PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 26, 2010

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: Advice Filing 10-002, Docket UE 216
PacifiCorp's 2011 Transition Adjustment Mechanism
Schedule 201, Cost-Based Supply Service

PacifiCorp (dba Pacific Power) submits for filing an original and five copies of Net Power Costs, Cost-Based Supply Service Schedule 201 - PacifiCorp's 2011 Transition Adjustment Mechanism ("TAM"). The Company is requesting an effective date of January 1, 2011 for these tariff sheets.

PacifiCorp waives paper service in this docket and requests that communications on this filing be addressed to the parties identified in subsection (C) herein.

A. Description of Filing

The purpose of the TAM filing is to update net power costs for 2011 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The TAM Guidelines adopted by Commission Order No. 09-274, specify that in a year in which the Company files a general rate case, the Company will filed both the TAM and the rate case no later than March 1, in order to allow a January 1 effective date. The Company is filing a general rate case on March 1, 2010, accordingly, the Company is filing the 2011 TAM by March 1, 2010.

This tariff filing is supported by testimony and exhibits from Company witnesses addressing overall net power costs and pricing. The testimony and exhibits contained in this filing address the OAR Division 22 requirements for filing tariffs or schedules that change rates.

B. Tariff Sheets

First Revision of Sheet No. 201-1	Schedule 201 Net Power Costs
First Revision of Sheet No. 201-2	Schedule 201 Net Power Costs
First Revision of Sheet No. 201-3	Schedule 201 Net Power Costs

C. Correspondence

It is respectfully requested that all communications related to this filing be addressed to:

PacifiCorp Oregon Dockets
825 NE Multnomah Street, Ste. 2000
Portland, OR 97232
oregondockets@pacificorp.com

Katherine A. McDowell
McDowell & Rackner PC
520 SW 6th Ave, Ste 830
Portland, OR 97204
Katherine@mcd-law.com

Jordan A. White
Legal Counsel
1407 W North Temple, Ste 320
Salt Lake City, Utah 84116
Jordan.white@pacificorp.com

Joelle Steward
Regulatory Manager
825 NE Multnomah Street, Ste 1800
Portland, OR 97232
joelle.steward@pacificorp.com

Additionally, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

A copy of this filing has been served on all parties to PacifiCorp's last TAM proceeding, UE 207, as indicated on the attached certificate of service.

Very truly yours,

Andrea L. Kelly

Andrea L. Kelly
Vice President, Regulation
Enclosures

cc: UE 207 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 26th of February, 2010, I caused to be served, via E-Mail and overnight delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

SERVICE LIST
UE-207

G. Catriona McCracken (C) (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
catriona@oregoncub.org

Gordon Feighner (C) (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
gordon@oregoncub.org

Robert Jenks (C)(W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
bob@oregoncub.org

Irion A. Sanger (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
ias@dvclaw.com

Randall J. Falkenberg (C)
PMB 362
8343 Roswell Road
Sandy Springs, GA 30350
consultrfi@aol.com

Jason W. Jones (C)
Department of Justice
Regulated Utility & Business Section
1162 Court St, NE
Salem, OR 97301-4096
Jason.w.jones@state.or.us

Kevin Higgins (C) (W)
Energy Strategies LLC
215 State Street, Suite 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

Katherine A. McDowell (C) (W)
McDowell & Rackner PC
520 SW Sixth Ave, Suite 830
Portland, OR 97204
Katherine@mcd-law.com

Joelle Steward (C) (W)
Pacific Power & Light
825 NE Multnomah, Ste 2000
Portland, OR 97232
Joelle.steward@pacificorp.com

Jordan A. White (W)
Pacific Power & Light
825 NE Multnomah, Ste 1800
Portland, OR 97232
Jordan.white@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Kelcey Brown (C)
Oregon Public Utility Commission
P.O. Box 2148
Salem, OR 97301
Kelcey.brown@state.or.us

Peter J. Richardson (C) (W)
Richardson & O'leary
PO Box 7218
Boise, ID 83707
peter@richardsonandoleary.com

Greg Bass (W)
Sempra Energy Solutions LLC
101 Ash Street HQ09
San Diego, CA 92101
gbass@semprasolutions.com

Amie Jamieson (W)
McDowell & Rackner PC
520 SW Sixth Ave, Suite 830
Portland, OR 97204
amie@mcd-law.com

Ariel Son
Coordinator, Administrative Services

Docket No. UE-216
Exhibit PPL(TAM)/100
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

February 2010

Q. Please state your name, business address and present position with PacifiCorp ("Company").

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). Currently, I direct the work of the integrated resource planning group, the load forecasting group, the net power cost group, and the renewable compliance area.

Purpose and Overview of Testimony

Q. Please explain the purpose of your testimony?

A. I present the Company's proposed 2011 Transition Adjustment Mechanism ("TAM") net power costs ("NPC"). Specifically, my testimony:

- Summarizes the content of the filing.
- Describes the major cost drivers in the 2011 TAM.

- Describes the changes in inputs that the Company has made to enhance NPC modeling, streamline the process and minimize controversy.
- Presents the Company's updated wind integration charges and explains that the Company proposes to update the wind integration charges in this proceeding based on the outcome of the August 2, 2010 wind integration study agreed to in the acknowledgement proceeding for the Company's 2008 Integrated Resource Plan, Docket LC 47.
- Describes how the filing is consistent with the TAM Guidelines.
- Introduces the other witnesses providing testimony in support of PacifiCorp's 2011 TAM.

Summary of PacifiCorp's 2011 TAM Filing

Q. Please provide background on the Company's 2011 TAM filing.

A. The TAM is PacifiCorp's annual filing to update its net variable power costs in rates. The updated power costs are used to set the transition adjustment for direct access and, in this case, become effective in rates on January 1, 2011. This is the Company's sixth TAM filing. The Company is filing the 2011 TAM concurrently with a request for a general rate increase.

Q. What are the forecasted normalized system-wide NPC for calendar year 2011?

A. The Company's total forecasted normalized system-wide NPC for the test period of 12-months ending December 31, 2011 are approximately $1.28 billion or $22.03/MWh.

Q. What is the estimated increase in Oregon-allocated NPC for calendar year 2011?

A. As shown in Exhibit PPL(TAM)/101, on an Oregon-allocated basis, the Company's forecasted normalized NPC for calendar year 2011 are approximately $56.6 million higher than the NPC currently in Oregon rates. The NPC currently in rates are the result of a settlement in the Company's 2010 TAM, Docket UE 207 ("UE 207").

Q. Do the proposed rates in the filing reflect the changes in load since UE 207?

A. Yes. Company witness Ms. Judith M. Ridenour explains the new tariff design for net power costs, adopted in the Company's 2009 general rate case, Docket UE 210. This new tariff, Schedule 201, reflects changes in load since the prior TAM. The load forecast in this filing reflects a decrease in Oregon loads when compared to the 2010 projected loads from UE 207. To capture this reduction in Oregon loads, rates have been designed to collect an additional $12.5 million of revenue. The combination of the $56.6 million in increased NPC and the $12.5 million of decreased revenues results in a total proposed revenue increase of $69.2 million. As explained in Ms. Ridenour's testimony, this is an overall average increase of approximately 7.0 percent. As described in the testimony of Company witness Mr. R. Bryce Dalley in the Company's general rate case filed on March 1, 2010, the drop in Oregon loads has also resulted in a reduction to Oregon's allocation factors used to allocate system NPC and is reflected in this filing.

Determination of NPC and Model Inputs and Outputs

Q. Please explain NPC.

A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for a future test period based on projected data using the Generation and Regulation Initiative Decision model ("GRID"). GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

Q. Is the Company's general approach to the calculation of NPC using the GRID model the same in this case as in previous cases?

A. Yes. The Company has used the GRID model to determine NPC in its Oregon filings for several years.

Q. Is the Company using the same version of the GRID model as used in UE 207?

A. Yes.

Q. What inputs were updated for this filing?

A. The system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, characteristics of the Company's generation facilities, planned outages and forced outages of the Company's generation resources are updated for this filing.

Q. Was the transmission topology also updated for this filing?

A. Yes. I discuss these changes in detail later in my testimony.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is attached to my testimony as Exhibit PPL(TAM)/102. Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy-load hours and light-load hours.

Q. Has the Company changed its modeling of normalized hydro generation?

A. No. As in previous TAM filings, the normalized hydro generation is produced by the Vista model. The Company continues to use the single-year median hydro generation as the input to the GRID model.

Q. Are the inputs to Vista prepared in the same way as in UE 207?

A. Yes, with the exception discussed below related to the exclusion of forced outages. The historical information used as the basis of the normalized generation continues to include all available years, except for the Bear River system. The Bear River system data excludes flood control years. The Company is, however, currently in the process of reviewing patterns of weather and streamflow changes for hydro generation in the context of changes in climate, both globally and in the region. Based on this review, the Company may propose changes to its modeling of normalized hydro generation in future proceedings.

Overview of the 2011 TAM

Q. Please generally describe the drivers of the Company's 2011 NPC in this filing.

A. As discussed above, the Company's 2011 NPC reflect an increase of $56.6 million compared to the 2010 NPC in rates. This increase is driven by a range of factors, including changes in the Company's portfolio of wholesale purchase and sales contracts, expiration of the long-term gas supply contracts for the Hermiston gas-fired generating plant, increases in third-party coal contract costs (mitigated by decreases in captive coal costs) and inclusion of the cost of integrating increasing amounts of wind resources into the Company's integrated six-state system. The offsetting factors that drive NPC downward in 2011 include decreases in the load forecast and the addition of new transmission and generation resources. Each of these factors is described below.

Q. Can you compare the results of the first five TAM proceedings to actual NPC?

A. Yes. To remove the impacts of load fluctuations, the Company has prepared the comparison on a $/MWh basis. As shown in Table 1, the NPC in rates have been lower than actual NPC in all years, except 2006, since the Company has filed the TAM.

Table 1

PacifiCorp
NPC In Rates vs. Actual ($/MWh)

	2006 UE 170	2007 UE 179	2008 UE 191	2009 UE 199	2010 UE 207	2011 Current
Initial Filing	14.52	15.32	17.29	18.72	18.76	22.03
Final November Update	14.21	15.53	17.01	18.82	18.62	
In Rates	14.21	14.87	16.88	17.31	17.54	
Actual NPC	13.88	16.70	18.92	17.85		
Difference from Final Update	(0.33)	1.17	1.92	(0.97)		
Difference from In Rates	(0.33)	1.83	2.05	0.55		

Q. Are the actual NPC adjusted to be comparable to the normalized NPC?

A. No. However, the only significant regulatory adjustments to the actual NPC are the revenue imputation to the Company's sales contract with the Sacramento Municipal Utility District ("SMUD") and the removal of the Rolling Hills wind project, which will have a combined net impact of increasing the actual NPC.

Q. To what do you attribute the Company's under recovery in NPC?

A. NPC are volatile and inherently difficult to forecast. Actual operation lacks the same certainty and perfect foresight as the optimization model in regards to the variables and constraints, such as hourly load and market prices, availability of generation and transmission facilities, and weather conditions that impact the amount of hydro and wind generation. As a result, the actual NPC may not necessarily achieve what the optimization model projects. That said, given the inputs at the time of the NPC study, GRID reasonably simulates the operation of the Company's system consistent with the optimization logic that is built into GRID. However, when the GRID forecast is discounted by numerous mathematical modeling adjustments in a settlement or litigated order, the GRID result is distorted and generally increases the magnitude of the Company's NPC under recovery. It also results in an understated NPC baseline for the next year, which increases the size of the rate change the Company needs to seek to actually recover its NPC.

Major Cost Drivers in the 2011 TAM

Q. On a net basis, does the expiration and addition of power purchase and sale contracts contribute to the NPC increase in this case?

A. Yes.

Q. What are the major changes to power contracts in the calendar year 2011 test period?

A. The contracts that have expired or will expire, change or are new in the test period include:

- On June 30, 2011, the exchange contract between the Company and the Alcoa Power Generating Inc. ("APGI") for approximately 100 megawatts of capacity from the Rocky Reach project expires. Under this contract, the Company receives energy during peak periods and returns energy during off-peak periods.
- On October 31, 2011, the contract between the Company and the Chelan Public Utility District ("Chelan PUD") for generation from the Rocky Reach project expires. Power purchased by the Company under this contract is priced at the embedded cost of the project.
- On August 31, 2011, the contract between the Company and the Bonneville Power Administration ("BPA") for 575 megawatts of capacity expires. Under this contract, the Company receives energy during peak periods and returns energy during off-peak periods. In addition, power received under this contract is delivered directly to a variety of the

Company's load pockets in the western control area at the Company's discretion.

- On September 30, 2011, the contract between the Company and the Grant Public Utility District ("Grant PUD") for displacement generation expires, which is priced at BPA's Priority Firm Power ("PF") rate.
- On December 31, 2010, the purchase contract between the Company and the Top of the World Wind Energy, LLC will take effect. This contract and the procurement process are described in the direct testimony of Company witness Mr. Stefan A. Bird.
- On January 1, 2011, the amount of sales to the Public Service Company of Colorado ("PSCol") reduces per the contract terms, which is a legacy sales contract at relatively high contract prices.

Q. Has the Company included in the 2011 TAM certain contracts that expire in the test period?

A. Yes. The contract between the Company and Kennecott for generation incentive payments and the contract between the Company and Monsanto for operating reserve purchases both expire at the end of 2010. However, due to the nature of these contracts, it is likely that parties will enter into new contracts for periods after the end of the current contracts. In the 2011 TAM, the current terms of these contracts are assumed to continue. The Company will engage in negotiations with both Kennecott and Monsanto this year, and reflect the results of the negotiation in its subsequent updates to the TAM.

Q. Have the Company's coal costs impacted the NPC in the current proceeding?

A. Yes. NPC are higher due to increases in the costs of third-party coal supply and transportation agreements, even though these increases are partially offset by decreases in the Company's captive coal costs. Details on coal costs are provided in the direct testimony of Company witness Ms. Cindy A. Crane.

Q. How does the expiration of the long-term contracts to supply natural gas for the Hermiston plant impact NPC?

A. The expiration of the long-term natural gas contracts for Hermiston increases NPC. The long-term contracts supplying natural gas for the Hermiston plant were entered into in 1996, when the prices for natural gas were low. Even with escalation, the contract prices are still lower than the current market prices.

Q. Has the Company changed its topology modeled in GRID?

A. Yes. To assure the reliability of the transmission network in the area governed by the Western Electricity Coordinating Council ("WECC"), the constraint in the cut plane named Tot 4A in Wyoming has been redefined by PacifiCorp Transmission and approved by WECC. As a result, the previously modeled transmission areas of "Wyoming NE" and "Wyoming SW" in GRID have been redefined. In addition, because of constraints that are present in the previous "Wyoming SW" transmission area, a "Trona" transmission area has been added to the topology to reflect such constraints.

Q. Does the Company model the impact of the Populus to Terminal transmission addition, which is included in the Oregon general rate case filed concurrently with the 2011 TAM?

A. Yes. The addition of the Populus to Terminal line increases the transmission capacity across Path C from southeast Idaho to northern Utah by approximately 780 megawatts. The additional transmission capacity makes it possible to better utilize the market price differentials between the east and west sides of the Company's system, reduces reliance on additional purchases of transmission from third parties, and improves reliability. For further details, please refer to the testimony of Company witnesses Mr. John A. Cupparo and Mr. Darrell T. Gerrard, in the Company's general rate case filed March 1, 2010.

Q. How does the retail load forecast impact the Company's NPC?

A. This filing reflects a decrease of approximately 1 percent in the total company load forecast compared to loads reflected in UE 207. All else held constant, decreased load reduces NPC. For further details, please refer to my testimony in the Company's general rate case filed March 1, 2010.

Q. Are the increases in NPC partially offset by higher hydro generation at the Company owned facilities compared to what was included UE 207?

A. Yes. The hydro generation from the Company's owned resources is approximately 100,000 megawatt-hours higher compared to what was included in UE 207. All else held constant, increases in hydro generation reduce NPC. This increase is mainly the result of the exclusion of forced outages and inclusion of a full year of operation of the Condit dam as described later in my testimony.

Q. Are NPC increases also partially offset by the inclusion of additional resources during calendar year 2011?

A. Yes. The generation from the 111-megawatt Dunlap I and 28.5-megawatt McFadden Ridge I wind resources located in Wyoming is included in the 2011 TAM. For further details on these resources, please refer to the testimony of Company witnesses Mr. Bird and Mr. Mark R. Tallman in the Company's general rate case filed March 1, 2010.

Q. Has the Company updated its wind integration charges?

A. Yes. There are two categories of wind integration charges, one for wind resources located in the Company's control area, and one for the Company's wind resources located in BPA's control area. For the former, the Company updated the value from the Company's 2008 Integrated Resource Plan ("IRP") to reflect the 2011 test period and the December 31, 2009 forward price curves. This resulted in a wind integration charge of $6.97 per megawatt-hour. For the latter, the charge has been updated to $1.29 per kW-month based on the result of BPA's 2010-2011 transmission rate case.

Q. Why are the Company's wind integration charges increasing?

A. The Company completed a comprehensive study of its wind integration costs as part of the 2008 IRP, which have increased as more wind resources have been added to the system. My testimony addresses this issue in more detail below.

2011 TAM Changes in Inputs to NPC

Q. Has the Company made changes to NPC inputs in order to streamline the process, minimize controversy or better reflect system operations?

A. Yes. In addition to incorporating changes to inputs that have been previously ordered by the Commission or included in Commission-approved stipulations, the Company has modified some inputs in response to adjustments raised by parties in previous proceedings in order to enhance NPC modeling, minimize controversy and streamline the process for the 2011 TAM. Additionally, the Company has reflected the provisions included in the partial stipulation filed in Docket UM 1355, for which Commission approval is pending. These changes are:

- Short-term Firm Trading Margin – In Docket UE 191, the Commission ordered the Company to approximate the margin that it generated from arbitrage trading activities based on a four-year historical record. The Company has again incorporated this adjustment, despite continued concerns about incorporating selective and one-sided adjustments based upon actual results into normalized NPC. The value of the short-term firm trading margin is calculated as the average margin of the four-year period ended June 30, 2009.
- Condit Dam Decommissioning – The Condit dam is currently targeted to be decommissioned as soon as October 2010. Due to the uncertainty around obtaining various licenses in time to proceed in October 2010, as in UE 207, the Company has assumed that the dam will be in operation through the end of the 2011 test period. However, the Company reserves the right to apply for a

deferral of the increase to NPC that would result if the Company successfully obtains all the necessary permits and begins decommissioning the facility before the end of 2011. In lieu of a deferral application, if more definitive information in known at the time of the rebuttal update, then the Company will revise NPC accordingly.

- Biomass Non-Generation Agreement – Adjustments have been proposed by the Industrial Customers of Northwest Utilities ("ICNU") in the last two TAM cases to include the non-generation agreement with the Biomass qualifying facility. The Company continues to believe that in normalized NPC, only the known contracts should be included. While the Company and Biomass have signed the non-generation agreements in past years, there is no certainty that the agreement will be signed on an on-going basis, especially given the uncertain economic condition in the housing market and the wood products industry. However, to limit controversy in this proceeding, the contract is included in the proposed NPC based on the average payments under previous agreements
- Daily Screens – In UE 207, ICNU proposed that the Company model the screen for uneconomic dispatch of gas-fired units on a daily basis. The Company continues to believe that daily screening of its gas-fired units is inconsistent with the decisions that have been modeled in GRID, which do not change on a daily basis. However, to minimize controversy in the case, the Company has revised its monthly screens to daily screens. Additionally, there

is one call option contract in the current test period, which was screened from being exercised.

- Market Caps – To improve the alignment of market caps and thermal availability in the 2011 TAM, the Company developed its market cap assumption based on the same 48-month period used to develop the availability of the thermal generation facilities.
- UM 1355 Partial Stipulation – The Company has included the following provisions consistent with the partial stipulation in UM 1355:
    - Exclusion of the first-year forced outages of the new plants in the determination of normalized forced outages.
    - Application of EFORd for the peaking units.
    - Inclusion of forced outages with a weekend/weekday split.
    - Exclusion of hydro forced outages. However, the Company continues to study the modeling of such outages, and may include the impact in future TAM filings.
    - Exclusion of ramping losses from the forced outage rate calculation. Instead, ramping losses are modeled as a load offsetting the coal-fired generation.
- Ramping losses for the coal-fired units the Company does not operate are approximated using the ratio of the lost generation to the capacities of the units that the Company does operate. By making this enhancement, all coal-fired units now reflect ramping losses.
- The Bear River system has multiple projects, of which only Oneida and Cutler

are capable of carrying reserves. As a result, the inputs for hydro generation at the Bear River system is refined to now have three separate inputs – Oneida, Cutler and run-of river.

Wind Integration Charges

Q. What has the Company included for wind integration charges in the 2011 TAM?

A. As previously mentioned, there are two categories of wind integration charges, one for the Company's wind resources located in the BPA's control area, and one for the wind resources located in Company's control area.

For the wind resources located in BPA's control area, the Company is relying on BPA's Record of Decision ("ROD") on July 21, 2009 that set the wind integration charges to $1.29 per kW-month beginning in October 2009 for variations in the wind generation within 30 minutes. This charge is approximately $5.89 per megawatt-hour based on a 30 percent capacity factor for the wind resource. This charge is an intra-hour wind integration charge only, because BPA does not perform inter-hour wind integration.

For the resources in the Company's control area, the Company has updated the wind integration charge to incorporate the latest information in the Company's 2008 IRP.

Q. Please explain the update to the Company's wind integration charges.

A. As part of its 2008 IRP filed with the Commission on May 29, 2009, the Company performed studies of the impact of integrating the generation from wind projects into its system. Based on the same assumptions and methodology but using the data applicable to the test period, the Company calculated the costs incurred for wind integration as $6.97 per megawatt-hour for the test period, which is composed of $5.16 per megawatt-hour for intra-hour costs and $1.81 per megawatt-hour for inter-hour rebalancing costs. Appendix F to the Company's 2008 IRP, which is included as Exhibit PPL(TAM)/103, discusses the components of the Company's wind integration charges in further detail.

Q. Which wind plants are assessed the Company's wind integration charges?

A. All wind plants in the Company's control area including non Company-owned wind plants, with the exception of Leaning Juniper and Goodnoe Hills, are assessed the Company's wind integration charge. Leaning Juniper and Goodnoe Hills are in BPA's control area and are assessed the BPA intra-hour wind integration charge. In addition, the two wind projects located in BPA's control area are also assessed the inter-hour wind integration costs from the Company's IRP.

Q. Does the Company propose to update its wind integration charges during this proceeding?

A. Yes. In its IRP process, the Company agreed to update the wind integration study by August 2, 2010, addressing comments from parties to the IRP process. If parties to the current proceeding agree, the Company will update its wind integration charge as an exception to the TAM Guidelines, which allow updates for third-party wind integration charges, but not for Company wind integration charges.

Q. Commission Order No. 09-432 in UE 207 states,

> ***"Pacific Power will provide an update to the Commission in 2010 on the status of the Federal Energy Regulatory Commission (FERC) study on wind integration and its potential impact on Oregon customers. Pacific Power will also notify the Commission if the Company will include a wind integration tariff in the Company's next FERC rate case."***[1]

What is the status of the FERC study and the Company's next FERC rate case?

A. On January 21, 2010, FERC issued a notice of inquiry on "Integration of Variable Energy Resources," which is attached to my testimony as Exhibit PPL(TAM)/104. Comments are due 60 days after the publication of the notice. In addition, per FERC's order in Docket No. ER07-882, the Company is required to file a rate case no later than June 1, 2011, in which case the Company will include a proposed wind integration charge in its transmission tariff rates pending any FERC guidance on the issue.

Compliance with TAM Guidelines

Q. Has this filing been prepared consistent with the TAM Guidelines adopted by Order No. 09-274?

A. Yes. The Company has complied with the provisions in the TAM Guidelines associated with the Initial Filing.

Q. Did the Company provide notice to parties on changes to the GRID model prior to the current filing?

A. Yes. On February 1, 2010, the Company sent a notice to the Commission Staff, the Citizens' Utility Board of Oregon, ICNU, and Sempra to inform parties that the Company has not made changes to its GRID model used to calculate its NPC.

[1] See Order No. 09-432 at p.7.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes. All NPC components have been updated. Additionally, the steam revenues associated with Little Mountain have been updated and are included in the general rate case that is being filed concurrently with the TAM.

Q. Has the Company provided information regarding its anticipated subsequent TAM updates?

A. Yes. Exhibit PPL(TAM)/105 to my testimony contains a list of known contracts that could be included in the Company's TAM updates in this filing based on the best information available at the time the NPC study was prepared. The Company will update this list as new information becomes available.

Q. Has the Company agreed to include other information in its initial TAM filing in this case?

A. Yes. The parties asked the Company to identify the 48-month historical period used to determine the outage rates and other inputs in the Initial Filing. The historical base period used for outage rates in the filing is 48-months ended June 2009.

Q. What workpapers did the Company provide with this filing?

A. Pursuant to the UE 207 Stipulation, the Company provided access to the GRID model concurrently with this Initial Filing. In addition, consistent with Attachment B to the TAM Guidelines, the Company is providing parties with workpapers, specifically the Company's NPC report workbook and the GRID project report.

Introduction of Witnesses

Q. Please list the other Company witnesses in the 2011 TAM and provide a brief explanation of the witness' testimony.

A. **Stefan A. Bird,** Senior Vice President, Commercial and Trading, discusses the procurement process for the Top of the World, LLC power purchase agreement.

Cindy A. Crane, Vice President, Interwest Mining and Fuels, discusses the primary factors for the increases in coal costs, and demonstrates the benefits of affiliated mining interests relative to the coal market.

Judith M. Ridenour, Regulatory Consultant, Pricing & Cost of Service, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-216
Exhibit PPL(TAM)/101
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Allocated Net Power Costs to Oregon

February 2010

CY 2011 TAM

	ACCOUNT	UE-207 FINAL CY 2010	**TAM CY 2011**		Factors CY 2010	2011 GRC Factors CY 2011	UE-207 FINAL CY 2010	**TAM CY 2011**
Sales for Resale								
Existing Firm PPL	447	24,974,154	**25,032,103**	SG	26.877%	26.177%	6,712,274	**6,552,676**
Existing Firm UPL	447	25,490,589	**25,490,589**	SG	26.877%	26.177%	6,851,076	**6,672,694**
Post-Merger Firm	447	641,195,998	**594,135,708**	SG	26.877%	26.177%	172,333,505	**155,527,424**
Non-Firm	447	55,979,012	**-**	SE	25.002%	24.283%	13,995,816	**-**
Total Sales for Resale		747,639,753	**644,658,400**				199,892,672	**168,752,793**
Purchased Power								
Existing Firm Demand PPL	555	58,677,959	**47,758,104**	SG	26.877%	26.177%	15,770,807	**12,501,681**
Existing Firm Demand UPL	555	46,338,071	**48,168,584**	SG	26.877%	26.177%	12,454,230	**12,609,132**
Existing Firm Energy	555	57,763,587	**52,340,132**	SE	25.002%	24.283%	14,441,994	**12,709,916**
Post-merger Firm	555	376,161,158	**490,088,073**	SG	26.877%	26.177%	101,100,399	**128,290,783**
Secondary Purchases	555	(12,954,749)	**-**	SE	25.002%	24.283%	(3,238,933)	**-**
Seasonal Contracts	555		**-**	SSGC	0.000%	0.000%	-	**-**
Other Generation Expense	555	7,682,475	**38,855,180**	SG	26.877%	26.177%	2,064,810	**10,171,154**
Total Purchased Power		533,668,503	**677,210,072**				142,593,306	**176,282,667**
Wheeling Expense								
Existing Firm PPL	565	43,189,893	**40,049,244**	SG	26.877%	26.177%	11,608,098	**10,483,726**
Existing Firm UPL	565	168,268	**259,960**	SG	26.877%	26.177%	45,225	**68,050**
Post-merger Firm	565	100,936,303	**99,966,153**	SG	26.877%	26.177%	27,128,533	**26,168,227**
Non-Firm	565	253,429	**101,247**	SE	25.002%	24.283%	63,362	**24,586**
Total Wheeling Expense		144,547,893	**140,376,605**				38,845,218	**36,744,589**
Fuel Expense								
Fuel Consumed - Coal	501	610,479,015	**638,135,027**	SE	25.002%	24.283%	152,631,345	**154,960,306**
Cholla / APS Exchange	501	55,113,078	**56,675,765**	SSECH	25.408%	24.812%	14,003,311	**14,062,190**
Fuel Consumed - Gas	501	7,304,914	**6,171,919**	SE	25.002%	24.283%	1,826,367	**1,498,746**
Natural Gas Consumed	547	410,130,960	**390,763,656**	SE	25.002%	24.283%	102,540,527	**94,890,350**
Simple Cycle Combustion Turbines	547	11,664,948	**9,951,264**	SSECT	23.286%	22.403%	2,716,330	**2,229,400**
Steam from Other Sources	503	3,498,000	**3,555,701**	SE	25.002%	24.283%	874,566	**863,442**
Total Fuel Expense		1,098,190,915	**1,105,253,332**				274,592,445	**268,504,434**
Net Power Cost		1,028,767,558	**1,278,181,609**				256,138,297	**312,778,897**

249,414,050

Increase Absent Load Change **56,640,600**

Oregon-allocated NPC Baseline in Rates from UE 207 256,138,297

$ Change due to load variance from UE-207 forecast (12,529,976)

2011 Recovery of NPC in Rates 243,608,321

Increase Including Load Change **69,170,576**

Exhibit PPL(TAM)/101
Duvall/1

Docket No. UE-216
Exhibit PPL(TAM)/102
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Net Power Costs Report

February 2010

_OR TAM_CY2011 GOLD _2010 02 13

Net Power Cost Analysis

12 months ended December 2011	01/11-12/11	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	12,067,303	1,011,177	970,001	1,021,378	991,597	1,013,220	992,327	1,018,921	1,020,010	996,802	1,010,489	1,002,652	1,018,728
BPA Wind s42818	2,732,820	342,495	287,172	278,041	216,033	203,850	165,372	124,026	117,524	154,511	225,798	284,430	333,569
Hurricane Sale s393046	11,291	941	941	941	941	941	941	941	941	941	941	941	941
LADWP (IPP Layoff)	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
Pacific Gas and Electric s512771	33,490,696	4,292,970	3,782,880	3,911,070	3,297,832	2,682,940	2,715,168	-	-	-	4,065,048	4,115,620	4,627,168
PSCO s100035	15,714,676	1,354,494	1,261,636	1,354,493	1,253,013	1,281,532	1,272,247	1,354,493	1,354,493	1,303,422	1,287,502	1,282,859	1,354,493
SCE s 513948	15,464,348	1,893,696	1,686,048	1,807,848	1,498,568	1,566,500	1,714,104	-	-	-	1,760,624	1,691,480	1,845,480
SMUD s24296	12,964,800	1,676,100	1,435,600	418,100	-	-	-	1,091,500	1,831,500	1,657,600	1,402,300	1,550,300	1,901,800
UMPA II s45631	9,599,125	593,283	561,909	593,283	582,825	593,283	932,517	1,779,848	1,400,150	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	127,535,649	13,330,110	11,941,627	11,550,109	9,935,924	9,507,220	9,887,791	7,534,684	7,889,574	7,001,031	12,510,939	12,606,221	13,840,417
Short Term Firm Sales													
COB	6,520,680	2,376,180	1,989,360	2,155,140	-	-	-	-	-	-	-	-	-
Four Corners	18,554,100	2,792,850	2,338,200	2,533,050	1,140,000	1,290,000	1,140,000	1,290,000	1,170,000	1,200,000	1,230,000	1,200,000	1,230,000
Mid Columbia	1,918,280	-	-	-	612,560	693,160	612,560	-	-	-	-	-	-
Palo Verde	10,204,000	1,746,600	1,630,800	1,821,600	845,000	812,500	845,000	-	-	-	845,000	812,500	845,000
STF Trading Margin	3,847,290	320,608	320,608	320,608	320,608	320,608	320,608	320,608	320,608	320,608	320,608	320,608	320,608
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	41,044,350	7,236,238	6,278,968	6,830,398	2,918,168	3,116,268	2,918,168	1,610,608	1,490,608	1,520,608	2,395,608	2,333,108	2,395,608
System Balancing Sales													
COB	100,032,426	8,432,101	7,689,577	8,260,905	6,915,025	6,058,322	5,750,433	6,917,866	11,704,187	9,946,208	7,851,445	8,851,599	11,654,761
Four Corners	190,610,291	22,173,680	17,960,830	10,599,379	9,809,287	10,389,687	9,603,687	13,038,397	18,346,862	13,565,616	20,869,606	22,488,466	21,764,794
Mid Columbia	52,758,199	6,518,448	5,747,611	6,104,795	2,454,785	214,214	306,080	3,477,374	4,742,787	5,576,045	2,604,990	6,161,000	8,850,072
Mona	15,770,088	931,993	736,172	1,398,479	1,157,384	1,802,837	1,994,611	2,154,701	1,601,076	1,665,601	1,208,996	399,189	719,049
Palo Verde	116,907,397	9,583,928	8,226,616	8,138,957	10,311,838	10,007,538	12,007,497	12,362,521	8,602,816	11,035,183	9,638,777	7,625,567	9,366,160
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	0	0	0	0	-	-	-	0	0	0	-	-	-
Total System Balancing Sales	476,078,401	47,640,150	40,360,805	34,502,514	30,648,319	28,472,598	29,662,308	37,950,859	44,997,728	41,788,653	42,173,813	45,525,820	52,354,836
Total Special Sales For Resale	644,658,400	68,206,497	58,581,399	52,883,020	43,502,410	41,096,086	42,468,266	47,096,151	54,377,910	50,310,291	57,080,359	60,465,149	68,590,861

Exhibit PPL(TAM)/102
Duvall/1

12 months ended December 2011	01/11-12/11	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental p27875	6,692,005	109,536	109,152	105,984	1,149,079	1,143,756	1,472,038	1,319,006	213,576	695,671	158,904	105,216	110,088
Blanding Purchase p379174	19,725	1,675	1,513	1,675	1,621	1,675	1,621	1,675	1,675	1,621	1,675	1,621	1,675
BPA Reserve Purchase	239,962	12,633	14,941	25,429	19,407	23,579	26,034	26,628	22,850	18,474	20,087	16,367	13,533
Chehalis Station Service	138,194	29,055	3,958	12,303	14,432	14,938	8,128	8,887	1,502	5,812	9,211	15,738	14,232
Combine Hills Wind p160595	4,524,776	432,970	282,581	500,360	352,602	327,379	393,913	378,074	375,144	357,491	383,774	427,943	312,546
Deseret Purchase p194277	33,122,503	2,783,629	2,663,182	2,783,629	2,743,480	2,783,629	2,743,480	2,783,629	2,783,629	2,743,480	2,783,629	2,743,480	2,783,629
Douglas PUD Settlement p38185	1,677,692	79,675	65,318	113,795	213,133	281,551	294,712	228,931	153,991	68,227	75,986	61,361	41,012
Gemstate p99489	2,716,400	222,200	219,500	224,300	215,100	215,100	215,100	215,100	221,500	215,100	265,600	265,600	222,200
Georgia-Pacific Camas	6,592,498	559,911	505,726	559,911	541,849	559,911	541,849	559,911	559,911	541,849	559,911	541,849	559,911
Grant County 10 aMW p66274	6,206,447	509,374	400,456	439,889	495,879	561,885	607,658	698,944	727,996	546,758	402,828	350,601	464,178
Hermiston Purchase p99563	96,744,682	8,733,111	8,216,478	8,838,083	7,002,442	7,439,697	6,665,236	6,896,457	10,024,888	9,141,053	4,075,137	8,556,546	11,155,554
Hurricane Purchase p393045	146,411	12,201	12,201	12,201	12,201	12,201	12,201	12,201	12,201	12,201	12,201	12,201	12,201
IPP Purchase	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
Kennecott Generation Incentive	10,817,668	-	4,044	800,371	920,556	959,748	910,649	2,249,537	2,239,223	2,074,771	658,770	-	-
LADWP p491303-4	2,191,564	-	-	-	-	-	199,840	1,417,184	387,190	187,350	-	-	-
MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves p510378	5,144,830	348,870	417,040	405,010	445,110	441,100	441,100	441,100	441,100	441,100	441,100	441,100	441,100
Morgan Stanley p272153-6-8	1,530,000	-	-	-	-	-	510,000	510,000	510,000	-	-	-	-
Morgan Stanley p272154-7	1,620,000	-	-	-	-	-	540,000	540,000	540,000	-	-	-	-
Nucor p346856	4,885,800	407,150	407,150	407,150	407,150	407,150	407,150	407,150	407,150	407,150	407,150	407,150	407,150
P4 Production p137215/p145258	16,193,520	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460
PGE Cove p83984	372,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000
Rock River Wind p100371	5,041,688	614,835	485,591	490,707	384,510	367,683	277,559	197,878	239,001	310,441	444,855	605,219	623,409
Roseburg Forest Products p312292	8,765,207	1,275,553	1,160,603	1,287,518	1,245,215	1,275,552	1,245,213	1,275,553	-	-	-	-	-
Small Purchases east	555,754	66,985	56,902	51,064	51,130	41,068	39,638	35,232	34,920	32,181	43,267	42,003	61,363
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind p460457	20,598,497	2,306,994	1,598,954	2,348,694	1,693,967	1,714,363	1,183,705	1,054,534	1,080,289	1,421,602	1,785,496	2,005,586	2,404,313
Top of the World Wind p575862	40,244,928	5,294,479	3,995,007	3,808,821	3,098,090	2,664,337	2,419,529	1,930,842	2,085,681	2,260,626	2,893,909	4,233,393	5,560,216
Tri-State Purchase p27057	9,466,043	831,889	802,465	836,167	687,306	750,168	748,490	806,217	826,754	789,136	754,019	803,255	830,177
Wolverine Creek Wind p244520	9,844,245	729,671	575,768	1,146,356	1,103,716	1,075,943	838,670	818,649	768,360	714,681	618,760	808,884	644,790
Long Term Firm Purchases Total	321,583,627	28,907,810	25,334,431	28,744,832	26,273,550	26,607,827	26,219,086	28,358,732	28,203,947	26,462,350	20,341,683	25,920,688	30,208,691
Seasonal Purchased Power													
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Exhibit PPL(TAM)/102
Duvall/2

_OR TAM_CY2011 GOLD _2010 02 13

Net Power Cost Analysis

12 months ended December 2011	01/11-12/11	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Qualifying Facilities													
QF California	4,124,858	398,062	478,363	627,366	717,853	721,228	528,623	153,104	74,693	62,716	60,027	89,359	213,463
QF Idaho	4,547,671	302,287	270,913	344,227	386,703	517,622	567,126	454,819	356,438	329,662	354,891	343,892	319,090
QF Oregon	17,246,887	1,551,725	1,437,468	1,625,005	1,779,749	1,805,845	1,581,412	1,357,425	1,264,871	1,248,061	1,124,149	1,104,051	1,367,126
QF Utah	871,281	59,262	66,933	65,863	80,934	84,008	83,483	79,255	74,127	76,935	77,116	68,804	54,561
QF Washington	2,428,571	164,940	152,423	159,234	172,767	225,970	248,820	280,180	268,269	249,785	193,207	161,086	151,891
QF Wyoming	752,906	16,187	15,266	14,785	39,689	113,239	115,452	123,636	123,411	110,495	49,581	15,951	15,214
Biomass p234159 QF	25,738,189	2,303,517	2,106,399	2,303,517	1,778,358	1,778,349	1,778,358	2,303,517	2,303,517	2,237,811	2,303,517	2,237,811	2,303,517
Chevron Wind p499335 QF	2,526,187	237,945	290,612	298,835	113,585	121,710	113,382	115,645	202,474	173,398	275,146	275,966	307,488
Evergreen BioPower p351030 QF	3,778,053	334,300	302,268	332,556	326,484	255,607	322,460	335,199	332,556	320,207	337,452	320,206	258,758
ExxonMobil p255042 QF	29,301,817	3,965,706	3,683,734	3,410,070	1,909,010	1,417,752	1,372,084	422,409	2,686,416	2,243,700	2,235,168	2,319,480	3,636,290
Mountain Wind 1 p367721 QF	8,433,522	1,194,975	766,959	790,896	591,375	496,443	361,689	399,341	543,790	634,302	711,923	830,892	1,110,937
Mountain Wind 2 p398449 QF	12,200,503	1,744,137	1,073,230	1,120,541	805,550	864,193	689,661	779,003	847,639	799,895	847,350	1,116,175	1,513,130
Oregon Wind Farm QF	10,159,994	585,047	645,974	828,357	1,015,178	1,024,666	1,192,475	1,207,116	936,269	754,362	766,948	892,409	311,194
SF Phosphates	3,996,342	338,468	310,494	338,468	329,143	338,468	329,143	338,468	338,468	329,143	338,468	329,143	338,468
Spanish Fork Wind 2 p311681 QF	2,791,086	178,085	195,370	172,119	162,289	169,850	246,015	291,587	349,486	281,183	226,042	247,779	271,280
Sunnyside p83997/p59965 QF	27,044,447	2,425,103	2,272,661	1,717,606	2,204,286	2,269,622	2,312,180	2,372,692	2,407,875	2,317,188	2,022,892	2,304,008	2,418,334
Qualifying Facilities Total	155,942,313	15,799,747	14,069,067	14,149,446	12,412,953	12,204,572	11,842,363	11,013,395	13,110,299	12,168,841	11,923,877	12,657,012	14,590,740
Mid-Columbia Contracts													
Canadian Entitlement p60828	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach p60827	3,513,187	351,319	351,319	351,319	351,319	351,319	351,319	351,319	351,319	351,319	351,319	-	-
Douglas - Wells p60828	3,541,016	293,486	293,486	293,486	293,486	293,486	293,486	293,486	293,486	298,283	298,283	298,283	298,283
Grant Displacement p270294	9,529,459	945,539	891,456	920,471	1,203,605	1,245,042	1,037,015	1,217,430	1,039,239	1,029,661	-	-	-
Grant Reasonable	(16,062,305)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)	(1,338,525)
Grant Surplus p258951	1,704,662	142,055	142,055	142,055	142,055	142,055	142,055	142,055	142,055	142,055	142,055	142,055	142,055
Grant - Wanapum p60825	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	2,226,020	393,873	339,791	368,805	651,939	693,377	485,350	665,764	487,574	482,792	(546,869)	(898,188)	(898,188)
Total Long Term Firm Purchases	479,751,960	45,101,429	39,743,288	43,263,083	39,338,443	39,505,776	38,546,799	40,037,892	41,801,820	39,113,982	31,718,691	37,679,512	43,901,243

Exhibit PPL(TAM)/102
Duvall/3

12 months ended December 2011	01/11-12/11	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Storage & Exchange													
APGI/Colockum s191690	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs p64676	2,287,686	170,462	129,226	64,332	84,356	84,446	153,645	91,207	89,548	368,772	171,399	305,880	574,415
BPA Exchange p64706/p64888	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Peaking p59820	38,410,000	4,801,250	4,801,250	4,801,250	4,801,250	4,801,250	4,801,250	4,801,250	4,801,250	-	-	-	-
BPA So. Idaho p64885/p83975/p647	(496)	-	-	-	-	(337)	(158)	-	-	-	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	4,500,000	375,000	375,000	375,000	375,000	375,000	375,000	375,000	375,000	375,000	375,000	375,000	375,000
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	45,197,190	5,346,712	5,305,476	5,240,582	5,260,606	5,260,358	5,329,737	5,267,457	5,265,798	743,772	546,399	680,880	949,415
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	5,579,600	498,800	417,600	452,400	440,800	498,800	440,800	498,800	452,400	464,000	475,600	464,000	475,600
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	979,400	356,900	298,800	323,700	-	-	-	-	-	-	-	-	-
STF Electric Swaps	(32,435,843)	(2,420,604)	(2,944,794)	(5,643,601)	(3,899,007)	(5,304,057)	(4,098,000)	(821,362)	(434,633)	(1,482,650)	(2,339,530)	(2,116,646)	(930,961)
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	(25,876,843)	(1,564,904)	(2,228,394)	(4,867,501)	(3,458,207)	(4,805,257)	(3,657,200)	(322,562)	17,768	(1,018,650)	(1,863,930)	(1,652,646)	(455,361)
System Balancing Purchases													
COB	6,180,670	50,880	146,743	361,382	-	864,628	657,576	3,958,034	10,809	77,096	21,676	27,175	4,671
Four Corners	9,366,069	1,601,832	338,298	3,204,094	1,455,961	-	-	709,205	467,275	219,181	-	581,052	789,171
Mid Columbia	72,438,996	1,148,649	1,107,636	1,591,120	5,879,510	10,537,867	9,263,947	14,439,711	11,287,338	4,952,764	7,331,342	3,300,465	1,598,647
Mona	51,183,475	4,740,656	5,106,049	3,623,403	4,651,903	81,056	567,180	2,850,913	7,658,057	1,708,654	4,163,175	8,044,700	7,987,731
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	113,375	-	-	2,202	111,173	-	-	-	-	-	-	-	-
Total System Balancing Purchases	139,282,585	7,542,016	6,698,726	8,782,202	12,098,547	11,483,551	10,488,703	21,957,862	19,423,478	6,957,695	11,516,193	11,953,391	10,380,220
Total Purchased Power & Net Inter	638,354,892	56,425,254	49,519,096	52,418,366	53,239,388	51,444,429	50,708,040	66,940,649	66,508,863	45,796,799	41,917,354	48,661,137	54,775,518

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Net Power Cost Analysis

12 months ended December 2011	01/11-12/11	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Wheeling & U. of F. Expense													
Firm Wheeling	140,275,358	11,978,051	11,743,543	11,380,944	11,632,589	10,857,864	10,729,703	11,686,174	11,511,429	12,354,290	12,197,602	12,060,868	12,142,301
ST Firm & Non-Firm	101,247	6,498	5,045	663	5,418	10,818	13,473	10,708	10,427	10,404	12,219	7,970	7,603
Total Wheeling & U. of F. Expense	140,376,605	11,984,549	11,748,588	11,381,607	11,638,007	10,868,682	10,743,176	11,696,882	11,521,856	12,364,694	12,209,821	12,068,838	12,149,904
Coal Fuel Burn Expense													
Carbon	16,280,295	1,485,237	1,339,815	1,457,893	1,439,113	1,353,403	1,335,826	1,479,146	1,455,784	1,346,167	1,399,395	748,512	1,440,004
Cholla	56,765,872	5,039,537	4,552,138	2,588,917	4,912,460	4,830,669	4,722,139	5,099,561	5,093,627	4,913,291	5,078,308	4,880,837	5,054,390
Colstrip	14,248,385	1,273,067	1,151,067	1,275,392	1,232,788	1,274,229	1,233,950	1,273,067	1,275,392	943,129	808,125	1,233,950	1,274,229
Craig	21,170,415	1,837,884	1,661,959	1,840,225	1,512,993	1,816,342	1,755,563	1,835,349	1,836,463	1,716,192	1,798,086	1,739,434	1,819,925
Dave Johnston	55,038,977	4,143,727	4,370,477	4,533,976	4,845,795	4,886,778	4,902,951	5,145,605	5,191,848	4,645,174	3,787,470	4,311,577	4,273,597
Hayden	9,867,154	905,131	827,662	474,129	797,952	857,660	834,830	913,172	876,969	824,075	865,579	824,445	865,549
Hunter	135,057,162	12,126,602	11,029,268	9,080,001	11,776,543	11,013,612	10,821,545	12,090,300	11,905,876	10,948,134	11,646,918	11,032,870	11,585,493
Huntington	88,723,458	7,972,542	7,210,065	7,379,001	4,623,515	7,576,368	7,544,598	7,899,931	7,966,720	7,344,288	7,878,730	7,468,298	7,859,403
Jim Bridger	180,840,300	15,868,983	14,433,064	15,193,915	11,629,642	12,275,768	15,652,787	16,231,952	16,222,884	15,677,504	16,226,692	15,497,078	15,930,034
Naughton	98,044,150	8,731,654	7,892,010	8,177,421	5,342,623	7,880,917	8,388,626	8,672,080	8,687,001	8,404,850	8,672,080	8,459,571	8,735,316
Ramp Loss	(927,711)	(47,193)	(75,896)	(70,191)	(68,333)	(93,478)	(66,238)	(98,063)	(94,120)	(56,885)	(83,549)	(115,998)	(57,768)
Wyodak	19,702,335	1,753,526	1,585,215	1,756,209	1,697,870	1,707,275	1,653,125	1,705,973	1,708,576	1,653,125	1,705,973	1,020,600	1,754,868
Total Coal Fuel Burn Expense	694,810,792	61,090,696	55,976,844	53,686,889	49,742,960	55,379,543	58,779,703	62,248,073	62,127,021	58,359,044	59,783,806	57,101,175	60,535,039
Gas Fuel Burn Expense													
Chehalis	67,961,211	-	-	-	-	-	-	6,546,064	13,232,767	12,449,835	12,659,625	9,303,425	13,769,495
Currant Creek	70,369,829	6,820,644	5,752,188	5,013,583	5,310,495	2,515,005	3,703,578	7,122,626	7,850,017	6,352,647	6,393,663	6,208,393	7,326,992
Gadsby	4,716,744	-	-	-	-	-	51,868	1,840,734	2,332,845	469,415	21,881	-	-
Gadsby CT	7,951,741	1,041,355	644,248	95,962	-	28,168	105,000	1,155,532	1,476,512	828,804	777,593	783,352	1,015,215
Hermiston	59,748,081	5,627,005	5,121,451	5,729,379	3,932,112	4,361,162	3,602,583	3,845,724	6,930,092	6,059,136	1,066,148	5,453,006	8,020,283
Lake Side	99,265,287	10,925,382	8,463,250	8,304,946	7,373,799	3,422,723	3,990,312	10,116,072	10,660,490	9,619,585	6,999,149	8,715,135	10,674,444
Little Mountain	8,173,122	1,153,132	1,037,920	1,113,674	956,049	846,027	-	66,073	-	-	841,494	1,023,315	1,135,439
Total Gas Fuel Burn	318,186,015	25,567,518	21,019,057	20,257,543	17,572,455	11,173,084	11,453,342	30,692,825	42,482,722	35,779,422	28,759,552	31,486,626	41,941,868
Gas Physical	112,171	39,625	35,614	37,693	(12,733)	(14,657)	(13,696)	(8,970)	(8,073)	(8,468)	(15,594)	38,131	43,298
Gas Swaps	50,916,361	1,746,165	1,602,994	2,233,143	2,886,786	3,357,236	3,854,695	6,165,219	6,103,003	6,075,875	6,152,384	5,566,215	5,172,648
Clay Basin Gas Storage	(532,136)	(195,026)	(190,150)	(146,960)	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	26,698,226	2,253,447	2,138,666	2,253,447	2,212,457	2,253,447	2,212,457	2,253,447	2,253,447	2,212,457	2,253,447	2,180,257	2,221,248
Start-up gas cost	11,506,202	937,643	801,777	754,723	737,075	388,208	589,362	1,639,820	1,227,996	1,141,932	987,704	1,110,246	1,189,716
Total Gas Fuel Burn Expense	406,886,839	30,349,372	25,407,959	25,389,589	23,396,040	17,157,318	18,096,160	40,742,341	52,059,097	45,201,218	38,137,494	40,381,474	50,568,778
Other Generation													
Blundell	3,555,701	325,459	293,916	325,368	305,667	306,271	296,361	296,742	306,229	296,361	163,031	314,884	325,413
Wind Integration Charge	38,855,180	4,415,095	3,381,368	3,860,682	3,200,075	3,025,985	2,760,846	2,338,097	2,425,740	2,517,846	3,080,389	3,749,380	4,099,678
Total Other Generation	42,410,881	4,740,553	3,675,283	4,186,049	3,505,742	3,332,256	3,057,207	2,634,839	2,731,969	2,814,207	3,243,420	4,064,264	4,425,091
Net Power Cost	**1,278,181,609**	96,383,927	87,746,371	94,179,481	98,019,727	97,086,143	98,916,019	137,166,632	140,570,895	114,225,671	98,211,535	101,811,739	113,863,469
Net Power Cost/Net System Load	**22.03**	**18.66**	**18.93**	**20.00**	**22.16**	**21.33**	**20.68**	**25.47**	**26.49**	**24.59**	**21.69**	**21.90**	**21.72**

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Docket No. UE-216
Exhibit PPL(TAM)/103
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Appendix F to 2008 IRP (Wind Integration Study)

February 2010

APPENDIX F – INITIAL 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.

In the initial wind integration cost study, PacifiCorp developed a methodology to support the costs associated in resource portfolio analyses 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.

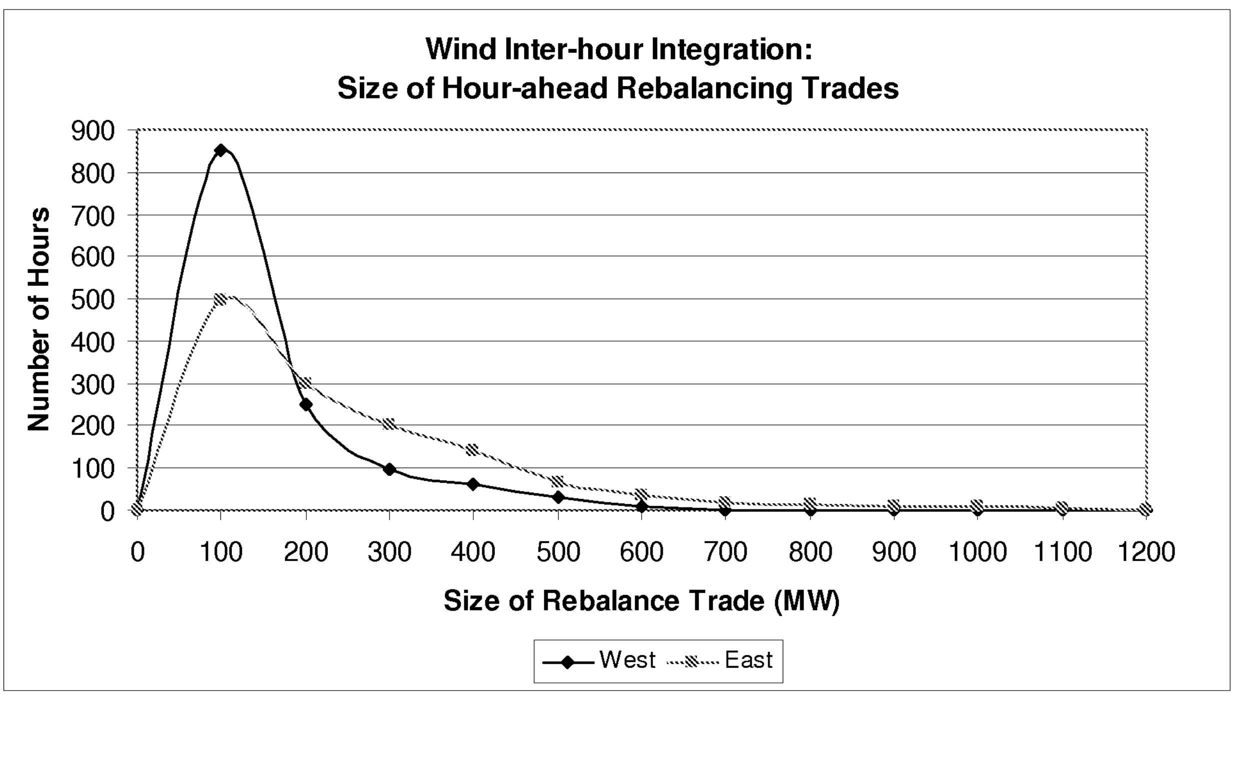
Hour-ahead variation

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

<u>Incremental Reserve ("Intra-Hour") Cost Calculation</u>

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)			Intra-hour Cost ($/Expected MWh)	Total ($/Expected MWh)
	Expected to Day-Ahead Cost ($/Expected MWh)	Day-Ahead to Hour-Ahead Cost ($/Expected MWh)	Total Cost ($/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
	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
Goshen, 29%	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
	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
Goshen, 24%	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
	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
Utah, 29%	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
	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
Utah, 24%	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
	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
Walla Walla, 35%	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
	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
Walla Walla, 29%	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
	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
Walla Walla, 24%	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.

Docket No. UE-216
Exhibit PPL(TAM)/104
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

FERC Notice of Inquiry on Integration of Variable Energy Resources

February 2010

130 FERC ¶ 61,053
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Chapter I

(Docket No. RM10-11-000)

Integration of Variable Energy Resources

(Issued January 21, 2010)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Inquiry.

SUMMARY: In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources (VERs) into the electric grid, and whether reforms are needed to eliminate those barriers. In order to meet the challenges posed by the integration of increasing numbers of VERs, ensure that jurisdictional rates are just and reasonable, eliminate impediments to open access transmission service for all resources, facilitate the efficient development of infrastructure, and ensure that the reliability of the grid is maintained, the Commission seeks to explore whether reforms are necessary to ensure that wholesale electricity tariffs are just, reasonable and not unduly discriminatory. This Notice will enable the Commission to determine whether wholesale electricity tariff reforms are necessary.

DATES: Comments are due [Insert date that is 60 days after publication in the **FEDERAL REGISTER**].

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Mk Shean (Technical Information)
Office of Energy Policy and Innovations
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6792
Mk.Shean@ferc.gov

Timothy Duggan (Legal Information)
Office of General Counsel – Energy Markets
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8326
Timothy.Duggan@ferc.gov

SUPPLEMENTARY INFORMATION:

130 FERC ¶ 61,053
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources Docket No. RM10-11-000

NOTICE OF INQUIRY

(Issued January 21, 2010)

1. In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the extent to which barriers exist that may impede the reliable and efficient integration of variable energy resources (VERs)[1] into the electric grid and whether reforms are needed to eliminate those barriers. VERs, such as resources powered by wind and solar energy, continue to make up an increasing percentage of the nation's energy supply portfolio; however, they present unique challenges (such as location constraints and limited dispatchability) that are not typically presented by conventional electricity generating resources. VERs also present benefits, such as low marginal energy costs and reduced greenhouse gas emissions, which have contributed to the accelerated development of these resources. In order to meet these challenges and fully realize these benefits of VERs in a reliable and efficient manner, the Commission

[1] For purposes of this proceeding, the term variable energy resource (VER) refers to renewable energy resources that are characterized by variability in the fuel source that is beyond the control of the resource operator. This includes wind and solar generation facilities and certain hydroelectric resources.

seeks to explore whether reforms of existing policies are necessary to ensure that jurisdictional rates are just and reasonable and that the terms of jurisdictional service do not unduly discriminate against these resources.

I. Background

2. While the amount of VERs remains relatively small as a percentage of total generation, it is rapidly increasing, reaching a point where such resources are becoming a significant component of the nation's energy supply portfolio. In 2008, new wind generating capacity, totaling 8,376 MW, made up 42 percent of all newly installed generating capacity.[2] Moreover, in recent years, a number of state renewable portfolio standards and other incentives/mandates have been passed to encourage the development of renewable energy resources, in response to a growing concern about the environmental impacts and sustainability of the Nation's current electricity supply portfolio. As of December 2009, 30 states, including the District of Columbia, had a renewable portfolio standard.[3]

3. While VERs have many desirable characteristics, including low marginal energy costs and reduced greenhouse gas and other pollutant emissions, compared to conventional fossil-fueled generation, they also present unique challenges as public

[2] Div. of Market Oversight, Fed. Energy Regulatory Comm'n, 2008 State of the Markets Report 19 (2009), available at http://www.ferc.gov/market-oversight/st-mkt-ovr/2008-som-final.pdf.

[3] Div. of Market Oversight, Fed. Energy Regulatory Comm'n, Renewable Power and Energy Efficiency Market: Renewable Portfolio Standards 1 (2009), available at http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf.

utilities work to integrate VERs in a way that ensures system reliability. For example, because VERs cannot control or store their fuel source, they have limited ability to control their production of electricity, and the weather-related phenomena that drive VER output levels can be difficult to forecast. Also, the output from some VERs can be negatively correlated with demand, such that a resource's greatest energy output often comes at a time of limited energy demand. Changes in the rate of output from VERs may also result in substantial ramps,[4] which can require additional resources to allow System Operators[5] to balance generation and demand while maintaining reliability in real time.

4. In this proceeding, the Commission seeks to explore whether existing rules, regulations, tariffs, or industry practices within the Commission's jurisdiction may hinder the reliable and efficient integration of VERs, resulting in rates that are unjust and unreasonable and/or terms of service that unduly discriminate against certain types of resources. The Commission seeks comment on how best to reform any such rules, regulations, tariffs, or industry practices.

5. Under sections 205 and 206 of the Federal Power Act, the Commission has a responsibility to remedy undue discrimination with respect to transmission of electric energy and sales of electric energy for resale in interstate commerce and to ensure that

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[4] A ramp is the rate, expressed in megawatts per minute, that a generator changes its output.

[5] System Operator refers to the individual at a control center—balancing authority, transmission operator, generator operator (VERs as well as conventional resources), or reliability coordinator—whose responsibility it is to monitor and control the electric system in real time.

rates for these services are just and reasonable.[6] As the electric power industry has evolved, the Commission has discharged this responsibility in different ways. In Order No. 888, the Commission exercised its authority to remedy undue discrimination by requiring all public utilities to provide open access transmission service consistent with the terms of a pro forma open access transmission tariff (OATT).[7] The pro forma OATT addresses the terms of transmission service, including, among other things, the terms for scheduling transmission service, curtailments, and the provision of ancillary services. In Order No. 2003, the Commission acted to remove barriers in the generator interconnection process and adopted standard procedures (the Large Generation Interconnection Procedures or LGIP), and a standard agreement (the Large Generation Interconnection Agreement or LGIA) for the interconnection of generation resources larger than 20 MW.[8] More recently, in a further effort to remedy the potential for undue

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[6] 16 U.S.C. 824d, 824e.

[7] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[8] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), order on reh'g, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007). Similarly, the Commission also adopted standard procedures for the

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discrimination, the Commission revised and updated the pro forma OATT in Order No. 890.[9]

6. With limited exceptions,[10] these and other Commission efforts to remedy undue discrimination have not expressly accounted for the differences between VERs and more conventional generation resources. In large part this is due to the fact that the electric grid was developed during a time when electricity was almost exclusively generated from centralized, dispatchable resources that were powered by fuel sources that could be stored and used as needed. The Commission's policies and the concomitant implementation of its responsibility under sections 205 and 206 were premised on this underlying physical reality of the electric grid.

7. Where relevant, however, the Commission on several occasions has taken the operational characteristics of VERs into consideration in efforts to ensure just and

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interconnection of small generation resources. Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, order on reh'g, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), order granting clarification, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[9] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241, order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228, order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[10] See, e.g., Interconnection for Wind Energy, Order No. 661, FERC Stats. & Regs. ¶ 31,186, order on reh'g, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005) (adopting reforms to the LGIA and LGIP to establish standard technical requirements for interconnection of wind plants); Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665 (establishing a standard offer generation imbalance service, but exempting intermittent resources from the highest penalty band).

reasonable rates and to remedy undue discrimination. In Order No. 661, the Commission required public utilities to revise their LGIAs and LGIPs to incorporate standard technical requirements for the interconnection of wind resources larger than 20 MW.[11] In Order No. 890, the Commission applied a reduced penalty amount to intermittent resources' imbalances that would otherwise be subject to the highest-tier generation imbalance penalties, recognizing "that intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules."[12] In addition, in Order No. 890 the Commission created conditional firm point-to-point transmission service, noting that conditional firm service can be particularly beneficial to renewable energy resources.[13] Shortly after the issuance of Order No. 890, the Commission accepted a unique cost allocation mechanism for interconnection facilities connecting renewable energy resources that are location-constrained, recognizing that the difficulties faced by these resources are different from those faced by other generation developers, and therefore support an appropriate variation of the interconnection pricing policy.[14]

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[11] Order No. 661, FERC Stats. & Regs. ¶ 31,186 (adopting, among other things, a low voltage ride-through standard, a power factor range, dynamic reactive power capability, and supervisory control and data acquisition (SCADA) capability).

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 664-65.

[13] Id. P 912.

[14] Cal. Indep. Sys. Operator Corp., 119 FERC ¶ 61,061, at P 69-70 (2007). See also Southwest Power Pool, Inc., 127 FERC ¶ 61,283, at P 29 (2009) (accepting a proposal to allocate network upgrade costs differently for wind resources being used to

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8. Such actions are premised on the notion that targeted revisions to Commission policies are sometimes necessary to ensure that jurisdictional rates are just and reasonable and to prevent undue discrimination against any one type of customer or resource as the characteristics of the nation's generation portfolio change.

II. Subject of the Notice of Inquiry

9. In this proceeding, the Commission seeks to take a fresh look at existing policies and practices in light of the changing characteristics of the nation's generation portfolio with the aim of removing unnecessary barriers to transmission service and wholesale markets for VERs (and other technologies that may aid their integration) and promoting greater efficiencies that ultimately will reduce costs to consumers. While the Commission seeks comment on numerous challenges presented by the integration of VERs, this proceeding will not address issues related to transmission planning and cost allocation, as the Commission is considering those issues in another forum.[15]

10. Our goal is not to adopt rules that favor one type of supply source over another. Instead, the Commission's purpose in this proceeding is to investigate market and operational reforms necessary to achieve two goals: first, to ensure that rates for jurisdictional service are just and reasonable, reflecting the implementation of practices that increase the efficiency of providing service; and second, to prevent VERs from

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serve demand in a different zone than the methodology used for other resources).

[15] Transmission Planning Processes Under Order No. 890, Docket No. AD09-8-000 (Oct. 8, 2009) (notice of request for comments).

facing undue discrimination. These goals are consistent with the requirements of sections 205 and 206 of the FPA.

11. In addition, the Commission must ensure that any reforms are consistent with the need to maintain system reliability in accordance with Reliability Standards proposed by the North American Electric Reliability Corp. (NERC) and approved by the Commission pursuant to section 215 of the FPA.[16] Although the scope of this proceeding is directed to market and operational reforms, in certain instances where commenters believe existing NERC Reliability Standards should be modified or new standards developed in conjunction with the market reforms considered herein, they may indicate as much, if directly related to this proceeding. In responding to the following questions, commenters should indicate how the reforms that they propose ensure the reliable operation of the grid, or would impact the reliable operation of the grid, as required by the reliability standards.[17]

III. Questions for Response

12. To ensure that all generation resources are afforded non-discriminatory access to wholesale markets and the electric power grid and that wholesale market prices and the rates for transmission service are just and reasonable, the Commission seeks comment on the perceived barriers, and suggested solutions to removing those barriers, of integrating

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[16] 16 U.S.C. 824o.

[17] See id. at 824o(a)(3). We note that NERC has an ongoing stakeholder process to examine how to accommodate high levels of variable generation. See North American Elec. Reliability Corp., Accommodating High Levels of Variable Generation (2009).

VERs into the electric grid in a reliable and efficient manner. The Commission's preliminary view is that one of the most important operational issues affecting the integration costs for VERs involves the reserves necessary to address variability in VER output. Addressing this issue means examining a number of operational practices and processes that affect both the determination of the amount of reserves needed as well as the cost of those reserves. The Commission seeks comment on the impact of integrating an increasing number of VERs in the following subject areas: (1) data and reporting requirements, including the use of accurate forecasting tools; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and, (7) redispatch and curtailment practices necessary to accommodate VERs in real time.

13. The Commission does not seek to limit its inquiry and encourages all comments regarding the topics broadly discussed herein. Commenters are invited to share with the Commission their overall thoughts, including technical, commercial, and legal observations, on the challenges posed by the increasing number of VERs, operational and technical barriers faced by VERs, and the extent to which Commission policies can and/or should be revisited in light of the increasing number of VERs. Where commenters believe specific revisions to Commission rules and/or pro forma OATT provisions are necessary to implement their proposed reforms, they are encouraged to cite those rules and/or provisions with specificity and suggest revised language as appropriate. In this

Notice of Inquiry we seek information with regard to whether changes to rules or practices as applied to VERs will achieve the Commission's goals. However, there may be instances where a change to a rule or practice could also assure just and reasonable rates and address undue discrimination if applied to other resources. Therefore, we ask commenters to address whether any proposed changes to the Commission rules or OATT provisions should apply to all resources. In addition, the Commission seeks responses to the specific questions listed below.

A. <u>Data and Forecasting</u>

14. The scheduling and operational practices of the bulk power system are predicated on the ability to predict, with relative precision, the output of generation resources and the ability of reserve products to accommodate fluctuations in demand and emergency conditions. The rapid increase in the development of VERs has presented the industry with a variety of challenges related to predicting the exact output of VERs at any point in time.

15. These challenges could become more manageable for System Operators through the development and use of state-of-the-art meteorological forecasts, which are supplied with data from multiple diverse locations. Specifically, the implementation of enhanced forecasting tools and procedures could assist in projecting the output of VERs with greater accuracy, thereby promoting the efficient scheduling of all generation resources to meet expected demand, especially during the morning increase and evening decrease in demand. Enhanced forecasting could also allow System Operators in all regions to anticipate system ramping events more effectively and respond to them in an

economically efficient manner, thereby ensuring that jurisdictional rates are just and reasonable.

16. To assist in the development of state-of-the-art forecasting tools for VERs, the Commission seeks comment on whether and, if so, how the Commission should modify existing operational data reporting requirements. The Commission also aims to determine what data and what level of data-sharing is necessary, coupled with advanced communication and metering tools, to ensure that VERs are integrated in a reliable and efficient manner, particularly with respect to scheduling, ramping needs, and the procurement of reserve services.

17. To that end, the Commission seeks comment on the following questions:

1. What are the current practices used to forecast generation from VERs? Will current practices in forecasting VERs' electricity production be adequate as the number of VERs increases? If so, why?

2. What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (e.g., meteorological, outage, etc.), sampling frequency, and sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?

3. What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?

4. What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the pro forma OATT would be necessary to accommodate these requirements?
5. State-of-the-art forecasts may necessitate the sharing of meteorological data across regions to assure that the movement of weather patterns can be accurately predicted and analyzed. To what extent should meteorological data be made publically available to aid in the development of state-of-the-art forecasts? Should the Commission require public utilities to maintain a meteorological data reporting system? If so, should such a system be akin to or in collaboration with Open Access Same Time Information System (OASIS) postings? In order to retain the confidentiality of commercially sensitive data reported by VERs for the purpose of developing state-of-the-art forecasts, what limits and/or safeguards should be established to protect operational data and generator outage reports?
6. Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting? For example, should transmission providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?
7. To what extent is a lack of data regarding the operational status and forecasted

output of distributed, or behind-the-meter, VERs leading to a need for additional reserves? To what extent would the provision of such data reduce the need for System Operators to rely on reserves?

B. Scheduling Flexibility and Scheduling Incentives

1. Scheduling Flexibility

18. Existing scheduling practices were designed at a time when virtually all generation on the system could be scheduled with relative precision. With increasing numbers of VERs, System Operators appear to be relying more on expensive reserves, such as regulation reserves, to balance the variation in energy output from VERs. Improvements in scheduling procedures may offer the potential for greater efficiency in dispatching all energy resources if the degree of variability can be reduced, better anticipated, and/or planned for more precisely.

19. In regions outside of those run by regional transmission organizations (RTOs) or independent system operators (ISOs), resources typically schedule transmission service on an hourly basis and are only allowed to adjust their schedules during the hour for emergency situations that threaten reliability.[18] Because transmission schedules for VERs are typically set 20-30 minutes ahead of the hour, the forecast of output may be 90 minutes old by the end of the operating hour. Additionally, by limiting the ability of

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[18] Section 13.8 of the pro forma OATT requires transmission customers to schedule use of firm point-to-point transmission service by 10:00 a.m. the day prior to operation. However, section 13.8 of the pro forma OATT gives the transmission provider the discretion to accept schedule changes no later than 20 minutes prior to the operating hour.

resources to adjust their schedules during the hour or to submit shorter scheduling timeframes, non-RTO/ISO System Operators may not be utilizing the full operational flexibility of the resources on their systems to change output levels to address the variable output of VERs.

20. In RTOs/ISOs, real-time markets are employed to address imbalance energy needs. Real-time markets utilize intra-hour economic dispatch of internal resources, which affords RTOs/ISOs the ability to respond quickly and economically to fluctuations in VER supply. However, RTOs/ISOs often schedule external resources on an hourly basis, consistent with non-RTO/ISO scheduling practices.

21. The Commission questions whether the retention of existing transmission scheduling practices as additional VERs come on-line is causing rates for reserves (as part of transmission service) to become unjust and unreasonable by inhibiting the ability of VERs to establish operationally-viable schedules and preventing System Operators from utilizing the full flexibility of their systems. Accordingly, the Commission seeks to explore whether greater scheduling flexibility, such as intra-hour scheduling, could provide benefits to the system and facilitate the reliable and efficient use of all resources.

22. To that end, the Commission seeks comment on the following questions:

1. Would shorter scheduling intervals allow System Operators to more efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?

2. What are the benefits and costs of allowing resources and transactions to

schedule on an intra-hour basis, and what tariff and/or technical barriers exist to implementing intra-hour scheduling? Are there best practices that could be implemented to facilitate greater intra-hour scheduling?

3. Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?
4. Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?
5. How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?
6. If intra-hour scheduling is implemented in non-RTO/ISO regions, how would RTO/ISO scheduling practices at interties be affected? Would intra-hour scheduling at interties present problems for RTO/ISO markets? If so, describe the problems and feasible solutions for intra-hour scheduling at interties.

2. <u>Scheduling Incentives</u>

23. Reforms to existing scheduling practices to promote intra-hour scheduling could enable VERs to more accurately meet their schedules, which in turn should help to ensure

that rates for reserves are just and reasonable. In order to achieve overall improvements in scheduling accuracy, particularly with respect to VERs, it is also important to ensure that such resources have the appropriate incentives to meet their schedules with real-time output to the extent feasible.

24. In Order No. 890, the Commission adopted pro forma OATT imbalance provisions that implemented a graduated bandwidth approach to imbalance penalties that recognized the link between escalating deviations and potential reliability impacts on the system.[19] The Commission exempted intermittent resources from the third tier deviation band, which required imbalances of greater than 7.5 percent of scheduled amounts (or 10 MW) to be settled at 125 percent of the incremental cost or 75 percent of the decremental cost of providing the imbalance energy.[20] Instead, intermittent resources with such imbalances would only be subject to the second tier imbalance penalties, i.e., 110 percent of the incremental or 90 percent of the decremental cost.[21] The Commission is interested in examining the experience with this exemption to determine whether it has resulted in scheduling practices that may result in an overall rate for transmission service that is not just and reasonable.

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[19] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 663-64.

[20] Id. P 664-65.

[21] In RTOs/ISOs, because real-time markets are used to address imbalance energy needs, VERs are typically exempt from some pro forma OATT deviation penalties.

25. To that end, the Commission seeks comment on the following questions:

1. Has the exemption from third-tier penalty imbalances worked as a targeted exemption that recognizes operational limitations of VERs,[22] or has it encouraged inefficient scheduling behaviors to develop? If the latter, what reforms to this exemption would encourage more accurate scheduling practices?
2. Assuming that efficient forecasting and scheduling practices help minimize deviations between scheduled and actual energy output of VERs, are additional incentives needed to encourage VERs to submit schedules that are informed by state-of-the-art forecasting? What would be the proper incentives?
3. Under an RTO/ISO market design, are there sufficient incentives to encourage VERs to submit accurate schedules? What costs and/or penalties should be assigned to VERs when their real-time output is not accurately scheduled on a forward basis? Should VERs be treated the same as conventional resources with respect to deviations from their production schedules?

C. <u>Day-Ahead Market Participation and Reliability Commitments</u>

1. <u>Day-ahead Market Participation</u>

26. The presence of a day-ahead market is a key characteristic of most RTOs/ISOs. When resources are scheduled accurately in the day-ahead market, subsequent out-of-

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[22] For the purposes of this section, the term "VERs" refers to the same resources that the Commission identified as "intermittent" in Order No. 890. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 666.

market commitments are minimized and market participants can manage their financial exposure more effectively. However, VERs appear to participate in the day-ahead market on a limited basis, choosing instead to self-schedule the majority of their supply in the real-time energy markets (i.e., act as a price taker). Because day-ahead schedules are financially binding, there can be significant financial risk for VERs participating in the day-ahead market and not being able to meet these obligations in the real-time market. This may serve as a disincentive for VERs to participate in the day-ahead market.

27. In light of the increasing number of VERs, the Commission is interested in receiving comments on whether the lack of day-ahead market participation may be resulting in costly out-of-market commitments, thereby rendering rates unjust and unreasonable, as well as whether the financial risk associated with participating in the day-ahead market may unduly discriminate against VERs by inhibiting their ability to participate in such a market. Such comments should enable the Commission to determine whether reforms are necessary to facilitate VERs to participate more in the day ahead market rather than primarily in the real time market.

28. To that end, the Commission seeks comment on the following questions:

1. Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases? Will out-of-market commitments increase as the number of VERs increases? If so, why?
2. How can new or existing market design features assure that the day-ahead

market will accurately represent real-time system conditions and that day-ahead and real-time energy prices will converge under the scenario of increasing numbers of VERs?

3. Do current RTO/ISO market designs place undue barriers to participation in forward markets by VERs? Could the timing of certain RTO/ISO market design elements, such as the day-ahead market, be modified in a manner that would facilitate VERs to participate more in the day ahead market rather than primarily in the real time market? If so, how?
4. Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?
5. Should the financial risk of VERs' participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs' participating in the day-ahead market? If so, what are they?
6. Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

2. Reliability Commitments

29. Following the results of the day-ahead market, RTOs/ISOs conduct a reliability unit commitment process to ensure that sufficient generation will be available in the appropriate places to meet the RTO/ISO's estimate of the next day's forecasted demand. If the cleared resources are insufficient to meet that demand, the RTO/ISO commits additional units. Non-RTOs/ISOs conduct a similar assessment to evaluate the sufficiency of bilaterally scheduled resources.

30. Similar to the inefficiency associated with the lack of intra-hour transmission scheduling, the lack of a more frequent unit commitment process may result in unjust and unreasonable rates by causing System Operators to make inefficient reliability commitment decisions, which may cause unnecessary system uplift costs.

31. To that end, the Commission seeks comment on the following questions:

1. Would the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour reduce the amount of reserves needed and/or reduce system uplift costs? What would be the optimal time (e.g., 4 to 6 hours ahead of the operating hour) for such a process?
2. Would an additional market that coincides with the timing of an intra-day reliability commitment process be beneficial in the forward scheduling of VERs? If such a market is implemented, would an intra-day reliability commitment process be necessary? Should the frequency of scheduling

intervals resulting from such a market coincide with intra-hour schedules discussed above?

3. What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?

D. <u>Balancing Authority Coordination</u>

32. Smaller balancing authorities may be unable to capture the benefits associated with VERs that are spread across a large and/or diverse geographical area. Accordingly, the Commission is interested in determining whether a limited ability of smaller balancing authorities to efficiently integrate VERs may result in rates that are unjust and unreasonable. Therefore, the Commission seeks to explore whether increased coordination among balancing authorities has the potential to enlarge the base of generation and demand available to customers, thereby making variability more manageable and ultimately reducing overall costs. In this proceeding, the Commission seeks comments on ways to increase customer access to energy, capacity, and reserve products through the use of pseudo-ties,[23] dynamic scheduling, and/or other tools and agreements.

33. To that end, the Commission seeks comment on the following questions:

1. Will smaller balancing authorities, when operated individually, have higher

[23] Pseudo-ties are defined as telemetered readings or values that are used as "virtual" tie line flows between balancing authorities where no physical tie line exists.

VER integration costs than geographically or electrically larger balancing authorities? If so, why?

2. Should the Commission encourage the consolidation of balancing authorities? If so, indicate the potential for and impediments to consolidation among balancing authorities and the means by which the Commission should encourage consolidation.
3. What tools or arrangements (e.g., dynamic schedules, pseudo-ties, and virtual balancing authorities) are available and/or could be enhanced or created to reduce barriers to greater operational coordination among balancing authorities? What role should the Commission play in facilitating inter-balancing authority coordination?
4. What are the costs and benefits, if any, associated with the proliferation of small generation-only balancing authorities? How do NERC Certification and Reliability Standards encourage or discourage the creation of small generation-only balancing authorities?
5. The Commission is interested in receiving comments on whether the integration of VERs with small host balancing authorities may limit the benefits derived from geographical diversity and increase integration costs. Should the Commission encourage and/or facilitate the creation of a VER balancing authority, essentially a large area virtual balancing authority primarily designed to accommodate VERs across a broad geographic region? What would be the benefits and costs of creating such a large area entity?

6. Would a large area VER balancing authority be capable of capturing the reduced variability of VERs located across a broad and geographically diverse region? What tariff or technical limitations would prevent and/or inhibit the development of a large area VER balancing authority?
7. What reliability impacts may be associated with the creation of a large area VER balancing authority?
8. Should a large area VER balancing authority be limited only to VERs? Why or why not?
9. Should the Commission consider establishing specific policies that support the creation of a large area VER balancing authority? If so, why?

E. <u>Reserve Products and Ancillary Services</u>

34. During normal operations, System Operators maintain reserve products to ensure that demand and generation are kept in balance.[24] Reserve products are generally defined by the timeframes in which they are available. In the moments-to-seconds timeframe, Frequency Response services provide an immediate arresting of the frequency decline or increase due to any system imbalance. In the seconds-to-minutes timeframe, regulation services provide maneuverable capacity (typically through automatic generation control),

[24] Contingency Reserves are used to recover from variations caused by a system disturbance but not for balancing normal variations.

and in the minutes-to-hours time frame, following services[25] allow for the rapid deployment of resources to maintain and/or restore system balance.

35. The Commission seeks to explore whether the variability associated with increased VER deployment may result in an over-reliance on expensive reserves, such as regulation reserves. The Commission seeks to ensure that reserves are being used efficiently such that the resulting rates are just, reasonable, and not unduly discriminatory. The Commission is also interested in ensuring that requirements for VERs to contribute to system reliability are not unduly discriminatory. Finally, the Commission seeks to ensure that changes to the rules or requirements do not hinder the reliable operation of the grid under the reliability standards.[26]

36. To that end, the Commission seeks comment on the following questions:

1. To what extent do existing reserve products provide System Operators with the most cost-effective means of maintaining reliability during VER ramping events? To what extent would the other reforms discussed herein, if implemented, mitigate the need for additional reforms to existing reserve products without adversely impacting system reliability?

[25] In RTO/ISO markets, following services are generally provided through real-time energy markets.

[26] See 16 U.S.C. 824o(a)(3).

2. How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?
3. Would a following or similar reserve product facilitate the reduction of costs associated with ensuring that sufficient reserve capacity is available to address the uncertainty and variability associated with VERs? If so, what are the ideal characteristics of such a product?
4. Existing contingency reserve products were designed to be utilized by System Operators to respond to disturbances (i.e., contingency events) due to a loss of supply and to assure system reliability.[27] Does or should the definition of a contingency event include extreme VER ramping events? If so, would an additional level of contingency reserves be needed to achieve the same level of system reliability? In responding to this question, please include a proposed definition of "extreme ramping event."
5. Should a new category of reserves, that would be similar to contingency reserves, be developed to maintain reliability during VER ramping events in a cost effective manner? If so, what benefit would such reserves provide to System Operators and customers?

[27] Disturbance Control Performance, Standard No. BAL-002-0 (Apr. 1, 2005).

6. Could the expanded use of reserve-sharing programs between balancing authorities contribute to lowering the costs associated with integrating VERs? If so, how?
7. Should the ancillary services provisions of the pro forma OATT be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs? If so, how?
8. Are there new sources and/or providers for reserve products (such as inter-balancing authority pooling arrangements, demand response aggregators and/or storage devices) that can be used to maintain reliability and lower reserve costs during VER ramping events? Based on experience, are there characteristics of these new sources of reserves that would positively or negatively impact their ability to match the reserve product needs presented by the variability of VERs?
9. To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?
10. To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?
11. Should the Commission revisit the reactive power requirements set forth in

Order No. 661?[28] What other requirements, if any, should apply to VERs to ensure that all resources contribute to grid reliability in a manner that is not unduly discriminatory?

F. Capacity Markets

37. The procurement of capacity services, either through resource adequacy bilateral programs or centralized capacity markets, is commonplace in RTO/ISO markets.[29] Typically, VERs are eligible to receive compensation for capacity services in most RTOs/ISOs. However, due to their operating characteristics and the capacity rating rules, which vary among RTOs/ISOs, VERs are eligible to offer only a portion of their nameplate capacity. The price paid for capacity services depends in part on the amount of available capacity. Additionally, resources that participate in capacity markets typically are required to offer capacity in the day-ahead market, which, as discussed above, VERs often do not do.

38. The Commission questions whether existing rules governing capacity markets may result in rates for capacity services that are not just and reasonable. Moreover, to the extent existing rules limit the ability of VERs to provide capacity services that they are

[28] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 50-51.

[29] Centralized capacity markets exist in ISO New England, Inc., New York Independent System Operator, Inc., and PJM Interconnection LLC. California Independent System Operator Corp. and Midwest Independent Transmission System Operator, Inc. rely primarily on bilateral resource adequacy programs to procure capacity services.

capable of providing, the Commission seeks to explore whether such rules may be unduly discriminatory.

39. To that end, the Commission seeks comment on the following questions:

1. Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?
2. Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?
3. As more VERs choose to become capacity resources, will existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services? If not, what reforms may be necessary? For instance, should the Commission examine formation of forward ancillary services capacity markets?
4. Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?

G. Real-time Adjustments

40. Redispatch and curtailment protocols vary depending on the region of the country and scenario. The Commission is interested in receiving comments on whether VERs may be curtailed too frequently in response to transmission congestion, minimum

generation events,[30] and ramping events, because of a lack of clarity in curtailment protocols. Accordingly, the Commission seeks to explore whether redispatch and curtailment practices and protocols, especially as they relate to VERs, are transparent, non-discriminatory and efficient. The Commission also seeks to determine whether redispatch and curtailment protocols may result in unnecessary costs, thereby rendering rates unjust and unreasonable.

41. To that end, the Commission seeks comment on the following questions:

1. How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?
2. Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?
3. Some RTOs/ISOs will redispatch VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?
4. Should transmission loading relief protocols be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs? If so, how? Similarly, should redispatch and curtailment protocols in non-RTOs/ISOs be revised to consider economic merit for all resources? If so, how?

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[30] During a minimum generation event, system demand is at its lowest and generation resources tend to operate at the minimum feasible output level.

5. Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments during a minimum generation event? Should conventional base-load resources be offered incentives to lower their minimum operating levels or even shut down during minimum generation events to reflect an economically efficient dispatch of resources? If so, what would be the benefits and costs of doing so?
6. To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

IV. Comment Procedures

42. The Commission invites interested persons to submit comments, and other information on the matters, issues and specific questions identified in this notice.

43. Comments are due [Insert date that is 60 days from publication in the **FEDERAL REGISTER**]. Comments must refer to Docket No. RM10-11-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

44. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word

processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

45. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

46. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

V. Document Availability

47. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

48. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

49. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission. Commissioner Norris voting present.

(S E A L)

Kimberly D. Bose,
Secretary.

Docket No. UE-216
Exhibit PPL(TAM)/105
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

List of Expected Contract Changes

February 2010

List of Known Contracts Expected to be Updated During 2011 TAM

Sales and Purchases of Electricity and Natural Gas

1. New sales and purchases contracts, physical and financial, including contracts with qualifying facilities.
2. New sales and purchase contracts for natural gas, physical and financial.
3. Bell Mountain qualifying facility, approved by the Idaho Commission on January 25, 2010.
4. Lower Valley Electric qualifying facility increased its generating capacity. The new contract is currently before the Idaho Commission for approval.
5. Sales contract with Black Hills Company for energy price and fixed payments.
6. Sales contract with Public Service Company of Colorado for energy price.
7. Purchase contracts for generation from the Mid Columbia projects for fixed costs.
8. Purchase contract with Tri-State Generation and Transmission Association Inc for energy price.
9. New purchase contract with Monsanto for ready reserves.
10. New purchase contract with Kennecott for generation incentives.
11. New contract with Lewis County for purchase of station service for the Chehalis plant for a new contract with Lewis County.
12. Purchase contracts with Grant Public Utility District for 10 average megawatt energy and displacement energy for changes in BPA's Cost Recovery Adjustment Clause ("CRAC") and changes in BPA's transmission rates.
13. Contracts whose prices are linked to market indexes and inflation rates.
14. Purchase expenses of PGE Cove based on PGE projection.

Transportation and Storage of Natural Gas

15. Pipeline changes for transporting natural gas from market to Company's Generating Facilities.
16. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

17. Wheeling expenses that are impacted by changes in third parties' transmission tariff rates.
18. Wind integration charges for wind resources in the Company's control area and for Company wind resources in BPA's control area (see Direct Testimony of Greg Duvall).
19. Transmission from the Four Corners market to the SP15 market.
20. Contracts whose prices are linked to market indexes and inflation rates.

Coal Expense –

The table below lists the coal and transportation contracts that maybe affected by changed in volumes as well as changes to market indexes and inflation rates

		Captive		Fixed Price Contracts		Escalating Contracts		Transportation Contacts	
Plant	**Supplier/Mine**	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Bridger	Bridger Coal Company								
	Black Butte					√	√		
	Union Pacific Railway							√	√
Carbon	Deer Creek	√							
	Arch - Skyline			√	√				
	Utah Trucking							√	√
Cholla	Peabody Coalsales - Lee Ranch Mine					√	√		
	BNSF Railway							√	√
Colstrip	Westmoreland - Rosebud Mine					√	√	√	√
Craig	Trapper Mine	√							
	Rio Tinto- - Colowyo Mine						√		
	Union Pacific Railway								√
Hayden	Peabody Coalsales - Twentymile Mine					√	√		
	Pirate Trucking							√	√
Hunter	Deer Creek	√							
	Arch - Sufco			√	√				
	Arch - Dugout			√	√				
	Utah Trucking							√	√
Huntington	Deer Creek	√							
D Johnston	Black Hills - Wyodak Mine					√	√		
	Western Fuels - Dry Fork Mine								
	Peabody - Rawhide Mine			√	√				
	BNSF Railway							√	√
Naughton	Chevron Mining - Kemmerer Mine					√	√		
Wyodak	Black Hills - Wyodak Mine					√	√		

Docket No. UE-216
Exhibit PPL(TAM)/200
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Stefan A. Bird

February 2010

Q. Please state your name, business address and present position with PacifiCorp ("Company").

A. My name is Stefan A. Bird. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232. My present position is Senior Vice President, Commercial and Trading.

Qualifications

Q. Briefly describe your education and business experience.

A. I hold a B.S. in mechanical engineering from Kansas State University. I joined PacifiCorp Energy and assumed my current position in January 2007. From 2003 to 2006, I served as president of CalEnergy Generation U.S., an owner and operator of Qualifying Facility and merchant generation assets, including geothermal and natural gas-fired cogeneration projects across the United States. From 1999 to 2003, I was vice president of acquisitions and development for MidAmerican Energy Holdings Company. From 1989 to 1997, I held multiple positions at Koch Industries, Inc., including energy trading, financial trading, acquisitions, project engineering and maintenance planning in the United States, Latin America and Europe.

In my current position I oversee the Company's Commercial and Trading organization which is responsible for electricity and natural gas wholesale activities, dispatch of all of the Company's owned and contracted generation resources and wholesale purchases and sales to balance the Company's load and resources. My organization is also responsible for the Company's load and revenue forecast, integrated resource plan ("IRP") and net power costs ("NPC") modeling. Most relevant to this filing, I am responsible for acquisition of power resources for utilization in the Company's east and west balancing authorities (the "System") by means that include the negotiation of power purchase agreements ("PPAs") and the acquisition of generation resources through the requests for proposal ("RFP") process.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the prudence of the Top of the World Wind Energy, LLC ("Top of the World") power purchase agreement ("PPA"), for which the Company is seeking cost recovery in this proceeding. Specifically, my testimony:

- Describes the procedural history of the 2008R-1 RFP.
- Describes the economic analysis and selection of Top of the World in the 2008R-1 RFP.
- Provides a description of Top of the World.

Q. Please summarize your testimony.

A. The Top of the World PPA is a prudent acquisition that contributes to PacifiCorp's diverse and cost-effective portfolio of resources. The PPA was acquired through a fair, transparent and robust competitive bidding process that was overseen by an independent evaluator ("IE") appointed by the Commission.

The 2008R-1 RFP

Q. Please describe the 2008R-1 RFP procedural history.

A. The Company filed its initial application for the 2008R-1 RFP on March 4, 2008.

The Commission thereafter opened Docket UM 1368 and selected Boston Pacific Company to serve as the Oregon IE.[1] The purpose of the 2008R-1 RFP was to request and evaluate proposals to fulfill a portion of the renewable resource generation identified in the Company's 2007 Integrated Resource Plan ("2007 IRP"). To that end, the 2008R-1 RFP solicited System-wide renewable resources that would enable the Company to meet its service obligations. The 2008R-1 RFP targeted acquisition of up to 500 megawatts ("MW") of renewable resources with commercial operation dates prior to December 31, 2011 and with a limit of 300 MW per resource.[2] On September 23, 2008, the Commission approved the 2008R-1 RFP, with certain conditions that were all satisfied by the Company.[3] The 2008R-1 RFP was issued to the market on October 6, 2008 with proposals due December 22, 2008.

Q. Did the Company reissue the 2008R-1 RFP after receipt of proposals on December 22, 2008?

A. Yes. Because the acquisition of a successful resource under the 2008R-1 RFP would not occur until 2009, the Company was required to amend and reissue the 2008R-1 RFP to accommodate Utah's resource procurement law.[4]

Q. Were there any changes to the Amended 2008R-1 RFP?

A. Yes. The Amended 2008R-1 RFP included three changes: (1) it allowed the original bidders to update their proposals; (2) it provided new bidders the opportunity to bid into the amended 2008R-1 RFP; and (3) it modified the

[1] *See* Order No. 08-248.
[2] 300 MW is the upper limit permitted by Utah Senate Bill 202. Qualifying Facilities that are at least 10 MW were eligible, pursuant to Guideline 6 in Order No. 06-446.
[3] *See* Order No. 08-476.
[4] *See* Utah Code Ann. 54-17-502(2) (a) (i).

schedule to allow for updated and new proposals.

Q. Did the Commission approve the Amended 2008R-1 RFP?

A. Yes. The Commission approved the Amended 2008R-1 RFP on January 21, 2009.[5] The Company issued the Amended 2008R-1 RFP to the market on January 26, 2009 with proposals due February 27, 2009.

Q. Please describe the Amended 2008R-1 RFP Initial Shortlist selection process.

A. The Company's analysis of the 2008R-1 RFP proposals focused on determining which resources would provide the best value to customers on a System-wide planning basis to meet customer requirements at the least cost, on a risk-adjusted basis. To achieve these objectives, the Company evaluated alternatives in a two step process. First, the Company selected three Initial Shortlists: (a) west wind; (b) east wind; and (c) all other renewable resources. The purpose of first selecting three separate Initial Shortlists was to capture location resource diversity and the different sources of renewable resources.

To select groups of proposals to comprise each of the three Initial Shortlists, the IE agreed with the Company's goal to: (1) select the proposals with the greatest net benefit in terms of price and non-price benefits; (2) select a diversity of bidders and projects; (3) select a mix of PPA and build-own-transfer ("BOTs") alternatives; (4) determine a relatively clear split between the score of the last proposal evaluated and the next proposal that was not selected; and (5) achieve the RFP goal that each category contain up to 500 MW or 5 proposals.[6] Each proposal received up to a maximum of 100 points. The three Initial

[5] *See* Order No. 09-017.
[6] *See* The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2008R-1/Renewables RFP (May15, 2009) at p. 13.

Shortlists were comprised of the highest scoring proposals in each of the three respective segments, based on price (up to 70 points) and non-price factors (up to 30 points). The price factor was derived by using the PacifiCorp Structuring and Pricing RFP base model, which determines the top-performing proposals on the basis of the net present value revenue requirement ("Net PVRR") per kilowatt month. The Net PVRR component views the value of the energy and capacity as a positive and the offsetting costs of the proposal as a negative. The more positive the Net PVRR, the more valuable a given resource is to the Company's customers.

The non-price factors evaluated were negative or positive based on the following criteria: (a) conformity with Amended 2008R-1 RFP proposal requirements; (b) conformity with the *pro forma* PPA or BOT documents and/or Asset Acquisition and Sale Agreement, attached as exhibits to the amended 2008R-1 RFP; (c) feasibility of the proposal; (d) site control or permitting of the proposal; and (e) operational viability of the proposal. Based on the application of the price and non-price factors, the Company selected proposals to comprise the Initial Shortlists.

Q. Please describe the 2008R-1 RFP Final Shortlist selection process.

A. After the Company selected the three Initial Shortlists, it moved to step two of the evaluation process – selection of the Final Shortlist. To select the Final Shortlist, the Company applied its next highest alternative cost for compliance ("ACC") analysis methodology for renewable resources to each of the three Initial Shortlists. This resource-specific analysis allows the Company to compare a resource against the potential next highest alternative cost for renewable resource compliance. In essence, the result of the ACC analysis shows how the resource compares to the undifferentiated power market. The ACC analysis also incorporates a resource's risk-adjusted system benefit, using the Company's IRP stochastic production cost model. A negative ACC indicates that the resource is valued below undifferentiated market alternatives; whereas a positive ACC indicates that the resource is valued above undifferentiated market alternatives. Upon completion of the ACC analysis and the PVRR (d) analysis, the Company selected four alternatives for inclusion in the Final Shortlist, one of which was Top of the World.

Q. Did the IE concur with the 2008R-1 Final Shortlist and recommend acknowledgment?

A. Yes. The IE concurred with the selection of the Final Shortlist and recommended its acknowledgment by the Commission. *See* The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2008R-1 Renewables RFP (May 15, 2009) in Docket UM 1368 ("Final Report"), attached as Confidential Exhibit PPL(TAM)/201.

Q. Please explain the basis of the IE's recommendation, as outlined in the IE's Final Report.

A. The IE based its recommendation to acknowledge the 2008R-1 RFP Final Shortlist on six key points. First, the selected proposals represented the resources with the greatest net benefits to customers as determined by the ACC. Second, the proposals represented the top options from a competitive process. Third, the

IE's independent analysis confirmed that the selected proposals represent the lowest cost alternatives for customers, with an accounting for risk. Fourth, the shortlist provided a diversity of projects, bidders, and transaction types for negotiations going forward. Fifth, the 2008R-1 RFP aligned with the Company's IRP process. Sixth, the Company agreed to conduct an analysis at the time it made its procurement decision to show how the accuracy of output projections and asset life were reflected in the final decision.

Q. Did the IE determine that the 2008R-1 RFP process was fair and transparent?

A. Yes. On page 14, the Final Report states:

> [Throughout the 2008R-1 process the IE was] in constant contact with the Company and had multiple discussions on dozens of issues. The IE believes the quality of the effort is reflected in the excellent response to the RFP. All of this work has led to what we believe was a fair and transparent process which complies with Commission guidelines and will, we hope, lead to a positive result with the supply of new renewable resources for the ratepayers of Oregon.

Q. Did Commission Staff recommend acknowledgment of the 2008R-1 RFP Final Shortlist to the Commission?

A. Yes. Commission Staff reached the following conclusions in its June 11, 2009 report to the Commission:

> 1. PacifiCorp conducted its 2008R-1 RFP fairly and properly;
> 2. PacifiCorp selected the best bids for the revised final shortlist consistent with the cost-risk decision criteria used to develop the renewable resource schedule acknowledged in the 2007 IRP; and
> 3. PacifiCorp's revised Final Shortlist represents the best options from a very competitive procurement process and is indicative of current market for renewable resources.[7]

[7] Public Utility Commission of Oregon Staff Report (June 11, 2009) at p. 7.

Q. Did the Commission acknowledge the 2008R-1 RFP Final Shortlist?

A. Yes. The Commission acknowledged the Final Shortlist at its June 16, 2009 public meeting.[8]

Q. Did the IE conclude that the negotiation phase of the RFP was conducted in a fair and reasonable manner?

A. Yes. The IE concluded that the negotiation phase of the 2008R-1 RFP process was carried out in a fair and reasonable manner. *See* Boston Pacific report of the Independent Evaluators on negotiations in PacifiCorp 2008R-1RFP (September 18, 2009) at p. 1, attached as Confidential Exhibit PPL(TAM)/202.

Q. Did the IE's report on the negotiation phase of the RFP conclude that Top of the World was the best choice of projects from the final shortlist?

A. Yes. The IE considered price, technology and willingness to meet the requirements of the RFP in reaching this conclusion.

Q. Does the record developed in the RFP process show that Top of the World is a prudent and cost-effective resource?

A. Yes. Additionally, the acquisition of Top of the World is consistent with PacifiCorp's IRP action plan and PacifiCorp's renewable resource commitments resulting from the MidAmerican Energy Holdings Company acquisition. These are generally discussed in the direct testimony of Company witness Mr. Mark R. Tallman in the Company's general rate case filing.

Q. Please describe the Top of the World PPA.

A. Top of the World is a 20-year PPA for 200.2 MW and associated renewable energy credits. The Company will purchase all of the output associated with the

[8] *See* Order No. 09-247.

project. PacifiCorp has the option to purchase the facility at fair market value at the conclusion of the initial 20-year term. The Top of the World project is comprised of 66 General Electric turbines (each capable of producing 1.5 MW) and 44 Siemens Energy, Inc. turbines (each capable of producing 2.3 MW). The project is located in located near Casper, Wyoming and is expected to reach commercial operation on or before December 31, 2010. The terms and conditions of the PPA are consistent with other wind PPAs entered into by the Company.

Q. Does this conclude your direct testimony?

A. Yes.

CONFIDENTIAL
Docket No. UE-216
Exhibit PPL(TAM)/201
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Stefan A. Bird

Oregon IE Final Closing Report

February 2010

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CONFIDENTIAL
Docket No. UE-216
Exhibit PPL(TAM)/202
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Stefan A. Bird

Oregon IE Report on Negotiations

February 2010

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REDACTED
Docket No. UE-216
Exhibit PPL(TAM)/300
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Cindy A. Crane

February 2010

Q. Please state your name, business address and present position with PacifiCorp ("Company").

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. My position is Vice President, Interwest Mining Company and Fuel Resources for PacifiCorp Energy.

Qualifications

Q. Briefly describe your business experience.

A. I joined PacifiCorp in 1990 and have held positions of increasing responsibility, including Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis and Vice President of Strategy and Division Services. My responsibilities have included the management and development of PacifiCorp's ten-year business plan, assessing individual business strategies for PacifiCorp Energy, managing the construction of the Company's Wyoming wind plants and assessing the feasibility of a nuclear power plant. In March 2009, I was appointed to my present position as Vice President of Interwest Mining Company and Fuel Resources. In my position I am responsible for the operations of Energy West Mining Company and Bridger Coal Company as well as overall coal supply acquisition and fuel management for PacifiCorp's coal plants.

Purpose and Summary

Q. What is the purpose of your testimony?

A. I explain the Company's overall approach to providing the coal supply for the Company's coal plants.

Q. Please summarize your testimony.

A. My testimony:

- Explains the coal cost increases reflected in the filing and describes the primary reasons for the increases.
- Provides background on the third-party coal contract revisions that are driving the increase in coal costs in this filing.
- Reviews the Company's affiliate mine coal costs, which have decreased in this filing, and compares them to other supply alternatives.
- Demonstrates that Oregon customers benefit from the Company's diversified coal supply strategy.

Overview of the coal supplies for the Company's coal plants

Q. How does the Company plan to meet fuel supplies for its coal plants in 2011?

A. The Company employs a diversified coal supply strategy. For 2011, the Company will meet approximately 67 percent of its fuel requirements from third-party multi-year contracts and 33 percent with coal from the Company's affiliate mines.

Q. What percentage of the Company's third-party coal contracts are fixed and what percentage are indexed?

A. In 2011, approximately 33 percent of the Company's total coal supply will be priced under fixed-price contracts and 34 percent will be priced under contracts that escalate/de-escalate based on changes to producer and consumer price indices.

Q. Please identify the affiliate mines which supply the Company's coal plants.

A. Coal production from the Company's Bridger mine is dedicated to the Jim Bridger plant. Energy West's Deer Creek mine supplies a portion of the coal requirements for the Carbon, Hunter and Huntington plants and the Trapper mine is dedicated to the Craig plant.

Coal cost increases in the 2011 Transition Adjustment Mechanism ("TAM")

Q. Do coal costs in the 2011 TAM reflect an increase from cost levels reflected in the Company's August update in the 2010 TAM?

A. Yes. Coal costs have increased by approximately $34 million on a total-company basis. Average coal costs have increased from $26.84/ton in the 2010 TAM to $28.61/ton in 2011 in this filing, an increase of $1.77/ton.

Q. Are the cost increases in this case due to third-party coal supply or coal from affiliate mines?

A. The increases in coal costs are due solely to third-party coal supply and transportation agreements. Affiliate mine costs have significantly decreased from the 2010 TAM. Deer Creek mine costs have decreased from [redacted] Bridger mine costs have decreased from [redacted]. Overall, third-party coal supply costs have increased by approximately $55 million total-company, while the costs of coal from affiliate mines have decreased by approximately $21 million total-company, netting to the $34 million total-company increase reflected in this case.

Q. Which PacifiCorp plants are experiencing cost increases in third-party contract coal supply?

A. In 2011, the Company expects third-party coal supply cost increases at the Hunter, Naughton, Jim Bridger and Dave Johnston plants as follows:

- The majority of the Hunter plant's requirements are supplied by the Sufco mine under the Company's long-term coal supply agreement with Arch CoalSales. The Company expects an increase in the Sufco coal price pursuant to a price re-opener.
- The Company expects an increase in the Naughton plant coal price pursuant to a price re-opener provision with Chevron Mining related to the Kemmerer mine.
- The Company will experience an increase in the delivered cost of Black Butte coal to the Jim Bridger plant due to higher rail and coal cost expense.
- The Company will experience an increase in Dave Johnston plant costs as a result of coal contracts executed in 2009 following the Company's Powder River Basin ("PRB") coal solicitation.

Coal cost increases related to contract price-reopeners

Q. Please describe the Arch CoalSales ("Arch") contract price-reopener.

A. The Company's long-term coal supply agreement with Arch for Sufco coal extends through 2020 and contains several price re-openers. The next price re-opener occurs January 1, 2011. The Company and Arch are required to exchange estimates of the prevailing market price for Sufco coal for 2011 by April 1, 2010.

If the differential between the two estimates exceeds five percent, the price is determined by a three factor formula. The three factor formula would [redacted].

Q. Please explain what price is included in the 2011 TAM.

A. The Company utilized the three factor formula to estimate the 2011 Sufco coal price. The weighted average coal price of [redacted] represents a [redacted] over the 2010 price of [redacted] This results in a [redacted] in Hunter plant costs as compared to the 2010 TAM.

Q. How does the 2011 Sufco price compare to current Utah coal prices?

A. Favorably. Based on discussions with other coal producers, Utah coal is being transacted for approximately $41/ton, beginning in 2010, for a multi-year arrangement. Additionally, the Sufco coal price represents the delivered price into the Hunter plant whereas other market transactions are priced at Freight On Board ("F.O.B") loadout. Taking into consideration transportation costs, the 2011 Sufco price is approximately [redacted] ton less than market.

Q. Please describe the price reopener related to the Naughton contract.

A. The Company's long-term coal supply agreement with Chevron Mining's Kemmerer mine extends through 2016 and contains several price re-openers. The next price re-opener was scheduled to occur on January 1, 2011. However, [redacted], Chevron Mining requested that the Company consider advancing the price re-opener date to January 1, 2010. The Company is willing to consider advancing the re-opener date only if there is an overall cost reduction over the remaining term.

Q. How is the price set under the Chevron Mining contract?

A. If Chevron Mining and the Company cannot agree to a negotiated price, then the Company is required per the terms of the re-opener provision to issue a solicitation for both coal supplies and transportation service. Chevron Mining then has the option to match this price for the five-year period starting January 1, 2011. The January 1, 2011 contract price would then be adjusted quarterly for changes in contract indices.

Q. Has the Company evaluated supply alternatives for the Naughton plant?

A. Yes. The Company has evaluated alternative supplies. Besides Chevron Mining's Kemmerer mine, there are only two other mines operating in Southwest Wyoming: the Company's Bridger Coal Company and Kiewit Mining's Black Butte. Bridger Coal is dedicated to the Jim Bridger plant and the preponderance of Black Butte's contract capacity during 2011 through 2014 (all but [redacted]) is committed to the Jim Bridger plant and the Valmy plant. With almost all of the Southwest Wyoming coal production dedicated to the Jim Bridger and Valmy plants, the majority of the Naughton plant's requirements would need to be imported from mines in Utah and the PRB.

Q. What is the distance between the alternate sources and the Naughton plant and the cost of the alternate sources?

A. The Black Butte mine is approximately 133 miles from the Naughton plant. The

Utah and PRB mines are located approximately 363 and 676 miles, respectively, from the plant. Taking into account transportation costs, the Company estimates the average cost to replace the coal supplied by the Kemmerer mine in 2011 would be in excess of [redacted].

Q. Please explain what price is included in the 2011 TAM for Kemmerer coal supply to the Naughton plant.

A. The 2011 estimate is based on a proposal the Company made to Chevron Mining in December 2009. The Company proposed a coal price of [redacted] (based on a heat content of 9,600 British thermal units per pound), with an effective date of January 1, 2010. Chevron Mining has since countered the Company's proposal with an offer of [redacted], also effective January 1, 2010. The estimated average price in the 2011 TAM of [redacted], was derived by escalating the Company's proposed 2010 coal price for changes to contract specific producer and consumer price indices. This price represents an [redacted].

Q. Please explain the increase in Black Butte costs.

A. The delivered cost of Black Butte coal to the Jim Bridger plant has increased in the 2011 TAM [redacted]. The 2010 TAM included 377,946 tons of prior Black Butte contract coal deliveries at a delivered price [redacted] and 1,500,000 tons of Black Butte coal under the current Black Butte agreement at a [redacted]. Overall, delivered Black Butte costs are $8.3 million higher total-company in the 2011 TAM, with the majority of the increase, $6.3 million, attributable to the depletion of the Black Butte carryover tonnage. Escalation of the contract specific producer and consumer price increases under the current Black Butte agreement account for approximately $1.7 million of the overall increase and higher rail costs, approximately $0.3 million, constitute the remainder of the increase. The increase in the rail rates reflects the terms of the new Union Pacific rail agreement executed in November 2009.

Q. Please explain the increase in Dave Johnston plant coal supply costs.

A. In the spring of 2009, the Company released a solicitation for PRB coal supplies for the Dave Johnston plant. The Company sought replacement coal supplies for contracts terminating in 2010. The increase in coal costs relates to the higher priced contract supplies obtained through the solicitation. As a result of these new contracts, coal supply costs to the Dave Johnston plant have increased by $5.3 million total-company.

Q. Will third-party contract costs be updated during this proceeding?

A. Yes. Pursuant to the TAM Guidelines, the costs associated with contracts will be updated in the Rebuttal Update if new information is available.

Coal costs related to the Company's affiliate mines

Q. Please provide an overview of the decreases in costs at the Deer Creek mine.

A. As noted above, Deer Creek costs in the 2011 TAM are projected to [redacted] in 2011. The savings in production costs is the result of increased mine production. Deer Creek is projected to produce 3.63 million tons in 2011 compared to 3.0 million tons in 2010. The lower production level in 2010 was the result of the rebuild/replacement of the longwall system during the latter half of 2010.

Q. Did customers benefit from the longwall rebuild?

A. Yes. The longwall shields had reached their maximum life of 40,000 cycles. Continued mining required either purchase of a new longwall system or rebuild of the existing system. While the rebuild/replacement option was cheaper than purchasing a new longwall, both options were significantly superior to the alternative of purchasing replacement coal. Even with the cost increase in 2010, the Deer Creek mine was the least-cost supply for the Utah plants. The longwall rebuild allows the Deer Creek mine to extract the remaining economic coal reserves at a substantial savings relative to market. Like any major capital addition, the costs of the Deer Creek mine longwall rebuild caused 2010 costs to be higher than they otherwise would have been. However, customers will reap the benefit of the longwall rebuild for an extended period of time. This long-term view of mining operations is imperative, rather than a focus on a single-year view.

Q. Please explain the change in Bridger Coal costs between 2010 and 2011.

A. The 2011 TAM reflects a significant decrease in Bridger Coal Company costs from [redacted]. Underground operating costs [redacted] and surface operating costs [redacted]. The decrease in underground costs is largely due to a combination of increased coal production and reductions in contract services, royalties and transfers from inventory. The royalty reduction is a result of the Company's renegotiation of a royalty agreement with Anadarko in

2009. The decrease in Bridger surface costs, approximately [redacted], is mostly due to the accounting impact of the Emerging Issues Task Force 04-6 (EITF 04-6) pronouncement. Without EITF 04-6, surface costs are similar, approximately [redacted], in both 2010 and 2011.

Q. Are the Bridger surface and underground separate operations?

A. No. Bridger Coal Company is an integrated mine complex and, as was discussed in the 2010 TAM, the surface operation is the swing coal supply for the Bridger plant. Both operations share common assets such as conveyors, scrapers, dozers, light duty vehicles, maintenance shops, administrative buildings, etc. Mine administration personnel including purchasing, planning, engineering, environmental services, information technology, safety, human resources, administration services, government relations and surveying support both operations.

Q. Would Bridger Coal Company costs increase if surface mining ceased?

A. Yes. Without the surface operation, Bridger mine costs would increase. Shared costs, services and assets would be assigned entirely to the underground operations or final reclamation. The increase in final reclamation costs would require increased funding of the reclamation trust. Additionally, the Bridger mine would continue to absorb the depreciation expense for surface operation equipment such as draglines, scrapers, trucks, and other assets that will still be utilized in final reclamation activities.

Q. What other benefits does the Bridger surface operation provide?

A. The Bridger surface operation is critical to coal blending. All coal, surface and underground, has an assigned coal quality. Mine plans are developed on a monthly basis to ensure that the delivered coal product to the Bridger plant meets specific coal quality constraints. On a daily basis surface operation and deliveries are adjusted to meet specification. All coal blending is performed by the surface operation.

Q. Do other mines in the Southwest Wyoming blend coal?

A. Yes. Both the Kemmerer and Black Butte mines blend coal. Both mining operations blend coal from multiple pits to meet specific contract parameters. With underground mining, however, operations are limited to the mining of a single coal seam. Without the surface operation, Bridger Coal could not deliver a coal stream that would meet the requirements of Jim Bridger plant's operations.

Q. Please compare Bridger mine costs relative to other supply options.

A. Bridger mine costs remain considerably less than any available market alternative. Though Kiewit Mining recently notified the Company that the Black Butte mine has [redacted] tons of uncommitted production capacity through 2014, this amount is insufficient to replace the coal supply from the Bridger mine. In any event, the delivered cost of this uncommitted tonnage to the Jim Bridger plant is approximately [redacted] in 2011, over [redacted] higher than Bridger mine costs in the test period. The projected delivered cost of PRB coal in 2011 is over $[redacted] than Bridger mine costs in the test period without considering the costs of capital modifications required for the Bridger plant to switch to PRB coal supply.

Q. What is the least cost supply for the Jim Bridger plant?

A. It is the supply approach that is being pursued by the Company. A combination of the current Black Butte agreement and the combined Bridger surface and underground operations continue to be the optimum coal supply for the Jim Bridger plant. Without the Bridger surface operation, the Jim Bridger plant test period costs would be higher. The decremental cost of Bridger surface production, mine costs less fixed costs, is approximately [redacted] in 2011 which remains considerably less than the delivered cost of either Black Butte or PRB coals.

Q. How does the Company's Trapper mine compare to other alternatives?

A. The 2011 Trapper price is [redacted] delivered to the Craig plant. This price is considerably less than the Company's other Colorado coal supplies. The price is over [redacted] less than the delivered price under the Company's long-term coal supply agreement with the Colowyo mine.

Summary

Q. Please summarize the benefits of the Company's coal supply strategy.

A. Coal costs in 2010 and 2011 vividly demonstrate the value of the Company's diversified coal supply strategy. In 2010, affiliate coal costs increased significantly, in large part due to operation of EITF 04-6 and the longwall rebuild at the Deer Creek mine, while third-party coal supply costs increased more moderately. In 2011, third-party coal supply costs are increasing more significantly, due to the timing of long-term coal contract re-openers. At the same time, these cost increases are offset by reductions in affiliate mining costs, associated with increased production capacity and the operation of EITF 04-6. Thus, in both 2010 and 2011, customers will benefit from the Company's diversified strategy by more balanced and less extreme cost increases.

Q. Does the nature of the Company's coal cost increases in 2010 and 2011 demonstrate the importance of reviewing the reasonableness of the Company's coal costs on a multiple year basis, instead of a single year?

A. Yes. A least-cost fueling strategy cannot be based on annual determination of the Company's captive mines relative to other available supply options. Decisions to invest in the affiliate operations are made on the same basis the Company makes with respect to investment in its service territory. Such analysis is based on an extended period over a mine's life. While mine production costs will typically fluctuate more than contract prices, it is unreasonable to limit recovery of production costs in a particular year when the captive operations are superior to other supply options over the extended period and consistently provide benefits to customers. This is especially true in a case such as this where there is no risk of cross subsidization between the utility and the affiliate.

Q. Please summarize your testimony.

A. The Company has pursued a diversified coal supply strategy, relying on fixed contracts, indexed contracts and affiliate-owned coal mines to meet the fuel needs of its coal plants. This strategy has resulted in a long-term, stable and low-cost supply of coal. In particular, the operating cost for each of the three affiliate mines remains considerably less than market. The Company is committed to a regular review of its fueling strategies in its efforts to reduce fuel costs and optimize customer benefits.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-216
Exhibit PPL(TAM)/400
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

February 2010

Q. Please state your name, business address and present position with PacifiCorp ("Company").

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah St., Suite 2000, Portland, Oregon 97232. My present position is Consultant, Pricing & Cost of Service, in the Regulation Department.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the Regulation Department in October 2000. I assumed my present responsibilities in May 2001. In my present position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six state service territory, including those contained in the Company's last Oregon General Rate Case ("GRC"), Docket UE 210 ("UE 210") and Transition Adjustment Mechanism ("TAM"), Docket UE 207 ("UE 207").

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I will explain the changes in the Company's TAM tariff design since the last TAM filing, present the Company's proposed TAM rates and proposed tariff, and provide a summary of the impact on customer bills.

TAM Design

Q. Please explain the changes in the design of the Company's tariffs which have been implemented since UE 207.

A. In UE 210, the Company proposed to split net power costs ("NPC") out of generation costs and to collect NPC through a separate tariff rate schedule. The purpose of this change was to allow NPC to be more easily and accurately updated through TAM filings. In order to accomplish this, the Company proposed a new Schedule 201 to collect the Company's approved NPC. Schedule 200, which up until that time collected all generation costs, was redesigned to collect only the non-NPC generation costs. This new tariff structure was accepted by the parties and included in the all-party Rate Spread and Rate Design Stipulation approved by the Commission in Order No. 10-022. The Company's revised Schedule 200 and new Schedule 201, Net Power Costs, Cost-Based Supply Service, became effective February 2, 2010. Schedule 201 currently in effect is designed to collect the NPC as approved in UE 207.

Q. How does this new tariff design affect the Company's TAM filing in this proceeding?

A. As a result of the changes described above, only Schedule 201, Net Power Costs, Cost-Based Supply Service, is proposed to be revised in this proceeding. Schedule 200, which currently collects the non-NPC generation costs, changes only in the context of a GRC.

Q. In the previous TAM, the Company proposed a load growth/loss adjustment consistent with Order No. 08-543 from Docket UE 199. Is this adjustment necessary with the new tariff design?

A. No. A specific load growth/loss adjustment is no longer required with the new tariff rate design. However, the proposed Schedule 201 rates are designed to collect the Company's proposed NPC in the test period and they reflect changes in load.

Rates and Tariff

Q. How has the proposed NPC been allocated to the customer classes?

A. Consistent with the TAM Guidelines adopted by Order No. 09-274, the proposed NPC has been allocated to the customer classes proportionately based on the generation allocation factors from the Company's most recent cost of service study which has been filed in the Company's general rate case concurrent with this TAM filing. This methodology accurately allocates NPC to each customer class and ensures synchronization between the TAM and GRC. The spread of the proposed NPC to the customer classes is shown in page one of Exhibit PPL(TAM)/401.

Q. Do the rate blocks and ratios between the rate blocks in proposed Schedule 201 follow the same design as the existing Schedule 201 rates?

A. Yes. The rates in the Company's proposed Schedule 201 utilize the same rate blocks and ratios between rate blocks as the existing Schedule 201 rates.

Q. Have you prepared an exhibit showing the calculation of the proposed Schedule 201 rates?

A. Yes. Pages two and three of Exhibit PPL(TAM)/401 show the calculation of the proposed Schedule 201 rates.

Q. Please describe Exhibit PPL(TAM)/402.

A. Exhibit PPL(TAM)/402 contains the revised tariff Schedule 201, Net Power Costs, Cost-Based Supply Service.

Q. Is the Company proposing changes to its one-year or three-year option Transition Adjustment tariffs (Schedule 294 and 295) at this time?

A. No. The Transition Adjustment will be established in November, just prior to the open enrollment window. The Company will file changes to Schedule 294 and 295, Transition Adjustment, once the final TAM rates have been posted and are known.

Comparison of Present and Proposed Customer Rates

Q. What are the overall effects of the changes proposed in this filing?

A. The overall proposed increase to rates is 7.0 percent on a net basis. Page one of Exhibit PPL(TAM)/403 shows the estimated effect of the Company's proposed prices by Delivery Service schedule both exclusive (base) and inclusive (net) of applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Have you prepared an exhibit which shows the impact on customer bills as a result of the proposed changes to Schedule 201?

A. Yes. Exhibit PPL(TAM)/403 contains monthly billing comparisons for customers at different usage levels served on each of the major Delivery Service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. What is the estimated monthly impact to an average size residential customer?

A. The estimated monthly impact to a residential customer using 900 kilowatt-hours is $4.79.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-216
Exhibit PPL(TAM)/401
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Development of TAM Adjustment for January 1, 2011

February 2010

PACIFIC POWER
STATE OF OREGON
Functionalized Net Power Cost Revenue Requirement
Forecast 12 Months Ended December 31, 2011
Dollars in Thousands

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	Functionalized Generation Revenue Requirement from GRC	$681,451	$300,091	$57,108	$44	$112,264	$921	$71,097	$5,563	$32,080	$74,817	$18,570	$8,015	$880
2														
3	Net Power Cost Revenue Requirement	$312,779												
4	Net Power Cost Collection for Schedules not included in COS Study*	$9,315												
5	Net Power Cost for Schedules Included in COS Study	$303,464												
6														
7														
8	Generation Allocation Factors from GRC	100.00%	44.04%	8.38%	0.01%	16.47%	0.14%	10.43%	0.82%	4.71%	10.98%	2.73%	1.18%	0.13%
9														
10														
11	**Functionalized Net Power Cost Revenue Requirement- (Target)**	**$303,464**	**$133,637**	**$25,431**	**$20**	**$49,993**	**$410**	**$31,661**	**$2,477**	**$14,286**	**$33,317**	**$8,270**	**$3,569**	**$392**
12	Other Generation Revenue Requirement - (Target)	$377,987	$166,455	$31,677	$24	$62,271	$511	$39,436	$3,086	$17,794	$41,499	$10,301	$4,446	$488
13	Sum	$681,451	$300,091	$57,108	$44	$112,264	$921	$71,097	$5,563	$32,080	$74,817	$18,570	$8,015	$880

*Revenues by rate schedule as follow:

Schedule 47 Primary	$6,169
Schedule 47 Transmission	$2,556
Schedule 15	$243
Schedule 50	$208
Schedule 51 (partial)	$231
Schedule 52	$25
Employee Discount	($117)
Total not in study	$9,315

Exhibit PPL(TAM)/401
Ridenour/1

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues
Forecast 12 Months Ended December 31, 2011

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Dollars	Proposed Schedule 201 Rates	Proposed Schedule 201 Dollars
Schedule 4, Residential					
First Block kWh	2,377,829,142	1.660 ¢	$39,471,964	2.137 ¢	$50,814,209
Second Block kWh	1,474,392,920	1.967 ¢	$29,001,309	2.533 ¢	$37,346,373
Third Block kWh	1,454,617,662	2.428 ¢	$35,318,117	3.126 ¢	$45,471,348
	5,306,839,724		$103,791,390		$133,631,930
				Change	$29,840,540
Employee Discount					
First Block kWh	6,771,575	1.660 ¢	$112,408	2.137 ¢	$144,709
Second Block kWh	5,162,720	1.967 ¢	$101,551	2.533 ¢	$130,772
Third Block kWh	6,110,715	2.428 ¢	$148,368	3.126 ¢	$191,021
	18,045,010		$362,327		$466,502
		Discount	-$90,582	Discount	-$116,626
				Change	-$26,044
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	783,723,212	2.057 ¢	$16,121,186	2.666 ¢	$20,894,061
All additional kWh, per kWh	229,300,282	1.527 ¢	$3,501,415	1.979 ¢	$4,537,853
	1,013,023,494		$19,622,601		$25,431,914
				Change	$5,809,313
Primary Voltage					
1st 3,000 kWh, per kWh	578,291	1.993 ¢	$11,525	2.582 ¢	$14,931
All additional kWh, per kWh	236,272	1.479 ¢	$3,494	1.917 ¢	$4,529
	814,563		$15,019		$19,460
				Change	$4,441
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,416,918,832	1.984 ¢	$28,111,670	2.527 ¢	$35,805,539
All additional kWh, per kWh	577,181,460	1.930 ¢	$11,139,602	2.458 ¢	$14,187,120
	1,994,100,292		$39,251,272		$49,992,659
				Change	$10,741,387
Primary Voltage					
1st 20,000 kWh, per kWh	9,894,023	1.927 ¢	$190,658	2.341 ¢	$231,619
All additional kWh, per kWh	7,832,834	1.875 ¢	$146,866	2.278 ¢	$178,432
	17,726,857		$337,524		$410,051
				Change	$72,527
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	196,457,339	2.188 ¢	$4,298,487	2.779 ¢	$5,459,549
All additional kWh, per kWh	1,087,336,008	1.897 ¢	$20,626,764	2.410 ¢	$26,204,798
	1,283,793,347		$24,925,251		$31,664,347
				Change	$6,739,096
Primary Voltage					
1st 20,000 kWh, per kWh	12,885,979	2.131 ¢	$274,600	2.748 ¢	$354,107
All additional kWh, per kWh	89,396,932	1.842 ¢	$1,646,691	2.375 ¢	$2,123,177
	102,282,911		$1,921,291		$2,477,284
				Change	$555,993
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	1,516,088	2.836 ¢	$42,996	3.497 ¢	$53,018
Winter, All additional kWh, per kWh	1,266,400	1.932 ¢	$24,467	2.382 ¢	$30,166
Summer, All kWh, per kWh	145,634,151	1.932 ¢	$2,813,652	2.382 ¢	$3,469,005
	148,416,639		$2,881,115		$3,552,189
				Change	$671,074
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	10,180	2.747 ¢	$280	3.387 ¢	$345
Winter, All additional kWh, per kWh	58,532	1.872 ¢	$1,096	2.307 ¢	$1,350
Summer, All kWh, per kWh	634,837	1.872 ¢	$11,884	2.307 ¢	$14,646
	703,549		$13,260		$16,341
				Change	$3,081
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	146,179,349	1.869 ¢	$2,732,092	2.393 ¢	$3,498,072
Off-Peak, per off-peak kWh	113,993,767	1.819 ¢	$2,073,547	2.343 ¢	$2,670,874
	260,173,116		$4,805,639		$6,168,946
				Change	$1,363,307
Transmission Voltage					
On-Peak, per on-peak kWh	67,655,805	1.785 ¢	$1,207,656	2.281 ¢	$1,543,229
Off-Peak, per off-peak kWh	45,412,927	1.735 ¢	$787,914	2.231 ¢	$1,013,162
	113,068,732		$1,995,570		$2,556,391
				Change	$560,821

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues
Forecast 12 Months Ended December 31, 2011

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Dollars	Rates	Dollars
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	372,517,681	1.956 ¢	$7,286,446	2.484 ¢	$9,253,339
Off-Peak, per off-peak kWh	206,694,746	1.906 ¢	$3,939,602	2.434 ¢	$5,030,950
	579,212,427		$11,226,048		$14,284,289
				Change	$3,058,241
Primary Voltage					
On-Peak, per on-peak kWh	861,217,531	1.869 ¢	$16,096,156	2.393 ¢	$20,608,936
Off-Peak, per off-peak kWh	542,546,863	1.819 ¢	$9,868,927	2.343 ¢	$12,711,873
	1,403,764,394		$25,965,083		$33,320,809
				Change	$7,355,726
Transmission Voltage					
On-Peak, per on-peak kWh	203,502,316	1.785 ¢	$3,632,516	2.281 ¢	$4,641,888
Off-Peak, per off-peak kWh	162,576,434	1.735 ¢	$2,820,701	2.231 ¢	$3,627,080
	366,078,750		$6,453,217		$8,268,968
				Change	$1,815,751
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	10,138,210	1.077 ¢	$109,189	2.392 ¢	$242,567
	10,138,210		$109,189		$242,567
				Change	$133,378
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	10,594,088	0.885 ¢	$93,758	1.965 ¢	$207,847
	10,594,088		$93,758		$207,847
				Change	$114,089
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	16,562,760	1.397 ¢	$231,382	3.102 ¢	$513,202
	16,562,760		$231,382		$513,202
				Change	$281,820
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	1,061,343	1.070 ¢	$11,356	2.376 ¢	$25,218
	1,061,343		$11,356		$25,218
				Change	$13,862
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,250,113	0.457 ¢	$42,273	1.015 ¢	$93,889
	9,250,113		$42,273		$93,889
				Change	$51,616
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	846,933	0.787 ¢	$6,665	1.748 ¢	$14,804
	846,933		$6,665		$14,804
				Change	$8,139
TOTAL Before Employee Discount			**$243,698,903**		**$312,893,104**
Employee Discount			-$90,582		-$116,626
TOTAL SCHEDULE 201	**12,638,452,242**		**$243,608,321**		**$312,776,478**
Schedule 33 kWh	127,459,027			**Change**	**$69,168,157**
Schedule 47 Unscheduled kWh	8,748,730				
Total Forecast kWH	12,774,659,998				

Docket No. UE-216
Exhibit PPL(TAM)/402
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule 201

February 2010

PACIFIC POWER & LIGHT COMPANY
NET POWER COSTS
COST-BASED
SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-270, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0 - 500 kWh	2.137¢			(I)
		501-1000 kWh	2.533¢			
		> 1000 kWh	3.126¢			

For Schedule 4, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	**Primary**	**Transmission**	
23	First 3,000 kWh, per kWh	2.666¢	2.582¢		
	All additional kWh, per kWh	1.979¢	1.917¢		
28	First 20,000 kWh, per kWh	2.527¢	2.341¢		
	All additional kWh, per kWh	2.458¢	2.278¢		
30	First 20,000 kWh, per kWh	2.779¢	2.748¢		
	All additional kWh, per kWh	2.410¢	2.375¢		
41	Winter, first 100 kWh/kW, per kWh	3.497¢	3.387¢		
	Winter, all additional kWh, per kWh	2.382¢	2.307¢		
	Summer, all kWh, per kWh	2.382¢	2.307¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing *(continued)*

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	2.484¢	2.393¢	2.281¢	(I)
	Per kWh, Off-Peak	2.434¢	2.343¢	2.231¢	

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52	For dusk to dawn operation, per kWh	2.376¢
	For dusk to midnight operation, per kWh	2.376¢
54	Per kWh	1.748¢

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire
Mercury Vapor	7,000	76	$1.82
Mercury Vapor	21,000	172	$4.11
Mercury Vapor	55,000	412	$9.86
High Pressure Sodium	5,800	31	$0.74
High Pressure Sodium	22,000	85	$2.03
High Pressure Sodium	50,000	176	$4.21

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)
Horizontal, per lamp	$1.49	$3.38	$8.10
Vertical, per lamp	$1.49	$3.38	

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$1.49		
On 26-foot poles, vertical, per lamp	$1.49		
On 30-foot poles, horizontal, per lamp		$3.38	
On 30-foot poles, vertical, per lamp		$3.38	
On 33-foot poles, horizontal, per lamp			$8.10

(I)

(continued)

Monthly Billing *(continued)*

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$1.49		
On 26-foot poles, vertical, per lamp	$1.49		
On 30-foot poles, horizontal, per lamp		$3.38	
On 30-foot poles, vertical, per lamp		$3.38	
On 33-foot poles, horizontal, per lamp			$8.10

(I)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	70	31	$0.96
High Pressure Sodium	9,500	100	44	$1.36
High Pressure Sodium	16,000	150	64	$1.99
High Pressure Sodium	22,000	200	85	$2.64
High Pressure Sodium	27,500	250	115	$3.57
High Pressure Sodium	50,000	400	176	$5.46
Metal Halide	9,000	100	39	$1.21
Metal Halide	12,000	175	68	$2.11
Metal Halide	19,500	250	94	$2.92
Metal Halide	32,000	400	149	$4.62

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	70	31	$0.31
High Pressure Sodium	9,500	100	44	$0.45
High Pressure Sodium	16,000	150	64	$0.65
High Pressure Sodium	22,000	200	85	$0.86
High Pressure Sodium	27,500	250	115	$1.17
High Pressure Sodium	50,000	400	176	$1.79
Metal Halide	9,000	100	39	$0.40
Metal Halide	12,000	175	68	$0.69
Metal Halide	19,500	250	94	$0.95
Metal Halide	32,000	400	149	$1.51
Metal Halide	107,800	1,000	354	$3.59

Non-Listed Luminaire, per kWh 1.015¢

(I)

(continued)

Docket No. UE-216
Exhibit PPL(TAM)/403
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

February 2010

TAM Price Change

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2011

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
		Pre	Pro									Base Rates		Net Rates		
Line		Sch	Sch	No. of		Base		Net	Base		Net					Line
No.	Description	No.	No.	Cust	MWh	Rates	Adders[1]	Rates	Rates	Adders[1]	Rates	($000)	%[2]	($000)	%[2]	No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	484,011	5,306,840	$472,654	$19,369	$492,023	$502,495	$19,369	$521,864	$29,841	6.3%	$29,841	6.1%	1
2	**Total Residential**			484,011	5,306,840	$472,654	$19,369	$492,023	$502,495	$19,369	$521,864	$29,841	6.3%	$29,841	6.1%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,207	1,013,838	$94,181	($628)	$93,553	$99,995	($628)	$99,367	$5,814	6.2%	$5,814	6.2%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,419	2,011,827	$133,835	$10,844	$144,679	$144,649	$10,844	$155,493	$10,814	8.1%	$10,814	7.5%	4
5	Gen. Svc. 201 - 999 kW	30	30	882	1,386,076	$85,559	$4,215	$89,774	$92,854	$4,215	$97,069	$7,295	8.5%	$7,295	8.1%	5
6	Large General Service >= 1,000 kW	48	48	212	2,349,055	$128,583	($2,726)	$125,857	$140,813	($2,726)	$138,087	$12,230	9.6%	$12,230	9.8%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	381,991	$19,268	($446)	$18,822	$21,192	($446)	$20,746	$1,924	9.6%	$1,924	9.8%	7
8	Agricultural Pumping Service	41	41	6,211	149,120	$16,054	($3,276)	$12,778	$16,728	($3,276)	$13,452	$674	4.2%	$674	5.3%	8
9	Agricultural Pumping - Other	33	33	2,056	127,459	$5,327	$272	$5,599	$5,327	$272	$5,599	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			93,994	7,419,366	$482,807	$8,255	$491,062	$521,558	$8,255	$529,813	$38,751	8.0%	$38,751	7.9%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,167	10,138	$1,332	$136	$1,468	$1,465	$136	$1,601	$133	10.0%	$133	9.1%	11
12	Street Lighting Service	50	50	258	10,594	$1,198	$144	$1,342	$1,312	$144	$1,456	$114	9.5%	$114	8.5%	12
13	Street Lighting Service HPS	51	51	710	16,563	$3,021	$338	$3,359	$3,303	$338	$3,641	$282	9.3%	$282	8.4%	13
14	Street Lighting Service	52	52	65	1,061	$117	$15	$132	$131	$15	$146	$14	12.0%	$14	10.6%	14
15	Street Lighting Service	53	53	266	9,250	$605	$83	$688	$657	$83	$740	$52	8.6%	$52	7.6%	15
16	Recreational Field Lighting	54	54	103	847	$75	$7	$82	$83	$7	$90	$8	10.7%	$8	9.8%	16
17	**Total Public Street Lighting**			8,569	48,453	$6,348	$723	$7,071	$6,951	$723	$7,674	$603	9.5%	$603	8.5%	17
18	**Total Sales to Ultimate Consumers**			586,574	12,774,659	$961,809	$28,347	$990,156	$1,031,004	$28,347	$1,059,351	$69,195	7.2%	$69,195	7.0%	18
19	**Employee Discount**				18,045	($397)	($17)	($414)	($423)	($17)	($440)	($26)		($26)		19
20	**Total Sales with Employee Discount**			586,574	12,774,659	$961,412	$28,330	$989,742	$1,030,581	$28,330	$1,058,911	$69,169	7.2%	$69,169	7.0%	20
21	AGA Revenue					$2,800		$2,800	$2,800		$2,800	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			586,574	12,774,659	$964,212	$28,330	$992,542	$1,033,381	$28,330	$1,061,711	$69,169	7.2%	$69,169	7.0%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 4 + Supply Service Schedule 200
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$16.44	$16.93	$0.49	2.98%
200	$24.13	$25.11	$0.98	4.06%
300	$31.83	$33.31	$1.48	4.65%
400	$39.52	$41.49	$1.97	4.98%
500	$47.23	$49.68	$2.45	5.19%
600	$55.66	$58.70	$3.04	5.46%
700	$64.09	$67.72	$3.63	5.66%
800	$72.52	$76.73	$4.21	5.81%
900	**$80.96**	**$85.75**	**$4.79**	**5.92%**
1,000	$89.40	$94.77	$5.37	6.01%
1,100	$98.93	$105.02	$6.09	6.16%
1,200	$108.48	$115.29	$6.81	6.28%
1,300	$118.01	$125.54	$7.53	6.38%
1,400	$127.56	$135.81	$8.25	6.47%
1,500	$137.10	$146.06	$8.96	6.54%
1,600	$146.64	$156.32	$9.68	6.60%
2,000	$184.81	$197.36	$12.55	6.79%
3,000	$280.22	$299.96	$19.74	7.04%
4,000	$375.63	$402.56	$26.93	7.17%
5,000	$471.03	$505.16	$34.13	7.25%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Secondary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$58	$67	$61	$70	5.40%	4.68%
	750	$78	$87	$83	$92	6.01%	5.39%
	1,000	$98	$107	$105	$113	6.39%	5.86%
	1,500	$138	$147	$148	$157	6.80%	6.39%
10	1,000	$98	$107	$105	$113	6.39%	5.86%
	2,000	$179	$187	$191	$200	7.03%	6.70%
	3,000	$259	$268	$278	$286	7.27%	7.03%
	4,000	$326	$335	$350	$359	7.19%	7.00%
20	4,000	$353	$362	$377	$386	6.64%	6.48%
	6,000	$488	$497	$521	$530	6.71%	6.59%
	8,000	$623	$632	$666	$674	6.75%	6.66%
	10,000	$758	$767	$810	$819	6.78%	6.70%
30	9,000	$745	$754	$792	$801	6.27%	6.20%
	12,000	$948	$957	$1,009	$1,017	6.41%	6.35%
	15,000	$1,150	$1,159	$1,225	$1,234	6.49%	6.44%
	18,000	$1,353	$1,362	$1,441	$1,450	6.55%	6.51%
31	9,300	$771	$780	$819	$828	6.24%	6.17%
	12,400	$980	$989	$1,043	$1,052	6.38%	6.33%
	15,500	$1,189	$1,198	$1,267	$1,275	6.47%	6.43%
	18,600	$1,399	$1,408	$1,490	$1,499	6.54%	6.50%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price Single Phase	Present Price Three Phase	Proposed Price Single Phase	Proposed Price Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
5	500	$57	$66	$60	$69	5.32%	4.60%
	750	$76	$85	$81	$90	5.95%	5.33%
	1,000	$96	$105	$102	$111	6.33%	5.79%
	1,500	$135	$144	$144	$153	6.75%	6.33%
10	1,000	$96	$105	$102	$111	6.33%	5.79%
	2,000	$174	$183	$186	$195	6.99%	6.64%
	3,000	$251	$260	$270	$279	7.24%	6.99%
	4,000	$317	$326	$340	$349	7.17%	6.97%
20	4,000	$344	$352	$366	$375	6.61%	6.44%
	6,000	$474	$483	$506	$515	6.69%	6.57%
	8,000	$605	$614	$646	$655	6.73%	6.64%
	10,000	$736	$745	$786	$795	6.76%	6.68%
30	9,000	$724	$733	$769	$778	6.25%	6.18%
	12,000	$920	$929	$979	$988	6.39%	6.33%
	15,000	$1,117	$1,126	$1,189	$1,198	6.48%	6.43%
	18,000	$1,313	$1,322	$1,399	$1,408	6.54%	6.50%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$351	$377	7.16%
	7,500	$527	$569	7.96%
	10,500	$703	$761	8.36%
31	9,300	$711	$763	7.32%
	15,500	$1,074	$1,160	8.07%
	21,700	$1,435	$1,556	8.44%
40	12,000	$913	$980	7.35%
	20,000	$1,381	$1,493	8.10%
	28,000	$1,839	$1,995	8.45%
60	18,000	$1,362	$1,463	7.39%
	30,000	$2,052	$2,218	8.10%
	42,000	$2,739	$2,970	8.45%
80	24,000	$1,802	$1,936	7.41%
	40,000	$2,718	$2,939	8.12%
	56,000	$3,634	$3,942	8.46%
100	30,000	$2,240	$2,406	7.42%
	50,000	$3,385	$3,660	8.12%
	70,000	$4,530	$4,914	8.47%
200	60,000	$4,402	$4,732	7.48%
	100,000	$6,692	$7,239	8.17%
	140,000	$8,983	$9,747	8.51%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
15	4,500	$344	$363	5.57%
	7,500	$508	$540	6.30%
	10,500	$671	$716	6.67%
31	9,300	$693	$732	5.72%
	15,500	$1,031	$1,097	6.41%
	21,700	$1,366	$1,459	6.76%
40	12,000	$889	$940	5.76%
	20,000	$1,325	$1,410	6.44%
	28,000	$1,751	$1,869	6.77%
60	18,000	$1,326	$1,402	5.79%
	30,000	$1,967	$2,094	6.45%
	42,000	$2,606	$2,782	6.78%
80	24,000	$1,752	$1,854	5.82%
	40,000	$2,604	$2,772	6.46%
	56,000	$3,456	$3,690	6.79%
100	30,000	$2,176	$2,303	5.83%
	50,000	$3,241	$3,451	6.47%
	70,000	$4,306	$4,598	6.80%
200	60,000	$4,267	$4,518	5.89%
	100,000	$6,396	$6,813	6.53%
	140,000	$8,525	$9,109	6.84%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,476	$2,651	7.05%
	50,000	$3,437	$3,717	8.16%
	70,000	$4,397	$4,783	8.78%
200	60,000	$4,459	$4,792	7.47%
	100,000	$6,379	$6,924	8.53%
	140,000	$8,300	$9,056	9.11%
300	90,000	$6,575	$7,066	7.48%
	150,000	$9,456	$10,265	8.55%
	210,000	$12,337	$13,463	9.12%
400	120,000	$8,611	$9,261	7.55%
	200,000	$12,452	$13,525	8.62%
	280,000	$16,294	$17,789	9.18%
500	150,000	$10,660	$11,469	7.59%
	250,000	$15,462	$16,799	8.65%
	350,000	$20,264	$22,129	9.21%
600	180,000	$12,709	$13,676	7.61%
	300,000	$18,472	$20,073	8.67%
	420,000	$24,234	$26,469	9.22%
800	240,000	$16,808	$18,092	7.64%
	400,000	$24,491	$26,620	8.70%
	560,000	$32,174	$35,149	9.25%
1000	300,000	$20,906	$22,508	7.66%
	500,000	$30,510	$33,168	8.71%
	700,000	$40,114	$43,829	9.26%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,349	$2,531	7.75%
	50,000	$3,278	$3,570	8.90%
	70,000	$4,207	$4,609	9.55%
200	60,000	$4,246	$4,593	8.16%
	100,000	$6,105	$6,671	9.28%
	140,000	$7,963	$8,749	9.87%
300	90,000	$6,262	$6,774	8.17%
	150,000	$9,049	$9,890	9.29%
	210,000	$11,836	$13,007	9.89%
400	120,000	$8,226	$8,902	8.22%
	200,000	$11,943	$13,058	9.34%
	280,000	$15,659	$17,213	9.93%
500	150,000	$10,185	$11,026	8.25%
	250,000	$14,831	$16,220	9.37%
	350,000	$19,476	$21,415	9.95%
600	180,000	$12,144	$13,150	8.28%
	300,000	$17,719	$19,383	9.39%
	420,000	$23,293	$25,616	9.97%
800	240,000	$16,063	$17,397	8.31%
	400,000	$23,495	$25,708	9.42%
	560,000	$30,927	$34,019	10.00%
1000	300,000	$19,981	$21,645	8.33%
	500,000	$29,271	$32,033	9.44%
	700,000	$38,562	$42,422	10.01%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$208	$230	$185	$222	$246	$185	6.68%	6.99%	0.00%
	5,000	$347	$369	$185	$370	$394	$185	6.68%	6.88%	0.00%
	7,000	$486	$507	$185	$518	$542	$185	6.68%	6.82%	0.00%
Three Phase										
20	6,000	$416	$460	$371	$444	$492	$371	6.68%	6.99%	0.00%
	10,000	$694	$737	$371	$740	$788	$371	6.68%	6.87%	0.00%
	14,000	$971	$1,015	$371	$1,036	$1,084	$371	6.68%	6.82%	0.00%
100	30,000	$2,082	$2,300	$1,514	$2,221	$2,461	$1,514	6.68%	6.99%	0.00%
	50,000	$3,470	$3,689	$1,514	$3,701	$3,942	$1,514	6.68%	6.87%	0.00%
	70,000	$4,857	$5,077	$1,514	$5,182	$5,424	$1,514	6.68%	6.82%	0.00%
300	90,000	$6,245	$6,900	$3,780	$6,662	$7,383	$3,780	6.68%	6.99%	0.00%
	150,000	$10,409	$11,066	$3,780	$11,104	$11,827	$3,780	6.68%	6.87%	0.00%
	210,000	$14,572	$15,232	$3,780	$15,546	$16,271	$3,780	6.68%	6.82%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
TAM Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$199	$220	$175	$213	$236	$175	6.74%	7.06%	0.00%
	5,000	$332	$353	$175	$355	$378	$175	6.74%	6.94%	0.00%
	7,000	$465	$486	$175	$497	$520	$175	6.74%	6.88%	0.00%
Three Phase										
20	6,000	$399	$441	$350	$426	$472	$350	6.74%	7.06%	0.00%
	10,000	$665	$707	$350	$709	$756	$350	6.74%	6.94%	0.00%
	14,000	$930	$972	$350	$993	$1,039	$350	6.74%	6.88%	0.00%
100	30,000	$1,994	$2,205	$1,504	$2,128	$2,361	$1,504	6.74%	7.05%	0.00%
	50,000	$3,323	$3,535	$1,504	$3,547	$3,780	$1,504	6.74%	6.93%	0.00%
	70,000	$4,652	$4,865	$1,504	$4,966	$5,200	$1,504	6.74%	6.88%	0.00%
300	90,000	$5,981	$6,615	$3,770	$6,384	$7,082	$3,770	6.74%	7.05%	0.00%
	150,000	$9,969	$10,605	$3,770	$10,641	$11,341	$3,770	6.74%	6.93%	0.00%
	210,000	$13,956	$14,595	$3,770	$14,897	$15,600	$3,770	6.74%	6.88%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$19,524	$21,156	8.36%
	500,000	$28,413	$31,133	9.57%
	700,000	$37,303	$41,110	10.21%
2,000	600,000	$38,719	$41,982	8.43%
	1,000,000	$55,207	$60,646	9.85%
	1,400,000	$72,270	$79,884	10.54%
4,000	1,200,000	$75,460	$81,986	8.65%
	2,000,000	$109,585	$120,462	9.93%
	2,800,000	$143,710	$158,938	10.60%
6,000	1,800,000	$112,446	$122,235	8.71%
	3,000,000	$163,633	$179,948	9.97%
	4,200,000	$214,821	$237,662	10.63%

Notes:

On-Peak kWh	64.39%
Off-Peak kWh	35.61%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$18,693	$20,312	8.66%
	500,000	$27,254	$29,953	9.90%
	700,000	$35,816	$39,594	10.55%
2,000	600,000	$37,046	$40,284	8.74%
	1,000,000	$52,879	$58,276	10.21%
	1,400,000	$69,286	$76,842	10.91%
4,000	1,200,000	$72,104	$78,580	8.98%
	2,000,000	$104,918	$115,713	10.29%
	2,800,000	$137,733	$152,845	10.97%
6,000	1,800,000	$107,694	$117,409	9.02%
	3,000,000	$156,916	$173,108	10.32%
	4,200,000	$206,138	$228,806	11.00%

Notes:

On-Peak kWh	61.35%
Off-Peak kWh	38.65%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$17,938	$19,470	8.54%
	500,000	$26,215	$28,770	9.74%
	700,000	$34,493	$38,069	10.37%
2,000	600,000	$35,422	$38,487	8.65%
	1,000,000	$50,688	$55,796	10.08%
	1,400,000	$66,527	$73,680	10.75%
4,000	1,200,000	$68,743	$74,873	8.92%
	2,000,000	$100,422	$110,640	10.17%
	2,800,000	$132,102	$146,406	10.83%
6,000	1,800,000	$103,019	$112,214	8.93%
	3,000,000	$150,538	$165,864	10.18%
	4,200,000	$198,057	$219,514	10.83%

Notes:

On-Peak kWh	55.59%
Off-Peak kWh	44.41%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.