Exhibit No.___(GND-4)
Docket No. UE-10___
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
	)	Docket No. UE-10______
Complainant,	)	
vs.	)	
PACIFICORP dba Pacific Power	)	
Respondent.	)	

PACIFICORP

EXHIBIT OF GREGORY N. DUVALL

2008 Integrated Resource Plan – Appendix F

May 2010

APPENDIX F – WIND INTEGRATION COSTS AND CAPACITY PLANNING CONTRIBUTIONS

This appendix summarizes the results of PacifiCorp's latest wind integration cost analysis, which will continue to be refined and expanded. This appendix also presents updated wind capacity contribution values using a statistical estimation methodology that was applied for the first time in the Company's 2007 IRP.

For the wind integration cost study, PacifiCorp developed a methodology to support the costs associated with resource portfolio analysis for the IRP as well as costs used in the evaluation of cost effective renewable resources. This approach decomposes the estimation of inter-hour (hour to hour) and intra-hour (within the hour) costs to integrate intermittent renewable resources. For inter-hour costs, these components include day-ahead and hour-ahead wind forecast variability, or what was referred to as system balancing costs in the 2007 IRP.[2] For intra-hour costs, the components include actual forecast variation, "regulation up" requirements, and "regulation down" requirements. These latter costs pertain to operational assessment and planning of wind variability down to 10-minute intervals or less. In addition to this cost breakdown, PacifiCorp reports integration costs for wind added in the PacifiCorp eastern balancing authority area (PACE), the PacifiCorp west balancing authority area (PACW), and a system weighted-average based on installed capacity in each control area.

The wind integration cost section first provides background on these cost components and then describes the estimation methodologies and cost results. Study caveats and areas for further research are also summarized. The costs results are expressed as a function of the amount and timing of wind included in the 2008 IRP preferred portfolio as well as existing wind (Table F.1). The section concludes with a discussion on future tools, approaches, and external coordination opportunities that PacifiCorp is actively considering or exploring to address the consequences of adding large quantities of wind.

Table F.1 – 2008 IRP Preferred Portfolio Wind Resource Additions by Year

Year	Capacity Additions (MW)	Capacity Factor	Region
Existing and Planned through 2010	1,284	--	System
2011	100	29%	Walla Walla
2011	100	29%	Yakima
2012	100	35%	Southwest Wyoming
2013	100	35%	Southwest Wyoming
2014	100	35%	Aeolus Wyoming
2015	150	35%	Aeolus Wyoming
2016	100	35%	Aeolus Wyoming
2017	100	35%	Southwest Wyoming

[2] PacifiCorp, 2007 Integrated Resource Plan, Appendix J, pp. 193-4.

Year	Capacity Additions (MW)	Capacity Factor	Region
2018	50	35%	Southwest Wyoming
2019	200	35%	Southwest Wyoming
2020	200	35%	Southwest Wyoming
2021	150	35%	Southwest Wyoming
TOTAL	2,734		

Due to a number of project schedules, this wind study was not completed in time to be incorporated into the 2008 IRP portfolio modeling. As discussed in Chapter 7 of Volume 1, a value of $11.75/MWh—based on Portland General Electric Company's latest wind integration study—was used for IRP capacity expansion optimization modeling purposes. While the Company acknowledged the differences between the PacifiCorp and PGE systems and the caveats associated with the PGE study, PacifiCorp believed that the PGE value represented a reasonable proxy until its own study could be completed. If the wind integration cost study yields a significantly different total value, the Company commits to perform a sensitivity study with the System Optimizer capacity expansion model and the 2008 IRP preferred portfolio modeling assumptions to determine the wind resource selection impact of the updated cost value.

WIND INTEGRATION COSTS

Background

In power planning and dispatch, any period in which load or generation varies from a steady value results in an increased cost for the utility to balance out this variation. Variations in the load and wind generation forecasts are managed with balancing activities. Once the hour-ahead schedule is given to the real-time staff, actual variation in load and wind generation within the hour is balanced using system generation resources. Current balancing activities treat wind forecast variations similarly to load forecast deviation; however, special attention is required for the greater percentage variability and near-term volume growth of wind generation.

The components of wind variability which give rise to integration costs can be divided into two groups: inter-hour and intra-hour. The inter-hour components of wind variability are:

- Day-ahead forecast variation: deviation of the long-term wind forecast (prior energy expectations) to the day-ahead forecast for the day prior to power delivery.
- Hour-ahead forecast variation: deviation of hour-ahead forecast from day-ahead forecast for the hour prior to delivery.

The rebalancing or closure of open positions generated as new load and wind forecast data becomes available requires the payment of transaction costs.

The other set of costs to be considered is associated with the intra-hour (within the hour) components of wind variability:

- Actual forecast variation: deviation of actual hourly average energy from the hour-ahead forecast,
- Regulate down: deviation of hourly maximum energy from the energy at the beginning of the hour, measured with ten minute granularity,
- Regulate up: deviation of hourly minimum energy from the energy at the beginning of the hour, measured with ten minute granularity,
- Automatic Generation Control (AGC): fine scale variation of energy over a one to two minute time scale.

These intra-hour factors require the holding of additional reserves above the standard requirement of 5 percent on wind generation. Due to the small impact, yet large analytical requirement, to determine reserves for AGC, this cost component is not addressed in the wind integration study; however, this issue may be pursued in the future as the company gains more experience in this area.

These inter- and intra-hour factors do not include long-term shaping effects. While benefits or costs may arise due to the hourly difference between expected future energy in moving from a flat-dispatched unit such as geothermal to a shaped profile unit such as wind, on a longer-term view, these differences are only the effect of different hourly prices or expected value on the forecasted future energy; therefore, no actual costs are incurred from balancing a new long-term wind pattern with system resource redispatch.

Determination of Incremental Reserve ("Intra-Hour") Requirements

Before all reserve costs can be estimated, the megawatt (MW) quantity of reserves required to maintain system reliability as additional wind in the Eastern and Western balancing authority areas of PacifiCorp's service region must be calculated. In previous wind integration studies, PacifiCorp has not captured the increased load-following reserve requirements caused by wind forecast error within the hour. Increasing the magnitude of wind resources on the system results in an increased reserve requirement due to the fact that wind forecasts are inherently inaccurate, particularly at within-hour granularity. Intra-hour wind variability requires the dispatch of existing units to balance the system as there is no intra-hour market.

Actual Variation

The deviation of the actual hourly average energy from the hour-ahead forecast can be computed given the historical hour-ahead wind generation forecast and actual hourly energy values. This produces statistical hourly distributions of the forecast versus actual energy. If this was the only source of the intra-hour uncertainty, the quantities of reserves may be easier to estimate by taking the 97.5th percentile of the variation distribution which represents two standard deviations of forecast error and the approximate PacifiCorp performance under Control Performance Standard II (CPS II)[3]). Reporting levels of reserves required with a 97.5% confidence interval adds an important reliability dimension to the calculation. While actual day-to-day balancing operations may require less reserves than suggested in this study, attention to tail events is an important consideration for overall system reliability. Additional considerations include the correlation

[3] The CPS II standard refers to the compliance bounds for the 10-minute average of the Area Control Error.

between forecast error and two additional sources of intra-hour uncertainty: “regulate down” and “regulate up”.

Regulate Down

For the purposes of this study, regulate down is the difference between the maximum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves up within an hour, other generation resources are required to reduce their output to compensate for this intra-hour energy deviation. The analysis of 10-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and the ten-minute period of maximum energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp’s CPS II standard.

Regulate Up

For the purposes of this study, regulate up is the difference between the minimum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves down within an hour, other resources on the system are required to increase output to compensate for this intra-hour energy deviation. The analysis of 10-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and minimum energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp’s CPS II standard.

These three intra-hour factors for different locations are not independent of each other and tend to exhibit some positive and negative correlations that are taken into account when measuring the standard deviation of the simultaneous and combined effect of these factors. Before estimating the total reserves requirement for intra-hour integration, correlations are estimated and applied to determine the total combined uncertainty on a regional level. Two standard deviations for the total probability distribution allowed for computation of reserves associated with all intra-hour factors in the Eastern and Western control areas.

System Balancing (“Inter-Hour”) Cost Calculation

The shape of a wind energy delivery pattern is different than the delivery patterns of other generation resources. The wind is intermittent and variable, so a wind pattern that is input as a forecast of expected generation differs considerably from the actual generation delivered. Alternatively, a dispatchable resource, like a CCCT, does maintain a flat schedule of energy delivery so generation units on the system do not have to redispatch and balancing activities do not have to occur to compensate for a block of flat energy. When a short-term wind forecast is created and compared to a longer-term wind energy expectation, balancing activities may have to occur to balance the deviation between the wind forecasts and realized output.

Day-ahead Variation

Because a day-ahead forecast of hourly wind energy always differs from the expected future energy level by some amount, the ideal of delivering a balanced energy profile on a day-ahead basis requires some adjustment in the energy position via transactional balancing. While deviation from a perfectly balanced schedule is normal, estimation of the impacts are assumed to be eliminated by balancing activities to the extent possible.

Fixing the imbalance in real-time is generally more expensive and, to this end, this study assumes that all forecast imbalances are addressed in the day-ahead market. This is limited by the size and availability of standard 25 MW blocks for standard 16-hour or 8-hour (on-peak and off-peak) delivery patterns. PacifiCorp incurs transaction costs every time it trades a block of 25 MW. These transaction costs may vary depending on the time of day and location and are currently estimated to be about $0.50 per MWh over market for purchases to cover a shortfall in forecast, and under market for sales to cover a forecast excess during most transactional hours. This internal assumption is generally accepted by balancing staff and is consistent with the assumption used in Portland General Electric's wind integration study. Given the hourly difference between the long-term expected wind generation and the historical wind generation forecasts at the day-ahead horizon, these costs may be estimated.

To calculate the transactional costs associated with balancing the hourly long-term expected wind generation to the hourly day-ahead wind schedule, the variation was calculated as the absolute value of the difference between the two forecasts. For October 2008 through April 2009, a sample week of hourly data from all existing wind plants on the system (for which data was available) was chosen for each month[4]. The distinction of costs between the Eastern and Western side of the system is reflective of different degrees of forecast accuracy. The existing data was scaled up to reflect the planned East and West additions to the system, 200 and 1,250 MW, respectively, for a total of 773 MW on the West and 1,784 MW on the East. The total deviation was found for each day for both heavy load and light load hours.

For example, on Day 1, the deviation for all heavy-load hours was added. The same was done for light-load hours. The resulting totals were rounded up to the nearest 25 MW increment to reflect actual transaction sizes available in the day-ahead market. The total daily variation was added up for each sample week and multiplied by an estimated bid-ask spread of $0.50 per MWh. PacifiCorp's front office provided this bid-ask spread estimate. The total transaction costs incurred for all sample weeks was divided by the total MWh of long-term expected generation for the same sample weeks and presented on a $/expected MWh basis provided in Table F.2. Transaction costs in the table below are lower in the Eastern control area and may be the result of more accurate forecasting, a more uniform wind pattern, and higher locational diversity.

Table F.2 – Wind Inter-hour Day-Ahead Balancing Transaction Costs

System	Wind Expected to Day-Ahead ($/Expected MWh)
West	$0.41
East	$0.23

[4] This period was chosen due to limited data availability.

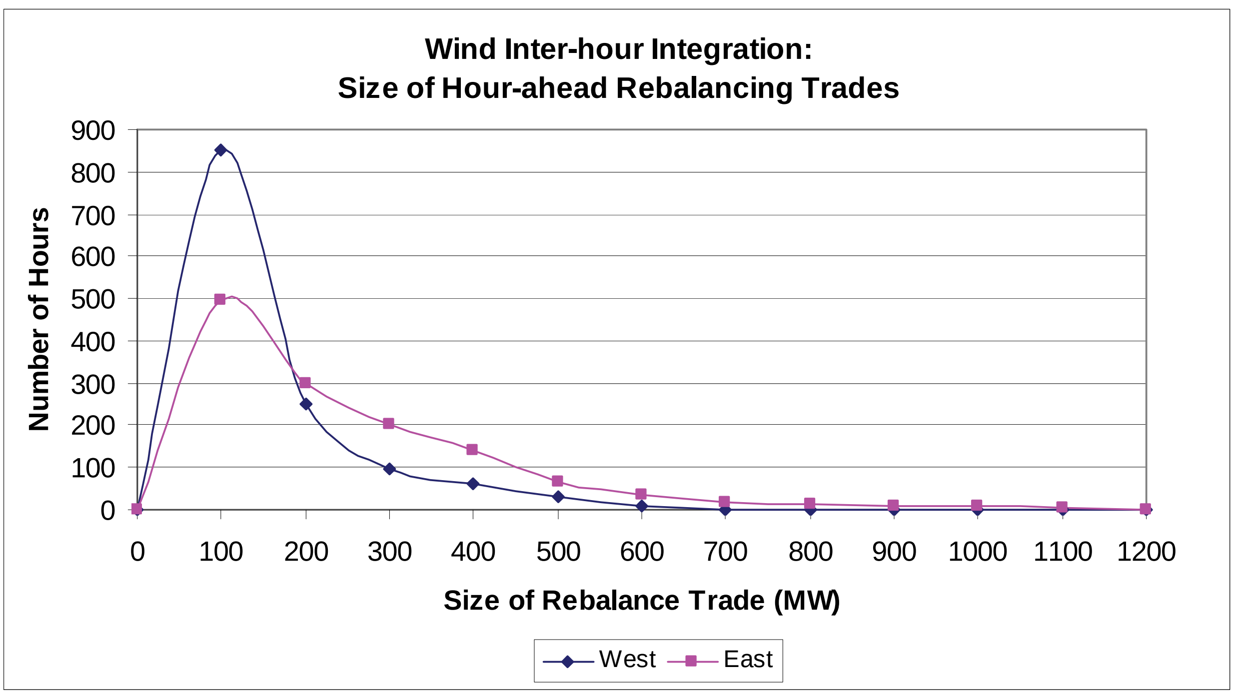
Hour-ahead variation

Similar to the day-ahead variation, the rebalancing of energy to close open positions due to the change in forecasted wind energy from the day-ahead schedule to the hour-ahead schedule also adds transaction costs. Hour-ahead transactions assume transactions in 1 MW increments, but transactions costs are up to twenty-five percent of the per-MWh energy costs. The precise percentage depends on then–current market conditions and the amount of energy traded.

In order to derive the hour-ahead forecast used by real-time for scheduling, a persistence methodology was used. When the real-time traders schedule wind for the upcoming hour, it is assumed that the actual wind generation level from the previous hour will persist for the next hour. In this study, the hour-ahead schedule was based on persistence. The existing October 2008 through April 2009 data was scaled up to reflect the planned East and West additions to the system, 200 and 1,250 MW, respectively, for a total of 773 MW on the West and 1,784 MW on the East. The total deviation was found for each day for both heavy load and light load hours.

The day-ahead to hour-ahead balancing transaction costs were calculated in largely the same fashion with the exception of the bid-ask spread used. Transactions undertaken to correct an imbalance, due to variations between the day-ahead and hour-ahead forecast, are of higher cost, which is dependent upon the quantity of power needed and market conditions. Figure F.1 shows the hourly frequency of various imbalance sizes based on 1,300 hourly deviations, which is constitutes the total number of sample hours.

Figure F.1 –Hour-Ahead Variation Frequency Distribution



It is also generally accepted in the hour-ahead market that, as the size of the transaction increases, the costs associated with transactions increases. Based on the frequency distribution above, a smaller cost is required for transactions of about 50 MW, which are transacted much more frequently. The distribution also indicates that, in general, transaction costs on the west portion of the system will be higher due to lower forecast accuracy. Specific transaction assumptions are listed in Table F.3.

Table F.3 – Inter-hour Hour-Ahead Balancing Transaction Cost Ranges

Trade Size (MW)		Transaction Cost (Bid-ask) Percentage by Region	
Lower Bound	Upper Bound	West	East
0	100	5%	5%
101	200	10%	10%
201	1,000	25%	15%

Table F.3 indicates that as more wind projects are added to the system, forecast improvements are necessary in order to prevent large variations which come with a higher market transaction cost. Consider, on an average basis, if a 100 MW wind project is added to the system, the shape of the distribution of the size of hourly errors will be about the same. As the distribution of error increases in a linear fashion, the cost associated with rebalancing does not. Since costs are greater as the size of transactions increases, the distribution of errors may increase on a linear basis, but costs will increase faster.

Once the hourly variance from the day-ahead forecast to the hour-ahead forecast has been calculated, the specific hourly variance is applied to the corresponding hourly real-time price from an independent energy information company that publishes hourly wholesale power indices. For PACE, Four Corners was used and for PACW, Mid-Columbia was used. The size of the variance determines the transaction cost, which is the product of the hourly price and the corresponding variance percentage. In Table F.4 below, the day-ahead to hour-ahead transaction cost is presented along with the total inter-hour cost for the east and west balancing authority areas.

Table F.4 – Wind Inter-hour Hour-Ahead Balancing Transaction Costs

System	Wind Expected to Day-Ahead ($/Expected MWh)	Wind Day-Ahead to Hour-Ahead ($/Expected MWh)[5]	Total Wind Inter-hour ($/Expected MWh)
West	$0.41	$2.80	$3.21
East	$0.23	$1.89	$2.12

<u>Determination of Incremental Reserve ("Intra-Hour") Requirements</u>

The indicated MW of additional reserves needed to balance the total intra-hour wind generation variations on PacifiCorp's system due to incremental wind addition is unique to each region of

[5] Values expressed are representative of the average cost to transact for the October 2008 through April 2009 period.

PacifiCorp's system. These values were derived by multiplying the within-hour standard deviation from all wind projects in each of the three regions in this study by a Z score of 1.96 (which is representative of the 97.5% confidence interval and PacifiCorp's CPS II requirement) and is inclusive of all three sources of inter-hour variation discussed. Table F.5 presents the corresponding reserve volumes for each region in the system and reflects fixed volumes of new annual wind projects spread through 2021 consistent with the company's general long-term wind acquisition strategy.

Table F.5 – Total Wind System Intra-hour Reserve Requirement (MW)

Resources	Capacity Additions	Total Reserve Requirement	Incremental Increase	Cumulative Increase
Existing and Planned through 2010	1,284	295.4		
2011	200	312.7	17.3	17.3
2012	100	331.2	18.5	35.8
2013	100	339.1	7.9	43.7
2014	100	349.1	9.9	53.6
2015	150	367.8	18.8	72.4
2016	100	380.5	12.6	85.0
2017	100	385.1	4.6	89.7
2018	50	402.0	16.9	106.6
2019	200	420.9	18.9	125.5
2020	200	433.2	12.3	137.7
2021	150	452.9	19.7	157.5

Incremental Reserve ("Intra-Hour") Cost Calculation

The previous section described the calculation of MW quantities associated with adding wind generation resources. In this section, the calculation of the cost associated with wind additions is described.

As the company installs larger volumes of wind resource generation, the company's cost to integrate these intermittent resources is anticipated to increase. This is because more and more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour-to-hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts often provide the needed flexibility. However, these hydro resources are not of adequate size to integrate all of the anticipated wind variability. Partially loaded gas turbines provide additional flexibility. Due to its low cost, it is economically preferable that coal is fully utilized to serve load rather than backed off to provide wind integration.

The study assumes that PacifiCorp would balance the intermittency of the wind by holding additional reserves on existing and future flexible resources. A reserve resource stack model was developed that is used to estimate both in-the-money and out-of-the-money reserve costs. The modeling of reserves added the requirements for load and reduced the requirement for hydro and contract reserves in the valuation. In-the-money reserve costs are measured by calculating market prices less the cost of thermal dispatch (fuel, variable O&M, CO_2 emission costs, and SO_2 emission costs). Out-of-the-money reserve costs are estimated by calculating the above-market operating costs of a unit dispatched at minimum capacity divided by the total amount of reserve capability available once at minimum load. The reserve requirement is then filled by the lowest cost in-the-money or out-of-the-money thermal resource considering the resource reserve capacities and unit ramp rates. PacifiCorp used market prices at Mona, Mid-Columbia, and Four Corners with the $45 CO_2 October 2008 price curve (2013 is the assumed start of CO_2 regulation).

The wind reserve results reported in Table F.6 are at the system level and include both existing and incremental wind projects. The reserve results are levelized on a real basis (with inflation effects removed) for the study period 2009 to 2030 by dividing the reserve cost by the wind expected megawatt-hour generation. The existing reserve available data ended in April 2014 so the data was escalated using the prior three-year average. The reserve study considered heavy load and light load hour for the analysis but was limited by the wind reserves calculated on an annual basis.

Table F.6 – Costs for Wind Intra-hour Incremental Reserves

Wind Existing and Incremental Approximately (MW)	System Wind Intra-hour Reserves
2,734	$9.40

To determine the cost impact of using a lower CO_2 cost, PacifiCorp estimated the intra-hour reserve cost assuming an $8 CO_2 tax. The wind reserve costs dropped to $7.51/MWh, expressed in $2009, representing a 20-percent decline relative the cost under the $45 CO_2 cost study. It is not necessarily true; however, that increasing the cost of CO_2 equates to a higher reserve cost. This relationship may be a function of near-term natural gas price curves.

Conclusion

The wind integration cost results are presented in Table F.7, and range from $9.96/MWh to $11.85/MWh for PacifiCorp's system in 2009 dollars, depending on the CO_2 tax level scenario. The inter-hour wind results were developed by weighting the PACW inter-hour wind costs by 30% (the PACW MW share of the system total) and the PACE wind costs by 70%, then adding the system wind reserves.

Table F.7 – Wind Integration Costs (2009 Dollars)

CO_2 Cost Scenario	System Balancing Cost (Inter-hour) Expected to Day-Ahead Cost ($/Expected MWh)	Day-Ahead to Hour-Ahead Cost ($/Expected MWh)	Total Cost ($/Expected MWh)	Intra-hour Cost ($/Expected MWh)	Total ($/Expected MWh)
$8 tax	$0.28	$2.17	$2.45	$7.51	$9.96
$45 tax	$0.28	$2.17	$2.45	$9.40	$11.85

The system wind integration costs are in line with the $11.75/MWh proxy value used for 2008 IRP portfolio modeling. Consequently, PacifiCorp did not conduct a wind resource sensitivity study using PacifiCorp's updated values.

TOOLS, APPROACHES, AND EXTERNAL OPPORTUNITIES

There are a number of wind integration tools, approaches, and potential external coordination opportunities that the Company has implemented or is actively investigating. These include the following.

- **Real-Time Balancing:** PacifiCorp has significantly advanced its forecasting process. At present, forecasts in advance of real-time scheduling are done at 40 to 45-minutes prior to the delivery hour and on a persistence forecast[6]. Operational experience has shown that persistence based scheduling in real-time significantly reduces forecast error from using model-based techniques in advance of 40 to 45-minutes prior to the delivery hour.

- **Day-to-Day Balancing** - PacifiCorp has retained an external firm to prepare forecasts every six hours for the primary purpose of day-to-day balancing activities. Finding tools to enhance/improve the day-to-day forecast is likely to lead to enhanced real-time forecasting and, therefore, reduced load following reserve requirements during most hours. Specific tools that will require ongoing investigation and/or capital allocation may include: enhanced wind project status feedback (to the external forecasting contractor); on-site radar devices; and/or contracting with third parties who can provide regional real-time wind data or pooling information with other control area operators to obtain consolidated forecasts.

- **Peer Review –** PacifiCorp will consider incorporating the concept of the peer group review for evaluation of its ongoing refinement of wind integration cost estimation methods as part of the IRP public participation process. At present, the industry is suffering from the lack of standardized wind integration study methods. As a result, it is necessary to examine each such study to unravel its assumptions and methodology to be able to understand how it compares to other studies.

[6] Persistence based scheduling is the practice of scheduling production for the next hour based on then-current production.

- **Curtailment Tools** – A number of tools exist for either curtailing wind project output during those hours where a critical need exists or limiting the impact of wind resources on the system during unusual ramping events. Such tools may include:

  – **Ramp Rate Limiters:** PacifiCorp's General Electric wind turbines in Wyoming include a ramp rate limiter option. This option enables PacifiCorp operators to set a maximum rate by which a wind project's output will change over time (MW/minute) during periods when the wind is ramping up

  – **Curtailment -** PacifiCorp's General Electric wind turbines in Wyoming include a curtailment option. This option enables PacifiCorp operators to curtail or limit the output of wind projects on short notice.

  – **Power Purchase Agreements (PPA) -** Many of PacifiCorp's PPAs include provisions enabling the Company to curtail output for certain reliability events or for other reasons. New PPAs all have such provisions. For example, PPAs entered into via the RFP process all contain such curtailment provisions. Additionally, the company will continuously review and refine PPA contractual requirements for output forecasting, outage reporting and curtailment.

  – **Large Generator Interconnection Agreements** (LGIA) **–** Federal Energy Regulatory Commission LGIAs all contain provisions[7] enabling the transmission provider to curtail or disconnect generation if necessary for reliability reasons.

  – **Mid-Hour Scheduling Practices** – At present, the practice of the **WECC** only compels mid-hour schedule changes when there is an "emergency" on the sink balancing authority area. PacifiCorp currently has other third Party wind generators who schedule wind generation for export out of PACW and PACE. There is no established practice compelling mid-hour schedule changes when the source balancing authority area is having an "emergency" which results in other than comparable service for point-to-point transmission customers as compared to network transmission customers. An evolution of mid-hour scheduling practices at WECC for emergencies involving wind generation could lead to a reduction in load following reserves being held. As the level of wind resources being scheduled for export out of a balancing authority area increases, the need for mid-hour schedule changes can be expected to significantly increase.

  - **Transmission Tariffs –** A variety of new tariffs and/or tariff adjustments can be expected to evolve over time:

    – **Integration Tariff:** At present, PacifiCorp does not have an integration tariff. An integration tariff may be appropriate when a transmission provider must integrate wind projects on an hourly basis that are scheduled off-system. As the demand for renewable resources continues to grow in the WECC, PacifiCorp may see a growing preponderance of interconnected wind projects being scheduled for export out of the

[7] Appendix G to the LGIA

balancing authority area. This is the main reason that BPA created an integration tariff. Integration tariffs attempt to appropriately capture the cost of intra-hour integration costs. An integration tariff also sends an appropriate price signal to generator owners regarding the value of good forecasting.

- **Imbalance Tariff:** PacifiCorp's imbalance tariff should be reviewed to determine if it provides an appropriate price signal to generation owners for good forecasting practices. It may be through the combination of an integration tariff and an imbalance tariff with increasing penalties that wind generation owners will have the incentive to deploy effective forecasting tools.

- **LGIA:** It may be necessary to evolve FERC standard LGIA language to capture the forecasting diligence and curtailment flexibility required of wind resources by transmission operators who also operate as the balancing authority.

- **Incentives**: If a transmission operator is also a regulated utility with load service obligation and is subject to RPS, it may be necessary for FERC to consider incentives for the entity who is the recipient of intermittent renewable resources (such as wind) to also be the entity responsible for providing the load-following reserves. Since RPS requirements are load-based, a fair application may be to require the load (i.e., sink control area) receiving the intermittent resource to either provide the load-following reserves necessary or telemeter the resource into its own balancing authority area.

• **Wind-only Balancing Authorities –** Some entities in the Pacific Northwest appear willing to pursue formation of a wind-only balancing authority. Here, an entity would contribute their wind resource into the balancing authority, schedule out of the balancing authority, and be responsible for their pro-rata share of intra-hour integration costs. Any entity in the market would be eligible to bid in load-following services to perform the balancing. This effort is only at the conceptual stage.

• **Reserve Sharing:** The creation of bilateral arrangements in addition to that found in the NWWP.

• **Balancing Market**: The creation of a 10-minute balancing market would provide accurate and appropriate price signals to owners of wind generation and would most likely be incorporated into integration tariffs in lieu of capacity costs.

• **ACE Pooling:** ACE pooling is yet another way to spread or socialize volatility associated with wind resources across multiple balancing authority areas.

• **Independent System Operator (ISO):** A reassessment of combining multiple balancing authorities.

• **Flexible Resources**: Creating more accurate forecasts, curtailing wind resources when necessary, and deploying one or more of the tools discussed above, can be expected to help optimize and minimize the amount of load-following reserves that a control area must carry to integrate wind resources. Ultimately, this will not be enough, leading to the need for significant transmission investments and/or an ISO. It is reasonable to expect that flexible resources will be required to manage the significant influx of wind resources that is likely to result from a Federal RPS, or to respond to increasing RPS standards in states like California. A significant policy issue centers on the payment for these flexible resources when they are required to maintain control area reliability. A time honored alternative is to apply the costs on a causation basis or socialize them in some fashion as deemed by the Federal Energy Regulatory Commission.

WIND CAPACITY PLANNING CONTRIBUTION

For the 2008 IRP, PacifiCorp used the Z statistic method[8] for estimating peak load capacity contributions on a monthly basis for incremental 100 MW blocks of wind capacity at each site reflected in the IRP models. This method is based on estimating the effective load carrying capability of wind. No changes to the methodology took place for the capacity contribution update; wind output data was updated based on new information obtained for resources added to PacifiCorp's system.

The results of the updated analysis as applied to the proxy (100-megawatt) wind resource options are shown in Table F.8. The July peak load carrying capability (PLCC) values are highlighted, since these are used by the capacity expansion model for determining how capacity reliability constraints are met.

Key observations from these results include the following:

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

[8] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

Table F.8 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource by Capacity Factor	Resource Size (Nameplate MW)	Jan	Feb	Mar	Apr	May	Jun	July PLCC	Aug	Sep	Oct	Nov	Dec
West Main, 35%	100	0.7	6.9	3.5	4.2	2.6	3.2	1.8	2.0	1.9	3.4	3.1	26.5
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	20.4
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.4
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4
West Main, 29%	100	0.0	2.9	0.0	1.0	0.0	0.0	0.2	0.0	0.0	0.9	1.1	16.4
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.8
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Main, 24%	100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyoming, 35%	100	4.2	30.5	14.4	0.0	1.3	2.9	5.2	8.1	3.5	0.8	13.2	10.3
	200	0.1	26.6	10.0	0.0	0.0	0.3	3.7	6.1	0.3	0.0	8.0	6.0
	300	0.0	22.8	5.7	0.0	0.0	0.0	2.3	4.2	0.0	0.0	2.9	1.7
	400	0.0	18.9	1.3	0.0	0.0	0.0	0.9	2.3	0.0	0.0	0.0	0.0
	500	0.0	15.1	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0
Wyoming, 29%	100	0.3	24.0	9.3	0.0	0.0	0.0	3.1	5.0	0.0	0.0	8.3	5.6
	200	0.0	20.4	5.3	0.0	0.0	0.0	2.3	3.7	0.0	0.0	3.6	1.9
	300	0.0	16.7	1.4	0.0	0.0	0.0	1.5	2.4	0.0	0.0	0.0	0.0
	400	0.0	13.0	0.0	0.0	0.0	0.0	0.6	1.1	0.0	0.0	0.0	0.0
	500	0.0	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyoming, 24%	100	0.0	17.9	4.2	0.0	0.0	0.0	0.8	1.3	0.0	0.0	3.1	1.0
	200	0.0	14.1	0.5	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0
	300	0.0	10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	400	0.0	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Yakima, 29%	100	2.8	3.0	4.8	8.0	4.6	6.7	4.7	6.3	8.7	10.2	1.8	27.9
	200	0.0	0.0	0.9	4.2	1.7	6.0	4.4	2.7	5.0	4.1	0.0	21.2
	300	0.0	0.0	0.0	0.4	0.0	5.2	4.0	0.0	1.4	0.0	0.0	14.6
	400	0.0	0.0	0.0	0.0	0.0	4.4	3.6	0.0	0.0	0.0	0.0	7.9
	500	0.0	0.0	0.0	0.0	0.0	3.6	3.2	0.0	0.0	0.0	0.0	1.2
Yakima, 24%	100	2.3	2.2	3.1	6.0	3.1	4.5	3.0	4.5	5.5	7.4	0.6	22.9
	200	0.0	0.0	0.2	3.3	0.9	4.1	2.8	2.2	2.7	2.2	0.0	16.3
	300	0.0	0.0	0.0	0.6	0.0	3.8	2.7	0.0	0.0	0.0	0.0	9.8
	400	0.0	0.0	0.0	0.0	0.0	3.4	2.5	0.0	0.0	0.0	0.0	3.3
	500	0.0	0.0	0.0	0.0	0.0	3.0	2.3	0.0	0.0	0.0	0.0	0.0

Regional Resource by Capacity Factor	Resource Size (Nameplate MW)	Jan	Feb	Mar	Apr	May	Jun	July PLCC	Aug	Sep	Oct	Nov	Dec
Goshen, 29%	100	12.9	31.0	28.0	23.6	24.4	23.8	16.1	30.0	27.8	17.0	27.9	24.4
	200	8.4	25.4	20.6	18.7	19.7	18.0	13.5	25.2	23.1	12.7	21.5	18.4
	300	3.9	19.8	13.2	13.8	15.0	12.2	10.8	20.4	18.4	8.4	15.1	12.4
	400	0.0	14.2	5.8	9.0	10.3	6.5	8.2	15.7	13.8	4.2	8.7	6.4
	500	0.0	8.6	0.0	4.1	5.7	0.7	5.5	10.9	9.1	0.0	2.4	0.4
Goshen, 24%	100	10.6	25.3	23.9	18.7	20.0	20.1	12.4	24.8	22.2	13.1	23.0	20.7
	200	7.0	20.2	17.1	14.7	15.9	15.1	10.7	20.7	18.2	9.3	17.1	15.5
	300	3.4	15.0	10.2	10.6	11.9	10.1	9.0	16.6	14.3	5.5	11.2	10.4
	400	0.0	9.9	3.4	6.5	7.8	5.1	7.2	12.5	10.3	1.8	5.3	5.2
	500	0.0	4.8	0.0	2.4	3.8	0.2	5.5	8.4	6.4	0.0	0.0	0.1
Utah, 29%	100	13.6	11.1	33.1	40.8	51.0	42.4	37.6	38.2	36.2	28.4	22.0	21.2
	200	10.3	9.1	28.0	35.2	45.7	38.5	34.1	34.0	31.5	23.6	18.4	17.1
	300	7.0	7.0	22.8	29.5	40.3	34.6	30.7	29.9	26.9	18.8	14.8	13.1
	400	3.6	5.0	17.6	23.9	35.0	30.7	27.2	25.8	22.3	14.0	11.2	9.0
	500	0.3	2.9	12.5	18.3	29.7	26.8	23.8	21.7	17.6	9.2	7.6	5.0
Utah, 24%	100	11.7	7.8	24.8	35.5	41.7	32.8	27.3	30.0	27.0	24.6	16.9	17.4
	200	8.5	6.3	20.4	29.9	36.7	28.9	24.2	26.1	22.4	19.9	13.8	13.8
	300	5.3	4.8	16.0	24.2	31.6	25.1	21.0	22.2	17.9	15.3	10.7	10.2
	400	2.0	3.3	11.5	18.6	26.5	21.2	17.9	18.3	13.3	10.6	7.7	6.6
	500	0.0	1.8	7.1	13.0	21.4	17.4	14.7	14.4	8.8	6.0	4.6	3.1
Walla Walla, 35%	100	3.2	3.4	7.2	11.0	6.3	9.6	7.2	8.5	13.2	13.0	3.6	33.3
	200	0.0	0.0	1.9	5.6	2.3	8.1	6.3	3.3	8.2	5.5	0.0	26.3
	300	0.0	0.0	0.0	0.3	0.0	6.6	5.5	0.0	3.3	0.0	0.0	19.2
	400	0.0	0.0	0.0	0.0	0.0	5.1	4.6	0.0	0.0	0.0	0.0	12.2
	500	0.0	0.0	0.0	0.0	0.0	3.6	3.7	0.0	0.0	0.0	0.0	5.2
Walla Walla, 29%	100	2.7	2.4	5.6	8.8	4.6	7.0	5.2	6.7	9.8	10.0	2.7	27.1
	200	0.0	0.0	1.7	5.4	1.9	6.2	4.8	3.3	6.1	3.8	0.0	20.4
	300	0.0	0.0	0.0	1.9	0.0	5.4	4.3	0.0	2.4	0.0	0.0	13.8
	400	0.0	0.0	0.0	0.0	0.0	4.6	3.8	0.0	0.0	0.0	0.0	7.1
	500	0.0	0.0	0.0	0.0	0.0	3.9	3.4	0.0	0.0	0.0	0.0	0.4
Walla Walla, 24%	100	2.1	1.5	3.4	6.4	3.0	4.6	3.3	4.9	6.2	7.3	1.3	21.9
	200	0.0	0.0	0.5	4.1	1.1	4.2	3.1	2.6	3.4	2.0	0.0	15.4
	300	0.0	0.0	0.0	1.8	0.0	3.9	2.9	0.3	0.5	0.0	0.0	8.9
	400	0.0	0.0	0.0	0.0	0.0	3.5	2.7	0.0	0.0	0.0	0.0	2.5
	500	0.0	0.0	0.0	0.0	0.0	3.2	2.5	0.0	0.0	0.0	0.0	0.0

*The generation data used to determine the PLCC for the generic Utah wind resource was derived from a single bid from the 2003 Renewables RFP. When compared to generation from qualifying facilities within the general region, the estimates appear reasonable.