PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 17, 2011

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 11-005 - PacifiCorp's 2012 Transition Adjustment Mechanism
Schedule 201, Net Power Costs, Cost-Based Supply Service
Schedule 205, TAM Adjustment for Other Revenues

PacifiCorp d/b/a Pacific Power submits for filing an original and five copies of the tariff pages identified below, to implement PacifiCorp's 2012 Transition Adjustment Mechanism ("TAM"). The Company is requesting an effective date of January 1, 2012 for these tariff sheets.

A. Description of Filing

The purpose of the TAM filing is to update net power costs for 2012 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 if the TAM is filed on a stand-alone basis (i.e., not in a year in which the Company files a general rate case), then it will be filed no later than April 1. The Company is not filing a general rate case in 2011, accordingly, the Company is filing the 2012 TAM prior to April 1, 2011.

This tariff filing is supported by testimony and exhibits from the following Company witnesses addressing net power costs and pricing:

- Greg Duvall, Director, Long-Range Planning and Net Power Costs
- Cindy A. Crane, Vice President, Interwest Mining and Fuel Resources (Confidential and Redacted Versions are included in the filing.)
- Judy Ridenour, Regulatory Consultant, Cost of Service and Pricing

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
Original Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Original Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Original Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues

C. Correspondence

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

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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
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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 216, as indicated on the attached certificate of service. Confidential material in support of the filing has been provided to parties pursuant to the Protective Order adopted by Order No. 10-069.

Very truly yours,

Andrea L. Kelly /B

Andrea L. Kelly
Vice President, Regulation
Enclosures

cc: UE 216 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 17th of March, 2011, I caused to be served, via email or overnight delivery, 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.

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Ariel Son
Coordinator, Regulatory Operations

Affidavit

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE ___

In the Matter of: PACIFICORP, dba PACIFIC POWER 2012 Transition Adjustment Mechanism Schedule 201, Cost-Based Supply Service	**AFFIDAVIT OF DEAN HARMON**

STATE OF UTAH)
) ss
County of Salt Lake)

I, Dean Harmon, being first duly sworn on oath, depose and say:

1. My full name is Dean L. Harmon. I am employed by PacifiCorp (or the Company). My present position is Lead Senior Business Consultant.

2. I am making this affidavit in compliance with Ordering Paragraph 4 of Public Utility Commission of Oregon Order No. 10-414 in Docket UM 1355, issued on October 22, 2010.

3. Ordering Paragraph 4 adopts the methodology described in Section II.A.2 of that order for calculating the Forced Outage Rate (FOR) for coal-fired electric generating plants owned by or operated under the direction of PacifiCorp for all general rate cases, annual power cost updates, and other power cost related proceedings.

4. Section II.A.2 of Order No. 10-414 requires that "[i]n preparing the 20-year rolling average FOR, the utility must utilize only available direct data and shall submit an affidavit to the Commission to that effect."

5. I prepared the 20-year rolling average FOR for coal-fired generating plants used to calculate net power costs in PacifiCorp's 2012 Transition Adjustment Mechanism.

6. In preparing the FOR, I used only available direct data.

I declare under penalty of perjury under the laws of the state of Oregon that the foregoing is true and correct based on my information and belief as of the date of this attestation.

SIGNED this 10 day of March, 2011, at Salt Lake City, Utah.

Signed: Dean L. Harmon

SUBSCRIBED AND SWORN to before me this 10 day of March, 2011.

Candace Turner

Notary Public, State of Utah
My Commission Expires Jan. 30, 2013

Notary Public
CANDACE TURNER
Commission #577514
My Commission Expires
January 30, 2013
State of Utah

Exhibit PPL/100
Gregory N. Duvall

Docket No. UE-
Exhibit PPL/100
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

March 2011

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. My present position 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 2012 Transition Adjustment Mechanism ("TAM") net power costs ("NPC"). Specifically, my testimony:

- Summarizes the content of the filing.
- Describes the major cost drivers in the 2012 TAM.

- Describes the Company's implementation of the Commission order in Docket UM 1355 regarding collar of thermal outages and heat rate deration.
- Presents the Company's 2011 Wind Integration Study ("Wind Study"), and the modeling of the impact of integrating generation from wind resources in this proceeding.
- Describes how the filing is consistent with the TAM Guidelines.
- Introduces the other witnesses providing testimony in support of the Company's 2012 TAM.

Summary of PacifiCorp's 2012 TAM Filing

Q. Please provide background on the Company's 2012 TAM filing.

A. The TAM is PacifiCorp's annual filing to update its NPC in rates. The updated NPC are used to set the transition adjustments for direct access and, in this case, become effective in rates on January 1, 2012. This is the Company's seventh TAM filing. The Company is filing the 2012 TAM on a stand-alone basis without a general rate case.

Q. What are the forecasted normalized system-wide NPC for calendar year 2012?

A. The Company's total forecasted normalized system-wide NPC for the test period of 12-months ending December 31, 2012 are approximately $1.56 billion or $24.96/MWh.

Q. What is the estimated increase in Oregon-allocated NPC for calendar year 2012?

A. As shown in Exhibit PPL/101, on an Oregon-allocated basis, the Company's forecast normalized NPC for calendar year 2012 are approximately $79.0 million higher than the NPC authorized in Docket UE 216 ("UE 216"). The 2011 NPC currently in rates are the result of a settlement in UE 216.

Q. Does the proposed rate increase in the filing reflect the changes in load since UE 216?

A. Yes. The 2012 load forecast in this filing reflects an increase in Oregon loads when compared to the 2011 forecast loads from UE 216. The rates approved in UE 216 collect an additional $21.1 million in the 2012 test period over the NPC approved in UE 216. As such, the proposed rate increase in this filing attributable to NPC is reduced from $79.0 million to $57.9 million. This present revenue change due to load variance is shown in Exhibit PPL/101.

Q. Because this is a stand-alone TAM filing, does the Company include an update to Other Revenues for certain items related to NPC, as stipulated in UE 216?

A. Yes. Exhibit PPL/102 shows the update to Other Revenues for which a baseline was set in UE 216. (See Order No. 10-363, Appendix A, page 16 for the baseline agreed to in UE 216.) Due to expiration of the ancillary services contract with Seattle City Light for the Stateline wind farm in 2011 and the expiration of the steam contract with Little Mountain in February 2012, Other Revenues are reduced by approximately $3.2 million in 2012. As a result of the decrease in Other Revenues, the TAM increases by $3.2 million. Once load growth is considered, an additional $0.5 million is necessary to recover the variance related to these revenues.

Q. What is the total amount that the Company is requesting in this filing?

A. The Company is proposing a total revenue increase of approximately $61.6 million in the 2012 TAM. As explained in Company witness Ms. Judith M. Ridenour's testimony, this is an overall average increase of approximately 5.2 percent.

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 216?

A. Yes, although a new release of the same version is being used that has a new report consolidating several individual reports necessary for the screening process, as directed by the Public Service Commission of Utah.

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, and availability of transmission capability are updated for this filing.

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/103. 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 216?

A. Yes. The historical information used as the basis of the normalized generation continues to include all available years, except for the Bear River system, which excludes flood control years.

Major Cost Drivers in the 2012 TAM

Q. Please generally describe the drivers of the increase in the Company's 2012 NPC in this filing.

A. The increase in 2012 NPC is driven by a range of factors, including increases in the Company's total system load, changes in the Company's portfolio of wholesale purchase and sales contracts, and increases in coal costs. The offsetting factors that drive NPC downward in 2012 include more generation from the Company's thermal resources, which limits or reduces the impact of higher load and the expiration of long-term firm contracts.

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

A. This filing reflects an increase of approximately 4.3 million megawatt-hours, or 7.5 percent, in the total company load forecast compared to loads reflected in UE 216. All else held constant, increased load increases NPC.

Q. What are the major changes to power contracts in the calendar year 2012 test period?

A. The 2012 test period in the current filing reflects a full year impact of the contracts that expired during the 2011 TAM test period. NPC increased when those contracts expired because the prices of those contracts were more favorable as compared to the current market prices. The increase in NPC is offset somewhat by the expiration in 2012 of relatively expensive qualifying facility ("QF") contracts, such as the Biomass QF.

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, and cost increases at the Company's captive mines. Approximately one-fourth of the NPC increase in this case is attributable to coal costs. Details on coal costs are provided in the direct testimony of Company witness Ms. Cindy A. Crane.

Q. Has the Company updated its inputs for wind integration costs?

A. Yes. Instead of calculating the wind integration costs as a line item outside GRID, the Company now models in GRID the additional reserves required to integrate generation from wind resources in its balancing authority areas. The additional reserve requirements are from the Company's Wind Study as part of the 2011 Integrated Resource Plan ("IRP"). I provide more detail about the content and the impact of the Wind Study later in my testimony.

Q. Has the Company made assumptions about the power rates and transmission rates proposed in the current rate cases of the Bonneville Power Administration ("BPA")?

A. Yes. The BPA rate cases will determine the new rates for the fiscal period beginning in October 2011. Given the current proposals made by BPA, the Company assumes that the wheeling expenses of the Company's transmission contracts with BPA would not change in the new BPA rate effective period that begins in October 2011. In the current filing, the Company has incorporated the proposed wind integration charge at $1.32/kW-month beginning in October 2011, which is a change from the current $1.29/kW-month. The Company has also incorporated the impact of BPA's proposal in charges for reserves and power. The Company will update these numbers in a later update after BPA issues its Record of Decision, which is currently expected in July 2011.

2012 TAM Changes in Inputs to NPC

Q. Has the Company made changes to NPC inputs in accordance with the stipulation in UE 216?

A. Yes. The Company has updated its inputs for the items identified in the UE 216 stipulation. Specifically, in the UE 216 stipulation the Company agreed to reflect the following methodological changes in the 2012 TAM:

- Screens – The Company will use a daily screening methodology that is more effective than that used in UE 216 and is based on logic which commits all gas plants up and backs down those that are not economic.
- Black Hills CTs – The Company will use a four-year average for the costs of the Black Hills combustion turbines.
- Heat Rates – The Company will not implement adjustments for scrubbers or other capital projects, but instead will rely on the traditional analysis of four years of actual data to derive the heat rate inputs.
- APS Supplemental Coal and Other – The Company will model the option contracts to be exercised only when economic.
- The Company will not include inter-hour wind integration charges for non-owned wind facilities.
- The Company will include modeling of non-firm transmission links and costs using a four-year average.

Q. Has the Company made other changes regarding GRID inputs to address issues raised in previous TAM proceedings?

A. Yes. In addition to incorporating the changes above, the Company also made the following changes:

- 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, 2010.

- Condit Dam Decommissioning – The Company has received additional permits since the Company filed its 2011 TAM. The Condit dam is currently targeted to be decommissioned as soon as October 2011. As in UE 216, the Company has assumed that the dam will be in operation through the end of the 2012 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 2012. In lieu of a deferral application, if more definitive information is known at the time of the rebuttal update, then the Company will revise NPC accordingly.
- Market Caps – To address the issues around the Company's assumption about market caps during the graveyard hours, the Company reviewed its overall approach to market caps and developed a more comprehensive approach to modeling market depth. Instead of specifying market depth for graveyard hours only, the Company now proposes to specify market depth during all hours, segregated by heavy-load-hour ("HLH") and light-load-hour ("LLH") periods. The Company believes that a market may be liquid, but this liquidity does not translate into unlimited sales at any time of day or night. Due to load requirements and transmission constraints in the region and static assumptions about market prices in GRID, among other things, the Company may not be able to sell all its economic generation to the markets. The market depths for

wholesale sales in GRID are now determined based on the historical short-term firm transactions during the same 48-month period on which availability of the thermal generation is based. The depths are then reduced by the quantity of short-term firm transactions that the Company has included in the normalized NPC study for the test period in all sales markets.

Implementation of Commission Order in Docket UM 1355

Q. Please briefly describe Commission Order No. 10-414 in Docket UM 1355, dated October 22, 2010.

A. In its order, the Commission affirms that the forced outage rates ("FOR") for ratemaking purposes will be based on actual outage data in the previous four years, and directs the Company to make changes to, or collar, its coal units' forced outage rates if, "in any one year, the FOR falls outside the 10^{th} or 90^{th} percentile for comparable NERC coal units." The changes to the forced outage rates will be based on "the 20-year rolling average FOR, or, if the plant has been in service less than 20 years, the average FOR over the life of the plant." The Commission also directs the Company to adjust the minimum generation levels and heat rates of the thermal generating units to reflect the expected impact of forced outages.

Q. Please briefly describe how the Company implemented the Commission order.

A. In the current filing, the base data for normalized outages are from the four-year period ended June 2010. For each coal-fired unit, the Company compares the actual FOR in each year with data reported by North American Electric

Reliability Corporation ("NERC") for the comparable units. The actual data in the six-month period in 2010 are compared against the most recent data available from NERC, which are for 2009. When the actual FOR is outside the 10th or 90th percentile of the NERC data, the FOR of the unit is replaced with the average FOR in the past 20-year period.[1] For the units that have annual FORs replaced, corresponding adjustments are made to the units' equivalent outage rates ("EOR"s) that are inputs to the GRID model. To make adjustments to minimum generation levels and heat rates of all thermal units, the Company assumes that for the portion of the time when the units were fully forced out, the Company would not own the capability of that portion of the units.

Q. Has the Company correctly implemented the Commission order in UM 1355?

A. Yes. The Company implemented the Commission order in UM 1355 in the same manner as in the Company's special update in UE 216, as revised, filed on December 20, 2010. As instructed by the Commission, however, the Company continues to review alternative approaches to modeling minimum generation levels and heat rates.

Wind Integration Charges

Q. Has the Company updated its approach to calculating wind integration charges?

A. Yes. As part of the 2011 IRP, the Company performed an extensive Wind Study

[1] As required by Order No. 10-414, included with this filing is the Affidavit of Dean L. Harmon attesting to the fact that he used only available direct data to prepare the 20-year rolling average FOR.

on the impact of integrating wind generation into its resource portfolio.[2] The Wind Study was created after reviewing the issues and concerns raised by various parties in Oregon and other jurisdictions, such as whether the wind integration costs should be studied independent of load, the amount of additional reserves needed to integrate the wind generation and what resources should be utilized to serve the additional reserve requirements.

Q. Please briefly describe the Company's Wind Study.

A. The purpose of the Wind Study is twofold. First, the Wind Study quantifies how wind generation affects the amount of additional reserves needed to maintain reliability. Second, the Wind Study determines the costs of integrating wind generation by measuring how system costs change with changes in operating reserve demand, and by measuring how system costs are affected by daily system balancing practices.

Q. What are the additional reserve requirements?

A. The Wind Study identified additional reserve requirements in two categories: regulating services that deal with load and wind variability in 10-minute intervals, and load following services that deal with load and wind variability over hourly time intervals. Both services respond to the up and down variations of wind generation. That is, the additional reserve requirements to integrate wind generation into the Company's resource portfolio consist of regulation up, regulation down, load following up and load following down. The Wind Study performed analyses of additional reserve requirements for load only (excluding

[2] The Wind Study can be found on the Company's website at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf.

wind generation) and for wind net of load (including wind generation), based on historical 10-minute data for the Company's system.

Q. In addition to regulating services and load following services, what other costs are incurred to integrate wind generation?

A. Given the size of the wind portfolio, and the possibility of rapid variations in wind generation from the forecast displayed in the historical actual operation, the Company expects that it will need to continue committing its gas units to be able to quickly respond to the magnitude of changes. At times, this "must-run" operation would require gas units to run when it would otherwise be uneconomic to do so, therefore adding to the wind integration costs.

Q. What are the costs identified by the Wind Study?

A. The Wind Study shows that the costs of integrating wind generation into the Company's resource portfolio (regulation and load following services, system balancing and the requirement of must-run) for the three-year period from 2011 to 2013 are $9.70 per megawatt-hour at the wind generation penetration level of 1,833 megawatts, which approximates the level of wind in the Company's balancing areas.

Q. How did the Company apply the results from the Wind Study?

A. Instead of applying the dollar per megawatt-hour charge to the wind generation, the Company updated the amount of load following requirement as modeled by GRID to capture the impact of regulation up and load following up, both of which are identified in the Wind Study. The assumption is that if the resources are sufficient to serve the regulation up and load following up, they may be sufficient to serve the regulation down and load following down. The amount of the total load following requirements is 337 average megawatts and 196 average megawatts for the east and west sides of the Company's system, respectively. In addition, as identified in the Wind Study, the Company also modeled the Currant Creek unit, and Gadsby units 4, 5 and 6 as must-run units that are not subject to the logic of being committed to run only when economic.

Q. **How much is included in NPC for system balancing costs which are incurred as a result of day-ahead forecast errors for wind and load?**

A. The Company modeled $0.70 per megawatt-hour for system balancing costs as indentified in the Wind Study.

Q. **Did the Company reasonably model the Wind Study results in GRID for the current filing?**

A. Yes. Given the complexity of the subject, I believe that the result from GRID has reasonably reflected the impact of integrating wind generation into the Company's portfolio. In addition, the Wind Study has addressed all the issues raised by the staff of Oregon Public Utility Commission ("Staff"), Citizens' Utility Board of Oregon ("CUB"), and Industrial Customers of Northwest Utilities ("ICNU") in the Company's previous TAM filings, such as reserve requirements being modeled within GRID, the requirements for wind generation being considered net of load, studies supporting the impact of integrating generation from wind facilities, and the quality of data used to prepare the study. However, given the limitation of data inputs to the normalized studies, I believe that the GRID modeled impact of integrating wind resources may understate the real costs. For example, the GRID model uses expected wind profiles of the wind projects which lack the variability reflected in the actual operations of the wind projects.

Q. What does the Company include as the system balancing costs for the non-owned wind projects, and the overall wind integration costs for projects located in the BPA's balancing area?

A. The forecast NPC in the current filing do not include system balancing costs for the wind projects located in the Company's balancing areas that the Company neither owns nor purchases the output. This is based on the assumption that the entities that own and/or operate those wind projects will balance their own system prior to handing over their generation schedule to the Company, which balances the variations within the hour as the balancing area authority. Following the same logic, forecast NPC include system balancing costs for projects located in BPA's balancing area: Leaning Juniper and Goodnoe Hills.

Q. Has the Company reflected intra-hour transmission schedule and dynamic scheduling in the Wind Study?

A. No. At present, there is no intra-hour market for such scheduling to take effect. I discuss the subject further below in regards to the Notice of Proposed Rulemaking ("NOPR" or the "Proposed Rule") on integration of variable energy resources issued by the Federal Energy Regulatory Commission ("FERC").

Q. Does Commission Order No. 09-432 in UE 207 require the Company to provide an update on FERC developments regarding wind integration charges?

A. Yes. The Order provides:

> "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."[3]

Q. What is the status of the FERC study on wind integration?

A. On November 18, 2010, the FERC issued a NOPR on integration of variable energy resources, such as wind. In general, the NOPR proposes that public utility transmission providers implement operational and scheduling changes to help integrate wind, including 15-minute intra-hourly transmission scheduling and power production forecasting using meteorological and operational data. FERC also proposes to add an ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area.

Q. Would the Proposed Rule allow the Company to charge non-owned wind generators the cost of integrating their generation into the transmission system, and how?

A. Yes. If the proposals in the NOPR remain unchanged and pending any additional guidance from FERC, the Company should be able to propose an ancillary service rate for regulation service to transmission customers delivering energy from a

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

generator located within the Company's balancing authority area, which would include wind. As required by the Federal Power Act, this charge would have to be applied on a non-discriminatory basis. Currently, the OATT does not permit public utility transmission providers to charge generators for regulation service unless the generator is a transmission customer who also serves load in the balancing area.

Q. Does the Company believe that this new wholesale ancillary service charge, if approved by FERC, will help recover the costs of integrating wind?

A. Yes. Regulation service is a type of energy reserve service necessary for integrating resources into the transmission system. Regulating reserves account for the variability of load and generation on the transmission system on a moment-to-moment basis. If the NOPR proposals remain unchanged and are approved as part of a final rule, the new charge would apply to resources when they are exporting to load in other balancing authority areas and would result in additional revenues from non-owned resources that are not delivering power to serve the Company's native load.

Q. Did FERC provide additional guidance in the NOPR on what it proposes to require before it will allow public utility transmission providers to impose a charge that collects a different volume of regulating reserves from variable energy resources?

A. Yes. In the NOPR, FERC states that, to the extent a public utility transmission provider proposes to impose a charge on variable energy resources for a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources, such differing volumes must be shown to be commensurate with the variability that the resources exhibit on the transmission provider's system. Additionally, the transmission provider must show that it has implemented the other operational and scheduling reforms proposed in the NOPR. The transmission provider must have implemented the new tools for at least one year prior to filing any such proposal.

Q. Do the NOPR proposals support the Company's plans to include a proposed charge in its transmission tariff rates as part of its June 2011 FERC transmission rate case?

A. Yes, the Company believes the FERC NOPR provides important guidance and direction on what the Company must do to address this issue. It is reasonable to assume the NOPR will become a final rule. As such, the Company believes the NOPR lays out the path to follow to begin charging non-owned facilities for the costs incurred to integrate them into the Company's balancing areas. The Company also believes, pending any additional guidance from FERC on this issue, that it can include a proposal for a new regulation service charge as part of its transmission rate case filing and that such a proposal has a higher chance of being accepted because of this recent guidance. If and when approved by FERC, such a charge will increase revenues that can be used to offset costs in the Company's retail revenue requirement calculations.

Q. What are the benefits to the Company's customers of providing such services to the non-owned generation?

A. As a balancing area authority, the Company owns and operates an extensive transmission network that it is required to operate safely and reliably for all of its customers, keeping all resources and loads in balance on a moment-to-moment basis. In addition, the Company is mandated to make its transmission network available to all generators in an open access and non discriminatory fashion. By providing wind integration services in addition to other transmission related services as a balancing authority, the Company ensures that its customers are served by a reliable system, with diverse resources. Moreover, any transmission revenues received from non-owned generation, which pays wheeling to the Company, are credited against retail revenue requirement and therefore have the effect of lowering the cost of service for retail customers.

Compliance with TAM Guidelines

Q. Has this filing been prepared consistent with the TAM Guidelines adopted by Order No. 09-274, with clarifications and amendments adopted by Order No. 09-432?

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 January 28, 2011, the Company sent a notice to the Staff, CUB, ICNU, and Sempra to inform parties that the Company has not made changes to its GRID model used to calculate its NPC except, as previously mentioned, the addition of a new report consolidating several individual reports necessary for the screening process.

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.

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

A. Yes. Exhibit PPL/104 contains a list of known contracts and Other Revenues 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 2010.

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

A. Pursuant to the Attachment B of the TAM Guidelines, the Company provided access to the GRID model and workpapers concurrently with this Initial Filing. Specifically, the Company is providing the NPC report workbook and the GRID project report.

Introduction of Witnesses

Q. Please list the other Company witnesses in the 2012 TAM and provide a brief explanation of the witness' testimony.

A. **Ms. Cindy A. Crane**, Vice President, Interwest Mining and Fuels, discusses the primary factors contributing to increases in the Company's coal costs, and demonstrates the reasonableness of the Company's coal supply costs.

Ms. 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-
Exhibit PPL/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

March 2011

PacifiCorp
CY 2012 TAM
Net Power Costs

	ACCT.	Total Company UE 216 Final TAM CY 2011	Total Company TAM CY 2012	Factor	Factors CY 2011	Factors CY 2012	Oregon Allocated UE 216 Final TAM CY 2011	Oregon Allocated TAM CY 2012
Sales for Resale								
Existing Firm PPL	447	25,965,364	26,081,862	SG	26.177%	25.623%	6,796,976	6,682,858
Existing Firm UPL	447	25,490,589	25,490,583	SG	26.177%	25.623%	6,672,694	6,531,357
Post-Merger Firm	447	425,569,012	479,326,113	SG	26.177%	25.623%	111,401,573	122,815,936
Non-Firm	447	-	-	SE	24.283%	24.336%	-	-
Total Sales for Resale		477,024,966	530,898,559				124,871,243	136,030,151
Purchased Power								
Existing Firm Demand PPL	555	50,413,276	2,798,085	SG	26.177%	25.623%	13,196,727	716,943
Existing Firm Demand UPL	555	46,845,802	46,946,386	SG	26.177%	25.623%	12,262,866	12,028,897
Existing Firm Energy	555	57,920,075	24,844,458	SE	24.283%	24.336%	14,064,911	6,046,166
Post-merger Firm	555	353,358,225	573,790,087	SG	26.177%	25.623%	92,498,892	147,020,087
Secondary Purchases	555	-	-	SE	24.283%	24.336%	-	-
Seasonal Contracts	555	-	-	SSGC	0.000%	0.000%	-	-
Other Generation Expense	555	38,906,526	3,726,876	SG	26.177%	25.623%	10,184,595	954,924
Total Purchased Power		547,443,905	652,105,892				142,207,992	166,767,016
Wheeling Expense								
Existing Firm PPL	565	40,049,244	27,034,359	SG	26.177%	25.623%	10,483,726	6,926,913
Existing Firm UPL	565	259,960	-	SG	26.177%	25.623%	68,050	-
Post-merger Firm	565	102,100,510	102,329,448	SG	26.177%	25.623%	26,726,940	26,219,492
Non-Firm	565	104,176	2,893,180	SE	24.283%	24.336%	25,297	704,087
Total Wheeling Expense		142,513,890	132,256,988				37,304,013	33,850,491
Fuel Expense								
Fuel Consumed - Coal	501	631,194,105	711,634,271	SE	24.283%	24.336%	153,274,821	173,183,855
Fuel Consumed - Coal (Cholla)	501	55,439,077	56,618,412	SSECH	24.812%	24.910%	13,755,347	14,103,650
Fuel Consumed - Gas	501	5,410,856	10,850,156	SE	24.283%	24.336%	1,313,935	2,640,502
Natural Gas Consumed	547	365,117,219	484,957,536	SE	24.283%	24.336%	88,662,546	118,019,633
Simple Cycle Combustion Turbines	547	8,178,179	36,248,503	SSECT	22.403%	24.329%	1,832,173	8,818,918
Steam from Other Sources	503	3,540,887	3,893,567	SE	24.283%	24.336%	859,844	947,542
Total Fuel Expense		1,068,880,323	1,304,202,445				259,698,666	317,714,100
Net Power Cost		1,281,813,152	1,557,666,766				314,339,428	382,301,456
Settlement Adjustment		(44,855,794)					(11,000,000)	
Total Net of Settlement Adjustment		1,236,957,358					303,339,428	

Increase Absent Load Change		78,962,027
Oregon-allocated NPC Baseline in Rates from UE 216	303,339,428	
$ Change due to load variance from UE-216 forecast	21,080,116	
2012 Recovery of NPC in Rates	324,419,544	
Increase Including Load Change		57,881,911
Add Other Revenue Change		3,745,661
Total TAM Increase		**61,627,572**

Exhibit PPL/102
Gregory N. Duvall

Docket No. UE-
Exhibit PPL/102
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Update to Other Revenues

March 2011

PacifiCorp
CY 2012 TAM
Other Revenues - Stand Alone TAM Adjustment

	Total Company					Oregon Allocated	
	UE-217 GRC [1]	CY 2012	Factor	Factors CY 2011	Factors CY 2012	UE-217 GRC [1]	CY 2012
[2] Seattle City Light - Stateline Wind Farm	(4,923,706)	-	SG	26.177%	25.623%	(1,288,883)	-
Non-company owned Foote Creek	(2,277,984)	(2,101,033)	SG	26.177%	25.623%	(596,310)	(538,340)
BPA South Idaho Exchange	(8,553,309)	(8,070,364)	SG	26.177%	25.623%	(2,239,007)	(2,067,839)
[3] Little Mountain Steam Revenues	(6,873,305)	(816,188)	SG	26.177%	25.623%	(1,799,231)	(209,129)
James River Royalty Offset	(5,430,652)	(5,052,094)	SG	26.177%	25.623%	(1,421,586)	(1,294,479)
Total Other Revenues	(28,058,956)	(16,039,680)				(7,345,017)	(4,109,787)

Decrease (Increase) in Other Revenues Absent Load Change		3,235,230 [4]
Baseline Other Revenues in Rates	(7,345,017)	
$ Change due to load variance from CY 2011 forecast	(510,431)	
Other Revenues in Rates using 2012 load forecast	(7,855,448)	
Decrease (Increase) in Other Revenues Including Load Change		**3,745,661** [4]

[1] Please refer to Exhibit B of the CY 2011 TAM stipulation (UE 216).
[2] Contract receipts associated with Seattle City Light/Stateline expire December 2011, therefore the Company assumes no revenues for test year ending December 2012.
[3] The Little Mountain steam contract expires February 2012. Therefore, revenues only reflect period from January - February 2012.
[4] Other Revenues are a reduction to the overall revenue requirement. A positive number indicates a reduction of other revenues which equates to an increase in the TAM request.

Exhibit PPL/103
Gregory N. Duvall

Docket No. UE-
Exhibit PPL/103
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

March 2011

Exhibit PPL/103
Duvall/1

PacifiCorp

ORTAM2012 GOLD _2011 03 01

Net Power Cost Analysis

12 months ended December 2012	01/12-12/12	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	13,117,062	1,096,975	1,078,212	1,096,215	1,087,484	1,099,093	1,084,104	1,090,750	1,110,755	1,079,712	1,101,303	1,087,216	1,105,244
BPA Wind s42818	2,723,176	340,042	294,963	276,011	214,371	202,376	164,143	123,104	116,688	153,456	224,285	282,497	331,240
Hurricane Sale s393046	8,259	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	-	-	-	-
LADWP (IPP Layoff)	25,490,583	2,164,955	1,955,435	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
NVE s811499	40,864,841	4,295,409	3,954,852	4,086,720	3,510,840	3,735,264	2,392,704	1,274,100	1,312,323	2,841,379	4,494,390	4,298,280	4,668,580
Pacific Gas & Electric s524491	26,770,166	3,331,310	3,038,600	3,031,338	2,426,900	2,013,410	2,016,504	-	-	-	3,477,348	3,508,340	3,926,416
SCE s513948	12,364,498	1,431,804	1,318,284	1,362,240	1,170,280	1,245,088	1,349,712	-	-	-	1,498,134	1,432,760	1,556,196
SMUD s24296	12,964,800	1,435,600	1,158,100	55,500	-	-	-	1,187,700	1,731,600	1,631,700	1,879,600	1,813,000	2,072,000
UMPA II s45631	9,586,807	593,283	572,367	593,283	582,825	593,283	909,742	1,779,848	1,400,150	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	143,890,193	14,690,410	13,371,845	12,667,294	11,088,847	11,054,501	10,013,056	7,621,489	7,837,504	8,594,003	15,433,298	15,100,032	16,417,914
Short Term Firm Sales													
COB	3,255,840	1,176,480	1,012,320	1,067,040	-	-	-	-	-	-	-	-	-
Four Corners	4,159,050	1,502,850	1,293,150	1,363,050	-	-	-	-	-	-	-	-	-
Palo Verde	12,078,000	1,023,000	957,000	1,023,000	990,000	1,023,000	990,000	1,023,000	1,023,000	990,000	1,023,000	990,000	1,023,000
STF Trading Margin	3,008,777	250,731	250,731	250,731	250,731	250,731	250,731	250,731	250,731	250,731	250,731	250,731	250,731
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	22,501,667	3,953,061	3,513,201	3,703,821	1,240,731	1,273,731	1,240,731	1,273,731	1,273,731	1,240,731	1,273,731	1,240,731	1,273,731
System Balancing Sales													
COB	59,824,091	6,179,872	4,735,991	5,333,655	4,568,403	712,778	1,960,491	2,622,740	5,045,560	5,717,208	6,918,100	7,441,080	8,588,215
Four Corners	92,341,940	7,000,491	6,944,402	5,653,092	4,899,069	4,403,407	5,108,876	8,979,683	13,179,755	10,456,152	9,485,302	5,898,583	10,333,128
Mead	5,542,745	44,856	41,093	42,008	35,048	38,325	1,131,280	2,184,600	890,963	1,009,437	37,596	44,179	43,359
Mid Columbia	63,661,143	4,790,530	11,459,573	8,176,008	110,971	-	-	2,919,034	3,864,583	4,228,667	8,810,277	10,085,530	9,215,970
Mona	21,316,593	1,670,552	921,971	1,152,689	99,732	1,292,572	1,271,776	3,665,939	3,510,541	4,127,067	1,110,366	1,237,944	1,255,444
Palo Verde	121,820,189	11,599,431	10,171,446	11,354,004	11,180,310	9,989,275	12,323,871	7,033,842	5,536,926	8,975,363	11,148,058	10,368,162	12,139,502
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	364,506,699	31,285,730	34,274,476	31,711,455	20,893,533	16,436,357	21,796,294	27,405,837	32,028,328	34,513,893	37,509,699	35,075,478	41,575,619
Total Special Sales For Resale	530,898,559	49,929,202	51,159,523	48,082,571	33,223,112	28,764,589	33,050,082	36,301,057	41,139,563	44,348,627	54,216,728	51,416,242	59,267,264

PacifiCorp

ORTAM2012 GOLD _2011 03 01

Net Power Cost Analysis

Purchased Power & Net Interchange

12 months ended December 2012	01/12-12/12	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Long Term Firm Purchases													
APS Supplemental p27875	2,777,248	383,034	405,565	266,994	-	-	267,424	368,995	241,115	-	-	187,762	656,359
Blanding Purchase p379174	7,387	2,517	2,354	2,517	-	-	-	-	-	-	-	-	-
BPA Reserve Purchase	240,496	12,632	15,481	25,440	19,404	23,582	26,041	26,631	22,844	18,465	20,087	16,360	13,529
Combine Hills Wind p160595	5,060,075	483,364	326,313	558,698	393,252	365,264	439,732	421,865	418,518	398,844	428,196	477,533	348,497
Deseret Purchase p194277	33,809,336	2,859,993	2,777,475	2,859,993	2,801,543	2,808,419	2,624,473	2,859,993	2,859,993	2,818,734	2,859,993	2,818,734	2,859,993
Douglas PUD Settlement p38185	1,412,030	56,194	40,370	93,050	159,471	262,312	291,876	195,910	120,602	56,790	49,234	47,463	38,757
Gemstate p99489	2,840,300	231,100	228,100	237,100	228,100	228,100	228,100	228,100	238,400	228,100	250,400	283,600	231,100
Georgia-Pacific Camas	7,079,675	599,645	560,957	599,645	580,301	599,645	580,301	599,645	599,645	580,301	599,645	580,301	599,645
Grant County 10 aMW p66274	6,196,901	508,607	400,305	439,308	493,060	564,497	606,361	697,496	726,746	544,560	403,478	350,127	462,357
Hermiston Purchase p99563	90,419,163	8,293,225	7,449,420	7,427,426	5,097,879	4,017,020	4,097,583	8,085,654	9,100,960	8,677,573	9,610,232	9,059,746	9,502,445
Hurricane Purchase p393045	96,749	12,094	12,094	12,094	12,094	12,094	12,094	12,094	12,094	-	-	-	-
IPP Purchase	25,490,583	2,164,955	1,955,435	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	2,969,213	-	-	-	-	-	-	1,252,183	1,261,249	307,951	147,830	-	-
LADWP p491303-4	2,013,461	-	-	-	-	-	199,840	1,239,081	387,190	187,350	-	-	-
MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves p510378	5,341,320	445,110	445,110	445,110	445,110	445,110	445,110	445,110	445,110	445,110	445,110	445,110	445,110
Nucor p346856	4,998,000	416,500	416,500	416,500	416,500	416,500	416,500	416,500	416,500	416,500	416,500	416,500	416,500
P4 Production p137215/p145258	17,189,506	1,436,722	1,456,145	1,415,037	1,454,371	1,443,176	1,439,444	1,414,565	1,385,954	1,439,444	1,438,200	1,438,200	1,428,248
PGE Cove p83984	120,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Rock River Wind p100371	5,059,015	614,814	502,777	490,687	384,295	367,660	277,470	197,812	239,058	310,515	445,041	605,478	623,408
Small Purchases east	744,706	84,944	69,272	63,446	57,715	50,603	46,102	50,982	51,588	50,565	62,008	67,171	90,309
Small Purchases west	29,087	624	810	346	1,895	6,389	1,338	2,076	1,617	9,404	1,549	1,970	1,069
Three Buttes Wind p460457	20,655,491	2,306,650	1,654,907	2,349,691	1,692,947	1,714,438	1,182,987	1,054,440	1,080,204	1,422,073	1,786,072	2,006,039	2,405,043
Top of the World Wind p522807	40,387,465	5,294,292	4,136,216	3,807,445	3,097,121	2,664,390	2,419,138	1,930,629	2,085,897	2,260,701	2,894,540	4,235,120	5,561,979
Tri-State Purchase p27057	9,525,219	812,606	805,943	822,099	665,898	741,016	757,263	805,487	841,875	769,129	842,666	824,107	837,129
Wolverine Creek Wind p244520	9,962,272	737,074	601,979	1,158,512	1,114,797	1,086,388	846,626	826,715	775,774	721,703	624,645	817,101	650,960
Long Term Firm Purchases Total	294,424,698	27,766,696	24,273,529	25,666,090	21,220,867	19,991,558	19,310,916	25,306,917	25,487,887	23,768,926	25,500,383	26,783,537	29,347,392
Seasonal Purchased Power													
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

ORTAM2012 GOLD _2011 03 01

Net Power Cost Analysis

12 months ended December 2012	01/12-12/12	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Qualifying Facilities													
QF California	4,242,962	409,268	508,007	643,774	739,317	742,835	543,992	157,132	76,330	63,984	60,510	91,478	206,336
QF Idaho	4,407,413	314,567	294,746	356,460	400,195	486,483	530,186	416,755	326,775	310,360	334,325	329,444	307,118
QF Oregon	19,226,035	1,714,837	1,672,670	1,830,485	1,980,015	1,992,901	1,750,925	1,475,368	1,374,664	1,373,350	1,264,132	1,291,894	1,504,794
QF Utah	1,021,765	78,966	80,848	83,797	87,447	88,460	85,374	85,240	79,611	79,880	95,547	93,127	83,467
QF Washington	2,662,771	220,539	209,660	214,574	220,369	246,571	232,366	239,324	226,308	218,741	213,843	213,619	206,857
QF Wyoming	782,423	17,098	16,570	15,560	41,298	117,264	119,573	128,054	127,833	114,483	51,701	16,829	16,160
Chevron Wind p499335 QF	2,860,911	314,433	318,117	314,579	127,371	146,116	156,038	141,061	229,675	187,180	294,081	298,132	334,128
DCFP p316701 QF	46,915	2,178	1,782	3,190	2,245	3,188	1,485	1,447	2,224	2,994	12,780	8,473	4,929
Evergreen BioPower p351030 QF	2,976,384	247,372	209,699	229,912	232,347	239,941	214,915	243,285	307,223	309,059	331,078	245,327	166,225
Kennecott Refinery QF	1,730,233	152,469	139,049	142,976	125,229	109,960	101,577	175,701	177,118	142,474	147,556	152,870	163,253
Kennecott Smelter QF	6,103,608	571,464	596,100	475,991	491,158	322,894	408,999	647,342	592,731	398,526	449,073	536,666	612,665
Mountain Wind 1 p367721 QF	8,455,541	1,197,304	793,911	789,572	588,918	500,215	362,582	401,438	544,170	623,963	716,405	830,352	1,106,712
Mountain Wind 2 p398449 QF	12,242,916	1,746,953	1,111,017	1,120,217	802,467	872,009	693,947	787,868	848,297	788,553	851,849	1,114,887	1,504,852
Oregon Wind Farm QF	10,942,679	629,509	722,021	892,694	1,084,359	1,107,713	1,280,930	1,297,180	1,004,046	805,100	827,935	958,913	332,279
Pioneer Wind Park I QF	10,783,000	1,260,819	1,281,894	1,116,988	777,830	640,872	573,512	409,165	466,881	691,520	932,542	1,284,901	1,346,075
Pioneer Wind Park II QF	44,550	-	-	-	-	-	-	-	-	-	-	-	44,550
Power County North Wind QF p5756	3,913,846	394,188	388,720	348,838	291,013	233,012	232,451	240,546	256,654	276,210	341,430	376,102	534,681
Power County South Wind QF p5756	3,529,056	355,433	350,502	314,544	262,402	210,104	209,597	216,896	231,421	249,055	307,862	339,126	482,115
SF Phosphates	4,525,475	352,431	349,909	405,585	442,734	296,751	412,126	361,930	374,557	373,054	430,796	372,714	352,886
Spanish Fork Wind 2 p311681 QF	2,758,290	177,251	200,228	171,042	160,811	166,684	239,704	283,545	342,200	274,672	224,329	247,756	270,067
Sunnyside p83997/p59965 QF	26,440,555	2,351,679	2,275,699	2,310,289	1,352,158	1,975,306	2,311,457	2,424,024	2,479,587	2,349,732	1,956,586	2,306,382	2,347,659
Tesoro QF	1,803,553	160,059	145,499	147,996	129,947	115,789	103,911	183,734	185,037	147,408	155,084	158,248	170,840
Threemile Canyon Wind QF p500139	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	7,094,019	711,073	681,965	622,681	508,158	452,590	340,341	588,691	564,528	515,789	679,820	635,652	792,730
Qualifying Facilities Total	138,594,901	13,379,891	12,348,612	12,551,743	10,847,789	11,067,658	10,905,987	10,905,727	10,817,870	10,296,087	10,679,264	11,902,893	12,891,379
Mid-Columbia Contracts													
Douglas - Wells p60828	3,543,085	293,652	293,652	293,652	293,652	293,652	293,652	293,652	293,652	298,468	298,468	298,468	298,468
Grant Reasonable	(10,181,443)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)	(848,454)
Grant Surplus p258951	1,732,133	144,344	144,344	144,344	144,344	144,344	144,344	144,344	144,344	144,344	144,344	144,344	144,344
Grant - Wanapum p60825	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	(4,906,225)	(410,458)	(410,458)	(410,458)	(410,458)	(410,458)	(410,458)	(410,458)	(410,458)	(405,641)	(405,641)	(405,641)	(405,641)
Total Long Term Firm Purchases	428,113,374	40,736,129	36,211,683	37,807,376	31,658,199	30,648,758	29,806,446	35,802,186	35,895,299	33,659,372	35,774,007	38,280,789	41,833,130

PacifiCorp

ORTAM2012 GOLD _2011 03 01

Net Power Cost Analysis

12 months ended December 2012	01/12-12/12	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs p64676	639,263	135,555	98,383	100,329	71,369	91,910	141,716	-	-	-	-	-	-
BPA Exchange p64706/p64888	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647(	(7,958)	-	-	-	-	(2,966)	(3,535)	(0)	(1,457)	-	-	-	-
Cargill p483225/s6 p485390/s89	1,398,400	-	-	-	-	-	-	460,000	496,800	441,600	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
Shell p489963/s489962	364,800	-	-	-	-	-	-	120,000	129,600	115,200	-	-	-
Total Storage & Exchange	7,794,505	585,555	548,383	550,329	521,369	538,944	588,181	1,030,000	1,074,943	1,006,800	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	11,254,500	953,250	891,750	953,250	922,500	953,250	922,500	953,250	953,250	922,500	953,250	922,500	953,250
STF Electric Swaps	(18,103,677)	(1,958,410)	(2,022,656)	(2,613,023)	(2,737,660)	(2,806,631)	(2,519,063)	249,015	520,460	280,545	(1,723,275)	(1,643,499)	(1,129,480)
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	(6,849,177)	(1,005,160)	(1,130,906)	(1,659,773)	(1,815,160)	(1,853,381)	(1,596,563)	1,202,265	1,473,710	1,203,045	(770,025)	(720,999)	(176,230)
System Balancing Purchases													
COB	18,027,599	-	156,797	181,331	311,806	4,979,133	2,330,627	5,472,231	3,416,535	970,752	11,957	55,609	140,822
Four Corners	9,744,366	751,118	221,102	2,036,174	1,188,851	267,920	181,815	1,256,335	663,409	1,268,159	596,304	852,818	460,363
Mead	9,947,134	36,486	39,791	142,692	190,217	149,405	526,354	1,474,282	3,397,001	500,816	2,277,829	225,421	986,840
Mid Columbia	121,705,035	4,333,108	633,646	4,305,283	18,667,422	18,906,432	16,308,966	19,444,608	17,308,856	10,164,851	4,245,404	2,244,871	5,141,589
Mona	55,533,926	4,163,652	7,019,692	4,100,019	8,608,239	2,294,685	3,538,166	1,994,179	4,284,769	2,655,187	6,838,541	4,085,432	5,951,368
Palo Verde	4,276,368	-	-	-	-	-	-	1,823,063	1,864,553	588,752	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	85,885	-	-	-	-	85,885	-	-	-	-	-	-	-
Total System Balancing Purchases	219,320,314	9,284,364	8,071,027	10,765,500	28,966,535	26,683,460	22,885,928	31,464,697	30,935,122	16,148,516	13,970,034	7,464,150	12,680,981
Total Purchased Power & Net Inte	648,379,015	49,600,889	43,700,188	47,463,431	59,330,942	56,017,782	51,683,992	69,499,148	69,379,073	52,017,734	49,424,016	45,473,940	54,787,881

Exhibit PPL/103
Duvall/5

PacifiCorp

ORTAM2012 GOLD _2011 03 01

Net Power Cost Analysis

12 months ended December 2012	01/12-12/12	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Wheeling & U. of F. Expense													
Firm Wheeling	132,042,550	11,698,821	11,388,445	11,502,343	11,621,892	11,100,784	11,228,333	10,490,097	10,343,456	10,317,594	10,267,675	10,702,361	11,380,751
ST Firm & Non-Firm	214,438	23,831	18,100	18,018	2,348	7,342	24,548	20,515	21,391	17,849	19,035	19,189	22,271
Total Wheeling & U. of F. Expense	132,256,988	11,722,652	11,406,545	11,520,362	11,624,239	11,108,126	11,252,881	10,510,612	10,364,847	10,335,443	10,286,710	10,721,550	11,403,022
Coal Fuel Burn Expense													
Carbon	21,745,525	1,868,127	1,747,188	1,908,441	1,133,904	1,727,702	1,673,474	2,013,650	1,968,127	1,835,684	1,997,979	1,939,046	1,932,202
Cholla	56,736,473	4,982,661	4,647,507	4,955,787	4,849,439	2,552,899	4,709,981	5,063,349	5,068,420	4,992,471	5,049,406	4,877,794	4,986,758
Colstrip	14,623,924	1,280,466	1,198,352	1,280,466	993,955	1,031,187	1,238,817	1,280,466	1,281,650	1,237,632	1,281,650	1,240,001	1,279,282
Craig	22,611,585	1,954,950	1,829,025	1,954,950	1,891,748	1,485,393	1,891,748	1,954,950	1,955,429	1,891,268	1,955,429	1,892,227	1,954,470
Dave Johnston	63,320,567	4,887,988	5,324,395	5,688,509	3,545,235	4,792,215	5,475,087	5,826,002	5,827,999	5,626,757	5,756,951	5,433,480	5,135,948
Hayden	15,292,309	1,358,252	1,271,858	1,360,522	753,470	1,322,280	1,150,932	1,360,522	1,360,687	1,316,421	1,360,687	1,316,751	1,359,928
Hunter	159,464,498	13,934,869	12,883,835	12,565,356	10,361,552	13,653,661	13,227,929	13,912,768	14,010,038	13,605,351	13,881,848	13,501,951	13,925,342
Huntington	102,164,506	8,925,419	8,233,852	8,809,728	8,605,537	8,709,131	8,241,693	8,985,111	9,062,964	8,314,987	7,936,932	7,435,505	8,903,646
Jim Bridger	187,429,135	16,362,558	14,788,777	15,572,823	12,981,307	12,378,941	14,039,670	17,465,917	17,356,059	16,775,132	17,626,659	16,061,278	16,020,016
Naughton	105,006,031	9,152,388	8,560,144	6,455,993	8,562,048	9,122,274	8,840,598	9,152,570	9,158,995	8,849,037	9,143,953	8,861,885	9,146,146
Ramp Loss	(893,089)	(40,837)	(74,120)	(62,394)	(69,945)	(103,235)	(58,876)	(91,069)	(87,274)	(49,103)	(94,880)	(91,362)	(69,995)
Wyodak	20,751,219	1,783,803	1,669,138	1,783,803	1,725,970	1,741,994	1,628,130	1,741,020	1,741,994	1,683,601	1,741,994	1,726,971	1,782,802
Total Coal Fuel Burn Expense	768,252,683	66,450,644	62,079,951	62,273,982	55,334,220	58,414,441	62,059,182	68,665,255	68,705,087	66,079,239	67,638,609	64,195,528	66,356,545
Gas Fuel Burn Expense													
Chehalis	105,669,370	10,022,170	13,287,489	12,264,626	-	-	-	8,152,743	10,768,982	10,423,655	12,129,838	13,683,504	14,936,362
Currant Creek	92,499,232	8,705,871	7,955,874	8,149,752	7,087,083	7,147,241	6,957,579	7,420,556	7,641,917	7,236,004	6,841,017	8,179,917	9,176,422
Gadsby	7,475,703	-	-	-	-	-	1,351,526	2,051,255	2,484,511	1,588,412	-	-	-
Gadsby CT	24,823,368	2,220,721	1,982,014	2,158,050	1,958,341	1,998,703	1,933,150	2,054,605	2,080,619	1,979,451	2,066,956	2,089,669	2,301,091
Hermiston	53,928,845	5,257,972	4,414,167	4,392,173	2,062,626	981,767	1,062,330	5,050,401	6,065,707	5,642,320	6,574,979	5,990,852	6,433,551
Lake Side	96,829,053	9,436,175	8,756,237	9,336,807	6,833,956	4,698,652	4,065,588	9,237,014	9,561,747	8,646,121	6,644,128	9,343,942	10,268,685
Little Mountain	1,723,407	895,590	827,817	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	382,948,978	36,538,500	37,223,598	36,301,409	17,942,005	14,826,363	15,370,172	33,966,574	38,603,483	35,515,962	34,256,918	39,287,884	43,116,111
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	122,778,948	10,328,770	9,694,630	8,687,822	9,859,012	13,569,182	13,702,822	11,747,208	11,544,828	11,268,938	9,371,704	7,078,583	5,925,450
Clay Basin Gas Storage	(26,750)	(124,447)	(111,374)	(93,553)	53,003	53,003	53,003	53,003	53,003	53,003	53,003	743	(69,141)
Pipeline Reservation Fees	26,355,018	2,216,747	2,134,766	2,216,747	2,175,756	2,216,747	2,175,756	2,216,747	2,216,747	2,175,756	2,216,747	2,175,756	2,216,747
Total Gas Fuel Burn Expense	532,056,195	48,959,570	48,941,620	47,112,425	30,029,776	30,665,295	31,301,754	47,983,532	52,418,060	49,013,659	45,898,372	48,542,966	51,189,168
Other Generation													
Blundell	3,893,567	356,150	333,138	356,150	178,441	335,123	314,272	324,725	324,650	324,487	345,595	344,603	356,232
Wind Integration Charge	3,726,876	403,993	332,272	370,157	301,983	292,635	266,942	232,656	234,099	247,607	300,146	356,729	387,657
Total Other Generation	7,620,444	760,143	665,411	726,307	480,424	627,758	581,214	557,381	558,749	572,094	645,741	701,332	743,889
Net Power Cost	**1,557,666,766**	127,564,696	115,634,191	121,013,936	123,576,490	128,068,812	123,828,941	160,914,872	160,286,254	133,669,541	119,676,720	118,219,074	125,213,240
Net Power Cost/Net System Load	**24.96**	**23.56**	**23.21**	**23.47**	**25.52**	**25.54**	**24.30**	**28.00**	**28.66**	**27.08**	**23.80**	**23.25**	**22.77**

Docket No. UE-
Exhibit PPL/104
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 or Known Contract Updates

March 2011

List of Known Contracts Expected to be Updated During 2012 TAM

Sales and Purchases of Electricity and Natural Gas

1. New electricity sales and purchase contracts, physical and financial, including contracts with qualifying facilities.
2. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
3. New natural gas sales and purchase contracts, physical and financial.
4. Changes in contract terms of existing natural gas sales and purchase contracts.
5. Contracts whose prices are linked to market indexes and inflation rates.
6. Five new qualifying facility contracts with Cedar Creek Wind, which are currently before the Idaho Public Utilities Commission.
7. New qualifying facility contract with Cargill, which is currently before the Idaho Public Utilities Commission.
8. Sales contract with Black Hills Company for energy price and fixed payments.
9. Purchase contracts for generation and fixed costs from the Mid Columbia projects.
10. Purchase contract with Tri-State Generation and Transmission Association Inc for energy price.
11. New purchase contract with Monsanto for ready reserves, or remove the expenses and impact on load of the assumed contract if new contract is not executed.
12. New purchase contract with Kennecott for generation incentives, or remove the expenses and impact on load of the assumed contract if new contract is not executed.
13. New qualifying facility purchase contracts with Kennecott, Tesoro and US Magnesium, or remove the assumed contracts if not executed.
14. 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.
15. Purchase expenses of PGE Cove based on PGE projection.
16. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

17. New pipeline and storage contracts for transporting natural gas from market to Company's generating facilities.
18. Changes in contract terms of existing pipeline and storage contracts.
19. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

20. New transmission contracts to wheeling power to serve the Company's load obligations.
21. Changes in contract terms of existing transmission contracts.
22. Wheeling expenses that are impacted by changes in third parties' transmission tariff rates.
23. Power, Transmission and Wind Integration rates that are impact by the current BPA rate cases.
24. Transmission from the Four Corners market to the SP15 market.
25. Contracts whose prices are linked to market indexes and inflation rates.

Generation Resources

26. Decommission date of Condit dam.

Other Revenue

27. Replacement contracts or changes in contract terms of existing contracts that will impact the Other Revenues reflected in Exhibit PPL/102.

<u>Coal Expense –</u>

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	X							
	Black Butte					X	X		
	Union Pacific Railway							X	X
Carbon	Deer Creek	X							
	Utah American Energy - West Ridge			X					
	America West - Horizon			X					
	Utah Trucking							X	X
Cholla	Peabody Coalsales - Lee Ranch Mine					X	X		
	BNSF Railway							X	X
Colstrip	Westmoreland - Rosebud Mine					X	X	X	X
Craig	Trapper Mine	X							
	Rio Tinto- - Colowyo Mine						X		
	Union Pacific Railway								X
Hayden	Open Position/Twentymile Mine					X	X		
	Pirate Trucking							X	X
Hunter	Deer Creek	X							
	Arch - Sufco			X	X				
	Utah American Energy - West Ridge			X					
	Utah Trucking							X	X
Huntington	Deer Creek	X							
	Arch - Sufco			X	X				
D Johnston	Open Position					X	X		
	Western Fuels - Dry Fork Mine			X					
	Peabody - Rawhide Mine			X					
	BNSF Railway							X	X
Naughton	Chevron Mining - Kemmerer Mine					X	X		
Wyodak	Black Hills - Wyodak Mine					X	X		

REDACTED
Docket No. UE-
Exhibit PPL/200
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Cindy A. Crane

March 2011

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. In March 2009, I was appointed to my present position as Vice President of Interwest Mining Company and Fuel Resources. 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. Specifically, 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 contracts that are contributing to the increase in coal costs in this case;

- Reviews the Company's affiliate mine coal costs and compares them to other supply alternatives; and
- Demonstrates that Oregon customers benefit from the Company's diversified coal supply strategy.

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; customers have benefited from this strategy. While coal costs have increased in this case, the Company's strategy has resulted in a long-term, stable and low-cost supply of coal for its customers. Additionally, test period costs for each of the three affiliate mines remain considerably less than the Company's market alternatives and further demonstrate the benefits of the Company's affiliate mines.

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 2012?

A. The Company employs a diversified coal supply strategy. For 2012, the Company will meet approximately 68 percent of its fuel requirements from third-party multi-year contracts and 32 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 2012, approximately 29 percent of the Company's total coal supply will be priced under current fixed-price contracts and 33 percent will be priced under contracts that escalate/de-escalate based on changes to producer and consumer price indices. The remaining portion of third party coal supplies, approximately six percent, is still under negotiation.

Q. Please identify which Company coal plants are supplied by the affiliate mines.

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 2012 Transition Adjustment Mechanism ("TAM")

Q. Do coal costs in the 2012 TAM reflect an increase from cost levels reflected in the Company's July update in the 2011 TAM?

A. Yes. Coal costs have increased by approximately [redacted] on a total-company basis. Average coal costs have increased from $[redacted]

Q. How much do the captive operations account for the overall increase?

A. [redacted]

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

A. With the exception of Colstrip, third-party supply costs have increased at all of the plants. The major causes are as follows:

- The majority of the Hunter and a portion of the Huntington plants' requirements are supplied by the Sufco mine under the Company's long-term coal supply agreement with Arch Coal Sales ("Arch"). The Sufco price in the 2012 TAM is [redacted]
- A portion of the Hunter and Carbon plants' requirements will be supplied by the West Ridge mine under a new coal supply agreement. The overall impact on test period results is approximately [redacted]
- The 2011 TAM included 300,000 tons of previously deferred Skyline tonnage at the Carbon plant. With the December 2011 expiration of this agreement, the Carbon plant will be supplied with coal from America West's Horizon mine under a new long-term coal supply agreement at an incremental cost of approximately [redacted]
- The Naughton plant is supplied under a long-term coal supply agreement with Chevron Mining's Kemmerer mine. The contract price was reset effective July 2010 pursuant to a price re-opener provision. The overall impact on test period results is approximately [redacted]
- The Company will experience an increase of approximately [redacted] in Dave Johnston plant costs largely as a result of the expiration of a long-term coal supply agreement with Wyodak Resources' Black Hills mine, as well as fixed price increases under two multi-year coal supply agreements and higher rail rates.

- The Company will experience an increase of approximately [redacted] in Hayden plant costs. The current agreement expires December 2011. The projected coal price in 2012 is based on ongoing negotiations with Peabody; the projected rail rate is based on discussions with the Union Pacific Railroad.
- The Company will experience an increase of approximately [redacted] in Cholla plant costs. The increase in current test period costs relate to the increased price of coal from Lee Ranch/El Segundo due to escalation of contract specific producer and consumer price increases under the coal supply agreement with Peabody, [redacted], and higher rail rates, [redacted], under the long-term rail agreement with the Burlington Northern Santa Fe.

Third-party coal costs related to the Utah plants

Q. Please describe the status of the Arch contract.

A. The Company's long-term coal supply agreement with Arch for Sufco coal, which extends through 2020, includes two price re-openers: January 2011 and January 2016. The parties have been in protracted negotiations over the January 2011 price-reopener for almost two years. The Company filed a complaint against Arch in November 2010 in the United States District Court for Utah. Nevertheless, negotiations continue as the parties attempt to reach a comprehensive settlement that addresses the 2011 price reopener, coal quality specifications, coal volumes, nominations, coal leases, etc.

Q. Please explain what price is included in the 2012 TAM.

A. The 2012 TAM reflects a weighted average delivered contract price, Freight On Board ("F.O.B.") Hunter plant, of [redacted] in the 2011 TAM. The price in the 2011 TAM was based on a preliminary analysis of the price reopener calculation. Since the development of the 2011 TAM, the Company has further analyzed the contract price reopener provision and continued good faith negotiations as required by the contract. The 2012 TAM cost estimate is based on the additional analysis and negotiations.

Q. Please discuss the Company's other third-party supply arrangements for Utah coal.

A. Since the 2011 TAM update, the Company has entered into two other coal supply agreements. The Company contracted with UtahAmerican Energy for coal supplies from the West Ridge mine for [redacted]. The West Ridge mine is the only other longwall operation in Utah not owned by Arch. High ash fusion temperature coals like West Ridge mitigate the low ash fusion characteristics of Sufco coal that can contribute to boiler slagging. The Company also contracted with America West Resources, Inc. for coal from the Horizon mine for [redacted], with an option to extend the contract through an additional [redacted].

Q. How do these prices compare to the current Utah coal prices?

A. Favorably. The Sufco coal price is a delivered price at the Hunter plant whereas other market transactions are normally priced at F.O.B. loadout. Currently, spot coal is being transacted for approximately $45/ton or equivalent to $48/ton at the

Hunter plant. [redacted].

Naughton plant coal costs

Q. Please explain what price is included in the 2012 TAM for the Naughton plant.

A. The 2012 TAM reflects a weighted average delivered contract price of [redacted]. The price in the 2011 TAM was based on ongoing negotiations with Chevron Mining. Negotiations were completed in September 2010 with an amendment to the current coal supply agreement that extends through 2016 and a new coal supply for the term of 2017 through 2021.

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

A. The original long-term coal supply agreement with Chevron Mining's Kemmerer mine contained several market price re-openers. A market price re-opener was scheduled to occur on January 1, 2011. [redacted].

Q. Did the Company evaluate alternative supply options?

A. Yes. [redacted]

[redacted]

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

A. [redacted]

Q. What was the estimated cost of the alternate sources?

A. [redacted]

Q. Was the Company able to negotiate a new contract price?

A. The Company successfully negotiated a new coal price with Chevron that eliminated the 2011 market price reopener provision. [redacted]

Q. Please summarize the supply agreements with Chevron Mining.

A. In September 2010, the Company and Chevron Mining restructured the coal supply arrangement to the Naughton plant. [redacted]

Other third-party coal costs

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

A. The Dave Johnston plant is currently supplied with coal from Western Fuels' Dry Fork mine, Peabody's Rawhide mine and Wyodak Resources' Wyodak mine. Both the Dry Fork and Rawhide agreements extend through 2013; the Wyodak agreement expires in December 2011. Approximately [redacted] is associated with annual fixed price increases under Rawhide and Dry Fork agreements and increased volumes under the Rawhide agreement and [redacted] is associated with higher rail rates. The remainder of the increase, approximately [redacted], is associated with the open position caused by the expiration of the Wyodak agreement.

Q. What is the size of the Dave Johnston open position in 2012?

A. The 2012 TAM reflects [redacted] tons of spot coal. [redacted] the Company is evaluating issuing a solicitation for PRB coal supplies for 2012 and 2013.

Q. Please explain the [redacted] increase in Cholla plant coal supply costs.

A. The increase in test period costs relate to the increased price of coal from Peabody's Lee Ranch/El Segundo [redacted].

Q. Please explain the [redacted] increase in Hayden plant coal supply costs.

A. The current coal supply agreement with Peabody for the supply of Twentymile coal expires in December 2011. The Hayden plant owners and Peabody have been in negotiations regarding an extension of the current coal supply agreement for an additional three-year period. [redacted].

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.

Affiliate mine coal costs

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

A. Deer Creek production costs in 2012 are projected to increase from [redacted]

[redacted]. There are four primary drivers for the Deer Creek cost increase: higher United Mine Workers of America wages and benefits, changes in ratio of continuous miner to total production which results in increased materials and supplies, increased post retirement costs and increased major overhaul expenses. In the 2011 TAM, approximately 21 percent of Deer Creek's production was produced by continuous miners; in the 2012 TAM approximately 25 percent of the production will be supplied by continuous miners. Continuous miner production is more labor intensive and consumes more supplies than longwall production. Pension and post retirement welfare costs prepared by Hewitt Associates resulted in an increase of [redacted]. Major overhaul expenses have increased with more difficult mining conditions in the lower Hiawatha seam. Despite the increase, Deer Creek coal costs are still considerably less than the Company's other supply options.

Q. Please explain the change in Bridger Coal costs between 2011 and 2012.

A. The 2012 TAM reflects an increase in Bridger Coal Company costs from [redacted] The increase in underground costs is largely a combination of increased wages and benefits, operating supplies and mine and equipment maintenance, contract services, depreciation and royalties.

Q. Have Bridger Coal Company staffing requirements changed?

A. Yes, between the mine's workforce and contractors, staffing requirements have increased with mine development, conveying and blending requirements.

Improving coal conveying reliability and equipment maintenance availability are critical to maximizing coal production and minimizing costs. In July 2011, Bridger Coal will deploy a third continuous miner section which requires additional staffing. The third miner is necessary to ensure timely development of longwall panels and completion of required underground mine construction projects.

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

A. Kiewit Mining has offered to sell the Company up to [redacted]. On a delivered cost basis, this coal is approximately [redacted] than Bridger Coal's test period costs. Similarly, any Kemmerer coal that becomes available, as part of the Naughton contract amendment, [redacted]. The transportation costs associated with hauling the coal 125 miles to the Bridger plant is prohibitive.

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 continues 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 is approximately [redacted].

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

A. The 2012 Trapper price of [redacted]. This price is considerably less than the Company's other Colorado coal supplies. The price is over [redacted] than the delivered price under the Company's long-term coal supply agreement with the Colowyo mine.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

March 2011

Q. Please state your name, business address and present position with PacifiCorp ("the 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 217 ("UE 217") and Transition Adjustment Mechanism ("TAM"), Docket UE 216 ("UE 216"). I have testified on behalf of the Company in regulatory proceedings in Oregon and California.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I explain the Company's TAM tariff and rate design, including the creation of a new TAM adjustment schedule for Other Revenues, present the Company's proposed tariffs, and provide a summary of the impact of the proposed rate change on customers' bills.

TAM Design and Proposed Tariffs

Q. Please describe the Company's tariff rate schedule which collects net power costs ("NPC").

A. The Company collects NPC through Schedule 201, Net Power Costs, Cost-Based Supply Service. Collecting NPC through a separate rate schedule allows NPC to be more easily and accurately updated through TAM filings.

Q. What is the rate design test period for this TAM?

A. In accordance with the TAM Guidelines adopted by Order No. 09-274, the rate design test year for this stand-alone TAM is the forecast test year during which the proposed Schedule 201 rates will be effective: the forecast 12 months ending December 2012.

Q. Have you prepared an exhibit showing the present and proposed rate spread and rates for Schedule 201?

A. Yes. Exhibit PPL/301 shows present and proposed Schedule 201 rates and revenues by customer class. Present and proposed Schedule 201 revenues reflect the projected test year sales forecasts.

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

A. Consistent with the TAM Guidelines for a stand-alone TAM, the proposed NPC have been allocated to the rate schedule classes proportionately based on each rate schedule class' proportion of present Schedule 201 revenues.

Q. Have the proposed Schedule 201 rates been designed consistent with the TAM Guidelines?

A. Yes. The TAM Guidelines require that the proposed Schedule 201 rate design reflect the method prescribed by the Commission in the most recent general rate case or other Commission proceeding regarding rate spread and rate design. The rates in the Company's proposed Schedule 201 utilize the same rate blocks and relationships between rate blocks as the existing Schedule 200 and 201 rates and thereby reflect the method prescribed in the Company's most recent general rate case, UE 217, and the most recent TAM, UE 216.

Q. How does the Company propose to reflect in rates the adjustment for Other Revenues required in this stand-alone TAM proceeding?

A. The Company proposes to create a new adjustment rate schedule to implement the required adjustment to Other Revenues. Keeping the rates for this adjustment separate from Schedule 201 will ensure (1) that the removal of cost-based rates in the calculation of the transition adjustments can be completed accurately, (2) that NPC in rates can be easily identified and updated in future TAM proceedings, and (3) that this adjustment will apply to all consumers, including direct access consumers, consistent with the treatment of Other Revenues in the general rate case. The proposed rate spread and rate design of Schedule 205, TAM Adjustment for Other Revenues, parallels the rate spread and rate design of Schedule 201.

Q. Have you prepared an exhibit showing the calculation of the proposed rates for Schedule 205, TAM Adjustment for Other Revenues?

A. Yes. Exhibit PPL/302 shows the calculation of the proposed rates for Schedule 205, TAM Adjustment for Other Revenues.

Q. Please describe Exhibit PPL/303.

A. Exhibit PPL/303 contains the revised tariff Schedule 201, Net Power Costs, Cost-Based Supply Service and the new proposed tariff Schedule 205, TAM Adjustment for Other Revenues.

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 5.2 percent on a net basis. Page one of Exhibit PPL/304 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 8 and 11 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 Klamath Dam Removal Surcharges (Schedule 199), 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 and new Schedule 205?

A. Yes. Exhibit PPL/304 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 Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

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

A. The estimated monthly impact to the average residential customer using 950 kilowatt-hours per month is $4.13.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit PPL/301
Judith M. Ridenour

Docket No. UE-
Exhibit PPL/301
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 Rates for Schedule 201 - Net Power Costs

March 2011

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues
Forecast 12 Months Ended December 31, 2012

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 4, Residential					
First Block kWh (0-1,000)	4,141,565,738	2.220 ¢	$91,942,759	2.616 ¢	$108,343,360
Second Block kWh (> 1,000)	1,516,382,991	3.032 ¢	$45,976,732	3.573 ¢	$54,180,364
	5,657,948,729		$137,919,491		$162,523,724
				Change	$24,604,233
Employee Discount					
First Block kWh (0-1,000)	*12,387,969*	*2.220 ¢*	*$275,013*	*2.616 ¢*	*$324,069*
Second Block kWh (> 1,000)	*5,989,914*	*3.032 ¢*	*$181,614*	*3.573 ¢*	*$214,020*
	18,377,883		*$456,627*		*$538,089*
		Discount	-$114,157	Discount	-$134,522
				Change	-$20,366
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	818,141,307	2.586 ¢	$21,157,134	3.047 ¢	$24,928,766
All additional kWh, per kWh	227,575,031	1.919 ¢	$4,367,165	2.261 ¢	$5,145,471
	1,045,716,338		$25,524,299		$30,074,237
				Change	$4,549,938
Primary Voltage					
1st 3,000 kWh, per kWh	652,857	2.505 ¢	$16,354	2.952 ¢	$19,272
All additional kWh, per kWh	196,094	1.859 ¢	$3,645	2.191 ¢	$4,296
	848,951		$19,999		$23,568
				Change	$3,569
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,455,446,266	2.451 ¢	$35,672,988	2.888 ¢	$42,033,288
All additional kWh, per kWh	570,656,338	2.384 ¢	$13,604,447	2.809 ¢	$16,029,737
	2,026,102,604		$49,277,435		$58,063,025
				Change	$8,785,590
Primary Voltage					
1st 20,000 kWh, per kWh	10,435,837	2.271 ¢	$236,998	2.676 ¢	$279,263
All additional kWh, per kWh	10,585,073	2.210 ¢	$233,930	2.604 ¢	$275,635
	21,020,910		$470,928		$554,898
				Change	$83,970
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	185,984,514	2.695 ¢	$5,012,283	3.176 ¢	$5,906,868
All additional kWh, per kWh	1,033,484,144	2.337 ¢	$24,152,524	2.754 ¢	$28,462,153
	1,219,468,658		$29,164,807		$34,369,021
				Change	$5,204,214
Primary Voltage					
1st 20,000 kWh, per kWh	11,625,931	2.665 ¢	$309,831	3.140 ¢	$365,054
All additional kWh, per kWh	75,588,762	2.304 ¢	$1,741,565	2.715 ¢	$2,052,235
	87,214,693		$2,051,396		$2,417,289
				Change	$365,893
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	1,970,732	3.392 ¢	$66,847	3.997 ¢	$78,770
Winter, All additional kWh, per kWh	1,669,130	2.311 ¢	$38,574	2.723 ¢	$45,450
Summer, All kWh, per kWh	144,065,283	2.311 ¢	$3,329,349	2.723 ¢	$3,922,898
	147,705,145		$3,434,770		$4,047,118
				Change	$612,348
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	10,934	3.285 ¢	$359	3.871 ¢	$423
Winter, All additional kWh, per kWh	57,900	2.238 ¢	$1,296	2.637 ¢	$1,527
Summer, All kWh, per kWh	528,676	2.238 ¢	$11,832	2.637 ¢	$13,941
	597,510		$13,487		$15,891
				Change	$2,404
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	76,021,473	2.321 ¢	$1,764,458	2.732 ¢	$2,076,907
Off-Peak, per off-peak kWh	53,652,452	2.271 ¢	$1,218,447	2.682 ¢	$1,438,959
	129,673,925		$2,982,905		$3,515,866
				Change	$532,961
Transmission Voltage					
On-Peak, per on-peak kWh	64,866,212	2.213 ¢	$1,435,489	2.604 ¢	$1,689,116
Off-Peak, per off-peak kWh	41,587,891	2.163 ¢	$899,546	2.554 ¢	$1,062,155
	106,454,103		$2,335,035		$2,751,271
				Change	$416,236

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues
Forecast 12 Months Ended December 31, 2012

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	401,277,165	2.410 ¢	$9,670,780	2.837 ¢	$11,384,233
Off-Peak, per off-peak kWh	219,190,369	2.360 ¢	$5,172,893	2.787 ¢	$6,108,836
	620,467,534		$14,843,673		$17,493,069
				Change	$2,649,396
Primary Voltage					
On-Peak, per on-peak kWh	973,431,348	2.321 ¢	$22,593,342	2.732 ¢	$26,594,144
Off-Peak, per off-peak kWh	605,886,086	2.271 ¢	$13,759,673	2.682 ¢	$16,249,865
	1,579,317,434		$36,353,015		$42,844,009
				Change	$6,490,994
Transmission Voltage					
On-Peak, per on-peak kWh	479,936,774	2.213 ¢	$10,621,001	2.604 ¢	$12,497,554
Off-Peak, per off-peak kWh	389,957,399	2.163 ¢	$8,434,779	2.554 ¢	$9,959,512
	869,894,173		$19,055,780		$22,457,066
				Change	$3,401,286
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	10,059,098	2.319 ¢	$233,113	2.733 ¢	$275,132
	10,059,098		$233,113		$275,132
				Change	$42,019
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,689,779	1.906 ¢	$184,848	2.246 ¢	$217,872
	9,689,779		$184,848		$217,872
				Change	$33,024
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	17,902,036	3.008 ¢	$537,976	3.545 ¢	$634,512
	17,902,036		$537,976		$634,512
				Change	$96,537
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	926,528	2.304 ¢	$21,347	2.715 ¢	$25,155
	926,528		$21,347		$25,155
				Change	$3,808
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,407,630	0.984 ¢	$92,571	1.160 ¢	$109,129
	9,407,630		$92,571		$109,129
				Change	$16,557
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	992,677	1.695 ¢	$16,826	1.997 ¢	$19,824
	992,677		$16,826		$19,824
				Change	$2,998
TOTAL Before Employee Discount			**$324,533,701**		**$382,431,676**
Employee Discount			-$114,157		-$134,522
TOTAL SCHEDULE 201	**13,561,408,455**		**$324,419,545**		**$382,297,153**
Schedule 33 kWh	122,259,174			**Change**	**$57,877,609**
Schedule 47 Unscheduled kWh	3,252,367				
Total Forecast kWH	13,686,919,996				

Exhibit PPL/302
Judith M. Ridenour

Docket No. UE-
Exhibit PPL/302
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 Rates for Schedule 205 - TAM Adjustment for Other Revenues

March 2011

PACIFIC POWER
STATE OF OREGON
Other Revenues - Stand-Alone TAM Adjustment: Schedule 205 Proposed Rates and Revenues
Forecast 12 Months Ended December 31, 2012

Rate Schedule	Forecast Energy	Present Schedule 201 Revenues	Proposed Schedule 205 Rates	Proposed Schedule 205 Revenues
Schedule 4, Residential				
First Block kWh (0-1,000)	4,141,565,738	$91,942,759	0.026 ¢	$1,076,807
Second Block kWh (> 1,000)	1,516,382,991	$45,976,732	0.035 ¢	$530,734
	5,657,948,729	$137,919,491		$1,607,541
Employee Discount				
First Block kWh (0-1,000)	*12,387,969*	*$275,013*	*0.026 ¢*	*$3,221*
Second Block kWh (> 1,000)	*5,989,914*	*$181,614*	*0.035 ¢*	*$2,096*
	18,377,883	*$456,627*		*$5,317*
	Discount	-$114,157	Discount	-$1,329
Schedule 23, Small General Service				
Secondary Voltage				
1st 3,000 kWh, per kWh	818,141,307	$21,157,134	0.030 ¢	$245,442
All additional kWh, per kWh	227,575,031	$4,367,165	0.022 ¢	$50,067
	1,045,716,338	$25,524,299		$295,509
Primary Voltage				
1st 3,000 kWh, per kWh	652,857	$16,354	0.029 ¢	$189
All additional kWh, per kWh	196,094	$3,645	0.021 ¢	$41
	848,951	$19,999		$230
Schedule 28, General Service 31-200kW				
Secondary Voltage				
1st 20,000 kWh, per kWh	1,455,446,266	$35,672,988	0.028 ¢	$407,525
All additional kWh, per kWh	570,656,338	$13,604,447	0.028 ¢	$159,784
	2,026,102,604	$49,277,435		$567,309
Primary Voltage				
1st 20,000 kWh, per kWh	10,435,837	$236,998	0.026 ¢	$2,713
All additional kWh, per kWh	10,585,073	$233,930	0.026 ¢	$2,752
	21,020,910	$470,928		$5,465
Schedule 30, General Service 201-999kW				
Secondary Voltage				
1st 20,000 kWh, per kWh	185,984,514	$5,012,283	0.031 ¢	$57,655
All additional kWh, per kWh	1,033,484,144	$24,152,524	0.027 ¢	$279,041
	1,219,468,658	$29,164,807		$336,696
Primary Voltage				
1st 20,000 kWh, per kWh	11,625,931	$309,831	0.031 ¢	$3,604
All additional kWh, per kWh	75,588,762	$1,741,565	0.027 ¢	$20,409
	87,214,693	$2,051,396		$24,013
Schedule 41, Agricultural Pumping Service				
Secondary Voltage				
Winter, 1st 100 kWh/kW, per kWh	1,970,732	$66,847	0.039 ¢	$769
Winter, All additional kWh, per kWh	1,669,130	$38,574	0.027 ¢	$451
Summer, All kWh, per kWh	144,065,283	$3,329,349	0.027 ¢	$38,898
	147,705,145	$3,434,770		$40,118
Primary Voltage				
Winter, 1st 100 kWh/kW, per kWh	10,934	$359	0.038 ¢	$4
Winter, All additional kWh, per kWh	57,900	$1,296	0.026 ¢	$15
Summer, All kWh, per kWh	528,676	$11,832	0.026 ¢	$137
	597,510	$13,487		$156
Schedule 47, Large General Service, Partial Requirements 1,000kW and over				
Primary Voltage				
On-Peak, per on-peak kWh	76,021,473	$1,764,458	0.027 ¢	$20,526
Off-Peak, per off-peak kWh	53,652,452	$1,218,447	0.027 ¢	$14,486
	129,673,925	$2,982,905		$35,012
Transmission Voltage				
On-Peak, per on-peak kWh	64,866,212	$1,435,489	0.025 ¢	$16,217
Off-Peak, per off-peak kWh	41,587,891	$899,546	0.025 ¢	$10,397
	106,454,103	$2,335,035		$26,614

PACIFIC POWER
STATE OF OREGON
Other Revenues - Stand-Alone TAM Adjustment: Schedule 205 Proposed Rates and Revenues
Forecast 12 Months Ended December 31, 2012

Rate Schedule	Forecast Energy	Present Schedule 201 Revenues	Proposed Schedule 205 Rates		Proposed Schedule 205 Revenues
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	401,277,165	$9,670,780	0.028	¢	$112,358
Off-Peak, per off-peak kWh	219,190,369	$5,172,893	0.028	¢	$61,373
	620,467,534	$14,843,673			$173,731
Primary Voltage					
On-Peak, per on-peak kWh	973,431,348	$22,593,342	0.027	¢	$262,826
Off-Peak, per off-peak kWh	605,886,086	$13,759,673	0.027	¢	$163,589
	1,579,317,434	$36,353,015			$426,415
Transmission Voltage					
On-Peak, per on-peak kWh	479,936,774	$10,621,001	0.025	¢	$119,984
Off-Peak, per off-peak kWh	389,957,399	$8,434,779	0.025	¢	$97,489
	869,894,173	$19,055,780			$217,473
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	10,059,098	$233,113	0.027	¢	$2,716
	10,059,098	$233,113			$2,716
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,689,779	$184,848	0.022	¢	$2,132
	9,689,779	$184,848			$2,132
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	17,902,036	$537,976	0.035	¢	$6,266
	17,902,036	$537,976			$6,266
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	926,528	$21,347	0.027	¢	$250
	926,528	$21,347			$250
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,407,630	$92,571	0.011	¢	$1,035
	9,407,630	$92,571			$1,035
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	992,677	$16,826	0.020	¢	$199
	992,677	$16,826			$199
TOTAL Before Employee Discount		**$324,533,701**			**$3,768,880**
Employee Discount		-$114,157			-$1,329
TOTAL SCHEDULE 201	**13,561,408,455**	**$324,419,545**			**$3,767,551**
Schedule 33 kWh	122,259,174				
Schedule 47 Unscheduled kWh	3,252,367				
Total Forecast kWH	13,686,919,996				

Docket No. UE-
Exhibit PPL/303
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 Schedules 201 and 205

March 2011

PACIFIC POWER
A DIVISION OF PACIFICORP

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	0-1000 kWh	2.616¢			(I)
		> 1000 kWh	3.573¢			(I)

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	3.047¢	2.952¢		(I)
	All additional kWh, per kWh	2.261¢	2.191¢		(I)
28	First 20,000 kWh, per kWh	2.888¢	2.676¢		(I)
	All additional kWh, per kWh	2.809¢	2.604¢		(I)
30	First 20,000 kWh, per kWh	3.176¢	3.140¢		(I)
	All additional kWh, per kWh	2.754¢	2.715¢		(I)
41	Winter, first 100 kWh/kW, per kWh	3.997¢	3.871¢		(I)
	Winter, all additional kWh, per kWh	2.723¢	2.637¢		(I)
	Summer, all kWh, per kWh	2.723¢	2.637¢		(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.		Secondary	Primary	Transmission	
			Delivery Voltage		
47/48	Per kWh On-Peak	2.837¢	2.732¢	2.604¢	(I)
	Per kWh, Off-Peak	2.787¢	2.682¢	2.554¢	(I)

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	2.715¢	(I)
	For dusk to midnight operation, per kWh	2.715¢	(I)
54	Per kWh	1.997¢	(I)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$ 2.08	(I)
Mercury Vapor	21,000	172	$ 4.70	
Mercury Vapor	55,000	412	$11.26	
High Pressure Sodium	5,800	31	$ 0.85	
High Pressure Sodium	22,000	85	$ 2.32	
High Pressure Sodium	50,000	176	$ 4.81	(I)

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	$1.71	$3.86	$9.25	(I)
Vertical, per lamp	$1.71	$3.86		(I)

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	$1.71			(I)
On 26-foot poles, vertical, per lamp	$1.71			
On 30-foot poles, horizontal, per lamp		$3.86		
On 30-foot poles, vertical, per lamp		$3.86		
On 33-foot poles, horizontal, per lamp			$9.25	(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	$1.71			(I)
On 26-foot poles, vertical, per lamp	$1.71			|
On 30-foot poles, horizontal, per lamp		$3.86		|
On 30-foot poles, vertical, per lamp		$3.86		|
On 33-foot poles, horizontal, per lamp			$9.25	(I)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$1.10	(I)
High Pressure Sodium	9,500	100	44	$1.56	|
High Pressure Sodium	16,000	150	64	$2.27	|
High Pressure Sodium	22,000	200	85	$3.01	|
High Pressure Sodium	27,500	250	115	$4.08	|
High Pressure Sodium	50,000	400	176	$6.24	|
Metal Halide	9,000	100	39	$1.38	|
Metal Halide	12,000	175	68	$2.41	|
Metal Halide	19,500	250	94	$3.33	|
Metal Halide	32,000	400	149	$5.28	(I)

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.36	(I)
High Pressure Sodium	9,500	100	44	$0.51	|
High Pressure Sodium	16,000	150	64	$0.74	|
High Pressure Sodium	22,000	200	85	$0.99	|
High Pressure Sodium	27,500	250	115	$1.33	|
High Pressure Sodium	50,000	400	176	$2.04	|
Metal Halide	9,000	100	39	$0.45	|
Metal Halide	12,000	175	68	$0.79	|
Metal Halide	19,500	250	94	$1.09	|
Metal Halide	32,000	400	149	$1.73	|
Metal Halide	107,800	1,000	354	$4.11	(I)

Non-Listed Luminaire, per kWh 1.160¢ (I)

55

Types of Luminaire	Compares to HPSV Lamp Size of (Watts)	Monthly kWh	Rate Per Luminaire	
Light Emitting Diode	100	29	$1.03	(I)
Light Emitting Diode	150	41	$1.45	(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

(N)

Purpose
This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

Applicable
To all Residential Consumers and Nonresidential Consumers.

Energy Charge
The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**		
			Secondary	**Primary**	**Transmission**
4	Per kWh	0-1000 kWh	0.026¢		
		> 1000 kWh	0.035¢		

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).

Schedule		Secondary	Primary	Transmission
23, 723	First 3,000 kWh, per kWh	0.030¢	0.029¢	
	All additional kWh, per kWh	0.022¢	0.021¢	
28, 728	First 20,000 kWh, per kWh	0.028¢	0.026¢	
	All additional kWh, per kWh	0.028¢	0.026¢	
30, 730	First 20,000 kWh, per kWh	0.031¢	0.031¢	
	All additional kWh, per kWh	0.027¢	0.027¢	
41, 741	Winter, first 100 kWh/kW, per kWh	0.039¢	0.038¢	
	Winter, all additional kWh, per kWh	0.027¢	0.026¢	
	Summer, all kWh, per kWh	0.027¢	0.026¢	

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. (N)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

(N)

Energy Charge (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission
47/48	Per kWh On-Peak	0.028¢	0.027¢	0.025¢
747/748	Per kWh, Off-Peak	0.028¢	0.027¢	0.025¢

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, 752	For dusk to dawn operation, per kWh	0.027¢
	For dusk to midnight operation, per kWh	0.027¢
54,754	Per kWh	0.020¢

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire
Mercury Vapor	7,000	76	$0.02
Mercury Vapor	21,000	172	$0.05
Mercury Vapor	55,000	412	$0.11
High Pressure Sodium	5,800	31	$0.01
High Pressure Sodium	22,000	85	$0.02
High Pressure Sodium	50,000	176	$0.05

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	$0.02	$0.04	$0.09
Vertical, per lamp	$0.02	$0.04	

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	$0.02		
On 26-foot poles, vertical, per lamp	$0.02		
On 30-foot poles, horizontal, per lamp		$0.04	
On 30-foot poles, vertical, per lamp		$0.04	
On 33-foot poles, horizontal, per lamp			$0.09

(N)

(continued)

Energy Charge (continued) (N)

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	$0.02		
On 26-foot poles, vertical, per lamp	$0.02		
On 30-foot poles, horizontal, per lamp		$0.04	
On 30-foot poles, vertical, per lamp		$0.04	
On 33-foot poles, horizontal, per lamp			$0.09

51, 751

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	70	31	$0.01
High Pressure Sodium	9,500	100	44	$0.02
High Pressure Sodium	16,000	150	64	$0.02
High Pressure Sodium	22,000	200	85	$0.03
High Pressure Sodium	27,500	250	115	$0.04
High Pressure Sodium	50,000	400	176	$0.06
Metal Halide	9,000	100	39	$0.01
Metal Halide	12,000	175	68	$0.02
Metal Halide	19,500	250	94	$0.03
Metal Halide	32,000	400	149	$0.05

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	70	31	$0.00
High Pressure Sodium	9,500	100	44	$0.00
High Pressure Sodium	16,000	150	64	$0.01
High Pressure Sodium	22,000	200	85	$0.01
High Pressure Sodium	27,500	250	115	$0.01
High Pressure Sodium	50,000	400	176	$0.02
Metal Halide	9,000	100	39	$0.00
Metal Halide	12,000	175	68	$0.01
Metal Halide	19,500	250	94	$0.01
Metal Halide	32,000	400	149	$0.02
Metal Halide	107,800	1,000	354	$0.04

Non-Listed Luminaire, per kWh 0.011¢

55

Types of Luminaire	Compares to HPSV Lamp Size of (Watts)	Monthly kWh	Rate Per Luminaire
Light Emitting Diode	100	29	$0.01
Light Emitting Diode	150	41	$0.01

(N)

Docket No. UE-
Exhibit PPL/304
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

March 2011

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, 2012

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line 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	484,883	5,657,949	$567,372	$11,655	$579,027	$593,584	$11,655	$605,239	$26,212	4.6%	$26,212	4.5%	1
2	**Total Residential**			484,883	5,657,949	$567,372	$11,655	$579,027	$593,584	$11,655	$605,239	$26,212	4.6%	$26,212	4.5%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,522	1,046,565	$111,304	($1,737)	$109,567	$116,153	($1,737)	$114,416	$4,849	4.4%	$4,849	4.4%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,061	2,047,124	$157,897	$7,472	$165,369	$167,339	$7,472	$174,811	$9,442	6.0%	$9,442	5.7%	4
5	Gen. Svc. 201 - 999 kW	30	30	821	1,306,684	$93,359	$1,881	$95,240	$99,290	$1,881	$101,171	$5,931	6.4%	$5,931	6.2%	5
6	Large General Service >= 1,000 kW	48	48	207	3,069,679	$194,014	($11,055)	$182,959	$207,373	($11,055)	$196,318	$13,359	6.9%	$13,359	7.3%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	239,380	$15,351	($941)	$14,410	$16,362	($941)	$15,421	$1,011	6.9%	$1,011	7.3%	7
8	Agricultural Pumping Service	41	41	6,095	148,303	$16,913	($2,369)	$14,544	$17,568	($2,369)	$15,199	$655	3.9%	$655	4.5%	8
9	Agricultural Pumping - Other	33	33	1,988	122,259	$7,336	$77	$7,413	$7,336	$77	$7,413	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			93,701	7,979,994	$596,174	($6,672)	$589,502	$631,422	($6,672)	$624,750	$35,248	5.9%	$35,248	6.0%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,026	10,059	$1,302	$264	$1,566	$1,347	$264	$1,611	$45	3.4%	$45	2.9%	11
12	Street Lighting Service	50	50	250	9,690	$1,089	$238	$1,327	$1,124	$238	$1,362	$35	3.2%	$35	2.7%	12
13	Street Lighting Service HPS	51	51	748	17,902	$3,200	$698	$3,898	$3,303	$698	$4,001	$103	3.2%	$103	2.6%	13
14	Street Lighting Service	52	52	55	927	$105	$23	$128	$109	$23	$132	$4	3.9%	$4	3.2%	14
15	Street Lighting Service	53	53	270	9,408	$597	$139	$736	$615	$139	$754	$18	3.0%	$18	2.4%	15
16	Recreational Field Lighting	54	54	104	993	$85	$18	$103	$88	$18	$106	$3	3.8%	$3	3.1%	16
17	**Total Public Street Lighting**			8,453	48,979	$6,378	$1,380	$7,758	$6,586	$1,380	$7,966	$208	3.3%	$208	2.7%	17
18	**Total Sales to Ultimate Consumers**			587,037	13,686,922	$1,169,924	$6,363	$1,176,287	$1,231,591	$6,363	$1,237,954	$61,667	5.3%	$61,667	5.2%	18
19	**Employee Discount**				18,378	($456)	($10)	($466)	($478)	($10)	($488)	($22)		($22)		19
20	**Total Sales with Employee Discount**			587,037	13,686,922	$1,169,468	$6,353	$1,175,821	$1,231,113	$6,353	$1,237,466	$61,645	5.3%	$61,645	5.2%	20
21	AGA Revenue					$2,886		$2,886	$2,886		$2,886	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			587,037	13,686,922	$1,172,354	$6,353	$1,178,707	$1,233,999	$6,353	$1,240,352	$61,645	5.3%	$61,645	5.2%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), 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 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$18.56	$19.00	$0.44	2.37%
200	$27.39	$28.25	$0.86	3.14%
300	$36.18	$37.49	$1.31	3.62%
400	$45.01	$46.75	$1.74	3.87%
500	$53.80	$55.98	$2.18	4.05%
600	$62.60	$65.20	$2.60	4.15%
700	$71.42	$74.46	$3.04	4.26%
800	$80.22	$83.70	$3.48	4.34%
900	$89.04	$92.96	$3.92	4.40%
950	**$93.42**	**$97.55**	**$4.13**	**4.42%**
1,000	$97.84	$102.18	$4.34	4.44%
1,100	$109.16	$114.10	$4.94	4.53%
1,200	$120.49	$126.03	$5.54	4.60%
1,300	$131.81	$137.94	$6.13	4.65%
1,400	$143.15	$149.87	$6.72	4.69%
1,500	$154.47	$161.79	$7.32	4.74%
1,600	$165.78	$173.69	$7.91	4.77%
2,000	$211.10	$221.38	$10.28	4.87%
3,000	$324.36	$340.57	$16.21	5.00%
4,000	$437.62	$459.77	$22.15	5.06%
5,000	$550.88	$578.96	$28.08	5.10%

* 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 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$66	$76	$69	$78	3.82%	3.33%
	750	$90	$99	$94	$103	4.23%	3.82%
	1,000	$113	$123	$118	$128	4.47%	4.11%
	1,500	$160	$170	$168	$177	4.73%	4.47%
10	1,000	$113	$123	$118	$128	4.47%	4.11%
	2,000	$207	$217	$217	$227	4.88%	4.67%
	3,000	$301	$311	$316	$326	5.03%	4.88%
	4,000	$380	$389	$399	$408	4.98%	4.86%
20	4,000	$409	$418	$428	$437	4.63%	4.52%
	6,000	$566	$576	$593	$602	4.67%	4.59%
	8,000	$724	$733	$757	$767	4.69%	4.63%
	10,000	$881	$890	$922	$932	4.70%	4.65%
30	9,000	$860	$870	$898	$907	4.38%	4.33%
	12,000	$1,096	$1,106	$1,145	$1,155	4.46%	4.42%
	15,000	$1,332	$1,341	$1,392	$1,402	4.52%	4.48%
	18,000	$1,568	$1,577	$1,639	$1,649	4.55%	4.53%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
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	$65	$74	$67	$77	3.78%	3.31%
	750	$88	$97	$91	$101	4.20%	3.78%
	1,000	$110	$120	$115	$125	4.44%	4.09%
	1,500	$156	$165	$163	$173	4.72%	4.44%
10	1,000	$110	$120	$115	$125	4.44%	4.09%
	2,000	$202	$211	$211	$221	4.87%	4.64%
	3,000	$293	$302	$307	$317	5.03%	4.87%
	4,000	$369	$378	$387	$397	4.97%	4.85%
20	4,000	$397	$407	$416	$425	4.62%	4.51%
	6,000	$550	$559	$575	$585	4.66%	4.58%
	8,000	$702	$712	$735	$745	4.68%	4.62%
	10,000	$855	$864	$895	$904	4.70%	4.65%
30	9,000	$835	$845	$872	$881	4.37%	4.32%
	12,000	$1,064	$1,074	$1,111	$1,121	4.46%	4.42%
	15,000	$1,293	$1,302	$1,351	$1,361	4.51%	4.48%
	18,000	$1,521	$1,531	$1,591	$1,600	4.55%	4.52%

* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$401	$422	5.38%
	7,500	$602	$638	5.96%
	10,500	$804	$854	6.25%
31	9,300	$811	$856	5.49%
	15,500	$1,228	$1,302	6.04%
	21,700	$1,643	$1,746	6.31%
40	12,000	$1,042	$1,100	5.51%
	20,000	$1,580	$1,676	6.06%
	28,000	$2,106	$2,239	6.32%
60	18,000	$1,557	$1,643	5.54%
	30,000	$2,349	$2,491	6.07%
	42,000	$3,137	$3,336	6.33%
80	24,000	$2,060	$2,175	5.56%
	40,000	$3,112	$3,301	6.08%
	56,000	$4,163	$4,427	6.34%
100	30,000	$2,560	$2,703	5.56%
	50,000	$3,875	$4,111	6.08%
	70,000	$5,189	$5,518	6.34%
200	60,000	$5,040	$5,322	5.60%
	100,000	$7,669	$8,138	6.12%
	140,000	$10,297	$10,953	6.37%

* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$367	$387	5.45%
	7,500	$547	$580	6.09%
	10,500	$727	$774	6.41%
31	9,300	$739	$781	5.59%
	15,500	$1,112	$1,181	6.19%
	21,700	$1,482	$1,578	6.49%
40	12,000	$949	$1,002	5.61%
	20,000	$1,429	$1,518	6.21%
	28,000	$1,899	$2,022	6.50%
60	18,000	$1,418	$1,497	5.64%
	30,000	$2,124	$2,256	6.22%
	42,000	$2,828	$3,012	6.50%
80	24,000	$1,875	$1,981	5.66%
	40,000	$2,813	$2,988	6.23%
	56,000	$3,751	$3,996	6.52%
100	30,000	$2,329	$2,461	5.67%
	50,000	$3,502	$3,720	6.24%
	70,000	$4,675	$4,980	6.53%
200	60,000	$4,568	$4,830	5.73%
	100,000	$6,914	$7,349	6.29%
	140,000	$9,261	$9,868	6.56%

* Net rate including Schedules 91, 290 and 297.

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,816	$2,967	5.37%
	50,000	$3,921	$4,164	6.19%
	70,000	$5,027	$5,361	6.65%
200	60,000	$5,081	$5,369	5.68%
	100,000	$7,292	$7,763	6.46%
	140,000	$9,502	$10,157	6.89%
300	90,000	$7,485	$7,910	5.69%
	150,000	$10,801	$11,501	6.48%
	210,000	$14,117	$15,092	6.90%
400	120,000	$9,792	$10,354	5.75%
	200,000	$14,213	$15,142	6.53%
	280,000	$18,635	$19,930	6.95%
500	150,000	$12,123	$12,823	5.77%
	250,000	$17,651	$18,808	6.56%
	350,000	$23,178	$24,792	6.97%
600	180,000	$14,455	$15,292	5.79%
	300,000	$21,088	$22,474	6.57%
	420,000	$27,720	$29,655	6.98%
800	240,000	$19,119	$20,230	5.81%
	400,000	$27,962	$29,805	6.59%
	560,000	$36,806	$39,381	7.00%
1000	300,000	$23,782	$25,168	5.83%
	500,000	$34,837	$37,137	6.60%
	700,000	$45,891	$49,106	7.01%

* Net rate including Schedules 91, 290 and 297.

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,764	$2,913	5.40%
	50,000	$3,850	$4,090	6.22%
	70,000	$4,937	$5,267	6.68%
200	60,000	$4,994	$5,279	5.70%
	100,000	$7,168	$7,633	6.49%
	140,000	$9,341	$9,987	6.91%
300	90,000	$7,353	$7,773	5.71%
	150,000	$10,614	$11,304	6.51%
	210,000	$13,874	$14,835	6.93%
400	120,000	$9,657	$10,212	5.75%
	200,000	$14,004	$14,920	6.54%
	280,000	$18,351	$19,628	6.96%
500	150,000	$11,955	$12,645	5.78%
	250,000	$17,388	$18,530	6.57%
	350,000	$22,821	$24,414	6.98%
600	180,000	$14,252	$15,078	5.80%
	300,000	$20,772	$22,140	6.58%
	420,000	$27,292	$29,201	6.99%
800	240,000	$18,847	$19,944	5.82%
	400,000	$27,540	$29,359	6.60%
	560,000	$36,234	$38,774	7.01%
1000	300,000	$23,442	$24,809	5.83%
	500,000	$34,309	$36,579	6.62%
	700,000	$45,176	$48,348	7.02%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
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	$246	$271	$175	$260	$287	$175	5.51%	5.78%	0.00%
	5,000	$410	$435	$175	$433	$460	$175	5.51%	5.68%	0.00%
	7,000	$575	$600	$175	$606	$633	$175	5.51%	5.63%	0.00%
Three Phase										
20	6,000	$493	$542	$350	$520	$574	$350	5.51%	5.78%	0.00%
	10,000	$821	$871	$350	$866	$920	$350	5.51%	5.68%	0.00%
	14,000	$1,149	$1,199	$350	$1,213	$1,267	$350	5.51%	5.63%	0.00%
100	30,000	$2,463	$2,712	$1,504	$2,598	$2,869	$1,504	5.51%	5.78%	0.00%
	50,000	$4,105	$4,354	$1,504	$4,331	$4,601	$1,504	5.51%	5.68%	0.00%
	70,000	$5,746	$5,996	$1,504	$6,063	$6,333	$1,504	5.51%	5.63%	0.00%
300	90,000	$7,388	$8,136	$3,770	$7,795	$8,606	$3,770	5.51%	5.78%	0.00%
	150,000	$12,314	$13,062	$3,770	$12,992	$13,803	$3,770	5.51%	5.68%	0.00%
	210,000	$17,239	$17,987	$3,770	$18,189	$19,000	$3,770	5.51%	5.63%	0.00%

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

Pacific Power
TAM Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
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	$237	$261	$175	$250	$276	$175	5.54%	5.81%	0.00%
	5,000	$395	$419	$175	$417	$443	$175	5.54%	5.71%	0.00%
	7,000	$553	$577	$175	$583	$610	$175	5.54%	5.67%	0.00%
Three Phase										
20	6,000	$474	$522	$350	$500	$552	$350	5.54%	5.81%	0.00%
	10,000	$790	$838	$350	$833	$886	$350	5.54%	5.71%	0.00%
	14,000	$1,106	$1,154	$350	$1,167	$1,219	$350	5.54%	5.67%	0.00%
100	30,000	$2,369	$2,610	$1,494	$2,500	$2,762	$1,494	5.54%	5.82%	0.00%
	50,000	$3,949	$4,190	$1,494	$4,167	$4,429	$1,494	5.54%	5.71%	0.00%
	70,000	$5,528	$5,769	$1,494	$5,834	$6,096	$1,494	5.54%	5.67%	0.00%
300	90,000	$7,107	$7,831	$3,760	$7,501	$8,287	$3,760	5.54%	5.82%	0.00%
	150,000	$11,846	$12,570	$3,760	$12,502	$13,288	$3,760	5.54%	5.71%	0.00%
	210,000	$16,584	$17,308	$3,760	$17,503	$18,289	$3,760	5.54%	5.67%	0.00%

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

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$22,461	$23,867	6.26%
	500,000	$32,869	$35,212	7.13%
	700,000	$43,277	$46,557	7.58%
2,000	600,000	$44,572	$47,384	6.31%
	1,000,000	$64,078	$68,764	7.31%
	1,400,000	$84,170	$90,731	7.80%
4,000	1,200,000	$87,122	$92,746	6.46%
	2,000,000	$127,306	$136,679	7.36%
	2,800,000	$167,489	$180,611	7.83%
6,000	1,800,000	$129,939	$138,375	6.49%
	3,000,000	$190,214	$204,274	7.39%
	4,200,000	$250,489	$270,172	7.86%

Notes:

On-Peak kWh	64.67%
Off-Peak kWh	35.33%

* 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 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$21,505	$22,859	6.29%
	500,000	$31,427	$33,683	7.18%
	700,000	$41,348	$44,506	7.64%
2,000	600,000	$42,640	$45,347	6.35%
	1,000,000	$61,173	$65,684	7.37%
	1,400,000	$80,292	$86,608	7.87%
4,000	1,200,000	$83,237	$88,650	6.50%
	2,000,000	$121,475	$130,498	7.43%
	2,800,000	$159,713	$172,345	7.91%
6,000	1,800,000	$124,399	$132,520	6.53%
	3,000,000	$181,757	$195,291	7.45%
	4,200,000	$239,114	$258,062	7.92%

Notes:

On-Peak kWh	61.64%
Off-Peak kWh	38.36%

* 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 + Cost-Based Supply Service
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	$21,180	$22,466	6.07%
	500,000	$30,590	$32,733	7.00%
	700,000	$40,000	$42,999	7.50%
2,000	600,000	$41,763	$44,334	6.16%
	1,000,000	$59,273	$63,558	7.23%
	1,400,000	$77,368	$83,367	7.75%
4,000	1,200,000	$81,258	$86,399	6.33%
	2,000,000	$117,449	$126,018	7.30%
	2,800,000	$153,640	$165,637	7.81%
6,000	1,800,000	$121,842	$129,555	6.33%
	3,000,000	$176,129	$188,983	7.30%
	4,200,000	$230,415	$248,411	7.81%

Notes:

On-Peak kWh	55.17%
Off-Peak kWh	44.83%

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