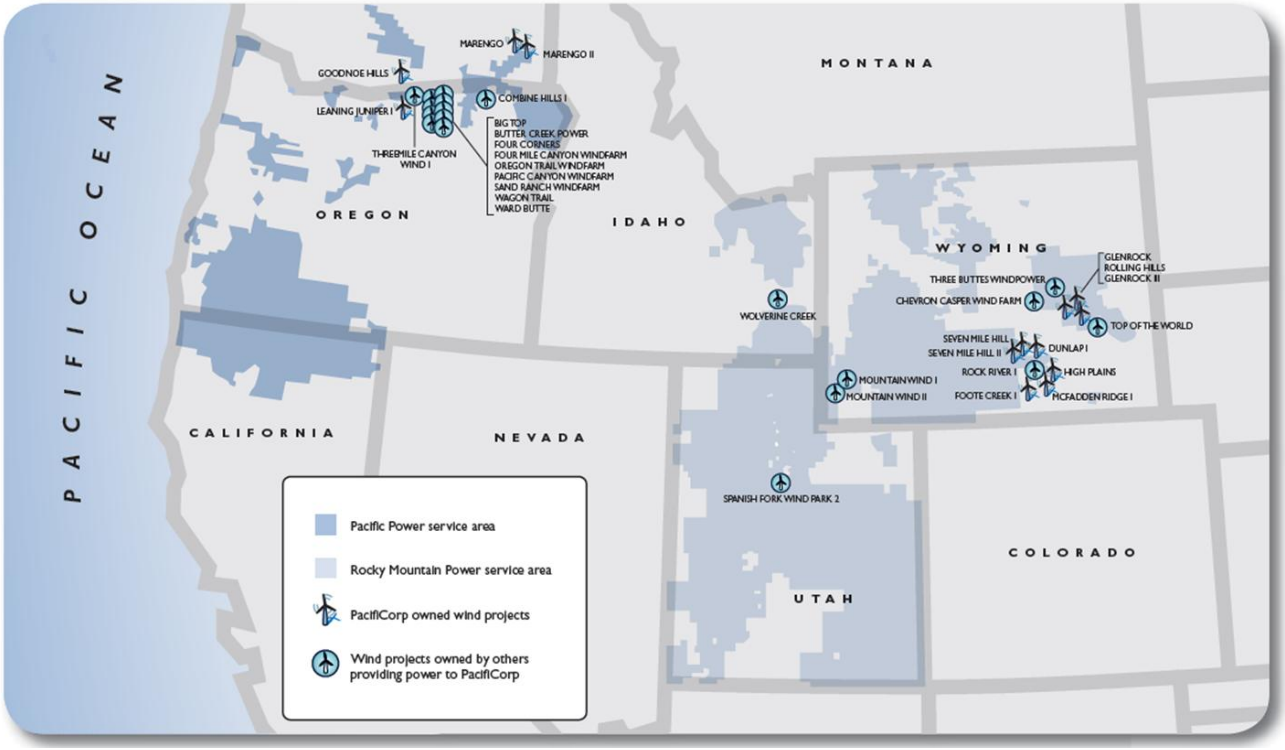
2.3.1 Overview of the Wind Generation Data Used in the Analysis

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

2.3.2 Historical Wind Generation Data

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

Figure 1. Representative map of PacifiCorp wind generating stations used in this study.



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

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

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

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

The PI system ten-minute interval data streams also sometimes exhibit unduly long periods of unchanged or "stuck" values for a given node. Because reserve requirements are driven by large, sudden changes in either wind or load, these data anomalies needed to be addressed. To address these anomalies, the values were held constant when "stuck" values were observed but for the last hour of "stuck" output to smooth the transition to the rest of the data series. For example, if a node's measured wind generation output was 50 MW for three weeks and the first new, fluctuating data value was 75 MW, the value of the last hour of "stuck" data would be replaced with the average of 50 MW and 75 MW. The Company investigated the impact of replacing some of the stuck values with corresponding hourly generation data on the Mountain Wind and Spanish Fork wind plants. As the effect of substituting Mountain Wind and Spanish Fork wind data for some of the stuck values was ascertained to be minimal (less than a tenth of a percent change in the resulting component reserve requirement), the operational data used for the Wind Study was not changed other than the instances described above.[6] In total, the wind generation data adjusted for stuck values represented only 0.5% of the wind data used in the Wind Study.

2.3.3 Historical Day-ahead Wind Generation Forecasts

Day-ahead wind forecasts for all owned and contracted wind resources were collected from daily historical records maintained by PacifiCorp commercial operations as well as from the Company's third party wind forecast service provider, Garrad Hassan Co. From year 2007 to year 2009 the same sets of historical day-ahead wind forecast data that were used for the Company's 2010 wind integration study were used again for the 2012 study for consistency. From year 2010 to the end of year 2011, Garrad Hassan provided complete data sets for the historical day-ahead wind forecasts. For transmission customers' resources the Company used the actual hourly wind generation data, eliminating the contribution of day-ahead "forecast error"

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

from these resources, which is consistent with the fact PacifiCorp does not schedule transmission customers' resources located within the Company's BAAs.

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

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

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

In the 2010 and 2011 day-ahead forecast data sets, 1.3% of the forecast hours were missing data, from one hour up to a week consecutive. If only one hour was missing, that hour forecast was created using the average of the previous hour forecast and the next hour forecast in order to smooth out the fluctuation in the data set. If several days' forecasts were missing, then the latest 24 hours of forecast data immediately before the missing days were copied and repeated to fill in the days-long gap. This approach is intended to preserve the smoothness of forecast data while trying not to reduce intermittency in real wind generation forecasts.

3. Method

3.1 Method Overview

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

Operating Reserves

In order to clarify this requirement, this section discusses the NERC regional reliability standard operating reserve requirement and how it fits into this study. NERC regional reliability standard BAL-STD-002-0[7] requires each Balancing Authority, such as PacifiCorp, to carry sufficient operating reserve at all times. Operating reserve consists of contingency reserve and regulating margin. These reserve requirements necessitate available generation surplus to that required to meet load obligations. Each of these types of operating reserve is further defined below.

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

Regulating margin is the additional capacity the Company holds in reserve to ensure it has adequate reserve at all times to meet the NERC Control Performance Criteria in BAL-007-1[8]. NERC Control Performance Criteria require the Company to carry regulating reserves incremental to contingency reserves to maintain reliability. However, these additional regulating reserves are not defined by a simple formula, but rather are the amount of reserves required by each BA to meet the control performance standards. Since the Company's last Wind Integration Study[9], the performance standards have evolved from a calculated Control Performance Standard

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

[8] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf. According to WECC Operating Committee meeting highlights (page 3), the field trial of this standard has been extended through Feb. 28th, 2013, and could be extended further in January 2013. The highlights are published here: https://www.wecc.biz/committees/StandingCommittees/MIC/10102012/Lists/Presentations/1/OC%20Oct%202012%20Highlights%20-%20Paul%20Rice.pdf

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

2 (CPS2) mandated by NERC BAL-001-0[10] to a more dynamic regime mandated by NERC BAL-007-1, called Balancing Authority ACE Limit (BAAL), in which the Company's performance standard can be affected by the frequency of the interconnection. This new standard allows a greater ACE when the ACE is actually correcting the frequency. However, the Company cannot plan on knowing when ACE will correct or exacerbate frequency so the L_{10} is used for the bandwidth in both directions of the ACE. Thus the Company determines, based on the unique level of wind and load variation in its system, and the prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and wind changes throughout the delivery hour. PacifiCorp further segregates regulating margin into two components to assist in the analysis: ramp reserve and regulation reserve.

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

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

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

Method Steps

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

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

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

3.2 Regulating Margin Requirements

As noted above, ten-minute interval wind generation and load data drives the calculation of the regulating margin requirement for ramp reserve and regulation reserve. The approach for calculating regulating margin requirements necessary to supply adequate operational capacity is based on merging current operational practice with a survey of papers on wind integration[11] and input from the TRC.

3.2.1 Ramp Reserve

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

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

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

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

3.2.2 Regulation Reserve

As ramp reserves represent the system flexibility required to follow the system's requirements without any uncertainty or error, the regulation reserve is necessary to cover uncertainty ever-present in power system operations. Very short-term fluctuations in weather, load patterns, wind generation output and other system conditions cause short term forecasts to change at all times. Therefore, system operators rely on regulation reserve to allow for the unpredictable changes bound to occur between the time the next hour's schedule is made and the arrival of the next

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

hour, or the ability to follow net load. Also, these very same sources of instability are active throughout each hour, requiring flexibility to regulate the generation output to the myriad ups and downs of customer demand, fluctuations in wind generation, and other system disturbances. To assess the regulation reserve requirements for PacifiCorp's BAAs, the Company compared the operational data to operational forecasts as described below.

3.2.3. Operational Forecasts

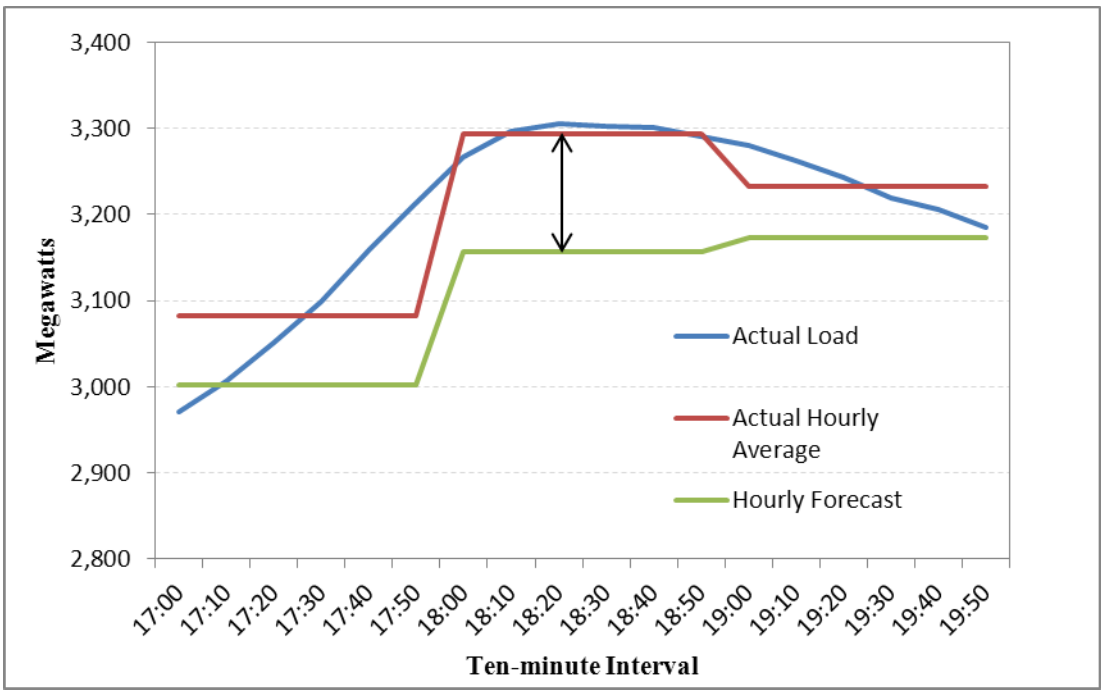
Regulation reserve consists of two components: (1) *regulating*, which is developed using the ten-minute interval data, and (2) *following*, which is calculated using the same data but estimated on an hourly basis. The Study Term load data and wind generation data are applied individually to calculate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

3.2.3.1 Load Following Operational Forecast

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

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

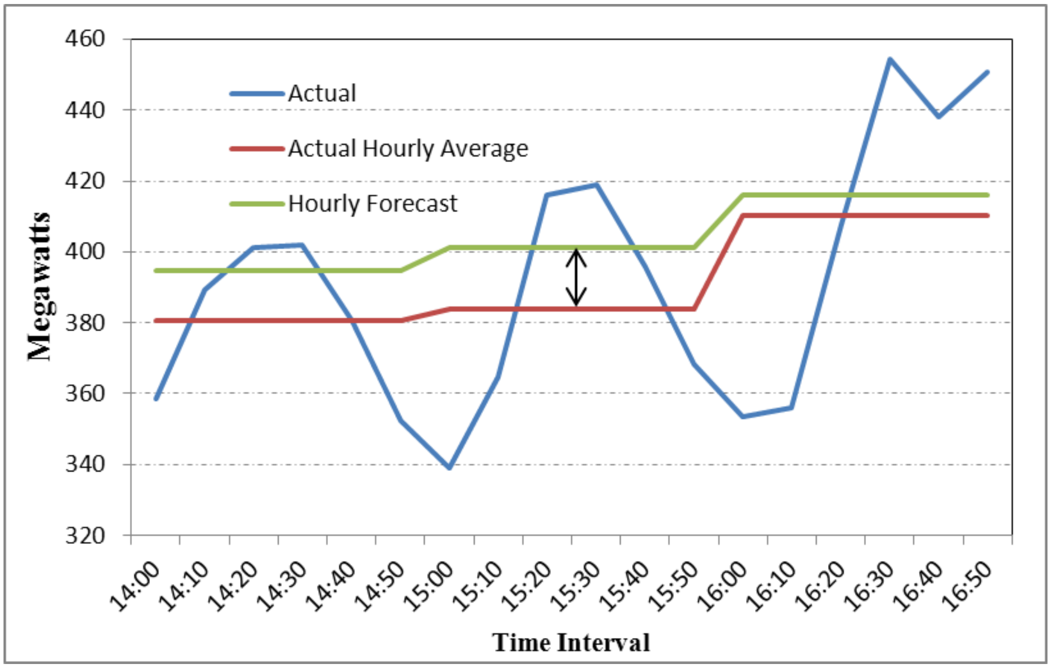
Figure 2. Illustrative load following forecast and deviation.



3.2.3.2 Wind Following Operational Forecast

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

Figure 3. Illustrative Wind following forecast and deviation.

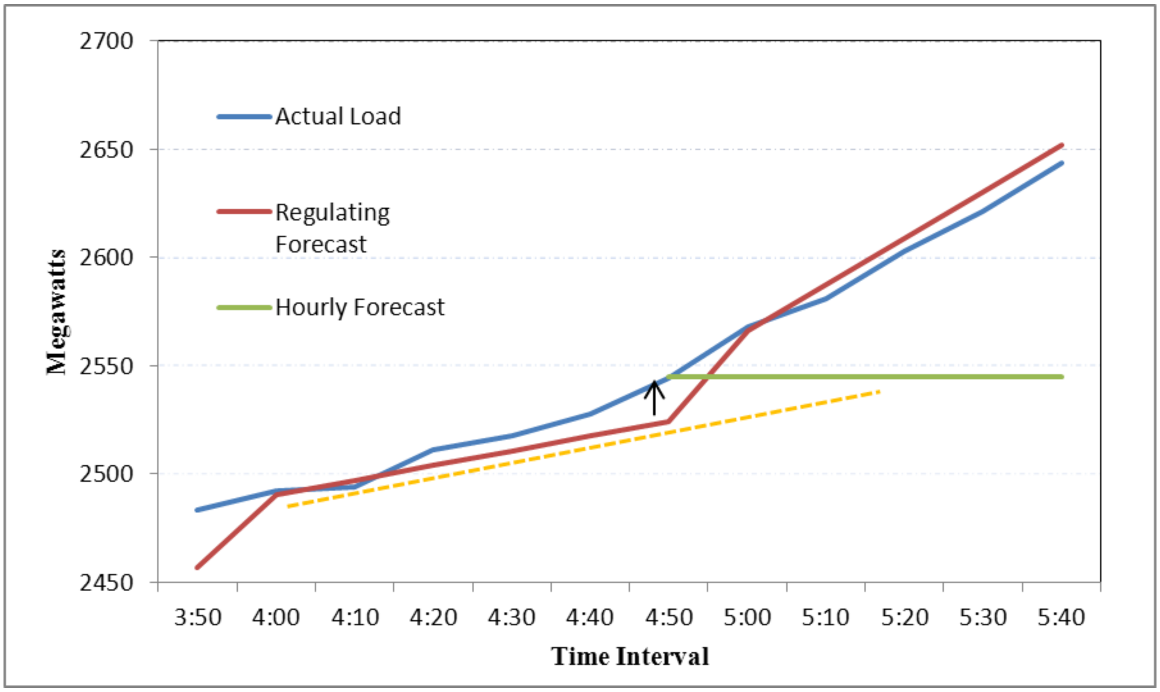


3.2.3.3 Load Regulating Operational Forecast

Separate from the variations in the hourly scheduled loads, the ten-minute load variability and uncertainty was analyzed by comparing the ten-minute actual load values to a *line of intended schedule*, which was represented by a line interpolated between an actual top-of-the-hour load value and the next hour's load forecast target at the bottom of that (next) hour. A sample of how the intended schedule compares to actual load data is shown in Figure 4, with the trend of the line of intended schedule tracking the orange line toward the load following forecast at the middle of the ensuing hour as based upon data from PacifiCorp's West BAA from December

2010. The method approximates the real time operations process for each hour. At the top of the given hour, the actual load is known and a forecast for the next hour was made. For the purposes of this study, a line joining the two points was made to represent the ideal path for the ramp or decline expected within the given hour. The actual ten-minute load values were compared to this straight line to produce a corresponding strip of load regulating deviations at each ten-minute interval, with one such deviation represented by the black arrow in Figure 4.

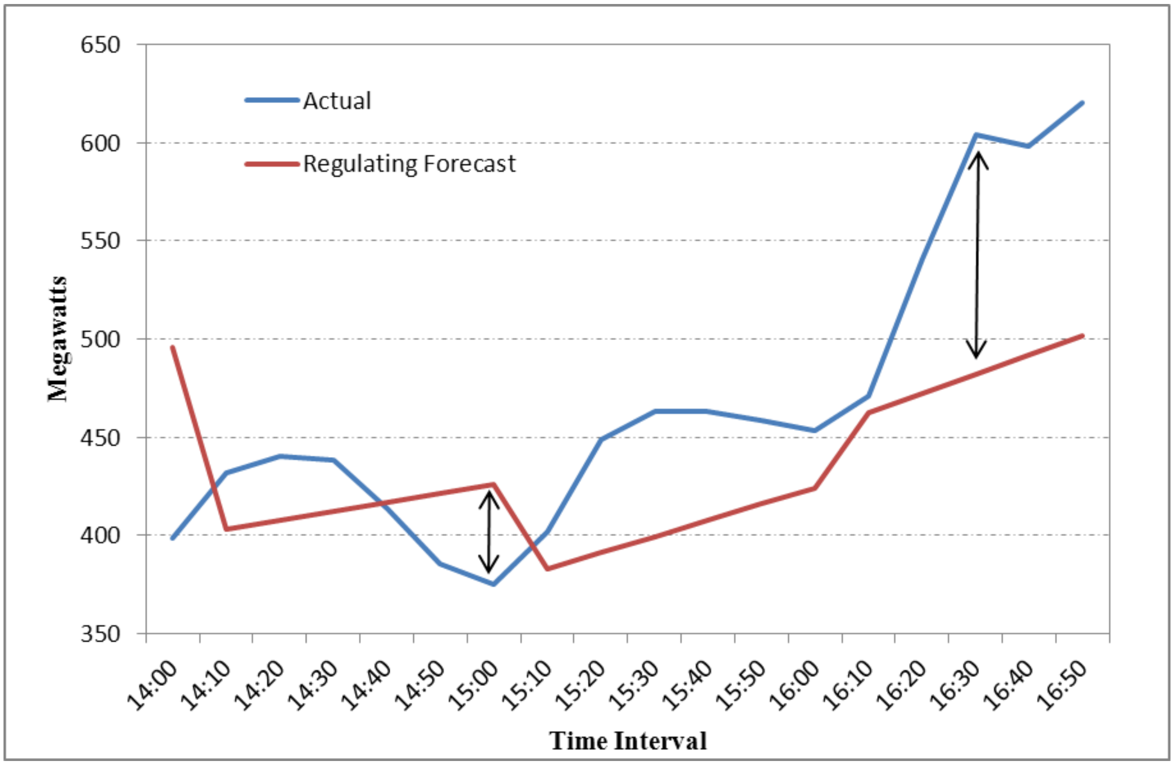
Figure 4. Illustrative load regulating forecast and deviation.



3.2.3.4 Wind Regulating Operational Forecast

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

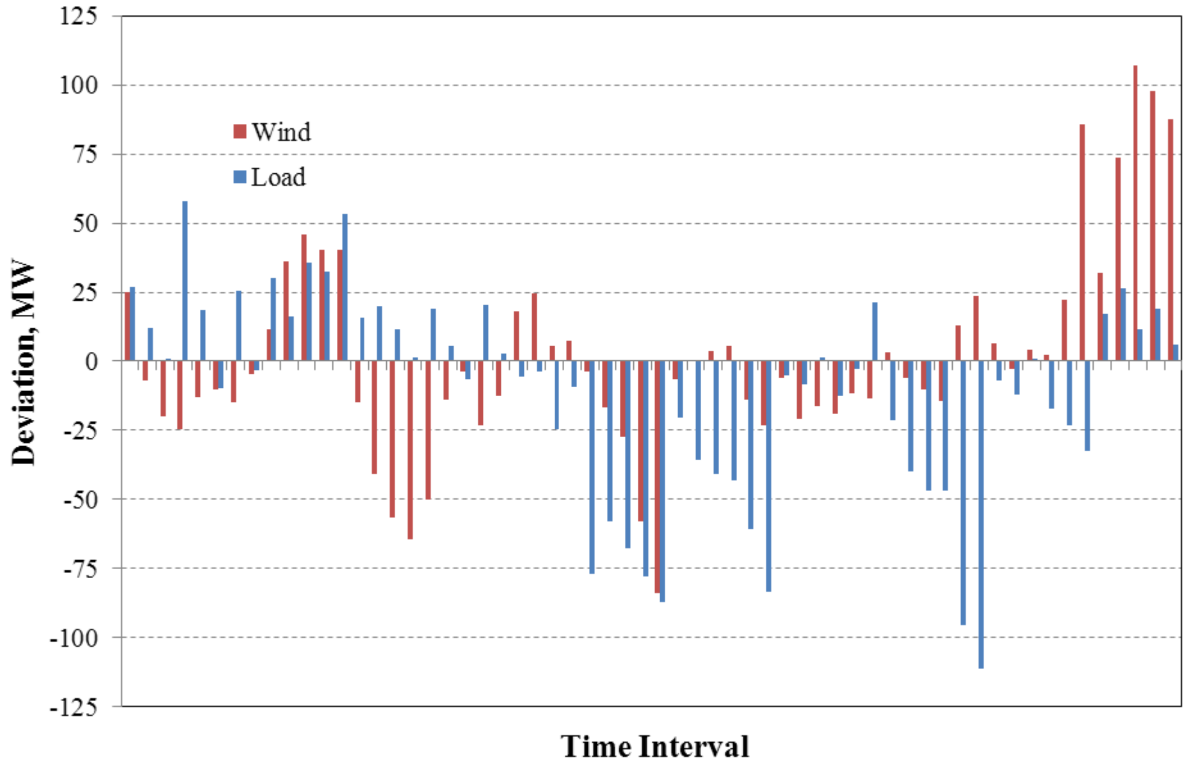
Figure 5. Illustrative wind regulating forecast and deviation.



3.2.4 Recording of Deviations

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

Figure 6. Illustrative example of independent load and wind regulating deviations.



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

3.2.5 Analysis of Deviations

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

Table 6 depicts the calculation of percentiles (every 5%) among the load regulating forecasts for June 2011 using East BAA operational data. For example, a load regulating forecast of 4,403.7 MW represents the fifth percentile of such forecasts for that month. Any forecast values below that value will be in Bin 20, along with the respective deviations recorded for those time intervals. Any forecast values between 4,403.7 MW and 4,508.8 MW will land the deviation for that particular interval in Bin 19.

Table 6. Percentiles dividing the June 2011 load regulating Forecasts into 20 bins.

East		
Bin Number	Percentile	Load Forecast
	MAX	7,615.4
1	0.95	7,266.1
2	0.90	6,732.9
3	0.85	6,379.8
4	0.80	6,097.3
5	0.75	5,894.0
6	0.70	5,744.7
7	0.65	5,642.5
8	0.60	5,561.3
9	0.55	5,484.0
10	0.50	5,400.7
11	0.45	5,311.9
12	0.40	5,213.7
13	0.35	5,098.6
14	0.30	4,980.8
15	0.25	4,868.5
16	0.20	4,748.0
17	0.15	4,626.8
18	0.10	4,508.8
19	0.05	4,403.7
20	MIN	4,233.6

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

Table 7. Recorded interval load regulating forecasts and their respective errors, or deviations, for June 2011 operational data from the East BAA.

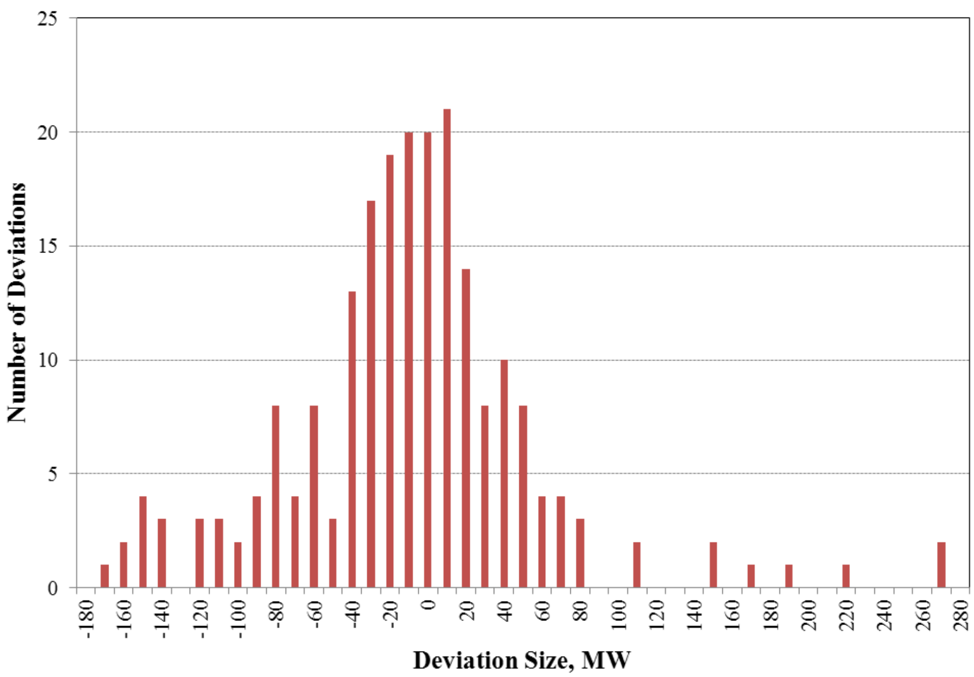
EAST

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

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

For example, consider the deviations grouped into one of the load regulating bins for June 2011 data in Figure 7. The deviations in this bin all occurred in time intervals with a load regulating forecast near 6,898 MW, from the East BAA using June, 2011 operational data. Most of the deviations are within 80 MW of the actual load value (a little over one percent, plus or minus). However, for load regulating deviations in this range, there is apparently a greater tendency where actual load was lower (more negative deviations than positive in Figure 7 below, and of greater magnitude), which requires the system’s installed generation to have to increase its output in a very short timeframe to balance, thus requiring what are called “up reserves”. It also bears noting that the deviations form a statistical distribution which is not normally shaped; and as more bins are examined, they also are not normally distributed and the longer tail can appear on either side.

Figure 7. Histogram of deviations occurring about a June 2011 East BAA load regulating forecast of 6,097 MW.



Bin Analysis

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

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

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

Where:

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

Forecast Bin$_i$ = the component forecast errors in each bin

The tolerance level, per Equation 1, represents a percentage of component deviations intended to be covered by the associated component reserve. As detailed in the method overview, section 3.1, the Company cannot apply contingency reserves to manage load and wind fluctuations, and therefore must carry sufficient regulating margin to avoid dipping into contingency reserve for this purpose. Any failure to manage these fluctuations can lead to disruption of services to customers. Surveying other recent wind integration studies[12], the company focused on two other large regional entities grappling with the same concerns; BC Hydro and Bonneville Power Administration ("BPA"). BC Hydro applies a 99.7% tolerance to respective load and wind reserve requirements[13], while the BPA customarily applies a 99.5% tolerance to its balancing requirements[14]. Considering the actions of other major market participants, and the requirement

[12] PacifiCorp reviewed wind integration studies sponsored by other regional utilities (Portland General Electric, Avista, Idaho Power, BC Hydro, BPA) and the National Renewable Electrical Laboratory. The more recent BC Hydro and BPA approaches are consistent with the Company's requirement to maintain contingency reserve requirements at all times.

[13] BC Hydro's Wind Integration Study is part of its Integrated Resource Plan, Appendix 6E, page 6E-9: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf

[14] Pacific Northwest National Laboratory, page 5: http://energyenvironment.pnnl.gov/ei/pdf/NWPP%20report.pdf

to maintain contingency reserves at all times, the Company has decided to apply a 99.7% tolerance in the calculation of component reserves, In doing so, the Company has sought to plan for as many deviations as possible, while excluding the very largest data points to allow for the potential existence of outlier values. However, in a departure from BC Hydro's and BPA's approaches, the Company will also net the appropriate system L_{10} from the resulting total reserves requirement[15], effectively reducing the target reserve requirement to a more aggressive level than those other market participants. The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails. Despite exclusion of extreme deviations with the use of the 99.7% tolerance, the Company's system operators will still be expected to meet reserve requirements without exceptions. The Company may also change the tolerance based on operational and customer feedback in the future.

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

The binned results can be reviewed for a month at a time, and patterns in the up- and down-reserves requirements by forecast level become more apparent for load and for wind as shown in Figures 8 and 9. For example, Figure 9 can be used to further explain the calculation method for the resulting component reserve demand. Bin 4 describes 36 hours (five percent of June's 720

[15] 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

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

Figure 8. **Load following component reserve profile; operational data from June, 2011.**

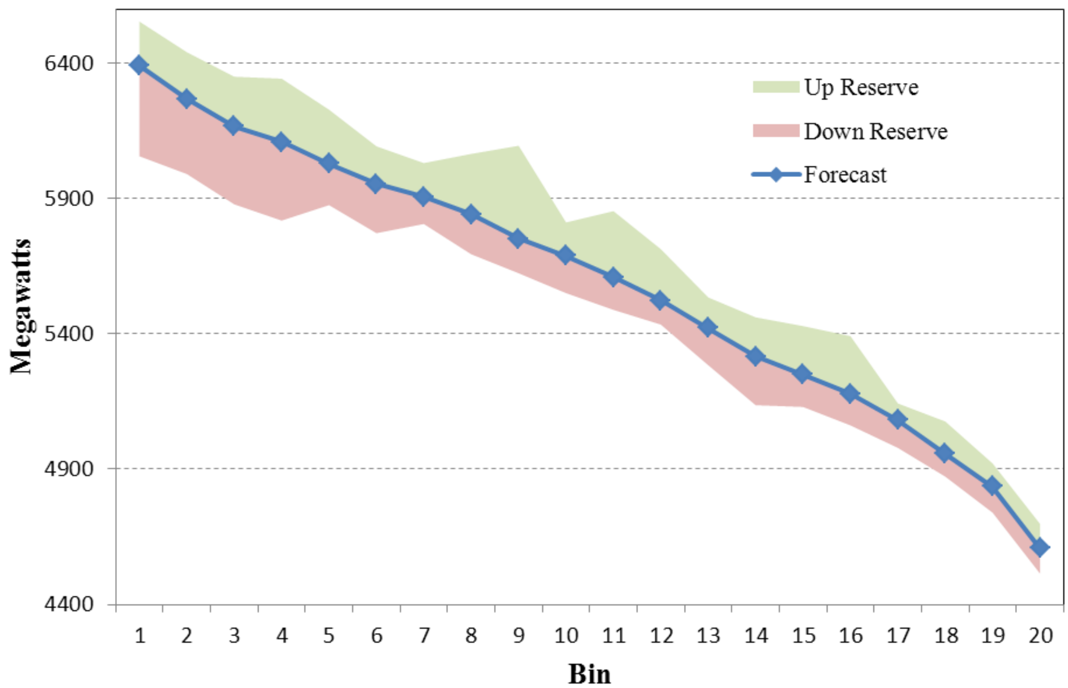
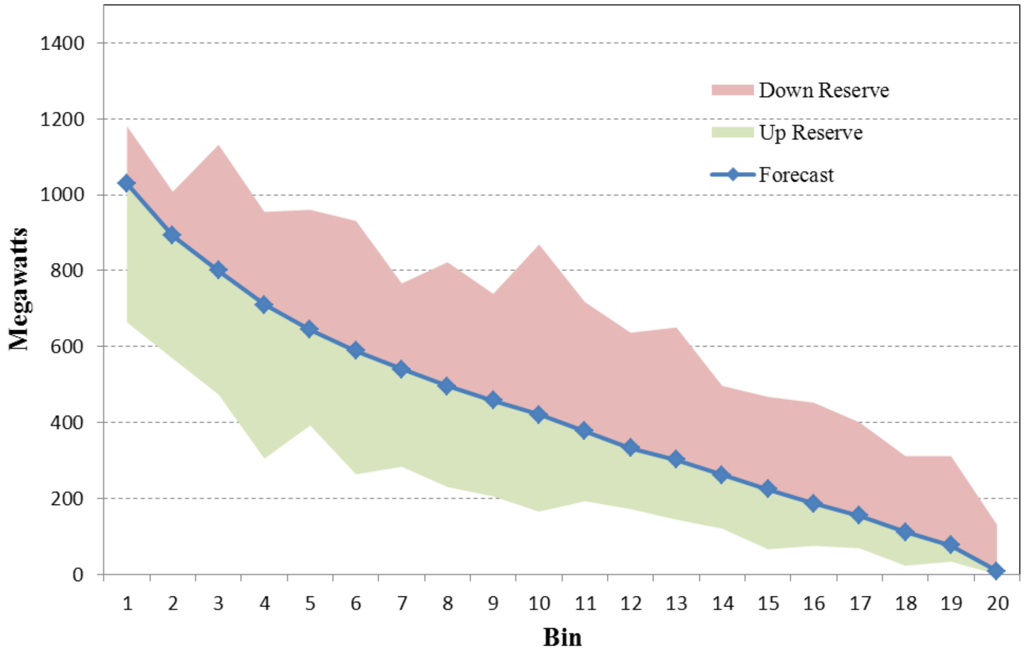


Figure 9. **Wind following component reserve profile; operational data from June, 2011.**



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

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

3.2.6 Backcasting

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

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

Table 8. **Sample reference table for load and wind following component reserves.**

	East			East		
Bin	Up	Load Forecast	Down	Up	Wind Forecast	Down
	163	10000	335	365	5000	151
1	163	6391	335	365	1029	151
2	172	6268	278	324	893	115
3	182	6168	289	327	801	331
4	233	6109	291	405	710	245
5	199	6029	153	252	645	316
6	138	5954	182	325	589	342
7	126	5905	99	256	540	227
8	223	5841	147	265	495	327
9	345	5750	126	253	459	281
10	123	5688	138	255	420	449
11	245	5608	120	184	377	340
12	189	5523	89	161	333	304
13	113	5421	137	158	302	348
14	145	5316	180	141	262	235
15	179	5250	120	158	224	243
16	213	5178	117	111	187	266
17	62	5081	102	86	155	246
18	119	4957	85	89	112	200
19	85	4836	97	44	77	234
20	90	4608	94	44	9	122
	90	0	94	44	0	122

Table 9. Sample reference table for load and wind regulating component reserves.

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

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

Application to component forecasts

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

Table 10. Interval load forecasts and component reserves requirement data for hour-ending 11 AM, June 1, 2011 in PacifiCorp's East BAA.

East	East	East	East	East	East	East	East	East
Time	Actual Load (10-min Avg)	Actual Load (Hourly Avg)	Following Forecast Load:	Load Following Up Reserves Specified by Tolerance Level	Load Following Down Reserves Specified by Tolerance Level	Regulating Load Forecast:	Load Regulating Up Reserves Specified by Tolerance Level:	Load Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	5,533.04	5,543.46	5,509.68	271.5	121.2	5500.6	142.4	102.4
06/01/2011 10:10	5,525.38	5,543.46	5,509.68	271.5	121.2	5542.6	149.1	94.0
06/01/2011 10:20	5,525.54	5,543.46	5,509.68	271.5	121.2	5552.1	149.1	94.0
06/01/2011 10:30	5,550.23	5,543.46	5,509.68	271.5	121.2	5561.6	149.1	94.0
06/01/2011 10:40	5,551.93	5,543.46	5,509.68	271.5	121.2	5571.1	149.1	94.0
06/01/2011 10:50	5,574.64	5,543.46	5,509.68	271.5	121.2	5580.7	149.1	94.0

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

Table 11. Interval wind forecasts and component reserves requirement data for hour-ending 11 AM June 1, 2011 in PacifiCorp's East BAA.

East	East	East	East	East	East	East	East	East
Time	Actual Wind (10-min Avg)	Actual Wind (Hourly Avg)	Following Forecast Wind:	Wind Follow Up Reserves Specified by Tolerance Level	Wind Follow Down Reserves Specified by Tolerance Level	East Wind Regulating Forecast:	Wind Regulating Up Reserves Specified by Tolerance Level:	Wind Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	550.82	555.26	485.02	242.45	270.43	485.0	238.1	226.2
06/01/2011 10:10	557.30	555.26	485.02	242.45	270.43	485.0	238.1	226.2
06/01/2011 10:20	529.71	555.26	485.02	242.45	270.43	485.0	238.1	226.2
06/01/2011 10:30	550.40	555.26	485.02	242.45	270.43	529.7	205.3	290.6
06/01/2011 10:40	560.53	555.26	485.02	242.45	270.43	529.7	205.3	290.6
06/01/2011 10:50	582.79	555.26	485.02	242.45	270.43	529.7	205.3	290.6

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

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

Total Regulating Reserves Requirement

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

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

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

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

Load Following = 271.5 MW
Load Regulating = 142.4 MW
Wind Following = 242.5 MW
Wind Regulating = 238.1 MW

Applying Equation 2:

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

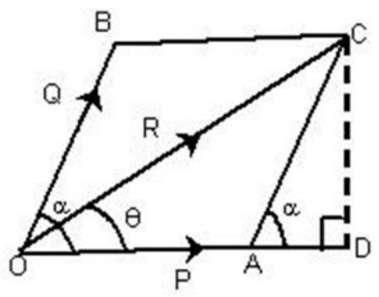
Per Equation 2, 457.7 MW of up reserves recommended for regulation reserve for the time interval between 10:00am and 10:10am, June 1, 2011 in the East BAA. In this manner, the component reserves requirements are used to calculate an overall reserves requirement for each ten-minute interval of the Study Term. The results of these calculations can be quoted in hourly or monthly requirements by averaging the reserves requirements of all the ten-minute intervals within the specified hour or month. Annual reserves requirements are quoted as the average of the twelve monthly requirements.

Wind and Load Correlation

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

The RSS equation is typically applied in the analysis engineering tolerances and supporting statistical concepts, and is derived from the Parallelogram Law[16].

Figure 10. Depiction of the Parallelogram Law.



Equation 3. Vector combination as prescribed by the Parallelogram law in Figure 10.

Resultant $\boldsymbol{R} = \sqrt{\boldsymbol{P}^2 + \boldsymbol{Q}^2 + 2\boldsymbol{P}\boldsymbol{Q}\cos\alpha}.$.

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

The Parallelogram Law allows correlation to be constructive (with positive correlation) and destructive (with negative correlation). In cases of constructive correlation, the resultant (**R** in the illustration above, the parallelogram's diagonal) is increased as the angle (**α**) between (**Q**) and (**P**) is reduced. Destructive correlation causes the angle (**α**) to open wider, reducing the diagonal of the parallelogram, and reducing the length of the diagonal, **R**. The Law of Cosines can be used to illustrate a proof[17] that the cosine of angle **α** equals the correlation between vectors **P** and **Q** ($\cos(\boldsymbol{\alpha}) = \rho_{\mathbf{PQ}}$).

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

[16] A proof of the parallelogram law is available at: http://www.unlvkappasigma.com/parallelogram_law/

[17] http://www.johndcook.com/blog/2010/06/17/covariance-and-law-of-cosines/

of a parallelogram to form a resultant (**R** in the illustration), four uncorrelated vectors corresponding to the component reserves for load following, load regulating, wind following, and wind regulating deviations are combined into a reserves requirement. The fact that there are four dimensions rather than two makes the process difficult to illustrate, but the effect is the same as in the two dimensional example above.

The Company applied the RSS formulation in its 2010 Wind Integration Study[18] after reviewing samples of the load and wind data used to perform the study[19], and reviewing studies by Idaho Power[20] and the Eastern Wind Integration and Transmission Study[21]. Since that time, additional studies have suggested use of this formulation directly[22] or noted that short term deviations from schedule in wind generation output and load are not correlated[23]. However, stakeholder interest has encouraged the Company to further review the correlation between wind and load reserve components.

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

Correlation Analysis

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

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

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

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

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

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

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

Table 12. Results of regression analyses between wind and load deviations.

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

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

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

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

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

Figure 11. PacifiCorp East BAA following regression plot.

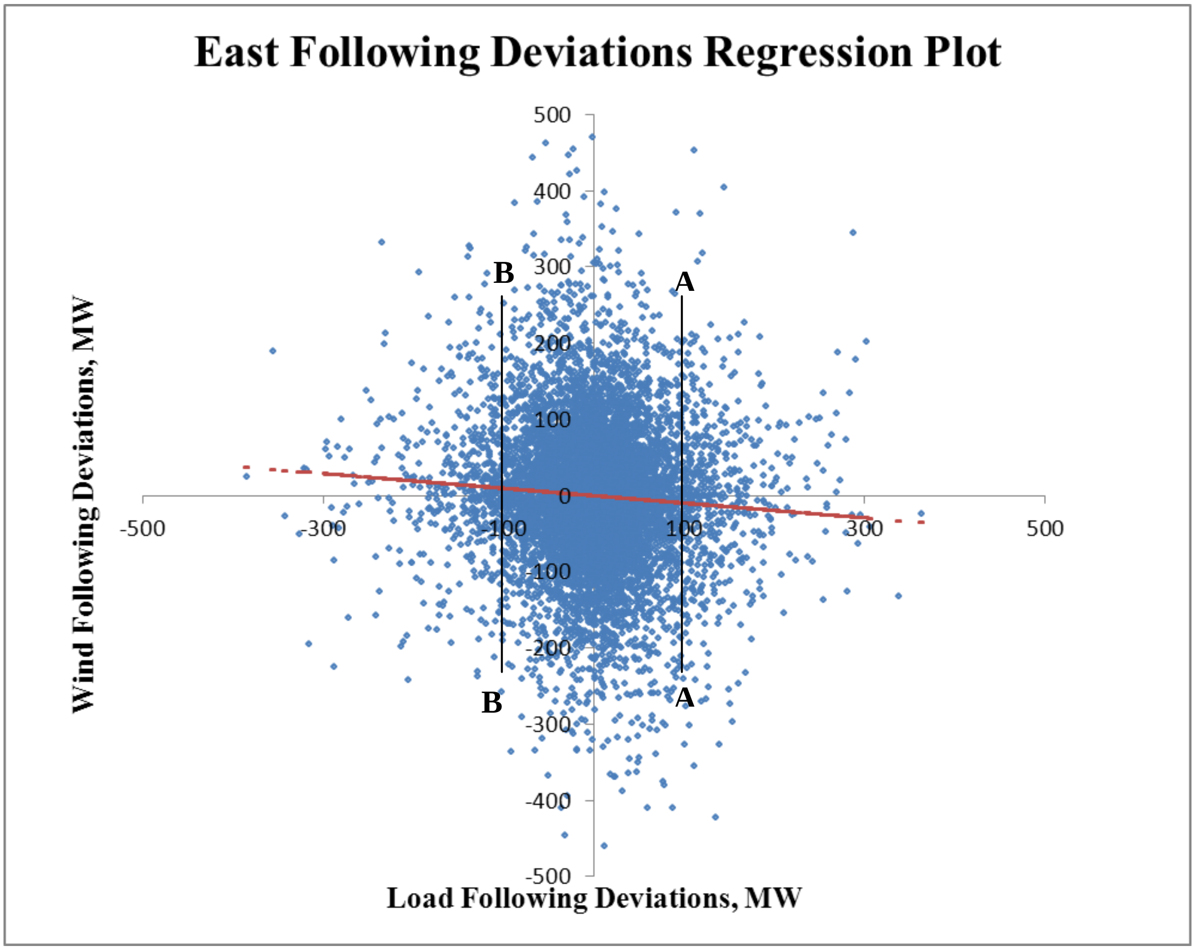
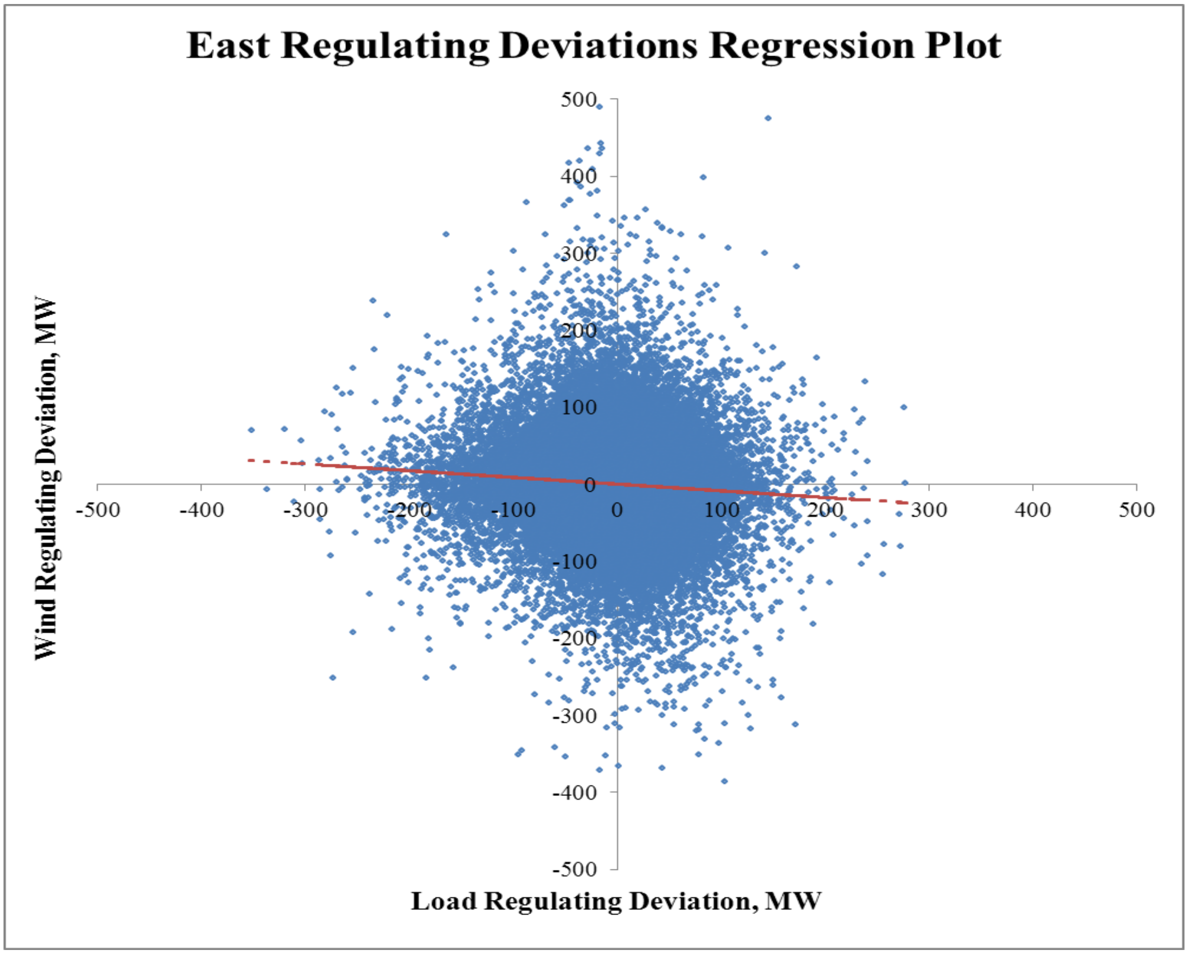
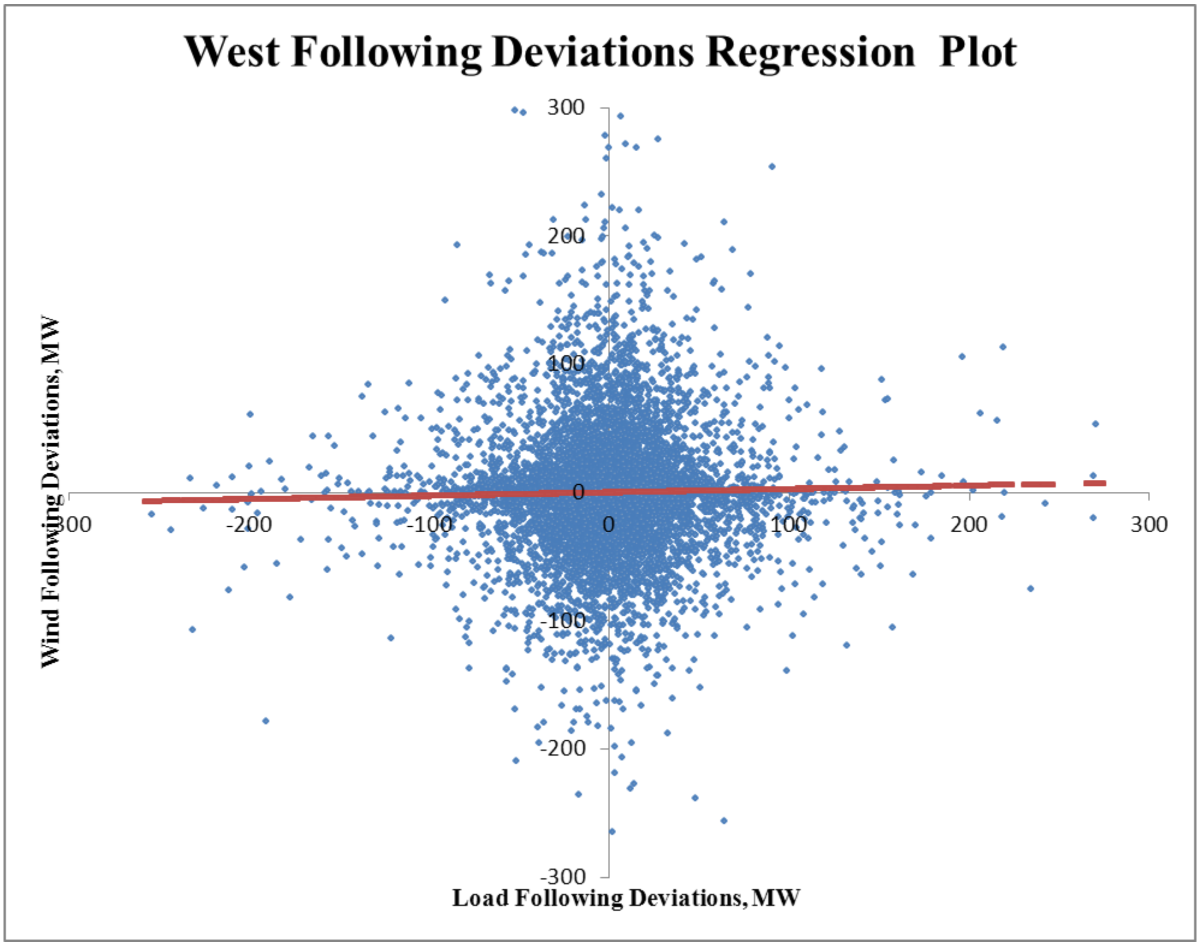


Figure 12. PacifiCorp East BAA regulating regression plot[24].



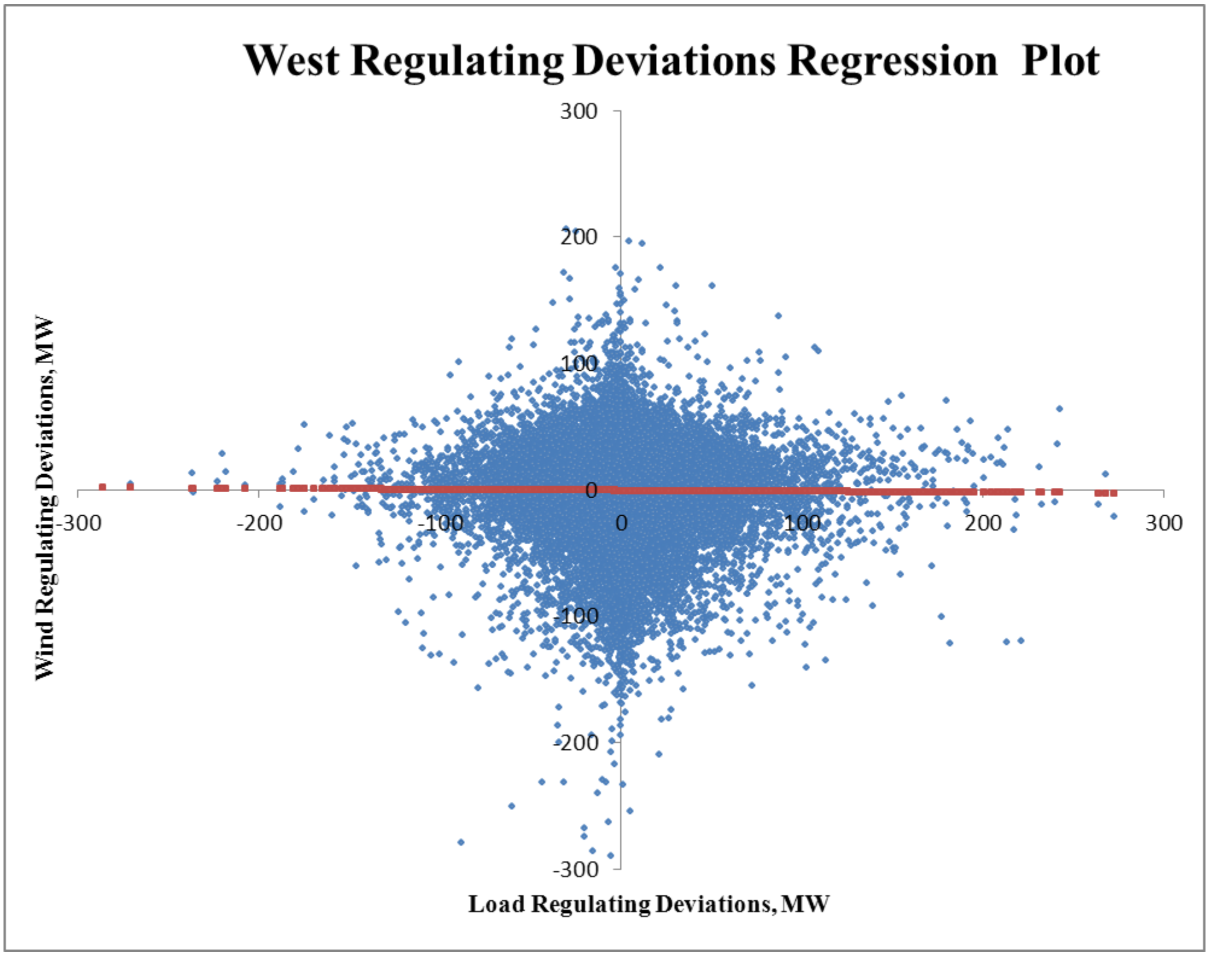
[24] Note cloud-like pattern of errors which is densest near zero, and the data does not tighten around the trend line.

Figure 13. PacifiCorp West BAA following regression plot[25].



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

Figure 14. PacifiCorp West BAA regulating regression plot[26].



3.3 Determination of Wind Integration Costs

3.3.1 Overview

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

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

generation affects regulating margin costs and system balancing costs, the Study utilizes the PaR model, and applies the regulating margin requirements calculated by the method detailed in section 3.2.

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

The five PaR simulations used in the Wind Study are summarized in Table 13. The first two simulations are used to tabulate operating reserve wind integration costs in forward planning timeframes. The approach uses a "P50" or expected wind profiles[27] and forecasted loads. The remaining three simulations support the calculation of system balancing wind integration costs. These simulations were run assuming operation in the 2013 calendar year, applying 2011 load and wind data. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis.[28] PacifiCorp resources used in the simulations are based upon the 2011 IRP Update resource portfolio.[29]

[27] P50 signifies the probability exceedence level for the annual wind production forecast; at P50 generation is expected to exceed the assumed generation levels half the time and to fall below the assumed generation levels half the time.
[28] The Study uses the June 29, 2012 official forward price curve.
[29] The 2011 Integrated Resource Update report, filed with the state utility commissions on March 30, 2012 is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRPUpdate/2011IRPUpdate_3-30-12_REDACTED.pdf.

Table 13. Wind integration cost simulations in PaR.

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

*Uses the unit commitment state from Simulation 3.
** Uses the unit commitment state from Simulation 4.

3.3.2 Calculating Operating Reserve Wind Integration Costs

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

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

3.3.3 Calculating System Balancing Wind Integration Costs

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

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

3.3.4 Allocation of Operating Reserve Demand in PaR

The five PaR Simulations require operating reserve demand inputs that must be applied consistent with the ancillary services structure native to the model. The PaR model distinguishes reserve types by the priority order for unit commitment scheduling, and optimizes them to minimize cost in response to demand changes and the quantity of reserve required on an hour-to-hour basis. The highest-priority reserve types are regulation up and regulation down followed in order by spinning, non-spinning, and finally, 30-minute non-spinning.[30] Table 14 shows these reserve categories and indicates which ones are used for the study. Reserve requirements in the model need to be allocated into these PaR reserve categories and are expressed as a percentage of load.

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

Table 14. Operating reserve categories used by the PaR model.

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

The regulation up and regulation down reserves in PaR are a type of spinning reserve that must be met before traditional spinning and non-spinning reserve demands are satisfied. The incremental operating reserve demand needed to integrate wind generation was assigned in PaR as regulation up. As down regulation reserves are a deployment of generation already committed to provide load, this feature was omitted from the Study. The traditional spinning and non-spinning reserve inputs are used for contingency reserve[31] requirements, which remain unchanged among all PaR simulations in the Study. The 30-minute non-spinning reserve is not applicable to PacifiCorp's system, and thus it is not used. Unused reserves such as regulation up are able to be used in PaR to satisfy spin or non-spin reserves.

Note that given the hourly granularity in PaR, there is no distinction between operating reserve categorized as regulation and load-following in terms of how the model optimizes their use. Further, owing to the hourly granularity of PaR and the fact that PaR optimizes dispatch for each distinct hour, regulation reserves are effectively released for economic dispatch from one hour to the next.

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

4.0 Results

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

Table 15. Regulating margin requirements calculated for PacifiCorp's East and West BAAs (MW).

	West Regulation	East Regulation	Ramp	Combined
Load-Only Reserves	101	168	119	388
Incremental Wind Reserves	65	125	9	200
Total Reserves	166	293	128	587

4.1 Production Cost Results

As described in section 3.3 and detailed in Table 13, PacifiCorp applied the reserve requirements calculated in this Wind Study to a production cost simulation in the Company's PaR model. For the regulating margin costs, the regulating margin required to manage variability due to load and wind on PacifiCorp's East and West BAAs was applied using a "with and without" approach; the margin required only to manage disturbances in load was modeled in a production cost simulation, then compared to a simulation run with the regulating margin necessary to manage load and wind disturbances. The regulating margin costs represents the costs incurred to hold additional reserves for wind to manage hour-to-hour operational disturbances, whereas the system balancing costs are incurred managing the deviation between the day ahead forecast for wind production and actual recorded production on PacifiCorp's Company-owned and contracted wind resources. Transmission customers' wind resources' day-ahead variability and uncertainty are excluded from the system balancing calculation. Wind integration costs are the sum of the regulating margin and system balancing costs, as presented in Table 16:

Table 16. Production Cost Results for the 2012 and 2010 Wind Studies.

	Regulating Margin Cost ($/MWh)	System Balancing Cost ($/MWh)	Wind Integration Cost ($/MWh)
2012 Wind Study (2012$)	$1.52	$0.36	$1.89
2010 Wind Study (2010$)	$8.85	$0.86	$9.70

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

4.2 Additional Scenarios

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

Historical Evaluation

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

Table 17. Historical reserves calculated throughout the Study Term (MW).

	Regulation West	Regulation East	Ramp	Total	Average Wind Capacity, MW
2007	185	194	134	512	606
2008	176	193	122	491	787
2009	150	211	121	482	1364
2010	158	261	122	541	1810
2011	166	293	128	587	2126

Table 18. Incremental Reserves due to installed wind generation capacity (MW).

	Regulation West	Regulation East	Ramp	Total	Average Wind Capacity, MW
2007	16	11	2	29	606
2008	26	14	3	42	787
2009	35	45	4	84	1364
2010	44	78	6	129	1810
2011	65	125	9	200	2126

Concurrent Evaluation

The calculations in this scenario are made for the load and wind deviations combined concurrently, by adding their concurrent errors, producing state bins and integrating the results for following and regulating reserves for load and wind separately. Despite the estimation of load and wind quantities separately in real time operations, and given no indication that short-term changes in load and wind are correlated[32], many stakeholders requested a calculation of the estimated reserves with implied correlation and other characteristics that may be observed in the short term variations of load and wind. The results of these calculations are presented in Table 19.

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

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

Table 19. Concurrent netting of load and wind errors scenario results(MW).

	Regulation West	Regulation East	Ramp	Total
Scenario	154	284	128	566
2012 Study	166	293	128	587

Reliability Based Control Market Structure

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

Table 20. 30-minute balancing interval scenario results (MW).

	Regulation West	Regulation East	Ramp	Total
Scenario	109	233	128	470
2012 Study	166	293	128	587

Combination of East and West Balancing Authority Areas

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

Table 21. Regulating margin requirements calculated assuming a single PacifiCorp BAA (MW).

	Regulation	Ramp	Total
Scenario	398	121	520
2012 Study	459	128	587