Docket No. UE 263
Exhibit PAC/1000
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Gary W. Tawwater

March 2013

DIRECT TESTIMONY OF GARY W. TAWWATER

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Gary W. Tawwater. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Manager, Revenue Requirement.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have been employed by PacifiCorp since March 2004. I was appointed to my current role as Manager of Revenue Requirement in August 2012. My primary responsibilities include the calculation and reporting of the Company's regulated earnings and revenue requirement, application of the inter-jurisdictional allocation methodologies, and the explanation of those calculations to regulators in the jurisdictions in which the Company operates. Before assuming my current position, I was the Manager of Regulatory Accounting, where I was responsible for overseeing the Company's Federal Energy Regulatory Commission (FERC) ledger, regulatory assets and liabilities, and other accounting activities. I received a Bachelor of Business Administration degree in finance with an emphasis in accounting from Stephen F. Austin State University in 1998. I have also attended various educational, professional, and electric-industry-related seminars.

PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. My direct testimony addresses the calculation of the Company's Oregon-allocated revenue requirement, excluding net power costs (NPC), and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $56.0 million revenue increase requested in this general rate case representing the increase over current rates required for the Company to recover its Oregon non-NPC revenue requirement of $901.1 million. As discussed by Ms. Joelle R. Steward, the revenue requirement increase will be reduced to $44.6 million if the Mona-to-Oquirrh tariff rider is approved once the project is placed in service in during 2013. The Company currently recovers its NPC through the Transition Adjustment Mechanism (TAM).
- The selection of the historical period of the 12 months ended June 2012 (Base Period) as the basis for the test period in this proceeding.
- The development of the forecast test year in this case, which is the 12 months ending December 31, 2014 (Test Period).
- Discussion of the 2010 Protocol inter-jurisdictional allocation methodology (2010 Protocol) used to determine Oregon-allocated results.
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service before January 1, 2014, the beginning of the Test Period.
- The calculation of the revenue requirement associated with the Lake Side 2 natural gas-fired generating plant (Lake Side 2), which the Company is proposing to recover as a separate tariff once the project is complete and used and useful.

- The presentation of the normalized results of operations for the Test Period demonstrating that under current rates the Company will earn an overall return on equity (ROE) in Oregon of 7.9 percent, which is below the Company's authorized ROE.

REVENUE REQUIREMENT

Q. What is the revenue requirement to achieve the requested ROE in this case?

A. At current rate levels, the Company will earn an overall ROE in Oregon of 7.9 percent during the Test Period. This return is less than the 9.8 percent ROE authorized in the Company's 2012 general rate case, docket UE 246 (2012 Rate Case).[1] The Company is not proposing to change to the authorized ROE. A 9.8 percent ROE produces a non-NPC revenue requirement of $901.0 million based on the 2010 Protocol. Exhibit PAC/1001 provides a summary of the Company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/1002 provides the supporting details and calculations and is discussed in greater detail later in my testimony.[2]

Q. Please explain how you have treated NPC in this filing.

A. As noted above, the Company recovers its NPC through the TAM, which was filed on March 1, 2013, for calendar year 2014 NPC. To model the non-NPC revenue requirement for this case, the Company first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then

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[1] *In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 (December 20, 2012). The parties to the partial stipulation in the 2012 Rate Case agreed to an overall rate of return of 7.655 percent and a 9.8 percent ROE for Oregon regulatory purposes. The stipulation was approved by the Commission in Order No. 12-493 on December 20, 2012.

[2] The revenue requirement impact of the Lake Side 2 is not included in Exhibits PAC/1001 or PAC/1002. As discussed later in my testimony, the revenue requirement associated with this investment is separately reflected in Exhibit PAC/1004 because the Company is not requesting rate recovery until the project is complete and used and useful.

removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as renewable energy tax credits, the hydro embedded cost differential (Hydro ECD), and the 2010 Protocol rate mitigation cap. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PAC/1001. Page 1.0 of Exhibit PAC/1002 also shows the division of revenue requirement between the TAM and general rate case components, and the resulting general-rate-case-related price change requested in this case.

BASE PERIOD

Q. Why did the Company use July 2011 through June 2012 as the historical basis, or Base Period, for the Test Period?

A. The Company selected the 12-month period ended June 2012 as the historical basis for this case because it was the most recent total-company data available for inter-jurisdictional allocations to achieve a filing date of March 1, 2013. The Company audits and extracts total company accounting information with the data components necessary for state allocations on a semi-annual basis for the 12-month periods ending June and December each year. This semi-annual data extract and review procedure is a key control measure to ensure the accuracy and reliability of the data, which serves as the basis for each of the Company's results of operations and general rate case filings.

Q. Why was a March 1, 2013 filing date for this general rate case necessary?

A. In Order No. 09-274, the Commission adopted a stipulation establishing guidelines for future TAM filings, including the following provision:

> In all future filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January 1 rate effective date*.[3]

Because of this agreement, a filing date later in the year is not possible.

Q. When will calendar year 2012 total-company data become available on an inter-jurisdictional allocation basis?

A. Only once total-company data is audited does it become available to begin analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total company financial data is finalized to ensure state-allocated data is accurate. Due to these complex steps, calendar year 2012 data will not be available for use as the basis of a forecast test period until the end of April 2013, approximately two months after the general rate case filing commitment date of March 1.

TEST PERIOD

Q. What Test Period did the Company use to determine revenue requirement in this case?

A. The forecast Test Period used by the Company in this proceeding is the 12 months ending December 31, 2014.

[3] *In the Matter of PacifiCorp dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at page 13 (July 16, 2009) (emphasis added).

Q. Why did the Company choose the year ending December 31, 2014, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during the time the new rates will be in effect. Rates from this case will be effective no later than January 1, 2014, which matches the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this general rate case also matches the test period used in the development of the NPC filed in the concurrent TAM.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case, the Company used the 12 months ended June 30, 2012. Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable, and anticipated events.

Q. What is the significance of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a solid foundation that is readily available for audit by all who wish to participate in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenues and costs.

A. Revenues are adjusted by applying the current Commission-approved tariff rates to the Test Period load projection. NPC are developed using the Generation & Regulation Initiative Decision (GRID) model. The results of the GRID run for the Test Period are embedded in the results for calculation purposes only; as previously mentioned, recovery of these costs is sought through the TAM filing. Historical operations and maintenance (O&M) expenses, excluding NPC, are split into labor and non-labor components. Non-labor costs are adjusted for inflation using inflation indices developed specifically for electric utilities provided by IHS Global Insight (Global Insight) and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs are also adjusted for contractual increases through the end of the Test Period.

Q. Does the Company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by Global Insight.

Q. How has the Company addressed areas where cost increases are different than inflation?

A. The Company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified that needed to be adjusted in the rate case, the business units were asked to provide support for changes in the number, or frequency, of activities. An example of this type of adjustment is the incremental O&M adjustment (adjustment page 4.9). Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production, not changes in volume or processes.

INTER-JURISDICTIONAL ALLOCATIONS

Q. What methodology did the Company use to calculate the Oregon-allocated revenue requirement in this case?

A. The Company's Oregon-allocated revenue requirement is calculated using the 2010 Protocol as described in the stipulation approved by the Commission in Order No. 11-244 in docket UM 1050 on July 5, 2011. This is the Company's second Oregon rate case filing since the Commission's approval of the 2010 Protocol.

Q. Does the rate mitigation cap impact the Company's requested price increase in the current case?

A. No. As shown on Page 1.1 of Exhibit PAC/1002, Oregon's revenue requirement under the Revised Protocol methodology plus 0.30 percent is $1,268.7 million, which is greater than the Oregon revenue requirement of $1,264.2 million calculated using the 2010 Protocol.[4] Consequently, the rate mitigation cap is not triggered and does not affect the Company's requested price change in this case.

[4] 2010 Protocol and Revised Protocol figures reflect Oregon's total revenue requirement for the Test Period, including TAM and general rate case components.

FORECAST CAPITAL ADDITIONS

Q. How has the Company treated forecast capital additions to electric plant in service in this filing?

A. As mentioned in the direct testimony of Mr. Richard P. Reiten, the Company has included capital additions to plant in service through December 31, 2013, rather than through December 31, 2014, which is the end of the forecast Test Period and the rate effective period. This treatment is consistent with the Company's 2010 general rate case docket UE 217 (2010 Rate Case) and the 2012 Rate Case.

LAKE SIDE 2

Q. Please describe the revenue requirement associated with the Lake Side 2.

A. As discussed by Mr. Stefan A. Bird, the Company projects to complete Lake Side 2 in the second quarter of 2014. Exhibit PAC/1004 shows the projected capital investment, depreciation expense and reserve, O&M expense, and tax impacts associated with this project. Page two of this exhibit shows the overall Oregon annual revenue requirement of $22.7 million for this investment. The other pages in this exhibit provide supporting documentation for the figures used to determine the Oregon revenue requirement impact. The Company is requesting approval of a separate tariff rider to collect the revenue requirement of Lake Side 2.

Q. When is the Company requesting to begin recovery of the costs associated with this investment?

A. As discussed by Ms. Steward, the Company is proposing to recover the revenue requirement associated with this investment through a separate tariff, following a prudence review in this case, once the project becomes used and useful. This is consistent with the treatment of the Mona-to-Oquirrh transmission project tariff rider approved in Order No. 10-493 in the 2012 Rate Case.

OREGON RESULTS OF OPERATIONS

Q. Please describe Exhibit PAC/1002.

A. Exhibit PAC/1002, which was prepared under my direction, is the Company's Oregon results of operations report (Report). As previously explained, the Base Period for the Report is the 12 months ended June 30, 2012, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending December 31, 2014. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base, and loads in the Test Period. The Report presents operating results for the Test Period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PAC/1002 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of Oregon-allocated results according to the 2010 Protocol. Page 1.0 breaks out the non-NPC results and calculates the revenue requirement the Company is requesting as part of this general rate case (column 5). Page 1.2 contains a summary of the general rate case request.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by FERC account

and 2010 Protocol allocation factor.

- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company.
- Tab 9 is a restatement of Tab 2 with the Oregon allocation based on the Revised Protocol method, as required by Commission Order No. 11-244.
- Tab 10 contains the calculation of the 2010 Protocol allocation factors. Factors in this case are based on the load forecast through December 2014 and pro forma account balances.
- Tab 11 contains the Company's most recent lead lag study, which is based on calendar year 2010 data.
- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

Tab 3—Revenue Adjustments

Q. Please describe the information contained behind Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index, which contains a brief overview of the assumptions used to project Test Period revenues and a list of each normalization adjustment included in this section of the exhibit. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues and each adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Pro Forma Revenue (page 3.1)—**This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the Test Period based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

Wheeling Revenue (page 3.2)—This adjustment reflects the level of wheeling revenue for the Test Period by adjusting the actual revenue for normalizing, annualizing, and pro forma changes. Imbalance penalty revenue and expense is removed to avoid any impact on regulated results. The Company has not included any incremental Open Access Transmission Tariff (OATT) revenue associated with the Company's pending transmission rate case, Docket No. ER11-3643, at FERC. The Commission recently approved the Company's application to defer Oregon's allocated share of any incremental OATT revenues.[5]

Sulfur Dioxide (SO_2) Emission Allowances (page 3.3)—The Environmental Protection Agency (EPA) established guidelines that govern the volume of SO_2 that can be emitted from power plants and granted the issuance of SO_2 emission allowances. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. This adjustment reflects the gain on sales of SO_2 allowances based on a four-year amortization period ending December 2014. This is the same methodology

[5] *In the Matter of PacifiCorp d/b/a Pacific Power Application for Deferred Accounting of Revenues Related to Open Access Transmission Tariff,* Docket No. UM 1639, Order No. 13-045 (February 12, 2013) (emphasis added).

included in the Company's last four general rate cases, dockets UE 179, UE 210, the 2010 Rate Case, and the 2012 Rate Case.

Renewable Energy Credit (REC) Revenues (page 3.4)—This adjustment removes all REC revenue booked during the 12 months ended June 2012. Most of Oregon's share of RECs is banked for compliance; however, not all RECs meet the Oregon Renewable Portfolio Standard (RPS) qualifications. Oregon's revenue from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in docket UP 260.

Ancillary Revenue (page 3.5)—In December 2011, the Company renewed its contract with Seattle City Light (SCL) to receive real time output from SCL's share of the Stateline wind farm and return power two months later. The ancillary revenue booked in the 12 months ended June 2012 is adjusted to reflect the Test Period revenue expected per the terms of the new contract. The impact on NPC is included in adjustment 5.1 and in the TAM.

Tab 4—O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical summary and the specific adjustments. The O&M Expense Adjustment Index begins on page 4.0.1 with a brief overview of assumptions used to adjust operation, maintenance, administrative, and general expenses. The numerical summary (pages 4.0.2–4.0.3) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense and Revenue (page 4.1)—**This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses. It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

Wage and Employee Benefits (page 4.2)—Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, and post-employment benefits for changes expected beyond the actual costs experienced in the period ended June 2012. Mr. Erich D. Wilson's testimony provides an overview of the compensation and benefit plans provided to employees at the Company and supports the costs related to these areas included in the Test Period.

Collective bargaining agreements are used to escalate union wages where increases are specified wage increases for non-union and exempt employees are based on the Company's actual merit increases or Global Insight's Consumer Price Forecast. Incentive compensation for non-union employees is included using a three-year average of the ratio of annual incentive expense to base wages. Pension expense and other employee benefit costs are adjusted to the planned expense for the Test Period, based on actuarial reports where available or by escalating actual costs.

Page 4.2.1 of the Report provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual labor costs in the year ended June 2012 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Idaho Irrigation Load Control (page 4.3)—Incentive payments made to Idaho customers participating in the irrigation load control program and a portion of the program's administrative costs are initially system allocated in unadjusted accounting data. Consistent with the 2010 Protocol, demand side management (DSM) costs are situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in the inter-jurisdictional allocation factors. This adjustment corrects the booked allocation to assign these costs directly to Idaho.

Remove Non-Recurring Entries (page 4.4)—A variety of accounting entries were made to expense accounts during the Base Period that are non-recurring in nature or relate to a prior period. These transactions are removed in this adjustment from the results of operations to normalize the Test Period results. Details on the specific items in the adjustment can be found on page 4.4.1 of the Report.

Uncollectible Accounts (page 4.5)—Uncollectible accounts expense is adjusted to the Test Period level by applying the historical uncollectible rate (Oregon uncollectible accounts expense in FERC Account 904 divided by Oregon general business revenues) to the normalized general business revenues in the Test Period.

DSM Revenue and Expense Removal (page 4.6)—This adjustment removes from regulated results revenues and expenses related to DSM programs in various states because the costs are recovered via separate surcharges and are not included in base rates.

Insurance Expense (page 4.7)—In the 2010 Rate Case, the Commission authorized the Company to establish monthly accruals and associated reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution (Non-T&D) property losses, and third-party liability insurance. The Commission ordered the self-insurance accruals to begin on April 1, 2011, as a replacement for the expiration of the Company's captive insurance coverage with MidAmerican Energy Holdings Company. The Oregon-allocated monthly accrual for property related losses was based on a 10-year average of actual property losses, with each year escalated by the Consumer Price Index (CPI) to the Test Period. The Oregon-allocated monthly accrual for third-party liability insurance was established based on an annual average of historical insurance claim payments from April 2005 to December 2009.

The adjustment in this case uses the Commission-approved methodology for self-insurance accruals from the 2010 Rate Case, updated for known and measurable changes for both property and liability insurance. The adjustment also reduces both property and liability premiums for known and measurable changes in the Test Period and removes entries related to the captive insurance and a California regulatory asset.

Consistent with the treatment from the 2010 Rate Case, the Company is using a 10-year average of property damages for the self-insurance reserve accrual, using the most recent 10-year time period. Total company Non-T&D property premiums were $7.7 million for the 12 months ended June 2012 and will be reduced to $6.4 million for the Test Period.

In October 2012, the Company negotiated new liability coverage with a change in the per-event deductible to $10.0 million. Consistent with the treatment in the 2010 Rate Case, the third-party liability accrual in this case is calculated based on a five-year average of historical insurance events, from January 2008 through December 2012, with the events amounts adjusted to account for the change in the deductible.

Generation Overhaul Expense (page 4.8)—This adjustment normalizes generation overhaul expenses in the Base Period using a four-year average methodology. In this adjustment, overhaul expenses for the years ending June 2009 to June 2011 are restated to constant dollars to make them comparable prior to averaging.

Incremental O&M (page 4.9)—This adjustment adds incremental O&M to the Base Period to bring it to the projected O&M level for the 12 months ending December 2014, after accounting for Global Insight inflation escalation applied in adjustment page 4.12.

Naughton Unit 3 Write-Off Adjustment (page 4.10)—This adjustment removes expenses related to the Naughton Unit 3 write-off that occurred in June 2012.

Memberships and Subscriptions (page 4.11)—This adjustment removes expenses in excess of Commission policy as outlined by the Commission order in docket UE 94. National and regional trade organizations are recognized at 75 percent. The Company's mandated membership in the Western Electricity Coordinating Council (WECC) is included at 100 percent.

O&M Escalation (page 4.12)—This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on Global Insight, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based solely on electric utility costs for materials and services, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities.

The Global Insight indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The Global Insight study used to prepare this filing was the third quarter 2012 forecast, released November 8, 2012. The Global Insight data is proprietary and subject to copyright protection, therefore the indices utilized in the Company’s case are provided in Confidential Exhibit PAC/1005.

O&M Efficiency (page 4.13)—This adjustment reduces the Company’s O&M expense levels in the Test Period for efficiency initiatives realized since the historical test period. This adjustment reduces Oregon-allocated O&M by $4.0 million.

Tab 5—Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. Tab 5 includes adjustments to items that are generally related to NPC, but may or may not be addressed separately in the Company's TAM filing. Specifically, adjustment page 5.1, Net Power Costs relates solely to NPC and recovery of these costs is being sought in the TAM docket rather than the general rate case. This adjustment is included for modeling and computational purposes only. For example, Test Period revenue requirement includes a tax credit for renewable energy generated from renewable facilities (adjustment page 7.3). This tax credit is calculated based on the generation output of these facilities as modeled in GRID (adjustment page 5.1) for the Test Period. Adjustment pages 5.2 through 5.5 include items that are not addressed in the Company's TAM filing with the exception of the Black Cap Solar, LLC Project (adjustment page 5.5), which includes revenue requirement components in both the TAM and the general rate case.

The Net Power Cost Index on page 5.0.1 is a brief overview of assumptions used to adjust NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1)—**This adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling, and fuel in a manner consistent with the contractual terms of sales and purchase agreements, as well as normal hydro and temperature conditions for the Test Period. The GRID study for this adjustment is based on forecasted loads for the period. As I previously described, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; NPC is not part of the revenue requirement for the general rate case.

James River Royalty Offset (page 5.2)—On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the 20-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's NPC as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This adjustment adds the royalty offset to FERC account 456, other electric revenue, for the Test Period.

Little Mountain (page 5.3)—The Company has provided both electricity and steam from its Little Mountain plant to the Great Salt Lake Minerals Company since 1968. The current contract associated with this arrangement expired on February 28, 2012. However, on August 1, 2011, the electrical generator at the Little Mountain plant experienced a significant electrical fault and has not produced energy since that time. In August 2011, the Company installed a mobile packaged boiler in order to provide enough steam for the Great Salt Lake Minerals Company to maintain its operations. Since the plant no longer produces energy due to the generator failure, this adjustment removes the steam revenue and plant O&M expense, and no energy from the plant is included in the NPC study or the TAM. The asset balance is removed in adjustment page 8.6, depreciation expense is removed in adjustment page 6.1, and the accumulated depreciation reserve is removed in adjustment page 6.2.

Bonneville Power Administration (BPA) Residential Exchange (page 5.4)— The Company receives a monthly purchase power credit from BPA. This credit is treated as a 100 percent pass-through to eligible customers. Both a revenue credit and a purchase power expense credit are posted to unadjusted results. This adjustment reverses the BPA purchase power expense credit recorded in unadjusted results. The revenue credit is removed from Test Period results in the Pro Forma Revenues adjustment, page 3.1.

Black Cap Solar LLC Project (page 5.5)—As stipulated and approved by the Commission in the 2012 Rate Case, this adjustment adds the O&M expense, the lease payment expense, and the land balance associated with the project to the Test Period. The NPC benefit associated with this project is included in adjustment page 5.1, NPC and is reflected in the TAM.

Tab 6—Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1)**—This adjustment reflects the incremental depreciation expense associated with the capital additions included in the filing in the plant additions adjustment, page 8.6 and adjusting the depreciation expense for the proposed depreciation rates in docket UM 1647 effective January 1, 2014. The annualized level of depreciation and amortization expense for the Test Period is calculated by first applying the current composite depreciation and amortization rates to the December 2013 pro forma plant balances. The current composite rates used are those approved by the Commission in docket UM 1329, which became effective on January 1, 2008. The depreciation expense is then updated for the proposed depreciation rates filed in docket UM 1647, which the Company has requested become effective on

January 1, 2014, the beginning of the Test Period. The proposed rates in UM 1647 increase Oregon's allocated share of depreciation and amortization expense by $27.2 million. The detailed calculation of the depreciation and amortization expense is provided on pages 6.1 through 6.1.16.

Depreciation and Amortization Reserve (page 6.2)—This adjustment steps forward the depreciation and amortization reserve from the Base Period to a December 2013 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to Base Period balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2012, to December 31, 2013. An incremental reserve amount has been added to the December 31, 2013 balances to reflect the annualized level of depreciation and amortization expense included on page 6.1. The reserve balance calculations are detailed on pages 6.2 to 6.2.12.

Tab 7—Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of the tax adjustments included in this case. The numerical summary on page 7.0.2 identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1)—**This adjustment details the adjustment to interest expense required to synchronize the Test Period interest expense with Test Period rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2)—Property tax expense for the Test Period is computed by adjusting accruals from the Base Period for known or anticipated changes in the assessed values of the Company's operating property and the corresponding effect such changes will have on property tax expense for the Test Period. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1003.

Renewable Energy Tax Credit (page 7.3)—The Company is entitled to recognize federal and state income tax credits as a result of placing renewable generating plants in service. The federal tax credit is based on the kilowatt hours (kWh) generated by the plants, and the credit can be taken for the first 10 years of generation from qualifying property. This adjustment reflects the credit based on the qualifying production as modeled in GRID for the Test Period NPC study.

The Utah State Production Tax Credit expired in December 2011 and is not reflected in the Test Period. The Oregon Business Energy Tax Credit (BETC) is based on investment in qualifying plant, and the credit is used over a three to five year period on qualifying property.

Allowance for Funds Used During Construction (AFUDC) Equity (page 7.4)—This adjustment reflects the appropriate level of AFUDC equity into regulated results to align the tax schedule M with regulatory income. Per Commission Order No. 10-022, AFUDC equity in this case is included using flow-through tax treatment.

Medicare Deferred Accounting (page 7.5)—As established in dockets UM 1479 and the 2010 Rate Case, this adjustment recognizes the amortization of the Medicare deferral regulatory asset for the Test Period. This adjustment also normalizes the Base Period deferred income tax expense for a recent change in tax law. With the change in law, some of the costs related to other post-retirement benefits become non-deductible for income tax purposes.

Pro Forma Schedule M (page 7.6)—This adjustment normalizes the Schedule M to an estimated pro forma level of expense for the Test Period. The significant change in tax depreciation is primarily driven by the reduced bonus depreciation available in the Test Period as compared to the Base Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Pro Forma Deferred Income Taxes (page 7.7)—This adjustment normalizes the deferred tax expense to an estimated pro forma level of expense for the Test Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Pro Forma Accumulated Deferred Income Tax (ADIT) Balance (page 7.8)—This adjustment normalizes ADIT balances to an estimated pro forma level of rate base balance for the Test Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Wyoming Wind Generation Tax (page 7.9)—This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test Period results. The Wyoming Wind Generation Tax is an excise tax levied upon production of electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the entity producing the electricity. The tax is one dollar for each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

Franchise and Resource Supplier Taxes (page 7.10)—This adjustment normalizes the Base Period Oregon franchise tax and the Oregon energy resource supplier assessment to the Test Period level based on pro forma revenues in adjustment page 3.1. Ms. Steward discusses how the franchise and energy resource supplier taxes are included as a new unbundled rate element in the Company's rate design in this case.

Tab 8—Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components.

The numerical summary (pages 8.0.2–8.0.3) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1)—**This adjustment supports the calculation of cash working capital balance included in rate base using the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on the lead lag study prepared by the Company using calendar year 2010 information. The Company is using the same lead lag study in this case that was used in the 2012 Rate Case. An electronic version of the lead lag study is included as part of the Company's workpapers.

Trapper Mine Rate Base (page 8.2)—The Company owns a 21.4 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base and reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks the reclamation liability forward to December 2013. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.

Jim Bridger Mine Rate Base (page 8.3)—The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the Company's portion of the pro forma December 31, 2013 net plant balance to rate base. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.

Customer Advances for Construction (page 8.4)—Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Plant Additions (page 8.5)—To reasonably represent the cost of system infrastructure required to serve customers, the Company has identified capital projects that will be used and useful by December 31, 2013.

Capital additions by FERC functional category are listed on pages 8.5.5 to 8.6.12, indicating the in-service date and amount by project. This adjustment is based on plant balances as of December 31, 2013. As described earlier in my testimony, the accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements. Projects over $5 million (total-company basis) are described on pages 8.6.13 through 8.6.18 of the Report.

This adjustment does not include the impact of Lake Side 2, which is reflected in Exhibit PAC/1004. As discussed earlier in my testimony, the Company is requesting recovery of the revenue requirement associated with this project through a separate tariff rider.

Plant Retirements (page 8.6)—Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through December 31, 2013. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

Miscellaneous Rate Base (page 8.7)—This adjustment reflects the change in the fuel stock balance from the Base Period to the Test Period. This adjustment also reflects the working capital deposits that are offsets to fuel stock costs. In addition, balances for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural gas plants are walked forward to reflect payments and transfers of capital to electric plant in service through December 31, 2013.

Powerdale Hydro Removal (page 8.8)—This adjustment removes costs related to the Powerdale hydroelectric plant from results. Powerdale was decommissioned after it was damaged by a flood in November 2006. Deferred accounting for the unrecovered plant balance was authorized by the Commission in docket UM 1298 and was fully amortized December 2010. Consistent with dockets UE 210, the 2010 Rate Case, and the 2012 Rate Case, the Company amortized the decommissioning regulatory asset beginning January 1, 2010. This regulatory asset will be fully amortized before the beginning of the rate effective period in this case. Accordingly, this adjustment removes the O&M expense associated with the plant, the amortization expense related to the unrecovered plant regulatory asset, and the decommissioning regulatory asset balance.

Regulatory Asset Amortization (page 8.9)—This adjustment normalizes regulatory assets from the Base Period to the Test Period. In addition, in docket UE 210, the Company agreed to set up tariff riders to collect the balance of the Grid West, the 2000 Transition Plan, and the MidAmerican Energy Holdings Company (MEHC) Oregon Transition Plan regulatory assets. These separate tariff riders are credited to revenues when collected and removed from revenues in the Pro Forma Revenue adjustment page 3.1. These regulatory assets are amortized in unadjusted results by charging expense. This adjustment removes that expense.

Klamath Hydroelectric Settlement Agreement (KHSA) (page 8.10)—This adjustment accounts for the total Test Period costs related to the KHSA. As approved by the Commission in docket UE 219, effective January 1, 2011, the depreciation of existing Klamath facilities is being accelerated so that assets will be fully depreciated by December 31, 2019. Relicensing and settlement process costs are also amortized at a rate that will achieve a zero net book value by December 31, 2019.

Miscellaneous Asset Sales and Removals (page 8.11)—This adjusts the Company's Base Period for various assets that were sold or removed, including the sale of Snake Creek hydroelectric plant to Heber Light and Power Company, the removal of Deseret Power's portion of the Hunter unit two scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the removal of the Goose Creek switching station. Asset balances for Snake Creek and Condit are removed in the adjustment to plant retirements, page 8.7. The Oregon-allocated proceeds related to the gain on the sale of Snake Creek will be placed in the property sales balancing account and passed through to customers in Schedule 96, Property Sales Balancing Account Adjustment, as outlined in docket UP 275, Commission Order No. 11-331.

Remove Rolling Hills (page 8.12)—This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. This treatment is consistent with Commission Order No. 08-548.

Plant Held for Future Use (PHFU) (page 8.13)—This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Commission Order No. 01-787.

Carbon Plant Retirement (page 8.14)—This adjustment includes the impact of accelerated depreciation for the Carbon plant as stipulated and approved in the 2010 Rate Case. Depreciation of the Carbon plant is accelerated so that assets are fully depreciated by April 15, 2015. The Carbon plant is depreciated using Commission-approved rates from the end of the Base Period through

December 31, 2012. The level of expense reflected in the Test Period is based on an annualized level of depreciation expense using the proposed accelerated rate.

Pension and Other Postretirement Welfare Plan Balances (page 8.15)—This adjustment adds into rate base the Company's prepaid pension and other post-retirement welfare balance, net of the accumulated deferred income tax liability. This adjustment is discussed in detail in the direct testimony of Company witnesses Mr. Douglas K. Stuver.

Tab 9—Revised Protocol

Q. Please describe the information contained behind Tab 9.

A. Tab 9 is restatements of Tab 2 using the Revised Protocol allocation methodology. The Company is providing these restated results in compliance with Commission Order No. 11-244.

Tab 10—Allocation Factors

Q. Please describe the information contained behind Tab 10 Allocation Factors.

A. Tab 10 Allocation Factors summarizes the derivation of the jurisdictional allocation factors using the 2010 Protocol.

Q. Please explain how the inter-jurisdictional allocation factors applied in this case comply with the Commission order approving the 2010 Protocol.

A. Each of the inter-jurisdictional allocation factors included in this case is calculated in the same manner prescribed in the 2010 Protocol approved by the Commission in Order No. 11-244. Specifically, "Tab 2—Results of Operations of the Report" applies allocation factors to the revenue requirement components as outlined in Appendix B of the 2010 Protocol. In addition, the calculations of the allocation factors included in this case are consistent with the algebraic derivations approved by the Commission shown in Appendix C of the 2010 Protocol.

Q. What exhibits included in this filing demonstrate compliance with Order No. 11-244?

A. Two files are provided as part of this filing to demonstrate the Company's compliance with Order No. 11-244. First, "Tab 10—Allocation Factors" in the Report shows the calculation and derivation of each 2010 Protocol factor included in the filing. An electronic version of this section of my exhibit is provided with the Company's workpapers. In addition, the Company's revenue requirement model, the Jurisdictional Allocation Model (JAM), is provided as part of the Company's workpapers. The "Factors" tab within the Excel-based model shows the linked formulas and inputs used in the development of each of the allocation percentages. As noted above, the calculations in this section of the model were developed based on the algebraic derivations set forth in Appendix C of the 2010 Protocol.

Q. Are the forecast loads used to derive the inter-jurisdictional allocation factors the same as the forecast loads used to develop Test Period revenues and NPC?

A. Yes. The forecast loads used in the calculation of allocation factors are consistent with the loads used in the development of Test Period revenues and NPC. By using the same load forecast for each of these revenue requirement components, an appropriate matching is achieved. The load forecast applied in this case is described in detail in the testimony of Mr. Gregory N. Duvall.

Q. Although a consistent load forecast is used for inter-jurisdictional allocation factors, Test Period revenues, and NPC, are there any differences in the application of these loads?

A. Yes. NPC and inter-jurisdictional allocation factors are developed using forecasted loads at the system input level instead of the metered or sales level used in the development of Test Period revenues. The differences between the system input level and sales level are line losses. In addition, allocation factors are adjusted for load curtailments consistent with the 2010 Protocol.

Q. Will the Company need to update inter-jurisdictional allocation factors as part of this proceeding?

A. As described in the testimony of Mr. Duvall in the concurrent TAM filing, interruptible contracts with three large industrial customers expire in 2013 or 2014. Depending on the terms of new contracts, there is a possibility of an impact to the jurisdictional loads used to compute allocation factors under the 2010 Protocol. To the extent there is a change in how the contracts are structured such that curtailments for these contracts are reflected as reductions to jurisdictional loads, the Company would need to update the allocation factors in the TAM and in this proceeding to ensure an appropriate matching of costs and benefits. Accordingly, the Company may update 2010 Protocol allocation factors during the pendency of this proceeding.

Tabs B1–B20

Q. Please describe the information contained behind Tabs B1–B20.

A. Tabs B1 through B20 contain the historical results for the Base Period and are organized by major FERC function. The data contained in this section of the Report match the unadjusted data found under Tab 2—Results of Operations.

Q. Does this conclude your direct testimony?

A. Yes.