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July 15, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

Re: Docket UE 264—PacifiCorp's Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power submits for filing the Reply Testimony and Exhibits of Mr. Gregory N. Duvall and Ms. Cindy A. Crane.

Confidential material in support of the filing is being provided to parties under Order No. 10-069, the standing protective order adopted for all TAM proceedings.

Please direct informal correspondence and questions regarding this filing to Bryce Dalley, Director, Regulatory Affairs, at (503) 813-6389.

Sincerely,

William R. Griffith /AS
William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 264 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of Pacific Power's Reply Testimony & Exhibits on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 15th of July 2013.

Carrie Meyer
Supervisor, Regulatory Operations

Docket No. UE 264
Exhibit PAC/500
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Gregory N. Duvall

July 2013

Q. Are you the same Gregory N. Duvall who previously submitted direct and supplemental direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony has two parts: a Transition Adjustment Mechanism (TAM) update section (Reply Update), consistent with the TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363, and a reply section responding to the parties' proposed adjustments.

In the Reply Update, I provide corrections and contract, fuel, and forward price curve updates to the Company's March 1, 2013 filing (Initial Filing). In addition, I explain the reasonableness of the Company's revised system net power costs (NPC) of $1.460 billion for the test period of the 12 months ending December 31, 2014.

In my reply testimony, I respond to the adjustments to the Company's NPC presented by Messrs. John Crider and Jorge Ordonez on behalf of Commission Staff (Staff), Mr. Bob Jenks and Ms. Nadine Hanhan on behalf of the Citizens' Utility Board of Oregon (CUB), Mr. Michael C. Deen on behalf of the Industrial Customers of Northwest Utilities (ICNU), Mr. Kevin Higgins on behalf of Noble Americas Energy Solutions, LLC (Noble Solutions), and Mr. Steve Chriss on behalf of Wal-Mart Stores, Inc. (Walmart).

Q. Please identify the other Company witness providing reply testimony supporting the 2014 TAM.

A. Ms. Cindy A. Crane, Vice President, Interwest Mining & Fuels, provides testimony rebutting ICNU's adjustment to coal fuel expense for the Jim Bridger plant and Staff's adjustment to certain O&M expenses embedded in the costs of fuel from the Company's affiliate mining companies.

REASONABLENESS OF COMPANY'S REPLY UPDATE NPC

Q. In the Initial Filing, the Company requested system NPC of $1.457 billion for the test period ending December 31, 2014. Has your NPC recommendation increased?

A. Yes. The Company's system NPC in the Reply Update are $1.461 billion, an increase of approximately $3.5 million from the Company's Initial Filing. The NPC report for the Reply Update is attached to my testimony as Exhibit PAC/501.

Q. What is the increase in NPC from the Initial Filing on an Oregon-allocated basis?

A. As illustrated in Exhibit PAC/502, on an Oregon-allocated basis, the Company's NPC are approximately $364.1 million, a $0.9 million increase from the Initial Filing. Notwithstanding the higher NPC in the Reply Update, the overall rate impact continues to be a reduction from current levels. The revised TAM decrease requested by the Company is $48,371.

Q. Please explain the changes reflected in your revised NPC request.

A. First, consistent with the TAM Guidelines, the Company made corrections to the Initial Filing and updated the Company's proposed NPC with: (1) the most recent official forward price curve; and (2) new power, fuel, and transportation/transmission contracts, and updates to existing contracts. Second, the Company accepts Staff's and CUB's objection to the Company's proposal to comprehensively update the TAM to reflect the renewal terms of the Company's large interruptible contracts.

Q. Is the Company's revised NPC recommendation in this case reasonable?

A. Yes. The Reply Update reflects the most recent information available to the Company in the determination of 2014 NPC and sets a reasonable and realistic NPC baseline for 2014.

Q. What are the ramifications of adopting Staff's and intervenors' NPC adjustments?

A. Adopting the modeling adjustments proposed by Staff and intervenors in this case would produce an artificially low overall level of NPC and decrease the accuracy of the Company's projected NPC. Furthermore, the parties' adjustments to coal costs eliminate costs previously recoverable in Oregon NPC. The Company has consistently under-recovered NPC in Oregon and removing previously-allowed costs from NPC increases the likelihood of continued NPC under-recovery.

Q. Is it important to set the most accurate NPC forecast possible to meet the Commission's goals for the TAM and the Company's new power cost adjustment mechanism (PCAM)?

A. Yes. As stated by the Commission, the purpose of the TAM is to capture costs associated with direct access and prevent unwarranted cost shifting.[1] The TAM is

[1] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Increase*, Docket UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).

calculated by comparing the value of energy used to serve direct access loads with the cost of service rate under the customers' specific energy-only tariff. The Commission approved an annual NPC update to ensure that both value of freed-up energy and the cost of service rate are calculated for the same period using the same data. In addition, under PacifiCorp's new PCAM, rates will be adjusted in 2015 to address differences between the 2014 TAM NPC baseline determined in this case and actual 2014 NPC. The more accurate the NPC forecast is in this case, the less likely it is that the Company will need to adjust rates through a PCAM surcharge or surcredit in 2015.

NPC CORRECTIONS AND UPDATES

Q. Please identify the corrections in the Reply Update.

A. The Company included seven corrections in its Reply Update:

- **Lake Side 2 Pipeline Expense**—The Company included pipeline expenses related to the Lake Side 2 generation facility for two months prior to the unit's expected online date. Costs incurred prior to the unit being placed into service are capitalized and not reflected in NPC. The correction reduces total-company NPC by approximately $0.9 million.
- **Small Qualifying Facility (QF) Pricing**—The Company incorrectly calculated the contract prices for several QF contracts expected to extend through 2014. Correcting the contract prices increases total-company NPC by approximately $13,000.
- **Heat Rate Calculation**—The Company inadvertently excluded some months from the calculation of the 48-month average heat rate for its coal-fired

generating units. In addition, the calculation of derated heat rates was not updated to the June 2012 base period. Correcting the heat rate calculations reduces total-company NPC by approximately $3.7 million.

- **Hydro Generation**—The Company inadvertently relied on a previous version of normalized hydro flows used to calculate forecasted generation from the Lewis, Klamath, and North Umpqua river systems rather than updating to 2012 normalized hydro flows. In addition, the forced outage rate calculation for the Copco facility averaged incorrect rows in the spreadsheet. These corrections increase total-company NPC by approximately $1.0 million.
- **Gadsby Combustion Turbine (CT) Commitment**—The Company incorrectly calculated the start-up costs used to determine the unit commitment for the three Gadsby CT generators. The correction reduces total-company NPC by approximately $3,400.
- **Wheeling Contracts**—The Company did not include a replacement San Juan transmission contract that began in December 2012, and incorrectly calculated the capacity and rates for two Colorado-to-Mona transmission contracts. These corrections reduce total-company NPC by approximately $86,000.
- **Bonneville Power Administration (BPA) Exchange—**The Company inadvertently did not include the Summer Storage and Spring Energy Option provisions of the AC Intertie agreement with BPA (BPA Exchange). Deliveries and returns of energy under the BPA Exchange during 2014 are now included in the West Main transmission area in the Generation and

Regulation Initiative Decision (GRID). This correction increases total-company NPC by approximately $1.2 million.

Q. Please describe how the Company updated NPC.

A. Consistent with Section B of the TAM Guidelines,[2] the Company's Reply Update reflects its most recent official forward price curve, dated June 28, 2013, new power, fuel, and transmission/transportation contracts, and updates to existing contracts. Exhibit PAC/503 provides a summary of the impact on total-company NPC for each of the items.

Q. Please explain the specific updates to NPC in the Reply Update.

A. The Company's Reply Update includes the following specific updates:

- **Northwest Pipeline Chehalis Lateral Rate—**Northwest Pipeline provided an updated cost-of-service calculation for the Chehalis Pipeline Lateral, with the new monthly payment taking effect April 2013. The update reduces total-company NPC by approximately $53,000.
- **PacifiCorp Transmission Real Power Loss Factor—**On May 23, 2013, Federal Energy Regulatory Commission (FERC) approved the Settlement Agreement resolving all issues in the Company's FERC rate case. The settlement set the real power loss factor pursuant to Schedule 10 of PacifiCorp's OATT at 4.26 percent. Several purchase, sale, and exchange contracts are dependent on this factor. Updating the real power loss factor increases total-company NPC by approximately $134,000.

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[2] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service,* Docket UE 199, Order No. 09-274, Appendix A at 2-3.

- **Portland General Electric Company (PGE) Cove Annual Cost—**The annual purchase power expense for PGE Cove has been updated to reflect the latest projection by PGE. The update increases total-company NPC by approximately $53,000.
- **Arizona Public Service Company (APS) Firm PTP Transmission Rate—**This update reflects the updated firm point-to-point transmission rate for APS posted on OASIS with an effective date of June 1, 2013. The updated rate is also applied to the Company's transmission rights under the Long-Term Power Transactions Agreement and Asset Purchase and Power Exchange Agreement with APS. This update increases total-company NPC by approximately $0.5 million.
- **Platte River Power Authority Real Power Loss Factor**—Platte River has updated its Real Power Loss factor to two percent, effective May 1, 2013. Updating the real power loss factor increases total-company NPC by approximately $2,000.
- **Idaho Power Company (Idaho Power) Firm Point to Point (PTP) Transmission Rate**—This update reflects the updated PTP transmission rate for Idaho Power for fiscal year ending September 30, 2014, posted on OASIS on May 31, 2013, with an effective date of October 1, 2013. This update increases total-company NPC by approximately $0.8 million.
- **Douglas Public Utility District (Douglas PUD) Pro-forma**—This update incorporates the fiscal year September 1, 2013 – August 31, 2014 preliminary

pro-forma published by Douglas PUD on April 30, 2013. This update decreases total-company NPC by approximately $100,000.

- **Black Hills Corporation (Black Hills) Sales Contract—**This update reflects the new annual fixed and variable costs the Company provided to Black Hills on June 10, 2013, for its sales contract with Black Hills. This update increases total-company NPC by approximately $0.3 million.
- **Small QFs—**The Company has not entered any new QF contracts for the test period; however, an updated Idaho Schedule 37 rate was recently approved and published. The revised rate has been applied to the expiring Idaho QF that was extended through the test period. Updating this contract decreases total-company NPC by approximately $32,000.
- **Coal Costs—**Contract prices are updated per terms of the contracts to reflect changes in volumes, as well as market price indexes and inflation rates. The update to coal prices decreases total-company NPC by approximately $0.5 million. After accounting for changes in system dispatch related to all corrections and updates described above, total coal expense in the Company's Reply Update is approximately $6.4 million lower than the Initial Filing.
- **Official Forward Price Curve and Short-Term Firm (STF) Transactions—**The Reply Update replaces the official forward price curve dated December 31, 2012, with the official forward price curve dated June 28, 2013. There have been no new wholesale STF transactions for electricity and natural gas for the test period, either physical or financial, through June 30,

2013. This update increases total-company NPC by approximately $5.0 million.

Q. Have you updated the TAM for either the BPA rate increase included in the Initial Filing or the long-term natural gas supply (LTNG) contract discussed in your supplemental direct testimony?

A. No. BPA is scheduled to release its final record of decision (ROD) in its 2014 Joint Power and Transmission Rate Proceeding on July 22, 2013, with rates effective in October 2013. While the Company now has the preliminary ROD, it does not have information from BPA confirming the rate impact. Instead of including an estimate of the impact of the preliminary ROD in the TAM Reply Update, the Company intends to reflect BPA's final ROD in the Final Update to the TAM in November 2013. Updating the TAM in the Final Update for BPA's final ROD is consistent with the Company's approach in docket UE 227.

The Company has not yet executed the LTNG contract. If the LTNG contract is executed later this summer or early fall, the Company will include it in the Final Update to the TAM.

Uncontested Adjustment—No Updates for New Interruptible Contracts

Q. Please describe the position of Staff and CUB on updating the Company's interruptible contracts.

A. The Company included three large interruptible contracts in the Initial Filing according to their current terms, but noted that the contracts expired in 2013-2014. In my direct testimony, I proposed to update all aspects of the TAM, including loads and allocation factors, as necessary to accurately model the terms of any new agreements negotiated to extend or replace these interruptible contracts. Staff and CUB objected to the Company's position and proposed that the Company continue to assume extension of the interruptible contracts under the existing terms, without updates for loads, prices, and curtailment provisions associated with the extended or new agreements.

Q. Has the Company made progress in negotiating extensions of the expiring interruptible contracts?

A. Yes. The Company and parties in Idaho reached a settlement resolving a planned general rate case filing. The settlement includes an extension of the current Monsanto contract modeled in the Company's Initial Filing. The settlement was filed with the Idaho Public Utilities Commission on June 3, 2013, and is pending Commission approval.

Negotiations with Nucor are still underway; however, the load and curtailment provisions are expected to be substantially similar to those currently in effect and modeled in the Company's Initial Filing. As a result, the Company is willing to accept Staff's and CUB's position and forego further updates to these contracts in this case.

RESPONSES TO STAFF AND INTERVENOR ADJUSTMENTS

General Response to ICNU Adjustments

Q. Do you have any general concerns with regard to ICNU's proposed adjustments in this case?

A. Yes. Mr. Deen grosses up the impact of each of his adjustments for revenue requirement-related components such as uncollectible accounts and franchise fees. These components are addressed in general rate cases, are not part of NPC, and are outside the scope of the TAM.

Q. Do ICNU's proposed adjustments include any other non-NPC components?

A. Yes. Mr. Deen proposes an adjustment to reduce the price of coal from the Bridger Coal Company. The merits of this adjustment are addressed in the reply testimony of Ms. Crane. As part of his adjustment, Mr. Deen proposes to reduce the TAM by the amount of return on investment associated with the Bridger Coal Company mine. This return on investment is not included in the TAM to begin with, however, because only the production costs of coal are included in NPC. In other words, Mr. Deen's adjustment proposes to reduce the TAM for costs not included in the TAM.

Q. Is there an additional issue with ICNU's proposed adjustment related to the Jim Bridger Heat Rate Improvement?

A. Yes. In his testimony, Mr. Deen indicates that the adjustment "represents the incremental NPC change in GRID after correcting for the heat rate calculation error PacifiCorp acknowledged in response to ICNU Data Request 2.1."[3] However, Mr. Deen's adjustment of $1.2 million on an Oregon-allocated basis is based on the NPC impact from the Company's original filing, not the Company's corrected values. When compared against the Company's corrected heat rates, Mr. Deen's adjustment is reduced.

[3] ICNU/100, Deen/4.

Q. Have you restated the TAM impacts of ICNU's adjustments, removing non-NPC components and incorporating the impact of the Company's correction to the Jim Bridger heat rates?

A. Yes. The restated adjustments are as follows:

- Jim Bridger Heat Rate Improvement—$3.3 million total-company reduction, $0.8 million Oregon-allocated
- Coal Fuel Expense—$10.4 million total-company reduction, $2.6 million Oregon-allocated
- Wind Energy Shaping—$4.6 million total-company reduction, $1.1 million Oregon-allocated

Wind Energy Shaping

Q. Please explain the adjustment to wind shaping proposed by Staff, CUB and ICNU.

A. Staff, CUB, and ICNU all propose that the Company's hourly wind shaping be removed, and that the previous wind shaping—a P50 forecast[4] divided into six, four-hour blocks per day—be used for each day in a month. This adjustment would reduce total-company NPC by approximately $4.6 million.

Q. Has the Commission recently provided guidance applicable to the Company's wind forecasting in the TAM?

A. Yes. In Order No. 12-409 in docket UE 245, the Commission stated it "will expect Pacific Power to refine its modeling to produce the best possible estimates

[4] A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast.

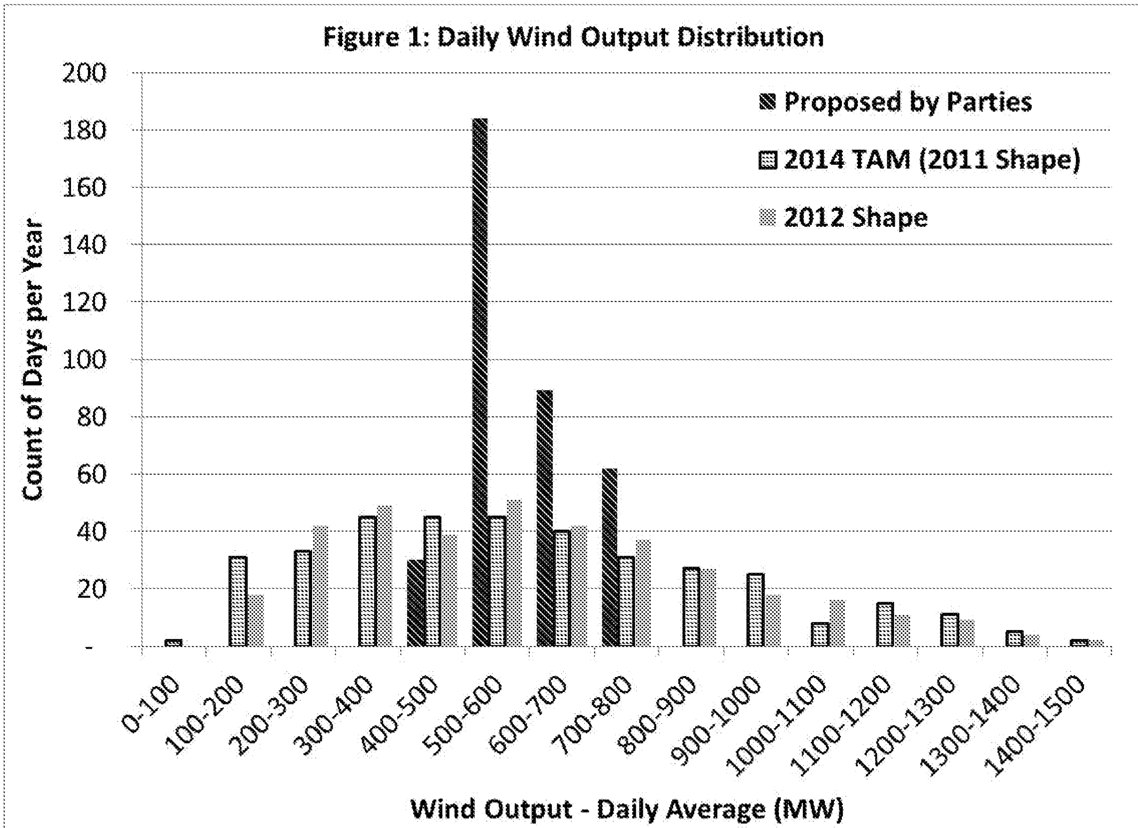
of all components of net power costs."[5] In Order No. 12-493 in docket UE 246, the Commission acknowledged "that ORS 469A.120(1) provides for recovery of prudently incurred SB 838 compliance costs"[6,7] and stated that "any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility."[8] Together, these orders direct the Company to refine its NPC modeling to capture the costs related to integrating, firming, or shaping wind generation in the TAM forecast, rather than in the PCAM true-up. The Company's new, more granular approach to wind shaping in the TAM responds to this direction.

Q. Does the wind generation profile used in the Company's previous TAM filings and advocated by parties in the current TAM adequately represent the variation in wind generation expected during 2014?

A. No. As I explained in my direct testimony, the Company has historically input wind generation into GRID using the P50 forecast divided into six, four-hour blocks per day. Generation was flat over the four-hour block, and each period was identical for every day during a month. Consequently, the wind generation used previously in GRID exhibited very little variation, contrary to wind generation's inherently variable nature. The Company's new modeling approach includes a much more realistic distribution of wind output. This is demonstrated

[5] *In the Matter of PacifiCorp d/b/a Pacific Power,* Docket UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).
[6] *In the Matter of PacifiCorp d/b/a Pacific Power,* Docket UE 246, Order No. 12-493 at 14 (Dec. 20, 2012). (Order No. 12-493)
[7] ORS 469A.120(1) provides: "Except as provided in ORS 469A.l80(5), all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs, above-market costs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers."
[8] Order No. 12-493 at 13.

in Figure 1 which shows the distribution of daily wind generation in the Company's filing, the parties' proposal, and actual output during 2012.



Q. Have any of the parties provided evidence contradicting Figure 1 (*i.e.*, demonstrating that modeling wind output using six, four-hour blocks more accurately captures wind variability than the Company's proposed approach)?

A. No.

Q. Do some of the parties agree that a change in approach to modeling wind generation is warranted?

A. Yes. Staff states it "agrees that the P50 method does not reflect the intra-day variability that is inherent in wind generation and that some method of introducing this variability is reasonable."[9] CUB also states that it "appreciates that the Company is exploring new methods to make its modeling reflect the nature of wind generation."[10]

Q. What concerns do parties raise with regard to the Company's use of 2011 as the basis for its hourly wind shaping?

A. In general, the parties object to the use of a single year as the basis for shaping the P50 output and argue that a larger data set is required.

Q. Why did the Company use a single year, in this case 2011, to derive an hourly shape for wind energy?

A. As stated in Exhibit CUB/103 and the Company's response to ICNU Data Request 1.5, the Company used 2011 data because: (1) 2011 was the first year that all of the Company's owned resources were online for a full year; (2) 2011 wind data was the basis for the 2012 Wind Integration Resource Study (Wind Study) used to determine the wind integration costs in this case; and (3) 2011 represents the most recent data available at the time of the filing.

Q. Does the Company plan on using the most recent annual data available to determine the wind shape in future TAM filings?

A. Yes. The use of a single year wind shape is a way of creating a pattern of wind generation that reflects the actual operation of the Company's wind resources while maintaining correlations between the various projects in the Company's fleet.

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[9] Joint Staff/100, Crider-Ordonez/13.
[10] CUB/100, Jenks-Hanhan/5.

Q. What evidence do parties provide in support of their concerns about the use of the most recent annual data for shaping wind generation?

A. Only ICNU provides any evidence, citing a technical report published by the National Renewable Energy Laboratory (NREL).[11]

Q. Does that technical report support the conclusion that the Company's wind shaping based on a single year is inappropriate?

A. No. The NREL report reaches a contrary conclusion, finding that, "[f]or even shorter-term variations, such as power level from one hour to the next, changes of wind power levels become a stochastic process with a very narrow range of standard deviation values around its respective mean … when those mean and standard deviation values are expressed in terms of the installed capacity of the WPPs, they are almost constant on an annual basis … It can be concluded that short-term wind power fluctuations do not exhibit year-to-year variability."[12]

Q. Has the Company prepared an analysis of the variability of its wind plants similar to the analysis presented in the NREL report?

A. Yes. The NREL report uses the coefficient of variation (COV), defined as the ratio of standard deviation value to the mean value, to gauge the short term variability of wind generation at various facilities. In similar fashion, the Company calculated the COV of four wind plants included in the TAM. Table 1 below shows that the COV of the Foote Creek, Wolverine Creek, Goodnoe Hills, and Leaning Juniper wind plants is fairly consistent over time. It also shows that the variability in the Company's modeling is much closer to the historical levels.

[11] Long-Term Wind Power Variability, Y. H. Wan. Technical Report, NREL/TP-5500-53637. Retrieved online at http://www.nrel.gov/docs/fy12osti/53637.pdf.
[12] *Id.*

Table 1 demonstrates that the concerns expressed by Staff and CUB with regard to the daily and hourly wind variability from year to year are unfounded.

Table 1: Yearly COV Value of Hourly Wind Power (Normalized to Plant Nameplate Capacity)

Year	Leaning Juniper	Goodnoe Hills	Wolverine Creek	Foote Creek 1
2001				0.28
2002				0.26
2003				0.32
2004				0.33
2005				0.33
2006				0.33
2007			0.27	0.30
2008	0.36		0.30	0.30
2009	0.35	0.32	0.29	0.23
2010	0.32	0.29	0.29	0.24
2011	0.31	0.30	0.32	0.31
2012	0.28	0.30	0.31	0.27
Average	0.32	0.30	0.30	0.29
Proposed by Parties	0.11	0.11	0.08	0.13
Proposed by PAC	0.30	0.30	0.29	0.29

Q. Has the Company performed any analysis of wind shaping using years other than 2011?

A. Yes. The Company applied its new approach to wind shaping using actual data from 2012, which has become available since the time of the Company's Initial Filing. When the wind shape based on 2012 is included in GRID, the results show only a small change to NPC using 2011 data (an increase of approximately $643,000 total-company, or just $163,000 on an Oregon-allocated basis).

Q. How should this additional data point be viewed?

A. CUB suggests that the Company "should collect data on at least three years of actual wind generation before it uses its information to predict future values."[13] Data for 2013 is not yet available, and several wind projects came online in 2010, so the data set for that year or earlier would be incomplete. Using data for different years for different plants would remove the correlations resulting from their geographic distribution. Thus, 2011 and 2012 are the only years where historical wind data is now available. However, even though the 2013 data is not yet available, the median NPC resulting from the wind shapes for 2011 through 2013 cannot be lower than the NPC using the 2011-based shape and in fact could be higher. The use of the 2011-based shape is thus reasonable and conservative.

Q. What other concerns have parties raised with regard to wind modeling?

A. ICNU indicates that by "setting reserve requirements in GRID and including post-hoc inter-hour integration costs for wind output"[14] the Company may already "fully account for the costs of dealing with the variable output of wind resources."[15] I will address how each of the two wind integration requirements modeled by the Company is incremental to the hourly wind pattern. More details on wind integration modeling are included in the Wind Study, published as Appendix H in the Company's 2013 Integrated Resource Plan.

Q. What is the first wind integration requirement modeled by the Company?

A. The Company must have regulating reserves available to compensate for changes in wind output within each hour. To determine the regulating reserve requirement, the Wind Study examined the difference between forecast and actual wind output for each ten-minute period.

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[13] CUB/100, Jenks-Hanhan/6.
[14] ICNU/100, Deen/11.
[15] *Id.*

Q. Does the Company's wind shaping have variations within each hour?

A. No. GRID is an hourly model, and includes the average wind over the course of a given hour. In reality, wind output will be both higher and lower than the average level at various times during the hour. The Company includes a reserve requirement in GRID to ensure that sufficient resources are held available to compensate for those intra-hour changes in generation and keep the Company's resources and requirements in balance.

Q. Do the regulating reserves the Company includes in GRID compensate for difference between the P50 forecast and actual wind output?

A. No. The regulating reserves compensate for differences between the persistence forecast based on the wind output in the prior hour and the actual wind output. Since the forecast is based on actual data for the prior hour, it has the same variability as the actual data. Thus it is appropriate to include regulating reserves as well as an hourly wind shape.

Q. What is the second wind integration requirement modeled by the Company?

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

Q. Is it appropriate to include both this cost and an hourly wind shape?

A. Yes. The Company's filed GRID study uses the same wind shape to determine unit commitment and final dispatch, so the cost of less-than-optimal day-ahead unit commitment is not included. In addition, the day-ahead wind forecast used in the Wind Study has an hourly shape specific to each day, similar to that used in the Company's filing. It is not comparable to the average six, four-hour block wind shape proposed by parties. Therefore the Company's use of this cost with an hourly wind shape is a better fit to the methodology in the Wind Study.

Q. What is your recommendation on the hourly wind shaping adjustment?

A. The Company's Initial Filing contains a reasonable hourly wind shape that conservatively forecasts NPC for the test period, with the same annual, monthly, and daily volumes as the Company's normalized wind profiles used previously. The parties' proposal to maintain the current approach to modeling wind shaping produces a less accurate representation of wind generation over the test period.

Jim Bridger Heat Rate Improvement

Q. Please explain ICNU's adjustment to the heat rate at Jim Bridger 1 and 2.

A. ICNU proposes that the heat rate for Jim Bridger 1 and 2 be adjusted to reflect a step change related to turbine upgrades.

Q. How are the Company's heat rates for coal plants determined?

A. A quadratic equation relating hourly plant output to fuel consumption is developed that aligns 48 months of generation and fuel consumption data with expected fuel consumption over the plant's operating range. The use of a quadratic equation accounts for improved efficiencies at higher operating levels and helps ensure that the heat rate in the test period is not artificially increased by a low capacity factor in the historical period.

Q. Why are 48 months of historical data used?

A. This period is aligned with historical period used to normalize other thermal attributes in the Company's filing, specifically forced and planned outage rates.

Q. Are heat rates related to outages?

A. Yes. The efficiency of steam units tends to decline over time as components degrade. During a major plant overhaul, even without a turbine upgrade, worn seals are replaced, heat exchange surfaces are cleaned, and a portion of the unit's efficiency losses can be recovered. The use of a 48-month period for calculating heat rates ensures that normalized heat rates reflect the conditions present under most of a major planned outage cycle, which is typically four years. Using only the period immediately following an outage would understate the normalized heat rate.

Q. Has the Company previously proposed known and measurable adjustments to the 48-month heat rates?

A. Yes. In docket UE 216, the Company proposed incremental increases to heat rates for three units to reflect the addition of emissions control systems. The additional parasitic load of expanded emissions control systems reduces the net output of the plant, with a corresponding increase in heat rate.

Q. Have parties advocated against such heat rate adjustments in the past?

A. Yes. In his reply testimony on behalf of ICNU in docket UE 216, Mr. Randall J. Falkenberg stated that, "[b]ecause the Company's method allows for a continuous heat rate adjustment to take place, there is no need for pro-forma adjustments in this type of situation."[16] In his direct testimony in docket UM 1355, also on behalf of ICNU, Mr. Falkenberg expanded on this argument with regard to forced outage adjustments.[17] Mr. Falkenberg's testimony follows:

> **Q. SHOULD FORCED OUTAGE RATE DETERMINATIONS BE ADJUSTED WHEN NEW CAPITAL INVESTMENT IMPROVES RELIABILITY?**
>
> A. As a general matter, only after these improvements have shown up in the historical data. Customers may be asked to pay for the investments as they are made, but not see the benefits for several years. While arguably inequitable, it opens up a "can of worms" to make ad-hoc adjustments to address the expected or assumed reliability benefits of new investment. Further, there are likely to be situations where new capital investment arguably degrades reliability. For example, pollution control equipment, such as scrubbers could result in reductions to plant availability. It would be unfair to adopt a policy that favors either reliability enhancement or reliability degradation, but not both. Further, quantifying the impacts of such reliability improvements or degradations would be quite subjective. For these reasons, there should be a prejudice against making ad-hoc adjustments to the computation of outage rates. An advantage of a rolling average is that actual changes to plant reliabilities will be factored into the ratemaking process in due course.

The points made by Mr. Falkenberg concerning forced outage adjustments for new capital investments are equally applicable to heat rate adjustments.

[16] Docket UE 216, ICNU/100, Falkenberg/54.
[17] Docket UM 1355, ICNU/100, Falkenberg/21.

Q. What was the result of the Company's proposed heat rate adjustment in docket UE 216?

A. As part of the settlement stipulation, the Company agreed that it would not implement heat rate adjustments for scrubbers or other capital projects in future Oregon NPC modeling absent a change in facts or circumstances, but instead would rely on the traditional analysis of four years of actual data to derive the heat rate inputs. The relevant excerpt from Paragraph 8 of the UE 216 stipulation is provided below:

> 8. <u>Adjustments to NPC.</u> The Parties agree that the stipulated $11 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the Parties have accepted any elements of the Company's NPC study. The Company does, however, agree to reflect the methodology changes listed in this paragraph in the 2012 TAM. The Company will also make the methodology changes listed in this paragraph in subsequent TAM filings, absent a change in facts or circumstances identified by the Company….
>
> c. 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.[18]

The Company has continued to abide by this agreement despite additional reductions in net generation at Dave Johnston 4, Jim Bridger 3, Naughton 1, and Naughton 2 related to capital improvements. The heat rate impacts for these units continue to be based on a 48-month history.

[18] *In the Matter of PacifiCorp d/b/a Pacific Power, 2011 Transition Adjustment Mechanism,* Docket UE 216, Order No. 10-363, Appendix A, Page 5 of 18.

Q. What is your recommendation on the Jim Bridger Heat Rate Improvement adjustment?

A. This adjustment is contrary to the approach for modeling heat rates that the Commission approved in docket UE 216. The adjustment is also a reversal of ICNU's prior position on this issue, contradicts a clear, straightforward, and long-standing methodology, and is applied in a one-sided manner. For all of these reasons, it should be rejected.

Hydro Normalization

Q. What concerns does Staff raise with the Company's hydro modeling?

A. Staff found significant differences in estimated generation from one TAM to the next, and did not expect to see such changes "if the Company was attempting to model a normalized hydro year."[19] Specifically, Staff describes changes in generation at the Grant Priest Rapids and Grant Wanapum projects on the Mid-Columbia river system and at Copco units 1 and 2 on the Klamath River. Staff states that Idaho Power and PGE use normalized hydro generation to form their NPC calculations and recommends that the Company develop a normalized hydro forecast for future NPC proceedings.

Q. Do you agree with Staff's conclusion that the Company is using a single-year hydrology forecast rather than normalized hydro generation?

A. No.

Q. Does the Company use normalized hydro modeling in its filing?

A. Yes. For run of river plants (*i.e.*, plants without storage capability), annual generation is set at the 30-year median generation while the monthly shape is

[19] Joint Staff/100, Crider-Ordonez/12.

based on the average share by month for the 30-year period. The median is calculated on a water year basis, from October through September of the following year. The present filing is based on data for 1983 through 2012.

The Lewis, Klamath, North Umpqua, and Mid-Columbia plants have storage capability, so annual hydro output is normalized using median inflows. For the Lewis, Klamath, and North Umpqua plants, all available years of inflow data are used. For Mid-Columbia plants, the median is based on a 70-year period from the most recent Pacific Northwest Coordination Agreement study. In both cases, daily inflows are based on a more limited set of data and are smoothed to a monthly shape. These inflows are entered in the VISTA model which optimizes the weekly generation against the Company's official forward price curve, while adhering to the Company's current operational and license constraints.

Q. Is Staff's assertion that the Company did not use normalized hydro generation in docket UE 207 correct?

A. No. In docket UE 207, the Company used the same approach for developing normalized hydro generation as it did in this case, except that in the current filing, the Company has improved the modeling of hydro forced outages (a change that Staff supports). In fact, I filed direct testimony for the Company in docket UE 207 describing the same approach laid out above.

Q. Why are there year-to-year changes in hydro output at the Grant Priest Rapids and Grant Wanapum plants?

A. As an original purchaser, the Company is entitled to a share of the Grant Priest Rapids and Grant Wanapum plants. This share, which also determines the

Company's share of project expenses, is dependent on Grant County Public Utility District's (Grant County PUD) load. Grant County PUD provides preliminary estimates in the summer or fall of the year prior and finalizes the Company's share in December. Based on an updated projection provided by Grant County PUD in October 2011 that was included in the Final TAM Update in docket UE 227, the Company was due to receive 1.555 percent of the project output in 2012. At the time of the Final TAM Update in docket UE 245, Grant County PUD's projection indicated the Company would receive 1.116 percent of the project output for 2013. This difference accounts for the roughly 40 percent change in project output observed by Staff. The Company has not yet received updated projections from Grant County PUD for 2014, but will incorporate any changes in the TAM Final Update in this case if additional information is received.

Q. Why are there month-to-month changes in hydro output at the Copco plants?

A. As mentioned above, the Company's river systems with storage (including the Klamath River where the Copco plants are located) are normalized based on inflows. Because of their storage capability, these rivers do not necessarily generate at the same time the inflows occur. Instead, water can be stored until later periods when generation is more valuable. As a result, changes in prices from year-to-year shift generation between months.

In addition, the Company's Klamath hydro modeling reflects certain operational changes related to storage releases. In the past, the Company's

VISTA model was used to determine the timing of storage releases from Upper Klamath Lake; however, those releases are now controlled by the Bureau of Reclamation, whose primary goal is to protect certain fish species listed pursuant to the Endangered Species Act. In the current filing, storage releases from Upper Klamath Lake have been modeled based on the Bureau of Reclamation's recent ten-year history, which represent the best available information for the water management approach that will be in place in the test period and going forward.

Q. Do you have any other comments regarding Staff's characterization of hydro normalization in NPC filings?

A. Yes. Staff states that Idaho Power and PGE each use normalized hydro generation in their NPC filings. Staff does not mention, however, that Idaho Power is allowed to update its NPC filing to reflect the latest forecast from the Northwest River Forecast Center for its hydro forecast just two months prior to the rate effective date rather than using a normalized hydro forecast.[20] This approach allows Idaho Power to more closely match forecast and actual hydro generation outside of its PCAM, which is a significant benefit because Idaho Power meets approximately half of its load with hydro. This approach is in contrast to the Company's NPC modeling in TAM filings, which relies upon normalized hydro generation to determine forecast NPC.

Transition Adjustments

Q. Please summarize Noble Solutions' concerns regarding the Company's Schedule 294 and 295 transition adjustments.

A. Noble Solutions urges the Commission to require the Company to dispense with

[20] *In re Idaho Power Company*, Docket UE 195, Order No. 08-238 at Appendix A, Section 11(a) (2008).

the GRID-based calculation of the transition adjustment and instead calculate the transition adjustment based on a simple blend of market prices. Noble Solutions argues that since the Commission determined the transition adjustment calculation should not reflect relaxation of the GRID market caps, a GRID-based calculation is not workable. Noble Solutions also disagrees with the Commission's decision in docket UE 245 and recommends that the transition adjustment include a credit for freed-up BPA transmission of $1.422/MWh.

Q. Has the Commission previously provided policy direction applicable to the issue of simply using market prices to value freed-up energy?

A. Yes. The Commission addressed this issue in dockets UM 1081 and UE 179. In docket UM 1081, the Commission adopted an interim transition adjustment based on market prices for the near-term, but asked parties to work together to find a long-term solution. Subsequently, in docket UE 179, the Commission rejected the market price approach in favor of using differential GRID runs to value the loss of the direct access load.[21] In that case, the Commission found that using the differential GRID run approach to determine the transition adjustment proposed by PacifiCorp most closely met the requirements established in Order No. 04-516 in docket UM 1081.[22] The Commission went on to say, "[t]he purpose of the TAM is not to promote direct access, as ICNU would have us do. Rather, the

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[21] *In the Matter of Public Utility Commission Staff Investigation into Direct Access Issues for Industrial and Commercial Customers under SB 1149,* Docket UM 1081, Order No. 04-516, page 10.
[22] *In the Matter of PacifiCorp d/b/a Pacific Power and Light Co.,* Docket UE 179, Order No. 05-1050, page 21.

TAM is to capture costs associated with direct access, and prevent unwarranted cost shifting."[23]

Q. Is the current transition adjustment calculation based solely on the GRID valuation of the generation freed up by departing direct access customers?

A. No. The Company calculates the transition adjustment by first running GRID with 25 average megawatts of direct access load removed to determine the system response to lower load. Changes in market transactions are valued at average market prices, and changes in thermal generation are valued at the simple average of prices at the Mid-Columbia (Mid-C) and California Oregon Border (COB) markets and the cost of thermal generation.

Table 2 below demonstrates the value of the sample transition adjustment for Schedule 48 included with the Company's Initial Filing under various scenarios. As shown in Table 2 below, the current method of calculating the transition adjustment includes a significantly higher weighting of market value and lower weighting of generation than is justified by the GRID results. The overall transition adjustment value under the current method is significantly higher than the value as determined in GRID.

Table 2 - Annual Transition Credit/(Charge) Value ($M) and Market Weighting (%)

	Annual Transition Credit/(Charge) Value ($M)			Market Weighting		
Method	**HLH**	**LLH**	**Total**	**HLH**	**LLH**	**Total**
GRID-only Blend	1.1	(0.6)	0.5	96%	53%	77%
Filed Blend	1.3	0.6	2.0	99%	84%	92%
Higgins' Proposal	2.0	0.4	2.4	100%	100%	100%

[23] *Id.*

Q. Are generation costs a significant component in the current transition adjustment calculation?

A. No. Table 2 demonstrates that market value is the basis for 99 percent of the Company's filed transition adjustment in HLH hours and 92 percent of the transition credit overall.

Q. Does the OAR 860-038-005(42) definition of Ongoing Valuation prohibit the inclusion of thermal generation costs in the transition adjustment calculation?

A. No. Mr. Higgins implies that costs should be based on a forecast of prices in a major, formally constituted electricity market. However, the Company's generation resources previously used to serve departing direct access customer load are primarily located at some distance from major markets. A more general definition of a market would be any location where a buyer and seller can meet to transact in electrical power. During hours when all transmission to major markets is filled, as sometimes occurs in light load hours, the broader definition of a market would allow for sales closer to the generation resource in question. The use of the resource's operating cost is equivalent to the "ask" price the Company would require of would-be purchasers of generation at its plants and is the only forecasted price applicable to the freed-up generation in certain hours.

Q. Does a 50/50 blend of COB and Mid-C market prices correspond to the proportional change in market transactions by market as determined by GRID?

A. No. As shown in Table 3 below, the GRID results used as inputs to the example transition credit filed in this case include quantities of market transactions on the east side of the Company system and somewhat fewer transactions at COB than in Mr. Higgins' proposal. The filed method uses COB and Mid-C prices to value two-thirds of the generation impact, so the weightings of these markets are somewhat overstated compared to the actual GRID result.

Table 3 - Market and Generation Weighting Detail (%)

Resource	GRID-only Blend	Filed Blend	Higgins' Proposal
COB	18%	26%	50%
Four Corners	3%	3%	0%
Mead	1%	1%	0%
Mid Columbia	36%	44%	50%
Mona	12%	12%	0%
NOB	4%	4%	0%
Palo Verde	3%	3%	0%
Market Total	77%	92%	100%
Generation	23%	8%	0%

Q. Has the Commission previously ruled with respect to the BPA transmission credit?

A. Yes. As Noble Solutions acknowledges in its testimony, the Commission rejected a proposal to recognize a BPA transmission credit just last year in Order No. 12-409 in docket UE 245. The Commission affirmed this ruling on reconsideration in Order No. 13-008.

Q. Why does Noble Solutions raise this issue again in this case?

A. Noble Solutions argues that a BPA Transmission Credit is "necessary to address a structural impediment to the pricing of direct access service associated with the need for an [Electricity Service Supplier] to obtain wheeling from BPA…”.[24]

Q. Is this so-called “structural impediment” relevant to the appropriate determination of direct access rates and transition credits?

A. No. As described in OAR 860-038-0160(2)(b): “The direct access rates must exclude electric company costs that are avoided when a consumer chooses to be served under the direct access rate option.” Direct access rates are intended to compensate for electric company costs not for ESS costs.

Q. Is it still the case that the Company does not obtain value from freed-up transmission services as a result of losing load to direct access?

A. Yes. I addressed this issue in detail in my reply testimony in docket UE 245 (PAC/300). Depending on the location of the lost load and the existing transmission arrangements with BPA and the Company’s transmission function, there is little to no opportunity to realize the value of freed-up transmission with BPA. In addition, the Company may need to acquire additional transmission to deliver freed-up generation to market in order to realize the transition adjustment determined for the lost load. These additional costs are not reflected in the Company’s calculation of the transition adjustment.

Q. The Company owns 636 MW of long-term PTP BPA transmission rights from Mid-Columbia and a network integration agreement with BPA for 497 megawatts. Can the Company resell these BPA transmission rights when a customer goes to direct access?

A. With respect to network rights, the answer is no. With respect to PTP rights, the answer is that it can be sold only if it can be freed-up, which is not likely.

[24] Noble Solutions/100, Higgins/5.

Because customers that elect direct access retain the right to return to cost of service rate schedules, the Company must continue to plan for these customers and therefore must retain transmission rights to carry out this obligation. In addition, the Company uses a limited quantity of Mid-C transmission rights to help serve a much larger quantity of Oregon customers and optimize the dispatch of its system to the benefit of all retail customers. Plus, the expenses associated with this transmission are paid for by all retail customers, not just those in Oregon. Therefore, assigning a 100 percent share to a departing direct access customer would be inappropriate.

Q. Noble Solutions argues that the Company could simply sell transmission rights only for the time period for which direct access customers have departed. Do you agree?

A. No. Noble Solutions' argument assumes that PacifiCorp is relieved of all load service requirements when a customer chooses direct access. However, should the contractual and scheduling arrangements of the new provider fail at any time, for any period of time, the Company must retain its wheeling arrangements to cover this load as the provider of last resort.

Q. Noble Solutions also criticizes the Company for not relaxing market caps for the purposes of calculating the transition adjustment. Please comment.

A. As affirmed by the Commission in Order No. 12-409 in docket UE 245, market caps are necessary to accurately forecast NPC. When the market caps are relaxed, the GRID model creates additional value by making wholesale sales at high price markets and purchases at low price markets, reducing NPC. The value from this change is independent of any change due to departing direct access loads. Thus the value of the market cap relaxation amounts to a subsidy to direct access customers and their suppliers. Because the approach shifts costs among customers, it is inconsistent with the Commission's policy in setting the transition adjustment.

Q. Why is the relaxation of market caps unreasonable?

A. Simply put, relaxation of the market caps is based on the theory that the wholesale market size will increase when an ESS wins the business of a retail customer. As the Company has previously shown, an increase in the market size (relaxation of market caps) is unsupported.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 264
Exhibit PAC/501
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Net Power Cost Report

July 2013

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2014	01/14-12/14	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	13,896,755	1,170,467	1,121,672	1,178,452	1,152,574	1,148,146	1,106,628	1,174,229	1,176,353	1,159,837	1,174,588	1,150,248	1,183,560
BPA Wind s42818	2,777,811	348,131	291,837	282,577	219,469	207,190	168,048	126,033	119,463	157,106	229,620	289,217	339,120
Hurricane Sale s393046	12,839	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070
LADWP (IPP Layoff)	30,332,094	2,485,817	2,199,792	2,121,987	1,807,896	2,494,627	2,710,454	2,915,750	2,892,791	2,042,916	3,473,690	2,505,671	2,680,705
NVE s811499	-	-	-	-	-	-	-	-	-	-	-	-	-
Pacific Gas & Electric s524491	-	-	-	-	-	-	-	-	-	-	-	-	-
SCE s513948	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD s24296	12,964,800	1,491,100	814,000	133,200	532,800	-	3,700	1,272,800	1,761,200	1,753,800	1,583,600	1,676,100	1,942,500
UMPA II s45631	9,558,396	593,283	561,909	593,283	582,825	569,752	915,319	1,779,848	1,400,150	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	69,542,695	6,089,867	4,990,280	4,310,568	4,296,633	4,420,785	4,905,220	7,269,729	7,351,028	5,907,368	7,055,851	6,205,129	6,740,237
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	5,040,210	966,146	930,696	1,223,565	588,640	543,400	218,000	(567,944)	(485,576)	87,500	408,060	484,021	643,702
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	5,040,210	966,146	930,696	1,223,565	588,640	543,400	218,000	(567,944)	(485,576)	87,500	408,060	484,021	643,702
System Balancing Sales													
COB	63,702,522	7,021,529	5,167,993	5,410,974	2,875,490	828,611	768,861	5,524,736	7,427,358	7,798,061	6,094,345	6,978,011	7,806,553
Four Corners	99,443,142	7,582,975	6,588,120	5,760,435	7,513,896	5,482,996	5,395,628	12,846,612	13,524,808	9,039,457	8,284,087	9,608,266	7,815,862
Mead	34,909,347	2,966,418	2,647,878	2,785,967	2,602,519	2,721,711	2,362,492	3,373,274	3,432,382	3,097,730	3,151,922	2,968,377	2,798,679
Mid Columbia	35,114,857	4,729,515	5,420,100	3,911,524	190,532	-	-	1,107,828	1,970,488	2,757,640	3,741,514	5,380,375	5,905,342
Mona	27,280,505	2,401,822	1,620,500	1,567,149	1,837,429	1,337,210	1,940,229	2,676,999	3,111,960	2,679,642	2,883,846	2,356,271	2,867,448
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	121,520,562	10,296,763	10,058,221	10,515,064	9,955,434	9,745,568	10,911,164	8,201,681	8,085,369	10,567,878	11,596,000	10,788,237	10,799,183
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	39	-	-	-	-	-	-	-	-	-	-	-	39
Total System Balancing Sales	381,970,973	34,999,023	31,502,811	29,951,113	24,975,301	20,116,095	21,378,374	33,731,130	37,552,365	35,940,408	35,751,714	38,079,536	37,993,105
Total Special Sales For Resale	456,553,878	42,055,036	37,423,787	35,485,246	29,860,574	25,080,280	26,501,593	40,432,914	44,417,816	41,935,276	43,215,625	44,768,686	45,377,044

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Net Power Cost Analysis

12 months ended December 2014	01/14-12/14	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental p27875	1,027,180	82,327	256,546	-	89,829	119,484	-	157,050	-	-	-	162,285	159,660
Blanding Purchase p379174	30,485	2,589	2,339	2,589	2,506	2,589	2,506	2,589	2,589	2,506	2,589	2,506	2,589
BPA Reserve Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Combine Hills Wind p160595	4,721,025	452,445	294,182	523,139	367,365	341,486	411,545	394,481	391,208	372,846	400,343	446,574	325,411
Deseret Purchase p194277	35,062,550	3,057,429	2,922,969	3,057,429	3,005,139	2,295,489	2,540,131	2,986,464	3,057,429	3,012,609	3,057,429	3,012,609	3,057,429
Douglas PUD Settlement p38185	1,569,851	55,627	62,347	121,567	207,247	259,427	298,684	206,309	107,099	62,768	71,201	63,093	54,482
Gemstate p99489	3,173,700	259,700	256,600	261,600	256,600	256,600	256,600	256,600	275,500	256,600	279,000	298,600	259,700
Georgia-Pacific Camas	8,005,931	679,956	614,153	679,956	658,022	679,956	658,022	679,956	679,956	658,022	679,956	658,022	679,956
Grant County 10 aMW p66274	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase p99563	87,153,675	8,254,325	7,685,995	7,402,866	5,434,568	4,502,555	4,167,809	7,386,219	8,307,829	7,990,493	8,868,829	8,454,734	8,697,452
Hurricane Purchase p393045	124,675	10,390	10,390	10,390	10,390	10,390	10,390	10,390	10,390	10,390	10,390	10,390	10,390
IPP Purchase	30,332,094	2,485,817	2,199,792	2,121,987	1,807,896	2,494,627	2,710,454	2,915,750	2,892,791	2,042,916	3,473,690	2,505,671	2,680,705
Kennecott Generation Incentive	-	-	-	-	-	-	-	-	-	-	-	-	-
LADWP p491303-4	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves p510378	5,922,770	453,130	545,360	477,190	509,270	477,190	509,270	489,220	477,190	509,270	477,190	509,270	489,220
Nucor p346856	5,763,000	480,250	480,250	480,250	480,250	480,250	480,250	480,250	480,250	480,250	480,250	480,250	480,250
P4 Production p137215/p145258	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
PGE Cove p83984	323,118	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927
Rock River Wind p100371	4,940,853	602,477	475,465	480,833	376,185	360,263	271,745	193,727	234,387	304,450	436,506	593,879	610,937
Small Purchases east	63,612	6,169	5,843	6,927	5,272	4,441	4,456	4,014	4,540	6,041	5,035	5,050	5,824
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind p460457	20,598,497	2,305,957	1,595,827	2,351,686	1,690,904	1,714,594	1,181,550	1,054,247	1,080,038	1,423,022	1,787,220	2,006,944	2,406,509
Top of the World Wind p522807	40,244,943	5,293,929	3,991,014	3,804,691	3,095,183	2,664,504	2,418,361	1,930,206	2,086,326	2,260,849	2,895,806	4,238,570	5,565,507
Tri-State Purchase p27057	10,491,879	866,632	797,236	807,929	855,397	842,211	875,591	923,926	943,181	909,404	924,396	894,376	851,604
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind p244520	10,148,500	752,809	592,882	1,184,315	1,138,353	1,108,620	863,581	843,890	791,566	736,652	637,177	834,559	664,094
Long Term Firm Purchases Total	289,698,338	27,795,549	24,482,781	25,468,935	21,683,966	20,308,269	19,354,537	22,608,880	23,515,859	22,732,678	26,180,599	26,870,974	28,695,311
Seasonal Purchased Power													
Constellation 2013-2016	5,976,080	-	-	-	-	-	-	2,125,344	2,088,736	1,762,000	-	-	-
Seasonal Purchased Power Total	5,976,080	-	-	-	-	-	-	2,125,344	2,088,736	1,762,000	-	-	-

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Net Power Cost Analysis

12 months ended December 2014	01/14-12/14	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Qualifying Facilities													
QF California	6,482,536	598,322	666,806	746,661	943,624	957,255	740,539	358,152	271,160	252,014	254,701	279,790	413,512
QF Idaho	5,729,513	400,337	364,706	442,098	485,931	608,076	681,903	586,368	470,809	411,715	438,514	430,222	408,833
QF Oregon	28,499,402	2,373,828	2,197,879	2,565,252	2,888,639	3,078,348	2,696,295	2,309,311	2,176,416	2,228,225	2,043,575	1,794,061	2,147,574
QF Utah	1,479,880	102,812	108,080	124,327	136,385	146,757	151,054	129,083	125,176	109,054	123,353	124,136	99,664
QF Washington	621,960	30,218	30,215	30,183	34,688	50,951	72,868	89,684	94,343	81,223	47,097	30,272	30,218
QF Wyoming	820,551	33,655	32,391	31,721	50,804	106,694	107,417	115,151	115,036	104,170	58,055	32,687	32,769
Biomass One QF	13,959,322	1,377,264	1,248,655	1,377,264	669,775	681,086	662,105	1,377,265	1,377,264	1,109,553	1,387,312	1,318,590	1,373,190
Butter Creek Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind p499335 QF	2,768,349	349,376	336,640	332,339	141,314	163,665	163,950	147,450	245,924	200,165	306,517	318,301	62,708
DCFP p316701 QF	47,128	1,499	991	3,191	2,579	10,738	9,886	1,678	1,626	2,599	5,874	4,304	2,162
Evergreen BioPower p351030 QF	2,682,014	236,910	195,953	191,475	200,081	223,997	174,525	213,861	267,963	267,963	307,378	226,040	175,869
Five Pine Wind QF	7,012,206	631,658	538,807	639,592	500,428	505,233	405,386	512,743	606,087	514,693	622,867	681,952	852,759
Mountain Wind 1 p367721 QF	8,431,982	1,201,785	767,173	777,967	597,004	500,884	359,154	403,328	530,957	623,818	723,907	845,050	1,100,955
Mountain Wind 2 p398449 QF	12,197,204	1,754,283	1,073,247	1,113,679	811,417	873,809	682,723	793,988	820,036	786,510	858,947	1,134,646	1,493,919
North Point Wind QF	15,335,660	1,368,135	1,169,896	1,383,212	1,098,266	1,095,920	897,085	1,142,745	1,345,684	1,143,526	1,370,851	1,474,511	1,845,831
OM Power I Geothermal QF	4,010,196	387,630	347,151	383,340	341,740	331,705	283,772	255,303	264,429	301,315	357,096	370,301	386,415
Oregon Wind Farm QF	11,336,823	673,662	730,610	910,785	1,137,887	1,158,337	1,316,766	1,358,301	1,025,768	840,222	855,736	992,837	335,915
Pioneer Wind Park II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Power County North Wind QF p5756	3,868,758	356,889	359,953	327,469	314,542	254,641	216,337	277,290	254,274	287,790	377,388	362,609	479,577
Power County South Wind QF p5756	3,697,973	386,215	345,660	353,814	284,212	225,443	214,395	207,730	216,431	256,866	323,318	376,389	507,501
Roseburg Dillard QF	1,203,172	142,948	148,145	49,109	15,043	-	-	175,552	199,763	182,414	32,998	69,812	187,391
SF Phosphates	2,430,063	155,706	147,768	191,322	197,962	184,333	225,356	267,854	241,387	251,299	237,269	165,235	164,573
Spanish Fork Wind 2 p311681 QF	2,802,188	179,935	197,659	172,847	164,545	170,907	239,285	292,241	346,929	281,921	229,612	250,184	276,122
Sunnyside p83997/p59965 QF	27,305,266	2,403,339	2,296,550	2,370,796	1,587,109	2,172,215	2,397,716	2,445,520	2,437,939	2,348,338	2,030,299	2,373,713	2,441,732
Tesoro QF	1,343,277	114,187	102,848	114,187	111,003	114,083	110,307	113,491	114,083	110,307	114,783	109,811	114,187
Threemile Canyon Wind QF p500139	2,006,794	148,827	157,145	170,988	161,551	207,934	187,916	169,522	167,323	158,196	184,118	143,383	149,892
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	166,072,217	15,409,421	13,564,926	14,803,617	12,876,529	13,823,011	12,996,739	13,743,610	13,716,805	12,853,895	13,291,562	13,908,834	15,083,268
Mid-Columbia Contracts													
Douglas - Wells p60828	3,579,232	296,741	296,741	296,741	296,741	296,741	296,741	296,741	296,741	301,325	301,325	301,325	301,325
Grant Reasonable	(5,509,783)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)	(459,149)
Grant Surplus p258951	1,841,467	153,456	153,456	153,456	153,456	153,456	153,456	153,456	153,456	153,456	153,456	153,456	153,456
Mid-Columbia Contracts Total	(89,084)	(8,952)	(8,952)	(8,952)	(8,952)	(8,952)	(8,952)	(8,952)	(8,952)	(4,368)	(4,368)	(4,368)	(4,368)
Total Long Term Firm Purchases	461,657,550	43,196,018	38,038,756	40,263,601	34,551,544	34,122,329	32,342,324	38,468,882	39,312,448	37,344,205	39,467,793	40,775,439	43,774,210

Exhibit PAC/501
Duvall/3

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Net Power Cost Analysis

12 months ended December 2014	01/14-12/14	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs p64676	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange p64706/p64888	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647(	-	-	-	-	-	-	-	-	-	-	-	-	-
Cargill p483225/s6 p485390/s89	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Shell p489963/s489962	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	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
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	899,640	-	-	-	287,280	309,960	302,400	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	3,261,582	193,128	267,048	481,650	722,280	1,092,936	1,229,100	29,796	(491,088)	(114,450)	167,994	(48,960)	(267,852)
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	4,161,222	193,128	267,048	481,650	1,009,560	1,402,896	1,531,500	29,796	(491,088)	(114,450)	167,994	(48,960)	(267,852)
System Balancing Purchases													
COB	10,932,305	169,396	51,294	111,786	1,097,003	3,799,689	2,212,567	1,375,596	692,474	550,053	175,877	269,784	426,786
Four Corners	8,675,762	429,531	376,917	1,005,021	641,121	491,352	2,270,509	1,244,596	283,721	178,931	344,508	789,234	620,319
Mead	43,317	-	519	1,483	1,278	3,040	9,890	4,789	6,822	2,526	3,287	816	8,867
Mid Columbia	87,282,937	1,962,807	1,297,328	4,509,261	11,335,974	14,415,496	12,531,164	15,263,850	14,951,438	4,174,043	5,112,873	1,250,575	478,128
Mona	25,716,048	2,511,493	3,226,446	4,972,952	2,409,124	2,806,536	1,319,168	681,791	265,808	770,583	1,040,886	3,448,291	2,262,969
NOB	87,283	-	-	-	3,073	82,867	624	719	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	19,989	-	-	-	-	19,989	-	-	-	-	-	-	-
Total System Balancing Purchases	132,757,640	5,073,227	4,952,504	10,600,504	15,487,573	21,618,970	18,343,922	18,571,341	16,200,263	5,676,136	6,677,431	5,758,700	3,797,069
Total Purchased Power & Net Inte	603,976,412	48,912,372	43,708,308	51,795,755	51,498,677	57,594,195	52,667,746	57,520,019	55,471,624	43,355,891	46,763,218	46,935,180	47,753,428

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Net Power Cost Analysis

12 months ended December 2014	01/14-12/14	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Wheeling & U. of F. Expense													
Firm Wheeling	144,694,674	12,358,417	11,754,774	11,954,808	12,190,287	11,867,806	12,902,176	12,354,724	11,484,234	11,749,547	11,608,077	12,199,640	12,270,187
ST Firm & Non-Firm	44,413	8,532	5,467	3,990	1,985	2,477	3,204	1,620	1,188	715	1,113	1,026	13,095
Total Wheeling & U. of F. Expense	144,739,088	12,366,949	11,760,241	11,958,797	12,192,272	11,870,283	12,905,380	12,356,344	11,485,422	11,750,261	11,609,190	12,200,666	12,283,282
Coal Fuel Burn Expense													
Carbon	24,122,810	2,115,852	1,928,243	2,257,202	1,964,707	1,938,780	1,824,838	2,083,166	2,129,864	1,952,051	2,051,261	1,705,923	2,170,923
Cholla	58,248,252	5,260,013	4,778,806	5,218,560	4,384,263	4,330,200	4,003,200	4,597,302	5,251,766	5,051,501	5,190,156	4,975,315	5,207,169
Colstrip	15,500,288	1,392,985	1,257,742	1,391,852	1,191,055	696,682	1,304,489	1,392,985	1,391,852	1,347,904	1,392,985	1,346,771	1,392,985
Craig	23,973,804	2,097,084	1,893,771	2,096,129	2,029,313	1,387,664	2,024,791	2,097,084	2,096,129	2,029,313	2,097,084	2,028,358	2,097,084
Dave Johnston	60,531,934	5,060,469	4,835,081	4,187,932	3,917,159	5,036,440	5,056,057	5,660,074	5,690,269	5,399,570	5,448,825	5,104,149	5,135,908
Hayden	14,291,226	1,370,453	1,259,363	1,372,709	1,303,250	1,370,704	1,121,160	1,217,815	1,398,760	908,404	675,331	912,347	1,380,931
Hunter	167,362,418	14,656,148	13,305,871	11,235,098	11,772,549	14,009,962	13,423,140	14,945,354	15,187,127	14,702,573	14,879,406	14,256,397	14,988,792
Huntington	119,895,739	10,759,971	9,723,641	10,697,249	10,057,552	9,618,899	9,048,291	10,872,212	11,374,575	9,697,111	8,340,418	8,734,131	10,971,688
Jim Bridger	198,094,301	18,052,881	16,571,741	18,098,570	14,420,070	12,101,940	12,581,562	17,471,844	18,016,100	16,756,491	18,069,785	17,838,839	18,114,478
Naughton	108,542,776	9,661,118	8,785,865	6,511,447	7,028,654	9,365,302	9,298,484	9,758,586	9,752,717	9,450,647	9,757,097	9,417,064	9,755,794
Ramp Loss	(1,012,130)	(68,014)	(85,712)	(79,159)	(91,388)	(98,418)	(92,526)	(93,989)	(82,271)	(64,848)	(78,957)	(83,785)	(93,062)
Wyodak	24,456,236	2,172,503	1,969,668	2,179,096	2,091,121	1,287,672	1,993,415	2,139,823	2,138,319	2,069,462	2,137,903	2,109,736	2,167,517
Total Coal Fuel Burn Expense	814,007,654	72,531,463	66,224,081	65,166,686	60,068,304	61,045,828	61,586,902	72,142,258	74,345,207	69,300,178	69,961,294	68,345,243	73,290,208
Gas Fuel Burn Expense													
Chehalis	57,722,742	6,155,019	4,526,418	4,494,594	917,516	-	-	6,128,226	7,565,497	8,066,333	8,198,037	5,816,842	5,854,261
Currant Creek	55,719,517	6,003,203	5,457,943	6,200,705	5,069,953	4,300,027	1,168,304	5,131,615	6,489,635	4,631,289	3,236,908	3,690,821	4,339,115
Gadsby	3,178,015	-	-	-	-	-	-	1,341,009	1,837,006	-	-	-	-
Gadsby CT	5,483,502	785,729	603,049	557,197	316,732	194,960	89,563	626,698	827,318	519,330	426,642	392,160	144,125
Hermiston	36,165,635	3,802,061	3,354,450	2,972,997	1,840,434	924,574	608,123	3,032,890	3,939,480	3,682,843	4,132,181	3,790,389	4,085,214
Lake Side	79,234,254	7,182,705	6,728,569	7,298,250	5,564,835	5,116,200	5,060,264	7,340,593	8,242,687	7,708,381	4,797,028	7,097,830	7,096,910
Lake Side 2	51,830,465	-	-	-	-	-	6,203,442	7,497,947	8,001,813	7,428,528	7,611,085	7,349,184	7,738,467
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	289,334,129	23,928,716	20,670,429	21,523,742	13,709,470	10,535,760	13,129,696	31,098,979	36,903,435	32,036,703	28,401,881	28,137,225	29,258,092
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	24,049,288	2,848,079	2,584,750	2,917,705	141,450	107,570	82,500	3,110,060	3,035,737	2,911,725	2,231,783	2,167,710	1,910,220
Clay Basin Gas Storage	379,010	11,805	13,649	22,700	50,863	50,863	50,863	50,863	50,863	50,863	50,863	10,150	(35,336)
Pipeline Reservation Fees	33,923,845	2,595,306	2,458,354	2,595,306	2,546,925	2,595,306	2,991,304	3,039,684	3,039,684	2,991,304	3,039,684	2,991,304	3,039,684
Total Gas Fuel Burn Expense	347,686,272	29,383,906	25,727,182	27,059,453	16,448,708	13,289,499	16,254,362	37,299,586	43,029,720	37,990,595	33,724,211	33,306,389	34,172,661
Other Generation													
Blundell	3,441,624	308,498	278,656	308,530	280,115	243,525	272,223	281,277	281,307	280,989	299,424	298,583	308,498
Integration Charge	3,344,256	334,596	272,928	316,887	269,547	271,535	258,419	247,488	246,483	238,979	268,361	298,865	320,169
Total Other Generation	6,785,880	643,093	551,584	625,417	549,662	515,059	530,641	528,765	527,790	519,968	567,785	597,448	628,667
Net Power Cost	**1,460,641,427**	121,782,748	110,547,609	121,120,863	110,897,049	119,234,584	117,443,439	139,414,058	140,441,946	120,981,617	119,410,074	116,616,240	122,751,202
Net Power Cost/Net System Load	**24.51**	**23.14**	**23.92**	**24.84**	**24.02**	**24.80**	**23.89**	**25.69**	**26.21**	**25.49**	**24.72**	**24.04**	**23.28**

Exhibit PAC/501
Duvall/5

Docket No. UE 264
Exhibit PAC/502
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

Oregon-Allocated NPC—July 2013 Update

July 2013

PacifiCorp
CY 2014 TAM
July 2013 Update

		Total Company						Oregon Allocated		
	ACCT.	UE-245 Final TAM CY 2013	TAM CY 2014	**July Update CY2014**	Factor	Factors CY 2013	Factors CY 2014	UE-245 Final TAM CY 2013	TAM CY 2014	**July Update CY 2014**
Sales for Resale										
Existing Firm PPL	447	26,954,864	27,098,027	**26,861,555**	SG	25.777%	26.053%	6,948,197	7,059,849	**6,998,241**
Existing Firm UPL	447	30,104,809	30,332,094	**30,332,094**	SG	25.777%	26.053%	7,760,163	7,902,421	**7,902,421**
Post-Merger Firm	447	411,312,892	414,706,102	**399,360,229**	SG	25.777%	26.053%	106,024,762	108,043,387	**104,045,327**
Non-Firm	447	-	-	**-**	SE	24.314%	24.687%	-	-	**-**
Total Sales for Resale		468,372,565	472,136,224	**456,553,878**				120,733,122	123,005,658	**118,945,989**
Purchased Power										
Existing Firm Demand PPL	555	2,770,392	2,845,214	**3,031,512**	SG	25.777%	26.053%	714,128	741,264	**789,800**
Existing Firm Demand UPL	555	51,880,572	52,544,159	**52,532,746**	SG	25.777%	26.053%	13,373,335	13,689,330	**13,686,357**
Existing Firm Energy	555	25,377,752	25,882,481	**26,323,697**	SE	24.314%	24.687%	6,170,224	6,389,539	**6,498,461**
Post-merger Firm	555	602,895,671	532,436,997	**522,088,457**	SG	25.777%	26.053%	155,409,352	138,715,820	**136,019,714**
Secondary Purchases	555	-	-	**-**	SE	24.314%	24.687%	-	-	**-**
Other Generation Expense	555	4,324,005	3,354,157	**3,344,256**	SG	25.777%	26.053%	1,114,605	873,859	**871,279**
Total Purchased Power		687,248,392	617,063,008	**607,320,669**				176,781,645	160,409,811	**157,865,611**
Wheeling Expense										
Existing Firm PPL	565	24,712,270	27,925,313	**27,925,313**	SG	25.777%	26.053%	6,370,120	7,275,382	**7,275,382**
Existing Firm UPL	565	-	-	**-**	SG	25.777%	26.053%	-	-	**-**
Post-merger Firm	565	104,782,875	110,506,851	**111,710,154**	SG	25.777%	26.053%	27,010,044	28,790,352	**29,103,848**
Non-Firm	565	2,848,300	5,105,200	**5,103,620**	SE	24.314%	24.687%	692,522	1,260,307	**1,259,917**
Total Wheeling Expense		132,343,444	143,537,364	**144,739,088**				34,072,686	37,326,041	**37,639,148**
Fuel Expense										
Fuel Consumed - Coal	501	723,280,800	760,735,004	**755,904,092**	SE	24.314%	24.687%	175,855,014	187,800,618	**186,608,024**
Fuel Consumed - Coal (Cholla)	501	55,986,523	59,706,693	**58,103,562**	SSECH/SE	24.314%	24.687%	13,612,294	14,739,632	**14,343,871**
Fuel Consumed - Gas	501	5,235,787	3,416,494	**3,536,273**	SE	24.314%	24.687%	1,273,004	843,421	**872,990**
Natural Gas Consumed	547	316,175,110	334,359,033	**337,438,388**	SE	24.314%	24.687%	76,873,295	82,542,321	**83,302,513**
Simple Cycle Comb. Turbines	547	17,063,157	7,134,120	**6,711,611**	SSECT/SE	24.314%	24.687%	4,148,654	1,761,181	**1,656,877**
Steam from Other Sources	503	3,762,209	3,374,877	**3,441,624**	SE	24.314%	24.687%	914,725	833,147	**849,624**
Total Fuel Expense		1,121,503,586	1,168,726,221	**1,165,135,549**				272,676,986	288,520,320	**287,633,900**
Net Power Cost (Per GRID)		1,472,722,858	1,457,190,370	**1,460,641,427**				362,798,195	363,250,514	**364,192,670**
Oregon Situs Solar Project Benefit		(130,638)	(138,381)	**(133,776)**	OR	100.000%	100.000%	(130,638)	(138,381)	**(133,776)**
Total Net of Adjustments		1,472,592,220	1,457,051,989	**1,460,507,652**				362,667,557	363,112,133	**364,058,894**
							Increase Absent Load Change		444,576	**1,391,337**
					Oregon-allocated NPC Baseline in Rates from UE-245			$362,667,557		
					$ Change due to load variance from UE-245 forecast			1,439,708		
					2014 Recovery of NPC in Rates			$364,107,266		
							Increase Including Load Change		**(995,132)**	**(48,371)**
								Variance From Original Filing		**946,761**

Docket No. UE 264
Exhibit PAC/503
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Gregory N. Duvall

NPC Corrections and Updates

July 2013

Oregon TAM 2014 (February 2013 Filing)		
	$ NPC = $	1,457,190,370
	$/MWh = $	24.46

Oregon TAM 2014 (July 2013 Filing):

Corrections - one-off studies from the February 2013 Filing	NPC ($)	Impact ($)
C01_OR TAM CY2014 NPC Correct Lake Side 2 Pipeline	1,456,301,612	(888,758)
C02_OR TAM CY2014 NPC Correct Small QF pricing	1,457,203,791	13,421
C03_OR TAM CY2014 NPC Heat rate calc correction	1,453,490,700	(3,699,670)
C04_OR TAM CY2014 NPC Hydro Correction	1,458,145,701	955,331
C05_OR TAM CY2014 NPC GADCT Commitment Correction	1,457,186,963	(3,407)
C06_OR TAM CY2014 NPC Wheeling and Transmission Correction	1,457,104,830	(85,539)
C07_OR TAM CY2014 NPC Update BPA Exchange Term	1,458,417,093	1,226,723
Subtotal - corrections		(2,481,898)
Updates- One-off studies from the February 2013 Filing		
U01_OR TAM CY2014 NPC Update Chehalis Pipeline	1,457,137,150	(53,220)
U02_OR TAM CY2014 NPC Update PacTrans Loss Rate	1,457,324,557	134,188
U03_OR TAM CY2014 NPC Update PGE Cove Annual Cost	1,457,243,488	53,118
U04_OR TAM CY2014 NPC Update APS Trans Rate	1,457,726,448	536,078
U05_OR TAM CY2014 NPC Update PRPA Loss Rate	1,457,192,114	1,745
U06_OR TAM CY2014 NPC Update ID Trans Rate	1,457,943,369	753,000
U07_OR TAM CY2014 NPC Update DPUD Proforma	1,457,090,550	(99,819)
U08_OR TAM CY2014 NPC Update Black Hills Sale Rates	1,457,468,043	277,673
U09_OR TAM CY2014 NPC Update Small QF	1,457,158,459	(31,911)
U10_OR TAM CY2014 NPC Update Coal Cost	1,456,675,668	(514,701)
U11_OR TAM CY2014 NPC Update 1306OFPC	1,462,230,922	5,040,552
Subtotal - updates		6,096,703
Total Corrections and Updates from February Filed NPC =		3,614,805
System balancing impact of all adjustments		(163,747)
Oregon TAM 2013 with updates, corrections =	1,460,641,427	3,451,058

Exhibit PAC/503
Duvall/1

Docket No. UE 264
Exhibit PAC/600
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Cindy A. Crane

July 2013

Q. Are you the same Cindy A. Crane who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I describe the cost changes for the Company's coal and transportation agreements included in the 2014 Transition Adjustment Mechanism (TAM) update (Reply Update). In addition, I respond to the testimony of Industrial Customers of Northwest Utilities (ICNU) witness Mr. Michael C. Deen proposing an adjustment related to the cost of fuel supplied to the Jim Bridger coal-fired generating plant (Bridger plant) from the Bridger Coal Company (BCC). I also respond to the testimony of Public Utility Commission of Oregon (Commission) Staff witnesses Messrs. John Crider and Jorge Ordonez proposing adjustments to certain operation and maintenance (O&M) costs at BCC and at the Company's Deer Creek mine, operated by Energy West Mining Company (EWMC).

Q. Please summarize your testimony regarding changes to Company coal and transportation costs included in the TAM Reply Update.

A. Coal costs decreased by approximately $6.4 million on a total-company basis, with approximately $5.9 million of the decrease associated with reduced volumes and $0.5 million of the decrease associated with lower coal prices.

The update includes new coal supply arrangements for the Dave Johnston and Naughton generating plants, an update to Colstrip generating plant costs to reflect Western Energy's 2014 Annual Operating Plan (AOP), and an update of coal and transportation contract costs to reflect actual and projected changes in contract indices.

Q. Please summarize your testimony responding to ICNU's BCC adjustment.

A. My testimony demonstrates that the costs of fuel to the Bridger plant from BCC are reasonable and prudent. ICNU claims that the coal supply should be re-priced under the Commission's "lower of cost or market" affiliated interest rule, OAR 860-027-0048. My testimony shows that this rule is inapplicable and explains the Commission's long-standing policy requiring cost-of-service-based pricing for coal from the Company's affiliate coal mines, including BCC. I discuss the reasonableness of the cost increases in BCC-supplied coal in 2014 and demonstrate the absence of lower-cost fuel supply options to the Bridger plant. I also point out several errors and omissions in ICNU's proposed adjustment.

Q. Please summarize your testimony responding to Staff's BCC/EWMC adjustments.

A. Staff did not contest the reasonableness of the overall transfer price of coal supply from BCC and EWMC. There is no precedent for line item adjustments to costs at BCC and EWMC, such as those Staff proposes, when the overall transfer price is reasonable. In addition, the Company demonstrates that the challenged O&M costs are reasonable and necessary.

COAL AND TRANSPORTATION COSTS UPDATE

Q. Please identify the primary changes in coal costs in the TAM Reply Update.

A. The primary changes in coal costs occur at four plants:

- An April 2013 coal solicitation decreased Dave Johnston plant costs by approximately [redacted];
- Updating Colstrip plant costs to reflect Western Energy's 2014 AOP decreased costs by approximately [redacted];
- Execution of a coal purchase agreement with Haystack Mining Company in June 2013 and updates to the specific consumer and producer price indices in the Kemmerer contract increased Naughton plant costs by approximately [redacted]; and
- An update of Black Butte contract costs to reflect actual pricing as of July 2013 and projected changes in contract indices increased Bridger plant costs by approximately [redacted].

Q. Please describe the Company's new coal supply arrangements for the Dave Johnston plant.

A. My direct testimony reflected an open position at the Dave Johnston plant of approximately 1,000,000 tons of coal. The Company issued a solicitation for Powder River Basin coal supplies. As a result of the solicitation, the Company secured new coal supply arrangements with Western Fuels for Dry Fork mine coal for 2014 through 2016.

Q. How do Dave Johnston costs compare to the direct filing?

A. Test period coal costs have decreased by approximately [redacted] as a result of the new coal supply arrangements for the Dave Johnston plant. The Dry Fork coal contract price netted approximately [redacted] in savings; however, transportation costs will increase by approximately [redacted]. The increase in transportation expense reflects the longer rail haul to the Dry Fork mine. The open position in the direct filing assumed the coal would be supplied by Powder River Basin mines in the south-Gillette area, nearer to the Dave Johnston plant.

Q. Please explain the coal supply arrangements for the Colstrip plant.

A. The Colstrip mine is supplied by Western Energy's Rosebud mine. Test period costs are developed based on Western Energy's 2014 AOP for the Rosebud mine. I based the Colstrip coal costs in my direct testimony on the 2013 AOP. Western Energy provided the Colstrip plant owners with the 2014 AOP in June 2013. Updating 2014 coal costs to reflect the new AOP decreases costs by approximately [redacted].

Q. Please summarize the Company's new coal supply arrangement for the Naughton plant.

A. The Naughton plant is currently supplied under a long-term coal supply agreement with Westmoreland's Kemmerer mine. The coal supply agreement allows for periodic test burn of alternative coals. [redacted], the Company arranged for a test burn of [redacted] tons of coal from the Haystack mine in 2014. [redacted].

Q. Where is the Haystack mine located?

A. The Haystack mine is located in Southwest Wyoming, approximately 30 miles from the Naughton plant and 126 miles from the Jim Bridger plant. I discuss the Haystack mine in more detail below.

Q. What is the impact of the new supply arrangement on Naughton plant coal costs?

A. The contract price for Haystack coal is [redacted] per ton, Free-On-Board (F.O.B.) truck at the mine, or approximately [redacted] per ton delivered to the Naughton plant. The purchase of Haystack coal results in an increase to Naughton plant costs by approximately [redacted] because it offsets the amount of Tier 2 coal purchased under the Kemmerer contract. The remaining [redacted] increase is associated with update of contract-specific consumer and producer price indices and coal production quantities by lease. The update reflects a shift in coal production from private leases to federal coal leases at the Kemmerer mine, resulting in increased royalty costs.

Q. Please describe the [redacted] increase associated with the Black Butte contract.

A. The Black Butte contract is based on contract-specific consumer and producer price indices. A Black Butte F.O.B. mine price of [redacted] per ton was assumed in the Company's direct testimony; the update reflects a Black Butte F.O.B. mine price of [redacted] per ton, an increase of [redacted]. Transportation costs from the Black Butte mine to the Bridger plant remain unchanged at [redacted] per ton. Approximately [redacted] per ton of the increase relates to actual contract escalation through July, and the remaining [redacted] per ton relates to projected changes in contract indices.

Q. In your direct testimony, you discussed the contract price reopener provisions for the Wyodak and Cholla coal supply agreements and the plan to update coal costs in the TAM Reply Update. Have those price reopener negotiations been completed?

A. No. Negotiations are ongoing with both Wyodak Resources Development Company and Peabody. As I discussed in my direct testimony, the Wyodak contract price reopener includes a component equal to the levelized fixed charge associated with construction of a hypothetical rail unloading facility amortized on a straight-line basis over 20 years. The Company retained Burns & McDonnell Engineering Company to perform a feasibility study of a new railcar unloading facility. The Company shared the study with Wyodak Resources. The Company understands that Wyodak Resources retained CDG Engineers, Inc. to perform a similar feasibility study of a new railcar unloading facility, and the Company requested that Wyodak Resources supply a copy upon completion.

Negotiations continue between senior management of Arizona Public Service/PacifiCorp and Peabody. While the parties have exchanged settlement proposals, they have been unable to settle the January 2013 price reopener.

Q. Have the basic price reopener assumptions for Wyodak and Cholla changed from the Company's March 1, 2013 initial filing?

A. No. The price reopener assumptions remain unchanged. Coal prices for both plants were updated in the initial filing to reflect only minor changes to contract-specific indices. The Wyodak plant's coal price increased by [redacted]; Cholla increased by [redacted]. These increases remain reasonable forecasts for 2014.

ICNU'S ADJUSTMENT FOR BRIDGER COAL SUPPLY

Q. Please describe BCC.

A. BCC is a joint venture that mines coal at the Bridger coal mine for delivery to the adjacent Bridger plant. PacifiCorp (through its wholly-owned subsidiary Pacific Minerals, Inc.) owns a two-thirds interest in BCC, and Idaho Power Company (through its wholly-owned subsidiary Idaho Energy Resources Co.) owns a one-third interest. PacifiCorp and Idaho Power Company have the same ownership percentages in the Bridger plant. BCC began supplying coal to the Bridger plant in 1974.

Q. Please describe ICNU's BCC adjustment.

A. ICNU proposes an adjustment reducing the Company's Oregon-allocated net power costs (NPC) by $7.4 million. ICNU calculates this adjustment by first adding the rate base return on PacifiCorp's investment (ROI) in the Bridger mine from docket UE 263, the Company's 2013 general rate case, to the production costs of coal supply from BCC included in the 2014 TAM. Then ICNU compares the cost of BCC coal plus ROI to the cost of coal under the Company's contract with the Black Butte mine, adjusted for the heat content of the coal. ICNU concludes that BCC coal is higher cost than Black Butte coal and, under the Commission's affiliate transfer price rule (OAR 860-027-0048), proposes re-pricing BCC coal at the current contract price for Black Butte coal, calculated on a million British thermal unit (MMBtu) basis.

STANDARD FOR COST RECOVERY OF COAL SUPPLIED FROM BCC

Q. What is the Commission's standard for cost recovery for BCC-supplied fuel to Bridger in the Company's 2014 TAM?

A. My understanding is that the standard for cost recovery of Bridger fuel is the same as the standard for recovery of any other element of the Company's NPC, which is whether the cost is objectively reasonable.

Q. Does OAR 860-027-0048 change this standard as suggested by ICNU?

A. No. I understand that OAR 860-027-0048 applies to approval of proposed affiliate transactions for regulatory accounting purposes, not for ratemaking purposes.

Q. Has the Commission set a cost-based transfer price as a part of approving coal supply arrangements from BCC to the Bridger plant?

A. Yes. Since the 1970s, the Commission has allowed PacifiCorp to purchase coal from BCC at the actual, prudent costs of production, plus a return component on the investment in the Bridger mine limited to PacifiCorp's current authorized rate of return (ROR).[1] Under this approach, if BCC earns a margin over PacifiCorp's authorized ROR, it must credit this margin back to PacifiCorp through a reduced transfer price. In its most recent order on the supply agreement between BCC and Bridger, the Commission expressly approved the agreement as "fair, reasonable and not contrary to the public interest."[2]

[1] *In the Matter of Pacific Power*, Docket UF 3508, Order No. 79-754 (1979); *In the Matter of Pacific Power and Light Company*, Docket UF 3779, Order No. 82-606 (Aug 18, 1982).
[2] *In re PacifiCorp*, Docket UI 189, Order No. 01-472 (June 12, 2001).

Q. Has the Commission taken additional steps to ensure that customers' interests are protected in PacifiCorp's coal supply agreements with affiliate mining companies?

A. Yes. The Commission consolidated PacifiCorp's affiliate coal mining companies with PacifiCorp's regulated operations for regulatory purposes.[3] Because BCC's results are merged with and made a part of PacifiCorp's for ratemaking, there is no possibility of cross-subsidization.

Q. Has the Commission ever relied upon OAR 860-027-0048 to set the transfer price for Bridger coal supply from BCC?

A. Not to my knowledge. For several decades, the Commission has applied a cost-based approach instead of OAR 860-027-0048 in approving the transfer price.

REASONABLENESS OF BCC FUEL SUPPLY COSTS

Q. How does the Company plan to supply coal for its Bridger plant in 2014?

A. For 2014, BCC will provide almost two-thirds of the Bridger plant's coal requirements at [redacted] per ton. The remaining one-third of the coal will be supplied from the Black Butte contract at [redacted] per ton, reflecting the recent cost increases to that contract.

Q. In your direct testimony, Exhibit PAC/200, Crane/13-15, you explain the main drivers of the BCC cost increase in this case. Has any party challenged the reasonableness of these increases?

A. No. Staff's reply testimony correctly notes that most of the BCC cost increase is

[3] *In re Pacific Power*, Docket UE 21, Order No. 84-898 (Nov. 14, 1984).

associated with funds for reclamation activities.[4] I testified that these increases resulted from BCC updating its final reclamation plan to ensure that sufficient funds exist in the trust to support the required reclamation activities.

Q. Is the Company's approach to supplying fuel to the Bridger plant reasonable?

A. Yes. For decades, BCC has provided a low-cost, reliable source of fuel for the Bridger plant. PacifiCorp has also relied on a third-party contract with the Black Butte mine to supply the Bridger plant to ensure a diversified fuel supply. In some years, BCC's production costs are lower than the third-party supply from Black Butte, and in other years, BCC's production costs are higher. On balance and over the long term, PacifiCorp's diversified approach has produced a reasonably priced, stable coal supply to the Bridger plant.

Q. Are there lower-priced fuel supply options than BCC available to the Bridger plant in 2014?

A. No. BCC will supply approximately [redacted] million tons of coal to the Bridger plant in 2014. In addition to BCC, there are three other mines in Southwest Wyoming: Black Butte, Kemmerer, and Haystack. As outlined below, there is not enough production capacity in 2014 among the three mines to replace BCC. In addition, the estimated cost of alternative supplies demonstrates the reasonableness of BCC's costs.

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[4] Staff/100, Crider-Ordonez/7.

Q. Please explain the availability of additional coal supply from the Black Butte mine in 2014.

A. PacifiCorp understands that the Black Butte mine may have approximately [redacted] million tons of excess production capacity in 2014, less than [redacted] percent of the Bridger's plant 2014 production target.

Q. Please explain the availability and costs of additional coal supply from the Kemmerer mine in 2014.

A. The Kemmerer mine currently supplies PacifiCorp's Naughton plant. PacifiCorp understands that Kemmerer has approximately [redacted] million tons of excess coal available in 2014, at a price of $[redacted] per ton F.O.B. truck at the Kemmerer mine. As reflected in Confidential Exhibit PAC/601, including delivery costs to the Bridger plant, the price of this coal would be $[redacted] per MMBtu, exceeding BCC's cost of $[redacted] per MMBtu (or the cost of $[redacted] per MMBtu reflecting the ROI on the Bridger mine).

Q. Please explain the availability and costs of additional coal supply from the Haystack mine in 2014.

A. Kiewit Mining started construction of the Haystack mine in early 2012. The mine was expected to open in late 2013 and produce up to 1.5 million tons of coal annually. Due to a lack of demand, however, Kiewit closed the mine in April 2013. The mine is set to restart operations in early 2014.

Based upon the Haystack contract price of $[redacted] per ton, F.O.B. truck at the Haystack mine, the delivered price to the Bridger plant of Haystack coal would be $[redacted] per MMBtu, exceeding BCC's cost of $[redacted] per MMBtu (or the cost of $[redacted] per MMBtu reflecting the ROI on the Bridger mine).

Q. Is the Company reviewing how to ensure the long-term continuation of reliable supplies of low-cost, optimum quality fuel to the Bridger plant?

A. Yes. Looking ahead, the Company is reviewing how to respond to the expiration of the Black Butte contract in 2015, working to optimize production of both the surface and underground operations at BCC, and reviewing how the expected gas conversion of Naughton Unit 3 in December 2014 will impact the Kemmerer coal supply agreement. As the Company works through each of these issues, its primary goal will be to ensure the continuation of low-cost, reliable fuel supply to the Bridger plant.

ADDITIONAL GROUNDS FOR REJECTING ICNU'S ADJUSTMENT

Q. Are there other threshold issues associated with ICNU's proposed application of OAR 860-027-0048 in this case?

A. Yes. The first step of ICNU's adjustment is to add the Company's ROI on the Bridger mine from the Company's 2013 general rate case, docket UE 263, to the BCC production costs included in this case. ICNU is a party to a comprehensive settlement of docket UE 263, the approval of which is now pending before the Commission. The ROI on the Bridger mine (reflected in Page 8.3 of Exhibit PAC/1002) is not included in the stipulated adjustments that comprise the settlement.

Q. Are there errors in ICNU's ROI calculation?

A. Yes. As demonstrated in Confidential Exhibit PAC/602, ICNU's calculation is based upon an ROI that is overstated because it omits the impact of deferred taxes. Including the deferred taxes reduces ICNU's adjustment by approximately $550,000 to $6.9 million, producing a price of $[redacted] per MMBtu instead of the correct price of $[redacted] per MMBtu.

Q. OAR 860-027-0048 requires a utility to record the price of goods purchased from an affiliate in certain circumstances at the lower of cost or a fair market rate. How does the rule define "market rate"?

A. The rule defines market rate as "the lowest price that is available from nonaffiliated suppliers for comparable services or supplies." OAR 860-027-0048(1)(i) (emphasis added).

Q. Does ICNU's adjustment consider the fact that OAR 860-027-0048 requires market comparisons to be drawn from available alternate suppliers?

A. No. ICNU applies the Black Butte contract as source of the "market rate" even though the contract is several years old and the Black Butte mine has insufficient excess capacity to actually supply the Bridger plant in 2014. Even if OAR 860-027-0048 applied to BCC's fuel supply to the Bridger plant, ICNU inappropriately applies the rule by suggesting an alternate supplier without available supplies.

STAFF'S O&M ADJUSTMENTS TO BCC AND EWMC

Q. Staff proposes an adjustment of approximately $500,000 on an Oregon-allocated basis for certain O&M costs embedded in the coal supply costs from BCC and EWMC. Please provide a general response.

A. Staff did not challenge the reasonableness of the overall costs of coal supply from BCC and EWMC. Instead, Staff cites various cases for the proposition that the

Commission "has allowed rate-case type adjustments to certain itemized O&M costs related to the captive mines."[5] I understand that these cases do not support Staff's position, however, because none of them involve coal supply from affiliated mines. For the primary O&M adjustments Staff proposes (management overtime and incentive pay), the Commission should consider the reasonableness of the overall transfer price from BCC and EWMC and reject these adjustments.

Q. Staff proposes an adjustment to remove fines. Are any fines included in BCC and EWMC costs?

A. No.

Q. Staff's primary adjustments are for management overtime and incentives. Please explain why the mining companies' management overtime costs are reasonable.

A. At both mining operations, only certain employee groups are eligible for management overtime pay: (1) exempt employees in job classifications engaged in supervising represented employees that are deemed critical to the safe operation of the mine and work extra full eight-hour shifts; (2) non-exempt employees subject to the wage and hour laws established by the Fair Labor Standards Act; and (3) exempt employees whose regular schedule is outside the regular Monday through Friday work schedule and who work on holidays. Substantively, overtime expense is associated with ensuring front-line supervisory coverage during additional weekend shifts, as well as coverage for vacation or absenteeism. As a safety measure, the Company requires front-line supervision of

[5] Staff/100, Crider-Ordonez/7.

represented employees during all shifts.

Q. Please explain why the mining companies' incentive costs are reasonable.

A. Management personnel at BCC and EWMC are eligible for the same Annual Incentive Plan (AIP) offered to the rest of the Company. As more fully discussed in Mr. Erich D. Wilson's testimony in docket UE 263, the Company's AIP puts a portion of compensation "at risk" to encourage superior performance and achievement of Company, business unit, and individual employee goals. The AIP is an integral part of the overall compensation package for management employees and is crucial to employee retention in geographically competitive areas.

The compensation structure for management employees at the mining companies is comparable to other coal mining companies. InfoMine USA, Inc. surveys coal mines throughout the United States annually for information about wages, salaries, benefits, and incentive bonus plans. The survey includes salaries for technical, managerial, and administrative personnel. The Company subscribes to InfoMine's U.S. Coal Mine salaries, wages and benefits annual report. A review of InfoMine's 2012 survey demonstrates that the compensation structure for Company-operated mines is commensurate with coal mines of similar size in the Company's geographical area.

Q. Does this conclude your reply testimony?

A. Yes.

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Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Reply Testimony of Cindy A. Crane

Market Comparison of Coal Costs
for the Jim Bridger Coal-fired Generating Plant

July 2013

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Docket No. UE 264
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BEFORE THE PUBLIC UTILITY COMMISSION

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Exhibit Accompanying Reply Testimony of Cindy A. Crane

Industrial Customers of Northwest Utilities'
Return on Investment Calculation

July 2013

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