PACIFIC POWER
A DIVISION OF PACIFICORP

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August 31, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attn: Filing Center

RE: Docket No. UE-210 – Reply Testimony and Exhibits

Enclosed for filing by PacifiCorp dba Pacific Power ("Company") are an original and five (5) copies of the Company reply testimony and exhibits. Provided on the enclosed CDs (3) are electronic versions of the testimony, exhibits and workpapers, in their original format when available.

It is respectfully requested that all data requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 300 Portland, OR 97232

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

Very truly yours,

Andrea L. Kelly /JS

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc. Service List in Docket No. UE-210

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 210, on the date indicated below by email and/or overnight delivery, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: August 31, 2009.

Ariel Son

Ariel Son
Coordinator, Administrative Services

Docket No. UE-210
Exhibit PPL/101
Witness: Richard P. Reiten

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Richard P. Reiten

August 2009

Q. Are you the same Richard Patrick " Pat" Reiten who previously provided testimony in this docket?

A. Yes, as Exhibit PPL/100.

Purpose

Q. What is the purpose of your reply testimony?

A. The purpose of my reply testimony is to:

- Present an overview of the Company' s revised rate increase request contained in this reply testimony;
- Describe how the core recommendations of the Staff of the Oregon Public Utility Commission (" Staff") are out of step with recent electric utility industry trends and national, regional and state-wide public policy objectives;
- Explain that the adjustments on labor expense sponsored by Staff, the Industrial Customers of the Northwest Utilities (" ICNU") and the Citizens' Utility Board (" CUB") unreasonably and incorrectly target costs which the Company has aggressively and carefully managed; and
- Introduce the Company' s other witnesses who are providing reply testimony at this time.

Revised Rate Increase

Q. What level of *base* rate increase is the Company proposing in its reply testimony?

A. The Company is proposing an overall base rate increase of $82.7 million, or 8.5 percent, exclusive of net power costs and new tariff riders. This is a $9.4 million reduction from the Company' s initial filing. The reply testimony and exhibits of

Company witness Mr. R. Bryce Dalley provide a detailed description of the elements that the Company incorporated into its reply revenue requirement that give rise to the reduced request.

Q. What level of *net* rate increase is the Company proposing in its reply testimony?

A. The Company is proposing a net rate increase of $87.1 million, or 8.6 percent. The difference of $4.4 million is attributable to the Company' s acceptance of Staff witness Mr. Dustin Ball' s proposal to establish three new tariff riders. These are discussed by Company witnesses Mr. Dalley and Mr. William G. Griffith.

Industry Trends and Policy Objectives

Q. You stated above that Staff' s core recommendations are out of step with recent electric utility industry trends and national, regional and state-wide public policy objectives. To which electric utility industry trends and public policy objectives are you specifically referring?

A. First, across the nation and throughout the western United States, there is a focus on identifying ways to encourage utilities to invest in transmission infrastructure. As I discuss below, PacifiCorp has been taking a leadership role in this arena in partnership with regional stakeholders. Second, the policies of the Oregon Commission have consistently emphasized the need for utilities to provide safe and reliable service to customers. The adoption of comprehensive service quality standards and customer guarantee programs are just two examples of how the Commission has implemented this policy objective. Third, over the past few years, the Federal Energy Regulatory Commission (" FERC") and the North American Electric Reliability Corporation (" NERC") have adopted and implemented an extensive set of enhanced reliability requirements for planning and operating the North American bulk power system. Finally, there is broad recognition that these public policy objectives cannot be achieved without financially healthy utilities that have reasonable access to capital markets. Because of the overarching importance of this final issue, I address it first in the discussion that follows.

Reasonable Access to Capital Markets

Q. Please provide some perspective on the challenges PacifiCorp faces with respect to maintaining its access to capital markets at reasonable terms.

A. As discussed in the reply testimony of Company witness Dr. Samuel C. Hadaway, the utility industry continues to face major challenges related to the financial markets. As PacifiCorp faces a significant and ongoing need to invest in its business, its access to capital markets at reasonable terms is critical. This access is in large part dependent on a fair and supportive regulatory climate.

Q. Is there recent evidence of the importance of a reasonable regulatory environment in maintaining the Company' s current credit ratings?

A. Yes. On August 12, 2009, Moody' s updated its methodologies for evaluating the credit of regulated electric utilities and unregulated utilities and power companies. The following are excerpts from Moody' s press release describing the methodological changes:

> " Among the rating agency's four broad rating factors for regulated electric and gas utilities, Moody's said regulatory framework will

carry a 25% factor weighting, ability to recover costs and earn returns will carry 25% weight, diversification will carry 10% weight and overall financial strength, liquidity and key financial metrics will account for the remaining 40%."

" For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors," Moody's said. " For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues."

Moody's went on to say the ability to recover costs in a timely manner is " perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions," adding that among other considerations, " it will look at statutory protections in place to ensure full and timely recovery of incurred costs."

Q. Has PacifiCorp recently received similar feedback directly from Standard & Poor' s?

A. Yes. Standard & Poor' s made the same point about regulatory support in their April 2009 credit rating report on PacifiCorp stating:

" Despite recent rate relief in nearly all states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile; its returns on equity (ROE) remain under authorized levels and while leverage has improved since it was acquired by MidAmerican Energy Holdings Co. (MEHC) in 2006, cash flow metrics continue to be weak." They explain further that " Supportive rate case outcomes continue to be key to maintaining and improving upon the company's financial performance."

Q. Do you believe that the recommendations of Commission Staff are evidence of a predictable and supportive regulatory framework?

A. No, quite the opposite is true.

Q. Please explain.

A. There are two categories of Staff recommendations that account for $61.5 million, or 75 percent of the proposed disallowances in the Staff's case, that are inconsistent with a supportive and predictable regulatory framework. First, Staff recommends a $42.6 million reduction to the Company's revenue requirement based on a recommended return on equity ("ROE") that is outside the bounds of reason. As discussed in detail in Dr. Hadaway's testimony, Staff's recommended 9.4 percent ROE is 50 basis points lower than the lowest integrated electric ROE authorized across the nation in the last five years. In addition, Staff's recommended 9.4 percent ROE is 60 basis points below the recommendation of the ROE witness for the consumer advocate groups in this proceeding, notwithstanding the fact that Staff's role in Commission-litigated proceedings is to make recommendations that balance the interest of customers and shareholders.

Second, as discussed below, Staff recommends an aggregate $18.9 million reduction to the Company's revenue requirement related to reductions to the Company's rate base. If the Commission were to adopt such a drastic change from past practices, it would signal to the Company and the investment community that recovery of investment in Oregon is unpredictable and unlikely to provide for a timely recovery of costs.

Q. Have the rating agencies previously addressed the importance of regulatory support in Oregon for the recovery of the Company's capital investments?

A. Yes. Moody's October 2008 PacifiCorp credit opinion stated:

> "The company received somewhat less favorable regulatory treatment in its last general rate case. In September 2006, PacifiCorp was authorized to

> increase revenues by $43 million, $33 million in base rates and $10 million for increased power costs, which was less than half of the approximately $112 million increase originally requested in February 2006. The stable outlook incorporates Moody's expectation that PacifiCorp will continue to receive reasonable regulatory treatment for the recovery of its higher capital expenditures, and that the funding requirements will be financed in a manner consistent with management's commitment to maintain a healthy financial profile. The ratings could be adjusted downward if PacifiCorp's planned capital expenditures are funded in a manner inconsistent with its current financial profile, or if there were to be adverse regulatory rulings on current and future distribution rate cases such that we would anticipate a sustained deterioration in financial metrics…"

Investment in Transmission Infrastructure

Q. In your role as President of Pacific Power are you also responsible for PacifiCorp's six-state transmission business?

A. Yes. PacifiCorp owns and operates one of the largest privately held transmission systems in the U.S., extending nearly 16,000 pole miles across ten states in the western U.S. PacifiCorp's transmission business operates independently with a goal to provide efficient, low cost and reliable transmission services to all users of the system. As the Commission is aware, significant additions to the Company's electric transmission system will be needed in the next 10 years. The Company has projects underway to address those needs, specifically the Energy Gateway projects that will add approximately 2000 miles of new transmission lines across the West with segments scheduled to come online beginning in late 2010. The Company is also active in regional transmission planning processes to ensure that its actions are compatible with the needs of the region as a whole.

Q. Has the Commission encouraged PacifiCorp's efforts to include transmission investment in its resource planning?

A. Yes. The Commission's Integrated Resource Plan ("IRP") Guidelines and recent IRP orders have directed utilities to consider new transmission investment to enhance reliability and increase market access. In Order No. 08-232 on the Company's 2007 IRP, the Commission acknowledged the action items around new transmission investment, noting enhancements in the Company's transmission analysis and planning. The Company has received similar, positive feedback regarding its efforts in the Northern Tier Transmission Group through periodic updates and informal discussions with key stakeholders.

Q. Do certain of Staff's recommendations in this proceeding seem out of step with your understanding of the public policy objectives related to investment in transmission infrastructure?

A. Yes. There are two types of adjustments proposed by Staff that, if adopted by this Commission, would undermine the Company's confidence to proceed with transmission infrastructure investment.

First, Staff makes a "judgment call" to disallow $24 million in investment in the Three Mile Knoll transmission-level substation based on an informal e-mail exchange between a member of Commission Staff and an employee at the Bonneville Power Administration ("BPA"). It is particularly troublesome that Staff would rely so heavily on this e-mail exchange given that (1) the BPA employee noted that the estimates were "ball park rough" numbers for recent substation projects, (2) the voltage levels for the BPA projects (500/230kv) are completely different than the voltage levels at the Three Mile Knoll substation (345/138kv). In addition, Staff gave no consideration to the specifics of the substation’ s physical and geographic location, functional and interconnection requirements, design and overall reliability contribution to the area and the interconnected transmission grid.

Second, Staff proposes to disallow approximately $23 million in investment related to two recently completed upgrades to the transmission system because it questions the connection between that system investment and Oregon customers. The recommendation is inconsistent with the provisions of the Revised Protocol allocation methodology that was adopted by this Commission in Order No. 05-021 in Docket UM 1050. It is also inconsistent with the Commission IRP guidelines (Guideline 10) which require multi-state utilities “ to plan their generation and transmission systems on an integrated system basis.” Order No. 08-232.

System-wide allocation of transmission investments among all six states recognizes that customers benefit from the diverse nature of the integrated system. Departure from the provisions of the Revised Protocol and the IRP Guidelines with respect to transmission investment would create a significant and unnecessary uncertainty for PacifiCorp and could impact future investment decisions.

Company witness Mr. Kenneth T. Houston addresses the specifics of Staff’ s adjustments in his reply testimony.

Safe and Reliable Service

Q. You noted earlier that this Commission places great emphasis on the provision of safe and reliable service at a reasonable price. Is this also a priority for PacifiCorp?

A. Yes. At Pacific Power, we know that our customers expect reliability, dependability and exceptional service. Delivering safe and reliable power at reasonable prices is a responsibility I take seriously. As described in Company witness Mr. Richard A. Vail's reply testimony, the Company undertakes a systematic and rigorous capital budgeting exercise each year to ensure that the Company's distribution system in Oregon is able to reliably deliver electricity in a manner that meets our customers' needs. In addition, the Company is proud of its ability to consistently meet its Customer Service Commitments, which consist of seven Customer Guarantees and six Performance Standards.

Q. Would certain of Staff's recommendations undermine PacifiCorp's ability to provide safe and reliable service consistent with the Company's Customer Service Commitments?

A. Yes. Staff proposes two types of adjustments that, if adopted by this Commission, would undermine the Company's ability to invest in the system to meet customers' expectations of reliability, dependability and exceptional service.

First, Staff proposes to disallow nearly $270 million of Company-wide system investment. This is composed of:

(1) a proposed $131 million disallowance that removes investment that is scheduled to be placed in service after February 2, 2010,

notwithstanding the fact that this date is the beginning of the rate effective period, not the end,

(2) a proposed $135 million disallowance that removes 50 percent of all investment scheduled to be placed in service between June 30, 2008 and January 31, 2010, if the in-service date occurs on a monthly basis or at various points during the period, and

(3) a proposed $1.5 million disallowance related to two items that Staff's review determined were inappropriate for inclusion in rate base in Oregon.

As discussed in the reply testimony of Mr. Dalley, Staff's proposals are without precedent, are based on a flawed interpretation of the Commission's policy related to investment in future test periods, and would lead to an overall Oregon net plant in service for calendar year 2010 at a level <u>less than</u> the June 2009 actual level. If the Commission were to adopt this new approach to ratemaking, the Company would not have a reasonable opportunity to recover its costs even if it immediately discontinued making capital investments in the system.

Second, Staff proposes to disallow approximately $1.3 million associated with write-offs primarily related to providing estimates for new supply as part of the Company's fulfillment of one of its Customer Guarantees. PacifiCorp's Customer Guarantee No. 4 requires that, "[a]n estimate for new supply will be supplied to the Applicant or Customer within 15 working days after the initial meeting and all necessary information is provided and any required payment is made." If PacifiCorp fails to meet this requirement, a qualifying customer's account is automatically credited $50. Adoption of this recommendation by the Commission would either deny the Company the ability to recover a reasonable cost of doing business or require the Company to change the way it approaches this aspect of its business to the detriment of customer service.

Enhanced Reliability Requirements

Q. What new federal standards related to reliability of the bulk power system have been adopted over the past few years?

A. As I mentioned earlier, over the past few years, the FERC, the NERC and the Western Electricity Coordinating Council (" WECC") have adopted and implemented an extensive set of enhanced reliability requirements for planning and operating the North American bulk power system. Since March 2007, the FERC has approved 88 reliability standards developed by the NERC. The FERC has also approved 8 regional reliability standards proposed by the WECC. These standards are comprised of thousands of individual requirements and sub-requirements with which the Company must comply or face sanctions for violations of up to $1 million per day. In January 2008, the FERC approved eight additional cyber security and critical infrastructure protection standards proposed by the NERC. The additional standards became mandatory and enforceable in April 2008. As of August 2009, 134 standards are currently under development, and 150 standards are planned by 2013.

To comply with the standards, the Company has developed and is required to maintain a robust compliance program to ensure that these federal requirements are met. As part of this compliance program, the Company has incurred both labor and non-labor costs. Labor costs include salary and benefits for 11 new full-time employees necessary to provide critical support to the compliance program including training the Company's employees on the Standards of Conduct, management of the new compliance software, testing and maintenance of the new surveillance equipment, and development and administration of an enhanced security program for over 40 substations, 10 generation facilities, and 4 control centers. Non-labor costs include NERC and Critical Infrastructure & Protection Systems (CIPS) compliance consultant fees, maintenance of the electronic security perimeter and video surveillance equipment, increased training and development costs, and audit fees required by FERC.

Q. Are you responsible for PacifiCorp's overall compliance with these reliability standards?

A. Yes. The compliance functions within PacifiCorp report directly to me.

Q. Does Commission Staff propose to include in PacifiCorp's rates adequate funding to implement these federal reliability standards?

A. No. Staff proposes a reduction to the Company's revenue requirement of $1.4 million based on a conclusion that the level of expense included in the base period is sufficient to allow the Company to recover the additional costs associated with the mandatory standards. As discussed by Mr. Dalley, the Company incurred approximately $3.4 million of compliance costs for calendar year 2008. Since I do not expect the level of activity in this area to decline in the future, the cost of compliance activities in this case is already, if anything, understated.

Labor Expense

Q. Please provide the background against which the Commission should review the parties' adjustments to the Company's labor expense.

A. As explained in the Company's direct filing, through aggressive cost management, the Company has managed to keep its total wage and benefit expense in this case for the 2010 test period within 1 percent of that included in its previous rate case, UE 179, which utilized a 2007 test period.

Q. Have the parties proposed adjustments to the Company's labor expense which would result in even lower wage and benefit expenses than those included in the UE 179 filing?

A. Yes. The joint ICNU and CUB witness has proposed adjustments in excess of $55 million challenging the Company's employee level and the allocation of labor costs to Oregon. These adjustments reduce the Company's wage and benefit expenses to levels well below those proposed in UE 179. Indeed, the adjustments proposed jointly by ICNU and CUB would result in labor expenses similar to those experienced twenty years ago. As explained by Mr. Dalley, these adjustments are based on incorrect interpretations of Company data requests and inaccurate assumptions around the Company's projected labor costs for 2010.

Q. Have the parties also proposed adjustments for incentive compensation?

A. Yes. Staff, and ICNU-CUB have proposed similar adjustments to disallow incentive compensation. The adjustments propose to apply "standard" Commission policy on recovery of incentive compensation, without consideration of all aspects of that policy and without review of whether application of that policy (as defined by the parties) makes sense in this case, given the aggressiveness of the Company's overall approach to controlling its labor costs. Company witness Mr. Erich D. Wilson provides the Company's response to this issue.

Introduction of Witnesses

Q. Please list the Company witnesses and provide a brief description of their testimony.

A. **Dr. Samuel C. Hadaway**, Principal, FINANCO, Inc. testifies concerning the Company's return on equity. He replies to the recommendations of Staff witness Mr. Steve Storm and the joint ICNU-CUB witness Mr. Michael Gorman. Dr. Hadaway also presents evidence to further support his recommended 11.0 percent ROE.

Bruce N. Williams, Vice President and Treasurer, updates the calculation of PacifiCorp's cost of debt and capital structure. He also responds to the recommendations of Staff witness Mr. Jorge Ordonez and the joint ICNU-CUB witness Mr. Gorman.

Gregory N. Duvall, Director, Long Range Planning and Net Power Costs, responds to the testimony of Staff witness Mr. Robert Clark with respect to forecasts of state-specific peak loads. He also responds to the testimony of Staff witness Ms. Kelcey Brown, ICNU witness Mr. Randall Falkenberg and Fred Meyer Stores witness Mr. Kevin Higgins related to the Transition Adjustment Mechanism ("TAM").

R. Bryce Dalley, Manager, Revenue Requirements, presents the Company's reply testimony revenue requirement based on the calendar year 2010 test period. He also responds to the adjustments of numerous Staff witnesses and the joint ICNU-CUB witness Ms. Ellen Blumenthal.

Richard A. Vail, Director, Asset Management, presents the reply testimony in response to the disallowances proposed by Staff witness Ms. Deborah Garcia related to distribution investment.

Kenneth T. Houston, Director, Transmission, presents the Company's reply testimony in response to Staff witness Mr. Ed Durrenberger's proposed disallowances of transmission investments.

Erich D. Wilson, Director, Human Resources, presents the reply testimony in response to Staff witness Ms. Lisa Gorsuch and the joint ICNU-CUB witness Ms. Blumenthall on the adjustment to employee incentives. He also responds to various other adjustments related to employee benefits.

Norm Ross, Director, Tax Department, presents the Company's reply testimony in response to Staff witness Mr. Dustin Ball related to property taxes.

Craig Paice, Regulatory Consultant, Cost of Service and Pricing, presents the Company's reply testimony cost of service study. He also responds to the testimony of Staff witness Dr. George Compton, ICNU witness Donald Schoenbeck, CUB witness Mr. Bob Jenks and Klamath Water Users Association ("KWUA") witness Mr. Gary Saleba on cost of service issues.

William R. Griffith, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's reply testimony on proposed rate spread and changes in price design for the affected rate schedules. He also responds to the testimony of Staff witness Dr. Compton, Fred Meyer Stores witness Mr. Higgins and KWUA witness Mr. Saleba on pricing issues.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/214
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Samuel C. Hadaway

August 2009

Q. Please state your name and business address.

A. My name is Samuel C. Hadaway. My business address is FINANCO, Inc., 3520 Executive Center Drive, Austin, Texas 78731.

Q. Are you the same Samuel C. Hadaway who previously filed direct testimony on behalf of PacifiCorp in this case?

A. Yes, I am.

Purpose and Summary of Testimony

Q. What is the purpose of your reply testimony?

A. The purpose of my reply testimony is to respond to the rate of return on equity (“ROE”) recommendations offered by Public Utility Commission of Oregon Staff (“Staff”) witness Mr. Steve Storm and the joint Industrial Customers of Northwest Utilities and Citizens’ Utility Board of Oregon (“ICNU-CUB”) witness Mr. Michael P. Gorman. In my analysis, I will respond to the parties’ rate of return recommendations and demonstrate that their recommendations are not consistent with current market conditions. I will also update my analysis for current market costs and conditions.

Q. What are the parties’ ROE recommendations?

A. Staff witness Storm recommends an ROE of 9.4 percent. ICNU-CUB witness Gorman recommends an ROE of 10.0 percent. I continue to support an ROE of 11.0 percent. My updated discounted cash flow (“DCF”) analysis indicates an ROE range of 11.2 percent to 11.6 percent, as compared to the DCF range in my April 2, 2009 direct testimony of 11.0 percent to 11.6 percent. My updated risk premium analysis indicates a range of 10.62 percent to 11.39 percent, as compared to my initial risk premium range of 10.73 percent to 11.03 percent. My updated results show that my initial ROE recommendation of 11.0 percent is reasonable and that the other parties' recommendations are well below PacifiCorp's cost of equity capital.

Q. Please summarize your general assessment of the other parties' ROE analysis and recommendations.

A. Mr. Storm's ROE recommendation is far below the reasonable range. I will show that his 9.4 percent ROE recommendation is <u>50 basis points (0.5 percent) lower than any ROE</u> that has been authorized for any integrated electric utility in the United States in the last five years. While I will also demonstrate various technical flaws in Mr. Storm's analysis; on its face, his ROE recommendation is unreasonably low.

From a technical perspective, Mr. Storm's analysis is also dominated by consistently low assumptions, incorrect model inputs, and unexplained adjustments within his model. I will demonstrate that, but for his incorrect technical inputs and adjustments, his model would have supported an ROE range of 10.2 percent to 10.3 percent. Furthermore, with a more reasonable assumption about the DCF growth rate, his analysis supports an ROE of over 11 percent.

I will show that Mr. Gorman's 10.0 percent ROE recommendation is about 50 basis points lower than the average allowed ROE for electric utilities during 2008 and during the second quarter of 2009. As such, given the market turmoil that has occurred during the past year, his recommendation is below the current cost of equity capital for PacifiCorp. I demonstrate that with more reasonable input assumptions, his analysis would have supported a significantly higher ROE.

Overview of Current Capital Markets

Q. Why do you say that the other parties' ROE recommendations are not consistent with current capital market conditions?

A. The other parties seem to hold a mistaken belief that utility capital costs have decreased, not increased, over the past several months. This contention is simply wrong. While governmental policies and "flight to safety" issues have driven down short-term interest rates for banks and rates on U.S. Treasury securities, the cost of equity for utilities has not declined over the past year.[1] I will show that PacifiCorp's required ROE has increased and that the other parties have not reasonably included current capital market conditions in their recommendations.

Q. In your direct testimony, you provided capital market data through February 2009, which demonstrated wider corporate interest rate spreads relative to treasury bond interest rates and increased corporate borrowing costs. What do the most recent data show?

A. The month-by-month interest rate data updated through July 2009 are presented in Exhibit PPL/215, page 1. Those data are summarized below in Table 1.

[1] The term "flight to safety" refers to the tendency for investors, during periods of market turbulence, to remove money from more risky investments, such as corporate bonds and stocks, and to put the money into government securities such as Treasury bills and bonds. The effect causes a reduction in the supply of funds to corporations and an increase in funds invested in government securities. The result is wider "spreads" between corporate bond and government bond interest rates and higher capital costs for corporations.

Table 1
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-07	5.96	4.85	1.11
Feb-07	5.90	4.82	1.08
Mar-07	5.85	4.72	1.13
Apr-07	5.97	4.87	1.10
May-07	5.99	4.90	1.09
Jun-07	6.30	5.20	1.10
Jul-07	6.25	5.11	1.14
Aug-07	6.24	4.93	1.31
Sep-07	6.18	4.79	1.39
Oct-07	6.11	4.77	1.34
Nov-07	5.97	4.52	1.45
Dec-07	6.16	4.53	1.63
Jan-08	6.02	4.33	1.69
Feb-08	6.21	4.52	1.69
Mar-08	6.21	4.39	1.82
Apr-08	6.29	4.44	1.85
May-08	6.28	4.60	1.68
Jun-08	6.38	4.69	1.69
Jul-08	6.40	4.57	1.83
Aug-08	6.37	4.50	1.87
Sep-08	6.49	4.27	2.22
Oct-08	7.56	4.17	3.39
Nov-08	7.60	4.00	3.60
Dec-08	6.52	2.87	3.65
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
Mar-09	6.42	3.64	2.78
Apr-09	6.48	3.76	2.72
May-09	6.49	4.23	2.26
Jun-09	6.20	4.52	1.68
Jul-09	5.97	4.41	1.56
3-Mo Avg	**6.22**	**4.39**	**1.83**
12-Mo Avg	**6.57**	**3.92**	**2.64**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).

Three month average is for May 2009 through July 2009.

The data in Table 1 vividly illustrate the market turmoil that has occurred. Although utility interest rates have come down from the extreme peaks reached in October and November 2008, they remain at or above the rates that existed in 2007 before the subprime lending crisis began. The Federal Reserve's efforts to reduce short-term borrowing cost for banks (the Fed Funds rate) and lower rates on U.S. Treasury bonds have not had the same effect for corporate borrowers. In fact, increased risk aversion and market illiquidity have resulted in continuing difficulties for many corporations. While the effects of market turbulence may not be easily captured in financial models for estimating the rate of return, the market's turbulence and continuing elevated risk aversion should be considered explicitly in estimates of the cost of equity capital.

Q. What do forecasts for the economy and interest rates show for the coming year?

A. Exhibit PPL/215, page 2, provides Standard & Poor's ("S&P's") most recent economic forecast from its *Trends & Projection*s publication for July 2009. S&P forecasts significant economic contraction through the first three quarters of 2009. For all of 2009, S&P forecasts that real GDP will decline by 3.0 percent. S&P expects real GDP growth to become positive during the 4th Quarter of 2009 and for GDP to increase in real terms (before inflation) during 2010 by 1.2 percent.

S&P also forecasts that long-term government and high grade corporate interest rates will rise significantly from recent levels. The summary interest rate data are presented in the following table:

Table 2
Standard & Poor's Interest Rate Forecast

	July 2009 Average	Average 2009 Est.	Average 2010 Est.
Treasury Bills	0.2%	0.2%	0.6%
10-Yr. T-Bonds	3.6%	3.5%	4.9%
30-Yr. T-Bonds	4.4%	4.3%	5.7%
Aaa Corporate Bonds	5.4%	5.7%	6.7%

Sources: www.federalreserve.gov, (Current Rates). Standard & Poor's *Trends & Projections*, July 2009, page 8 (Projected Rates).

Table 2 updates the data found in Table 3 in my direct testimony. The data in Table 2 show that long-term Treasury interest rates during 2010 are projected to increase over 100 basis points from current levels. The rate on Aaa corporate bonds is also expected to increase by about the same amount. Although in the recently turbulent market environment it has been difficult to project rates for lower rated securities, these market data offer important perspective for judging the cost of capital in the present case.

Q. What are the implications of higher corporate borrowing costs for PacifiCorp's cost of equity?

A. There are several important implications. First, since equity must compete with debt for investor dollars, and because equity is riskier than debt, an increase in corporate borrowing costs will also cause an increase in the cost of equity. In addition, since corporate bond yields are a direct input to the risk premium method of estimating the cost of equity, higher corporate yields should result in higher risk premium-based estimates of the cost of equity. The other parties' failure to account for these factors cause their ROE estimates to understate PacifiCorp's cost of equity.

Q. How do the other parties' ROE recommendations compare to the rates of return authorized by other state utility commissions around the country?

A. They are lower. Table 3 below shows the average rates of return for each quarter over the past five years. It updates Table 4 in my direct testimony to include the first two quarters of 2009.

Table 3
Authorized Electric Utility Equity Returns

	2005	2006	2007	2008	2009
1st Quarter	10.51%	10.38%	10.27%	10.45%	10.29%
2nd Quarter	10.05%	10.68%	10.27%	10.57%	10.52%
3rd Quarter	10.84%	10.06%	10.02%	10.47%	
4th Quarter	10.75%	10.39%	10.56%	10.33%	
Full Year Average	10.54%	10.36%	10.36%	10.46%	10.41%
Average Utility Debt Cost	5.67%	6.08%	6.11%	6.65%	6.77%
Indicated Average Risk Premium	4.87%	4.28%	4.25%	3.81%	3.64%

Source: *Regulatory Focus*, Regulatory Research Associates, Inc., Major Rate Case Decisions, July 2, 2009. Utility debt costs are the "average" public utility bond yields as reported by Moody's.

These data show that the other parties' ROE recommendations are 50 to 100 basis points lower than the average authorized rates of return. Since 2005, the equity risk premiums in Table 3 (the difference between allowed equity returns and contemporaneous utility interest rates) have ranged from 3.64 percent to 4.87 percent. At the low end of this risk premium range, based on average single-A utility bond yields for the three months ended in July, the indicated cost of equity is approximately 10.0 percent (6.22% single-A bond yield + 3.64% risk premium = 9.86%). At the upper end of this risk premium range, with an allowed equity risk premium of 4.87 percent, the indicated cost of equity is approximately 11.0

percent (6.22% current single-A bond yield + 4.87% risk premium = 11.09%).[2] These data provide useful perspective for judging the adequacy of the Staff and ICNU-CUB ROE recommendations. This simplified equity risk premium analysis shows that the others parties' recommendations fall well below PacifiCorp's cost of equity capital.

Reply to Staff witness Mr. Steve Storm

Q. How does Mr. Storm's 9.4 percent ROE recommendation compare to authorized ROEs for other integrated electric utility companies around the country?

A. Mr. Storm's 9.4 percent recommendation is far below the quarterly averages shown in Table 3 above. It is, in fact, 50 basis points (0.5 percent) lower than the lowest ROE that has been authorized for any integrated electric utility in the United States in the past five years. In Exhibit PPL/216, I have reproduced the case-by-case data as reported by Regulatory Research Associates ("RRA") for the last five years.[3] As shown in Table 3 above, the quarterly ROE averages of these data have generally ranged between 10 percent and 10.5 percent, with the most recent 2nd Quarter of 2009 at 10.52 percent. Shown on page 5 of Exhibit PPL/216, the lowest authorized ROE for any integrated electric utility in the last

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[2] The utility bond yields are the average rates for the three-months ended July 2009 as shown previously in Table 1.

[3] The RRA data include cases for both integrated electric utilities, like PacifiCorp, and "electric delivery" companies that provide only transmission and distribution ("T&D") services. T&D companies are in states that have deregulated generation and these companies have been required to divest themselves of any generation assets that they might have held. Assuming the regulatory authorities in these jurisdictions allow the automatic recovery of generation expenses, it can be argued that the T&D companies are not exposed to power supply risks or the risk of generation ownership. These companies may be considered by the rating agencies and others to have lower operating risks (but they might not have lower financial risks), and their authorized ROEs generally have been lower than those for integrated electrics. In Exhibit PPL/216, the footnotes at the right of each case indicate which ones are for T&D only companies.

five years was 9.9 percent for Entergy Arkansas on June 15, 2007. These data show that Mr. Storm's current 9.4 percent ROE recommendation for PacifiCorp is far below the reasonable range.

Q. Are you recommending that the Commission should use other regulators' authorized returns as an independent estimate of PacifiCorp's cost of equity?

A. No. I recognize the circularity argument that is often made about using other regulators' authorized returns. I agree that using such returns as a sole or independent estimate would not be appropriate. However, to ignore such data for purposes of comparison or to put a given recommendation into perspective would be equally inappropriate. These data show that Mr. Storm's ROE recommendation is far below any reasonable estimate of PacifiCorp's cost of equity capital.

Q. Has the Commission addressed the use of other regulators' authorized returns in its ROE deliberations?

A. Yes. In a prior PacifiCorp case, Docket UE 116, the Commission addressed this issue and came to the following conclusion:

> We adhere to our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award.
>
> Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions as the basis for an ROE award for a utility. (Order No. 01-787 at 32.)

Q. Can you point to other regulatory commissions that use the RRA data as a benchmark for evaluating ROE recommendations?

A. Yes. The Missouri Public Service Commission (“ MPSC”) routinely compares witnesses recommendations to the RRA averages. In a recent Kansas City Power & Light case (Case No. ER-2006-0314, December 21, 2006), that commission offered an approach that is similar to the “ gauge of reasonableness” standard noted above:

> Again, while the Commission will not “ unthinkingly mirror the national average” in this case, the Commission finds that it is simply common sense to use national average ROEs as a reference point because that gives the Commission insight about the capital market in which KCPL must compete for equity dollars. (MPSC Final Order at 27.)

Q. What is the technical basis for Mr. Storm’ s 9.4 percent ROE recommendation?

A. Mr. Storm discusses his analysis on pages 9 though 29 of his testimony. While he did not provide an exhibit with his testimony that shows how his 9.4 percent ROE was calculated, he did provide the supporting computer model in his workpapers. Also, a 9.4 percent “ Adjusted ROE” appears in his Table 5 on page 29 of his testimony. He says that his recommendation is based on a three-stage DCF model (Staff/800, Storm/12) and the row in Table 5 (Staff/800, Storm/29) that corresponds to 9.4 percent ROE indicates that the following model inputs were used:

1) a long-term inflation rate of 2.3 percent;

2) a long-term real GDP growth rate of 2.8 percent;

3) a 5 percent downward adjustment applied to GDP growth; and

4) an 8 basis point downward adjustment to ROE to account for a lower equity ratio in his comparable group.

His analysis, based on items 1-3 above, produces an ROE estimate of 9.62 percent, which he adjusts downward with item 4 to 9.44 percent, which he then rounds to 9.4 percent.

Q. Do you agree with Mr. Storm' s model inputs and the adjustments shown in items 1-4 above?

A. No. All four of Mr. Storm' s primary model inputs cause his ROE estimate to be low. His estimate of long-term inflation (item 1) is almost 1/3 lower than the actual long-term inflation rate in the United States.[4] His estimate of real GDP growth (item 2) is also lower than the actual long-term real GDP growth rate.[5] Mr. Storm uses a combination of these two inputs to establish a " pre-adjustment" long-run nominal GDP growth rate of 5.16 percent (Staff/800, Storm/21, footnote 60). That GDP growth rate is over 100 basis points lower than the long-run GDP growth rate I forecasted (Exhibit PPL/204). Such a low GDP growth rate foundation in the DCF model contributes to a correspondingly low estimate of ROE.

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[4]In Exhibit PPL/204, I demonstrated that the average inflation rate in the United States for the past 60 years as measured by the GDP Price Deflator and the Consumer Price Index has been 3.4 percent and 3.7 percent, respectively. For consistency with lower inflation in the more recent years of my forecast, I used a long-term inflation rate of 3.2 percent.

[5]From Exhibit PPL/204, the 60-year average growth rate for real GDP is approximately 3.4 percent per year.

Q. Do you agree with Mr. Storm' s further downward adjustment to his GDP growth rate (item 3) based on his belief that utilities are a below average growth industry?

A. No. I disagree with Mr. Storm' s interpretation of the industry lifecycle concept (Staff/800, Storm/23). While it is true that electric utilities are not " high growth" companies, neither should they be characterized as " below average" growth companies, relative to GDP growth. To demonstrate this point, I have prepared in Exhibit PPL/217 a compilation of analysts' forecasted growth rates for the companies that comprise the S&P 500 Stock Index. The S&P 500 is widely recognized as representing the overall stock market average for the United States. The data in Exhibit PPL/217 show that the average company in the S&P 500 is expected by professional security analysts to grow its earnings at 10.54 percent per year. Therefore, while it is true that electric utilities represent a mature industry and that their 5-year analyst expected growth rates are lower than the average company in the S&P 500, it is not true that utilities, in the long-run, should be expected to grow more slowly than nominal GDP. That assumption implies that utilities will become a smaller part of the economy in the future (and other industries will become a larger part) and there is no reason to conclude that. While energy efficiency may lower electric use per unit of GDP, the future use of electric vehicles may very well increase that use per unit of GDP. For these reasons, Mr. Storm' s further downward adjustment to his already-low GDP growth rate is inappropriate.

Q. Do you agree with Mr. Storm' s fourth downward adjustment of ROE to account for a lower equity ratio in his comparable group?

A. No. While large differences in capital structure may be recognized by investors and may cause higher return requirements, Mr. Storm' s proposed adjustment is misplaced as the capital structure difference he points to is relatively small. Even with what appears to be an extreme approach on his part for dealing with the debt percentages of his comparable companies,[6] his group' s projected average debt ratio is about 52.5 percent, whereas PacifiCorp' s proposed debt ratio is 48.7 percent. My comparable group has a lower debt ratio than Mr. Storm' s for 2010 at 50 percent. Also, as shown in Exhibit PPL/202, the average debt ratio for my comparable group at year-end 2008, was 49.9 percent. Since all these debt ratios fall close to the 50/50 debt and equity percentages generally prescribed for single-A rated electric utilities, it is unlikely that any perceived difference in required ROE for PacifiCorp would exist, and if it did exist, it would be immaterial. It appears that Mr. Storm' s capital structure adjustment is simply a further attempt to reach a lower ROE.

Q. Are there other adjustments in Mr. Storm' s analysis that also affect his results?

A. Yes. These adjustments are not discussed or shown in Mr. Storm' s testimony or exhibits, contrary to the Commission' s Guidelines for Cost of Equity Witnesses

[6]On page 26, in footnote 73, Mr. Storm explains that two of his risk-comparable companies would not have met his debt ratio selection criterion (45%-55% debt) if he had used the 2010 projected data in his selection process. In fact, in his workpapers, his spreadsheet shows (see Comparable Companies Tab, Column AS, Rows 7-18) that four of his companies would not have meet the criterion and that five other companies have projected debt ratios of 53.5 percent or higher.

adopted in Dockets UE 115 and UE 116. See Order No. 01-777 at Appendix A. However, a careful review of Mr. Storm's electronic spreadsheet in his workpapers demonstrates that Mr. Storm made a least two unexplained and entirely incorrect adjustments to the data that significantly reduced his reported ROE estimate:

1) His choice to average the individual comparable company data into a single "composite company" (Staff/800, Storm/13) reduced his reported results by 30 basis points (0.3%);

2) An artificially created dividend cut in the year 2015 reduced his ROE estimate by an additional 30 basis points.

Additionally, Mr. Storm's judgmental 5 percent downward adjustment to GDP growth rate reduced his ROE estimate by an additional 20 basis points. In combination, these technical factors in Mr. Storm's analysis reduced his base ROE estimate from about 10.4 percent to the 9.6 percent shown in his spreadsheet model.

Q. Please describe Mr. Storm's 3-stage DCF model.

A. His 3-stage DCF model is structurally similar to the "multi-stage" DCF model I used. We both calculate the investor's expected rate of return from purchasing stock at today's prices and receiving a growing stream of dividends far into the future. In both of our models we used Value Line's projected data for Stage 1 (years 1-5).[7] For Stage 2, we both applied a long-term GDP growth rate. Stage 2 in Mr. Storm's model goes through year 40, at which time he calculates a DCF "terminal" stock price (Mr. Storm's third stage) which assumes that a future

[7]Mr. Storm extends his first stage for six years, which could have decreased his ROE estimate if his Stage 1 and Stage 2 growth rates had been significantly different. In this case, this feature does not appear to have made a significant difference in the Company's results.

owner would receive the dividend stream after year 40. In my model, Stage 2 continues for 150 years. As Mr. Storm states (Staff/800, Storm/14), our models should produce approximately the same ROE estimates if the same inputs and assumptions are used.

Q. Please explain why Mr. Storm’s averaging the data into a “composite company” reduced the ROE estimate.

A. Mr. Storm’s “composite company” approach is statistically incorrect because it inadvertently creates a weighting scheme that is not consistent with finding the expected value for the comparable company sample group. In Exhibit PPL/218, I have reproduced Mr. Storm’s 9.62 percent “composite company” result (Base Case), and I have also calculated the mean and median ROE estimate for his group from the individual company estimates (Case 1). The mean and median ROE values are 9.9 percent and 10.0 percent, respectively.

The 30 to 40 basis point difference between Mr. Storm’s “composite company” approach and the mean and median from the individual company estimates is caused by his incorrect weighting of the data. In his analysis, he created the “composite company,” to which he applied his model, by averaging companies’ stock prices, dividends, earnings, and other financial data. In effect, this process gave much more weight to companies with higher stock prices and much less weight to companies with lower stock prices. For example, on page 2 of Exhibit PPL/218, this effect can be seen by comparing the impact of averaging Entergy’s data in line 4 with the data for Empire District in line 3. Because Entergy’s price is almost five times greater than Empire’s and its dividends are more than twice as large, an average of these two companies obviously gives more weight to Entergy. Also, it can easily be shown that, under Mr. Storm’s approach, a simple 2-for-1 or 3-for-1 stock split for one of the companies would change his results, even though a stock split would have no impact on the group’s expected rate of return on equity. Although Mr. Storm may not have recognized it when he performed his analysis, his “composite company” approach seriously skewed the data and in this case resulted in a 30 basis point understatement of PacifiCorp’s ROE.

Q. Please explain the effect of Mr. Storm’s dividend cut for his “composite company” in 2015?

A. In Stage 1 of Mr. Storm’s model, dividends are based on Value Line’s projections for the years 2009-2014. For his “composite company” during that time, dividends increase from $1.83 per share to $2.23 per share, or at a growth rate of about 4 percent per year. Although Mr. Storm says that his growth becomes 4.91 percent in Stage 2 of his model, in fact, in 2015 the dividend drops by 3.6 percent. After that, the 4.91 percent adjusted GDP growth rate again drives the model. The effect of his unexplained dividend cut is a lower dividend stream over the remaining years of his model. As shown in Exhibit PPL/218 (Case 2), when this dividend cut is eliminated and Mr. Storm’s 4.91 percent growth rate is used in each year in Stage 2 of his model, the result is a 30 basis point increase in his estimated ROE.

Q. Is the dividend cut in Mr. Storm’s model appropriate?

A. No. While the multi-stage version of the DCF model is designed to accommodate changing growth rates, it does not contemplate a dividend cut. In fact, based on Mr. Storm's company selection criteria, his "composite company," with a dividend cut in 2015, would not be eligible for inclusion. (Staff/800, Storm/10, line 5.)

Q. What is the effect of removing Mr. Storm's 5 percent reduction to the GDP growth rate?

A. That result is shown in Exhibit PPL/218 (Case 3). The resulting mean and median ROE estimates are 10.4 percent and 10.5 percent, respectively.

Q. What is the result from Mr. Storm's model if your 6.2 percent forecast for GDP growth is used in the model for Stages 2 and 3?

A. As shown in Exhibit PPL/218 (Case 4), with a 6.2 percent long-term growth rate, Mr. Storm's model produces a mean and median ROE estimate of 11.1 percent.

Q. What do you conclude from your review of Mr. Storm's ROE analysis and testimony?

A. The multi-stage DCF model, if correctly applied, appropriately reflects the real increases public utilities are currently experiencing in their cost of capital. Apparently to avoid these results, Mr. Storm made a series of ad hoc adjustments, some apparent and some buried in workpapers, to produce an artificially low ROE. I have demonstrated why each of these ad hoc adjustments is incorrect or inappropriate. Without these adjustments (but still using Mr. Storm's proposed GDP growth rate), Mr. Storm's ROE recommendation would be between a range of 10.2 percent to 10.3 percent. In addition, Mr. Storm relied exclusively on his DCF analysis without presenting any corroborating analysis. In evaluating the reasonableness of Mr. Storm's conclusions I would suggest the Commission consider its own "gauge of reasonableness" standard noted above in drawing conclusions regarding the merits of Mr. Storm's ROE recommendation. Indeed, in UE 116, the Commission corrected Staff's DCF model to produce a 10.5 percent result, used this adjusted result with my DCF result of 11 percent to set a reasonable ROE range and selected the 10.75 percent mid-point as the final ROE.

Reply to ICNU-CUB witness Michael Gorman

Q. Please summarize Mr. Gorman's ROE recommendation.

A. Mr. Gorman's recommendation is summarized in the following table (Table 4 from Gorman Direct Testimony, ICNU-CUB/300, Gorman/39):

TABLE 4

Return on Common Equity Summary

Description	Results
DCF	10.80%
Risk Premium	10.00%
CAPM	8.60%

From this data, Mr. Gorman recommends an ROE range of 9.60 percent to 10.40 percent with a midpoint point estimate of 10.00 percent. The upper end of his range is the midpoint of the DCF and (equity) Risk premium range and the lower end is the approximate midpoint of the DCF and CAPM range.

Q. Does Mr. Gorman provide a more detailed analysis than is shown in the above table?

A. Yes. What cannot be seen in Mr. Gorman's Table 4 are the individual model results that Mr. Gorman averages for his summary. A closer examination of all of his results shows that his averaging may have diluted the higher results and given disproportionate weight to lower results. All of Mr. Gorman’ s model results are shown in Table 4 below:

Table 4
Gorman All-Inclusive ROE Summary

Description	Results	
Constant Growth DCF (Analysts Growth)	11.68%	
Constant Growth DCF (Sustainable Growth)	10.62%	
Multi-Stage Growth DCF Model	10.96%	
Risk Premium (Treasury Bond)	9.84%	
Risk Premium (Single-A Bond)	10.17%	
CAPM (Current Market Risk Premium)	~~8.73%~~	Not reasonable
CAPM (Historical Risk Premium)	~~8.41%~~	Not reasonable
Average Excluding Outliers & Extreme Data	10.65%	

As shown in Table 4, four of Mr. Gorman’ s seven models produce ROEs above 10.17 percent. His CAPM analyses produce a range of only 8.41 percent to 8.73 percent. These results should be removed because there are only 195 and 227 basis points above the 6.46 percent current cost of triple-B debt that Mr. Gorman uses in his equity risk premium analysis. When the remaining data are averaged the indicated ROE is 10.65 percent. Thus, by simply removing two unreasonably low estimates and considering all of Mr. Gorman’ s other models, the indicated ROE is significantly higher.

Q. Does Mr. Gorman agree that his CAPM results are not credible at this time?

A. Yes, on pages 38-39 of his testimony Mr. Gorman states:

> I believe my CAPM study is also impacted by the distressed financial market. The impact on the financial market has resulted in a decline in the market risk premium that was largely caused by a significant decline in stock market valuations and increase in Treasury bond valuations at the end of 2008. The market risk premium has been around 6.5% over the last several years, but declined to 5.6% at year-end 2008. I do not believe this reduced market risk premium is sustainable. Therefore, I recommend minimal or no weight be placed on the CAPM return estimate at this time. (emphasis added)

Q. Is there any potential confusion between Mr. Gorman's dismissal of his CAPM analysis and his table presentation of his results?

A. Yes. Mr. Gorman clearly states above that "minimal or no weight be placed on the CAPM return estimate at this time." However, in his ROE summary table on page 39, he clearly included his CAPM result in developing the final DCF average result. If the CAPM result were removed from his results table, the average of the remaining DCF result (10.80%) and equity Risk Premium result (10.00%) would be 10.40 percent.

Q. Is Mr. Gorman's decision to exclude his CAPM results consistent with the Oregon Commission's traditionally skeptical view of the CAPM model?

A. Yes. In Order No. 01-787 in Docket UE 116, the Commission gave Staff's CAPM results "no weight" because the results in that case "cast doubt on the validity" of the CAPM methodology. While the Commission did not reject the use of the CAPM model in its entirety, it made clear it would not rely upon the model unless it produced "supportable and reasonable" results. In this case, the CAPM model does not produce supportable and reasonable results, as Mr. Gorman acknowledges.

Q. What other general areas of disagreement do you have with Mr. Gorman' s analysis and recommendations?

A. Mr. Gorman' s analysis is negatively biased by his input assumptions and his application of the models. While he applies a non-constant growth DCF model similar to one I use and includes GDP growth as an input, he uses relatively short-term GDP growth rate forecasts that are significantly dominated by recent historically low inflation. His GDP growth forecast is based on inflation estimates that are almost a full percentage point below longer-term historical averages. This is inconsistent with the long-term growth assumption that is fundamental to the DCF model.

In his equity risk premium analysis, he selects risk premiums that are not consistent with recent risk premium data. He selectively applies those equity risk premiums in a way that creates a mismatch of older risk premium data with current interest rates. Furthermore, he fails to include the well-documented inverse relationship between equity risk premiums and interest rates; i.e., the tendency for risk premiums to widen when interest rates are low and narrow when interest rates are high. Without this feature, his equity risk premium theory is not consistent with sound academic research, such as studies by Harris and Marston. This omission causes his equity risk premium estimates to be significantly understated.

His CAPM analysis produces an average ROE estimate of 8.60 percent, which is by far the lowest number in his range. He should have discarded these results as he himself recommends. Without CAPM, a more reasonable interpretation of Mr. Gorman' s analysis indicates that he should have found an ROE in the 10.0 percent to 11.7 percent range.

Q. What specific disagreements do you have with Mr. Gorman' s three-stage DCF analyses?

A. In his three-stage (or multi-stage) model, he uses analysts' growth forecasts in the first five years and a GDP forecast for years eleven and later; in years six through ten, he interpolates growth in a linear fashion between the first and third stages. However, in all these models, his estimate of future GDP growth is too low. His forecasts are for five- and ten-year periods, as published by *Blue Chip Financial Forecasts* (ICNU-CUB/300, Gorman/27). The current Blue Chip consensus is low because it is based on assumed inflation rates of only about 2.0 percent, which is much lower than the long-term U.S. average inflation rate of over 3.0 percent. The currently depressed nature of economic forecasts detracts from Mr. Gorman' s use of these forecasts to estimate long-term growth.

Q. If Mr. Gorman had used your GDP growth forecast of 6.2 percent in his multi-stage growth DCF analyses, what would his results have been?

A. On page 2 of Exhibit PPL/219, I substitute my 6.2 percent long-term GDP growth rate into Mr. Gorman' s multi-stage DCF analysis. That revised analysis indicates an ROE of 11.74 percent.

Q. Please comment on Mr. Gorman' s equity risk premium ROE analysis.

A. His equity risk premium analysis is based on subjective and inappropriate selections from the data he presents, and it fails to include the well documented tendency for equity risk premiums to expand when interest rates are low. When his selectivity is removed and the analysis is modified to properly reflect wider equity risk premiums with lower interest rates, Mr. Gorman' s risk premium analysis indicates a much higher ROE.

Q. Please elaborate.

A. His equity risk premium data are presented in Exhibits ICNU-CUB/314 and 315. He discusses the analysis on pages 29-33 of his testimony. The analysis consists of two parts. In one approach he adds Government bond equity risk premiums of 4.40 percent and 6.08 percent to a projected 30-year Treasury bond yield of 4.60 percent. This produces an ROE range of 9.00 percent to 10.68 percent, with a midpoint of 9.84 percent. In his second approach, he adds equity risk premiums of 3.03 percent and 4.39 percent to the recent triple-B utility bond yield of 6.46 percent. This produces ROE estimates of 9.49 percent to 10.68 percent, with a midpoint of 10.17 percent. From these results, he concludes that an ROE of 10.00 percent is appropriate (midpoint of 9.84 percent and 10.17 percent).

Q. Why do you disagree with Mr. Gorman' s Government bond equity risk premium approach?

A. In this approach, he adds an equity risk premium of 5.24 percent to a Government bond yield of 4.60 percent to reach a result of 9.84 percent. An examination of the data in Mr. Gorman' s Exhibit ICNU-CUB/314 reveals the flaw in this analysis. In essence, Mr. Gorman is mismatching historical data with current rates in a way that is not reasonable.

Q. Please explain.

A. The last column in Exhibit ICNU-CUB/314 indicates that since 1986 the average

" Indicated Risk Premium" has been 5.17 percent. This is very close to the 5.24 percent risk premium that Mr. Gorman uses. However, the average Treasury Bond Yield over this period has been 6.37 percent, much higher than the current rate of 4.60 percent he uses. In fact, there are only two periods with rates as low as 4.60 percent in all of Mr. Gorman's data and they represent just one year (2008) and the first quarter of 2009. It is not reasonable for Mr. Gorman to apply a historical risk premium to currently low interest rate data without some adjustment to account for the relationship between interest rate levels and equity risk premiums. In Exhibit PPL/219, described below, I make the proper adjustment to Mr. Gorman's data to account for this relationship and show that his Treasury bond risk premium result should have been much higher.

Q. Does Mr. Gorman's utility bond risk premium analysis suffer from the same flaw?

A. Yes. His analysis in Exhibit ICNU-CUB/315 also illustrates the mismatch between historical risk premiums and current interest rates that plagues his Treasury bond risk premium analysis. A review of the data in Exhibit ICNU-CUB/315 shows that since 1986 the average equity risk premium has been 3.69 percent which is similar to the midpoint premium that Mr. Gorman uses of 3.71 percent. However, the average utility bond yield over this period has been 7.85 percent, which is significantly higher than the rate of 6.46 percent used by Mr. Gorman in this case. Again, Mr. Gorman has mismatched historical equity risk premiums with current low interest rates.

Q. In your equity risk premium analysis from your direct testimony, you used a standard regression analysis to account for the inverse relationship between equity risk premiums and interest rates. What do Mr. Gorman's risk premium data indicate when this approach is used?

A. In Exhibit PPL/219, pages 3-6, I have applied the standard regression analysis to calculate "interest rate adjustment" factors for his two risk premium studies. This approach properly takes into account the inverse relationship between equity risk premiums and interest rates. With this, Mr. Gorman's Treasury bond risk premium analysis indicates an ROE of 10.54 percent, as shown in pages 3-4 of Exhibit PPL/219. For his utility bond risk premium analysis, the indicated ROE is 10.66 percent (pages 5-6 of the same Exhibit). These results confirm that Mr. Gorman's equity risk premium data support a base ROE midpoint result of 10.60 percent (average of 10.54% and 10.66%).

Q. Has Mr. Gorman previously recognized the inverse risk premium-interest rate relationship?

A. Yes. In his testimony before the Texas Public Utility Commission in Docket No. 14965, page 15, lines 10-13, Mr. Gorman stated:

> The results of my study indicate an inverse relationship between a bond's real return and the equity risk premium. This result is consistent with the findings of published studies which indicate equity risk premiums move inversely with interest rates.

Had Mr. Gorman made a similar adjustment in this case, his equity risk premium results would have indicated a considerably higher ROE than he recommends.

Update of ROE Analysis

Q. Have you updated your ROE analysis to take into account recent data and the current conditions in the capital markets?

A. Yes. Consistent with my customary practice, I have updated my ROE analysis for current conditions using the same methodologies that I employed in my previous analysis.

Q. What are the results of your updated DCF analyses?

A. My updated DCF results are shown in Exhibit PPL/220. The indicated DCF range is 11.2 percent to 11.6 percent, with a midpoint of 11.4 percent.

Q. What are the results of your updated bond yield plus equity risk premium analysis?

A. My updated equity risk premium analysis is presented in Exhibit PPL/221. Based on projected single-A utility interest rates for 2010, the equity risk premium analysis indicates an ROE of 11.40 percent. Based on the most recent three month's average single-A utility interest rates, the equity risk premium ROE is 10.62 percent.

Q. What do you conclude from your updated ROE analyses?

A. My updated analyses show that PacifiCorp's current cost of equity capital is in the range of 10.6 percent to 11.4 percent, with a midpoint estimate of 11.0 percent. My updated analysis confirms that my original recommendation of 11.0 percent is reasonable and that the other parties' recommendations, as discussed herein, are too low.

Q. Does that conclude your testimony?

A. Yes, it does.

Docket No. UE-210
Exhibit PPL/215
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Long Term Interest Rate Trends
Standard & Poor' s Trends & Projections

August 2009

PacifiCorp Oregon
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-07	5.96	4.85	1.11
Feb-07	5.90	4.82	1.08
Mar-07	5.85	4.72	1.13
Apr-07	5.97	4.87	1.10
May-07	5.99	4.90	1.09
Jun-07	6.30	5.20	1.10
Jul-07	6.25	5.11	1.14
Aug-07	6.24	4.93	1.31
Sep-07	6.18	4.79	1.39
Oct-07	6.11	4.77	1.34
Nov-07	5.97	4.52	1.45
Dec-07	6.16	4.53	1.63
Jan-08	6.02	4.33	1.69
Feb-08	6.21	4.52	1.69
Mar-08	6.21	4.39	1.82
Apr-08	6.29	4.44	1.85
May-08	6.28	4.60	1.68
Jun-08	6.38	4.69	1.69
Jul-08	6.40	4.57	1.83
Aug-08	6.37	4.50	1.87
Sep-08	6.49	4.27	2.22
Oct-08	7.56	4.17	3.39
Nov-08	7.60	4.00	3.60
Dec-08	6.52	2.87	3.65
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
Mar-09	6.42	3.64	2.78
Apr-09	6.48	3.76	2.72
May-09	6.49	4.23	2.26
Jun-09	6.20	4.52	1.68
Jul-09	5.97	4.41	1.56
3-Mo Avg	**6.22**	**4.39**	**1.83**
12-Mo Avg	**6.57**	**3.92**	**2.64**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

			----- Annual % Change -----				2008	------ 2009 ------				------ E2010 ------		
2008	E2009	E2010	2008	E2009	E2010		4Q	R1Q	E2Q	E3Q	E4Q	1Q	2Q	3Q
						Gross Domestic Product								
$14,264.6	$14,066.0	$14,397.8	3.3	(1.4)	2.4	GDP (current dollars)	$14,200.3	$14,097.2	$14,026.6	$14,044.1	$14,096.0	$14,185.4	$14,321.9	$14,459.9
3.3	(1.4)	2.4	-	-	-	Annual rate of increase (%)	(5.8)	(2.9)	(2.0)	0.5	1.5	2.6	3.9	3.9
1.1	(3.0)	1.2	-	-	-	Annual rate of increase–real GDP (%)	(6.3)	(5.5)	(2.2)	(1.0)	0.7	1.3	2.5	2.2
2.2	1.6	1.2	-	-	-	Annual rate of increase–GDP deflator (%	0.5	2.8	0.0	1.5	0.8	1.2	1.4	1.6
						***Components of Real GDP**								
$8,272.1	$8,201.0	$8,292.6	0.2	(0.9)	1.1	Personal consumption expenditures	$8,170.5	$8,198.0	$8,193.3	$8,197.8	$8,215.0	$8,234.0	$8,263.6	$8,313.6
0.2	(0.9)	1.1	-	-	-	% change	(4.3)	1.4	(0.2)	0.2	0.8	0.9	1.4	2.4
1,188.5	1,129.3	1,146.0	(4.3)	(5.0)	1.5	Durable goods	1,108.6	1,134.1	1,127.5	1,131.2	1,124.4	1,121.9	1,125.3	1,154.5
2,378.4	2,315.4	2,359.7	(0.6)	(2.6)	1.9	Nondurable goods	2,318.6	2,316.4	2,303.6	2,313.7	2,327.9	2,339.6	2,352.6	2,367.6
4,714.3	4,747.2	4,780.5	1.5	0.7	0.7	Services	4,729.4	4,740.5	4,752.2	4,744.6	4,751.5	4,759.8	4,773.0	4,787.2
1,405.4	1,141.2	1,124.7	1.6	(18.8)	(1.4)	Nonresidental fixed investment	1,341.1	1,193.4	1,154.8	1,116.2	1,100.5	1,112.9	1,109.1	1,121.0
1.6	(18.8)	(1.4)	-	-	-	% change	(21.7)	(37.3)	(12.3)	(12.7)	(5.5)	4.6	(1.3)	4.4
1,047.0	847.0	891.6	(3.0)	(19.1)	5.3	Producers durable equipment	970.5	875.7	847.6	829.8	834.9	856.6	875.4	900.0
351.3	267.5	274.2	(21.0)	(23.8)	2.5	Residental fixed investment	323.9	285.8	267.0	259.4	257.9	257.1	265.2	278.2
(21.0)	(23.8)	2.5	-	-	-	% change	(22.9)	(39.4)	(23.8)	(10.9)	(2.3)	(1.2)	13.2	21.0
(29.1)	(81.5)	5.3	-	-	-	Net change in business inventories	(25.8)	(87.1)	(135.7)	(74.9)	(28.2)	(5.5)	11.0	5.5
2,070.2	2,092.0	2,101.9	2.9	1.1	0.5	Gov't purchases of goods & services	2,094.7	2,078.4	2,089.0	2,098.1	2,102.3	2,105.8	2,111.7	2,098.0
798.2	834.5	845.0	6.0	4.5	1.3	Federal	824.5	815.2	831.8	843.0	847.9	850.6	854.7	842.4
1,273.0	1,260.0	1,259.8	1.1	(1.0)	(0.0)	State & local	1,272.3	1,265.1	1,259.7	1,257.9	1,257.5	1,258.2	1,260.2	1,258.5
(390.2)	(310.9)	(358.1)	-	-	-	Net exports	(364.5)	(296.8)	(263.1)	(324.8)	(358.7)	(376.3)	(361.9)	(349.8)
1,514.1	1,298.1	1,360.0	6.2	(14.3)	4.8	Exports	1,454.9	1,327.7	1,286.6	1,283.3	1,294.7	1,313.9	1,344.2	1,374.7
1,904.3	1,609.0	1,718.1	(3.5)	(15.5)	6.8	Imports	1,819.4	1,624.6	1,549.7	1,608.1	1,653.4	1,690.2	1,706.1	1,724.5
						****Income & Profits**								
$12,100.7	$12,105.3	$12,339.9	3.8	0.0	1.9	Personal income	$12,119.5	$12,048.8	$12,193.9	$12,072.2	$12,106.2	$12,183.3	$12,281.2	$12,389.7
10,643.3	10,913.2	11,059.0	4.6	2.5	1.3	Disposable personal income	10,642.0	10,773.7	11,014.4	10,912.3	10,952.4	10,921.4	11,010.5	11,111.3
1.8	5.0	3.7	-	-	-	Savings rate (%)	3.2	4.3	6.2	4.8	4.7	3.9	3.9	3.7
1,597.3	1,400.9	1,576.8	(15.3)	(12.3)	12.6	Corporate profits before taxes	1,194.5	1,351.7	1,343.3	1,450.5	1,458.0	1,516.8	1,552.5	1,584.4
1,230.6	1,088.2	1,214.9	(14.3)	(11.6)	11.7	Corporate profits after taxes	931.2	1,054.2	1,046.0	1,122.9	1,129.5	1,171.2	1,196.0	1,219.8
14.88	30.00	37.26	(77.5)	101.6	24.2	‡Earnings per share (S&P 500)	14.88	6.88	1.29	(0.99)	30.00	32.14	34.20	35.85
						†Prices & Interest Rates								
3.8	(0.5)	2.0	-	-	-	Consumer price index	(8.3)	(2.4)	1.2	2.8	1.8	1.7	2.2	2.5
1.4	0.2	0.6	-	-	-	Treasury bills	0.3	0.2	0.2	0.2	0.3	0.4	0.4	0.6
3.7	3.5	4.9	-	-	-	10-yr notes	3.3	2.7	3.3	3.8	4.2	4.6	4.9	5.0
4.3	4.3	5.7	-	-	-	30-yr bonds	3.7	3.5	4.2	4.6	5.1	5.4	5.7	5.8
5.6	5.7	6.7	-	-	-	New issue rate–corporate bonds	5.8	5.3	5.5	5.7	6.1	6.4	6.7	6.8
						Other Key Indicators								
900.3	533.8	782.1	(32.9)	(40.7)	46.5	Housing starts (1,000 units SAAR)	658.0	527.7	500.8	543.0	563.7	630.9	723.4	839.3
13.1	9.9	11.2	(18.4)	(24.9)	13.9	Auto & truck sales (1,000,000 units)	10.3	9.5	9.8	10.0	10.1	10.3	10.7	11.6
5.8	9.4	10.4	-	-	-	Unemployment rate (%)	6.9	8.1	9.3	9.9	10.2	10.4	10.4	10.5
(4.4)	5.9	(7.1)	-	-	-	§U.S. dollar	49.5	6.9	(14.0)	(12.7)	(5.0)	(5.7)	(5.4)	(5.4)

Note: Annual changes are from prior year and quarterly changes are from prior quarter. Figures may not add to totals because of rounding. A–Advance data. P–Preliminary. E–Estimated. R–Revised.
*2000 Chain-weighted dollars. **Current dollars. ‡Trailing 4 quarters. †Average for period. §Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.

Exhibit PPL/215
Hadaway/2

Samuel C. Hadaway
Exhibit PPL/216

Docket No. UE-210
Exhibit PPL/216
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Regulatory Research Associates – Electric Utility Decisions

August 2009

ELECTRIC UTILITY DECISIONS *(Footnotes on page 9)*

Date	Company (State)	ROR %		ROE %		Common Eq. as % Cap. Str.		Test Year & Rate Base	Amt. $ Mil.	
1/13/04	Madison Gas and Electric (WI)	9.37	(G)	12.00		55.91		12/04-A	11.7	
2/26/04	Pacific Gas and Electric (CA)	---		---		---		---	-799.0	(B)
3/2/04	PacifiCorp (WY)	8.42		10.75		44.95		9/02-YE	22.9	
3/26/04	Nevada Power (NV)	9.03		10.25		33.97		5/03-YE	48.0	
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.94**		**11.00**		**44.94**			**-716.4**	
	OBSERVATIONS	**3**		**3**		**3**			**4**	
4/5/04	Interstate Power and Light (MN)	9.05		11.25	(R)	47.15		12/02-A	0.6	(I,R)
4/13/04	Aquila-MPS (MO)	---		---		---		---	14.5	(B)
4/13/04	Aquila-L&P (MO)	---		---		---		---	3.3	(B)
5/5/04	Wisconsin Electric Power (WI)	---		---		---		12/04-A	59.0	
5/18/04	PSI Energy (IN)	7.30		10.50		44.44	*	9/02-YE	107.3	
5/20/04	Rochester Gas & Electric (NY)	---		---		---		4/05-A	7.4	(B,1)
5/25/04	Idaho Power (ID)	7.85		10.25		45.97		12/03-A	39.5	(R,B,Z)
5/27/04	Sierra Pacific Power (NV)	9.26		10.25		35.77		7/03-YE	46.7	(B)
6/2/04	Pacific Gas & Electric (CA)	---		---		---		12/03-A	274.0	(B)
6/30/04	Kentucky Utilities (KY)	7.00	(G)	10.50		51.58		9/03-YE	46.1	(B,2)
6/30/04	Louisville Gas and Electric (KY)	6.79	(G)	10.50		48.60		9/03-YE	43.4	(B,3)
2004	***2ND QUARTER AVERAGES/TOTAL***	**7.88**		**10.54**		**45.59**			**641.8**	
	OBSERVATIONS	**6**		**6**		**6**			**11**	
7/16/04	Southern California Edison (CA)	---		---		---		12/03-A	73.0	
8/25/04	Aquila (CO)	8.76		10.25		47.50		8/03-A	8.2	(B)
9/2/04	Public Service New Hampshire (NH)	---		---		---		---	13.5	(B,Z,TD)
9/9/04	Avista Corp. (ID)	9.25		10.40		42.59		12/02-A	24.7	
2004	***3RD QUARTER AVERAGES/TOTAL***	**9.01**		**10.33**		**45.05**			**119.4**	
	OBSERVATIONS	**2**		**2**		**2**			**4**	
10/27/04	PacifiCorp (WA)	8.39		---		---		---	15.0	(B)
11/9/04	Narragansett Electric (RI)	8.89	(E)	10.50		50.00		---	-10.2	(B,Di)
11/23/04	Cincinnati Gas & Electric (OH)	---		---		---		---	85.0	(R,Z)
11/23/04	Detroit Edison (MI)	7.24		11.00		38.08	*	12/02-A	373.7	(I)
12/8/04	San Diego Gas & Electric (CA)	---		---		---		12/04-A	-8.2	(B,Di)
12/14/04	Interstate Power & Light (IA)	8.83		10.97		47.89		12/03-A	106.7	(I,B)
12/21/04	Georgia Power (GA)	---		11.25		---		12/05-A	194.1	(B)
12/21/04	Wisconsin Public Service (WI)	8.89	(G)	11.50		57.35		12/05-A	61.0	
12/22/04	PPL-Electric Utilities (PA)	8.43		10.70		46.87		12/04-YE	194.3	(TD)
12/22/04	Madison Gas and Electric (WI)	9.18	(G)	11.50		57.64		12/05-A	27.4	
12/29/04	Western Massachusetts Electric (MA)	---		9.85		---		---	9.0	(B,Di,Z)
2004	***4TH QUARTER AVERAGES/TOTAL***	**8.55**		**10.91**		**49.64**			**1047.8**	
	OBSERVATIONS	**7**		**8**		**6**			**11**	
2004	***FULL-YEAR AVERAGES/TOTAL***	**8.44**		**10.75**		**46.84**			**1092.6**	
	OBSERVATIONS	**18**		**19**		**17**			**30**	

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.	
1/6/05	South Carolina Electric & Gas (SC)	8.64	10.70	50.31	12/04-YE	41.4	
1/28/05	Aquila Networks-WPK (KS)	8.73	10.50	33.63	12/03-YE	7.4	
2/18/05	Puget Sound Energy (WA)	8.40	10.30	43.00	9/03-A	56.6	
2/25/05	PacifiCorp (UT)	8.37	10.50	47.80	3/06	51.0	(B)
3/10/05	Empire District Electric (MO)	9.18	11.00	49.14	12/03-YE	25.7	(B)
3/18/05	Dominion North Carolina Power (NC)	---	---	---	12/03	-12.0	(B)
3/24/05	Consolidated Edison of New York (NY)	8.08	10.30	48.00	3/06-A	325.0	(B,Z,TD)
3/31/05	Texas-New Mexico Power (TX)	---	10.25	40.00	---	-13.0	(B,Di)
2005	***1ST QUARTER AVERAGES/TOTAL***	**8.57**	**10.51**	**44.55**		**482.1**	
	OBSERVATIONS	**6**	**7**	**7**		**8**	
4/4/05	Central Vermont Public Service (VT)	8.14	10.00	55.53	12/03-A	-7.2	(R)
4/7/05	Arizona Public Service (AZ)	7.80	10.25	45.00 (Hy)	12/02-YE	67.6	(B)
5/2/05	Public Service Co. of Oklahoma (OK)	---	---	---	6/03-YE	-6.9	(B)
5/17/05	Wisconsin Electric Power (WI)	---	---	---	12/05-A	59.7	
5/18/05	Entergy Louisiana (LA)	8.76	10.25	48.73	12/02-A	0.0	(B)
5/25/05	Savannah Electric and Power (GA)	---	10.75	---	---	9.6	(B)
5/26/05	Atlantic City Electric (NJ)	8.14	9.75	46.22	12/02-YE	-3.1	(Di,B)
5/26/05	Idaho Power (ID)	---	---	---	---	9.4	
6/1/05	Jersey Central Power & Light (NJ)	8.50	9.75	46.00	12/02-YE	51.1	(Di,B)
6/8/05	Public Service New Hampshire (NH)	---	9.62 (R, Gn)	---	---	---	**
2005	***2ND QUARTER AVERAGES/TOTAL***	**8.27**	**10.05**	**48.30**		**180.2**	
	OBSERVATIONS	**5**	**7**	**5**		**9**	
7/19/05	Wisconsin Power and Light (WI)	9.41 (G)	11.50	61.75	6/06-A	18.6	
7/22/05	PacifiCorp (ID)	---	---	---	---	5.8	(B)
8/5/05	Cap Rock Energy (TX)	6.17	11.75	25.00 (Hy)	9/03-YE	-1.3	
8/15/05	AEP Texas Central (TX)	7.48	10.13	40.00	6/03-YE	-8.8	(TD,B)
9/28/05	PacifiCorp (OR)	8.06	10.00	47.56	12/06-A	25.9	(Bp)
2005	***3RD QUARTER AVERAGES/TOTAL***	**7.78**	**10.84**	**43.58**		**40.2**	
	OBSERVATIONS	**4**	**4**	**4**		**5**	
12/9/05	Empire District Electric (KS)	---	---	---	---	2.2	(B)
12/12/05	Madison Gas and Electric (WI)	8.88 (G)	11.00	56.65	12/06-A	35.9	
12/13/05	OGE Electric Service (OK)	8.66	10.75	55.69	12/04-YE	42.3	
12/16/05	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/06	3.3	
12/16/05	San Diego Gas & Electric (CA)	8.23	10.70	49.00	12/06	0.0	
12/16/05	Southern California Edison (CA)	8.77	11.60	48.00	12/06	-26.4	
12/22/05	Wisconsin Public Service (WI)	8.83 (G)	11.00	59.73	12/06-A	79.9	
12/21/05	Cincinnati Gas & Electric (OH)	8.24	10.29	47.53	6/05-A	51.5	(Di,B)
12/21/05	Avista (WA)	9.11	10.40	40.00	12/04-A	22.1	(B)
12/22/05	Consumers Energy (MI)	6.78	11.15	36.31 *	12/03-A	177.4	
12/28/05	Westar Energy North (KS)	7.89	10.00	44.59	12/04-YE	24.2	
12/28/05	Kansas Gas and Electric (KS)	7.89	10.00	44.59	12/04-YE	-21.2	
12/28/05	Dayton Power & Light (OH)	---	---	---	---	250.0	(E,B,Z)
12/30/05	NSTAR Electric (MA)	---	---	---	---	30.0	(B,Di,4)
2005	***4TH QUARTER AVERAGES/TOTAL***	**8.37**	**10.75**	**48.55**		**671.2**	
	OBSERVATIONS	**11**	**11**	**11**		**14**	
2005	***FULL-YEAR AVERAGES/TOTAL***	**8.31**	**10.54**	**46.73**		**1373.7**	
	OBSERVATIONS	**26**	**29**	**27**		**36**	

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/06	Northern States Power (WI)	8.94 (G)	11.00	53.66	12/06-A	43.4
1/25/06	Wisconsin Electric Power (WI)	---	---	---	---	229.7 (2)
1/27/06	United Illuminating (CT)	6.88 (3)	9.75	48.00	12/04-A	41.2 (R,Di,Z,3)
2/23/06	Aquila Networks-MPS (MO)	---	---	---	---	22.4 (B)
2/23/06	Aquila Networks-L&P (MO)	---	---	---	---	3.9 (B)
3/3/06	Interstate Power and Light (MN)	8.58	10.39	49.10	12/04-A	1.2 (I,B)
3/14/06	Kentucky Power (KY)	---	---	---	---	41.0 (B)
3/24/06	PacifiCorp (WY)	---	---	---	---	25.0 (B,Z)
3/29/06	Entergy Gulf States (LA)	---	---	---	---	36.8 (I,B)
2006	***1ST QUARTER: AVERAGES/TOTAL***	**8.13**	**10.38**	**50.25**		**444.6**
	MEDIAN	**8.58**	**10.39**	**49.10**		---
	OBSERVATIONS	**3**	**3**	**3**		**9**
4/17/06	PacifiCorp (WA)	8.10	10.20	46.00	9/04-A	0.0
4/18/06	MidAmerican Energy (IA)	---	11.90 (4)	---	---	---
4/26/06	Sierra Pacific Power (NV)	8.96	10.60	40.76	5/05-YE	-14.0
5/12/06	Idaho Power (ID)	8.10	---	---	12/05	18.1 (B)
5/17/06	Southern California Edison (CA)	---	---	---	12/06-A	133.9 (5)
6/6/06	Delmarva Power & Light (DE)	7.17	10.00	47.72	3/05-A	-11.1 (Di)
6/27/06	Upper Peninsula Power (MI)	7.75	10.75	47.12 *	12/06	3.8 (B)
2006	***2ND QUARTER: AVERAGES/TOTAL***	**8.02**	**10.69**	**45.40**		**130.7**
	MEDIAN	**8.10**	**10.60**	**46.56**		---
	OBSERVATIONS	**5**	**5**	**4**		**6**
7/6/06	Maine Public Service (ME)	8.45	10.20	50.00	12/05	1.8 (B,Di)
7/24/06	Central Hudson Gas & Electric (NY)	7.05 (6)	9.60	45.00	3/06-A	53.7 (B,Z,TD)
7/26/06	Appalachian Power (WV)	7.60	10.50	---	12/04-A	111.7 (B,Z)
7/28/06	Commonwealth Edison (IL)	8.01	10.05	42.86	12/04-YE	82.6 (R,TD,7)
8/23/06	New York State Electric & Gas (NY)	7.18	9.55	41.60	12/07-A	-36.3 (TD)
8/31/06	Detroit Edison (MI)	---	---	---	---	-78.8 (B,Z)
9/1/06	Northern States Power (MN)	8.81	10.54	51.67	12/06-A	131.5 (I,8)
9/5/06	CenterPoint Energy Houston Electric (TX)	---	---	---	12/05	-57.9 (B,TD)
9/14/06	PacifiCorp (OR)	8.16	10.00	50.00	12/07-A	43.0 (B,7)
2006	***3RD QUARTER: AVERAGES/TOTAL***	**7.89**	**10.06**	**46.86**		**251.3**
	MEDIAN	**8.01**	**10.05**	**47.50**		---
	OBSERVATIONS	**7**	**7**	**6**		**9**
10/6/06	Unitil Energy Systems (NH)	8.70	9.67	43.10	6/05-YE	2.8 (B,Di,Z)
10/27/06	Entergy New Orleans (LA)	---	---	---	---	3.9 (B,9)

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
11/21/06	Delmarva Power & Light (DE)	---	---	---	---	-12.0 (B,I,Tr)
11/21/06	Central Illinois Light (IL)	7.94	10.12	45.57	12/04-YE	20.7 (TD)
11/21/06	Central Illinois Public Service (IL)	8.06	10.08	48.92	12/04-YE	-8.0 (TD)
11/21/06	Illinois Power (IL)	8.33	10.08	51.56	12/04-YE	84.0 (TD)
12/1/06	Duquesne Light (PA)	---	---	45.00	12/06	117.0 (B,Di)
12/1/06	PacifiCorp (UT)	---	10.25	---	---	115.0 (B,Z)
12/1/06	Public Service of Colorado (CO)	8.85	10.50	60.00	---	107.0 (B)
12/4/06	Kansas City Power & Light (KS)	---	---	---	---	29.0 (B)
12/7/06	Central Vermont Public Service (VT)	8.55	10.75	55.57	12/05-A	10.8 (B)
12/14/06	Western Massachusetts Electric (MA)	---	---	---	---	4.0 (B,Di,Z)
12/18/06	PacifiCorp (ID)	---	---	---	---	8.3 (B)
12/21/06	Duke Energy Kentucky (KY)	---	---	---	---	49.0 (B)
12/21/06	Empire District Electric (MO)	9.07	10.90	49.74	12/05-YE	29.4
12/21/06	Kansas City Power & Light (MO)	8.83 (E)	11.25	53.69	12/05-YE	50.6
12/22/06	Green Mountain Power (VT)	8.65	10.25	52.76	12/05-A	19.0 (B)
12/28/06	Black Hills Power (SD)	---	---	---	---	7.9 (B)
2006	***4TH QUARTER: AVERAGES/TOTAL***	**8.55**	**10.39**	**50.59**		**638.4**
	MEDIAN	**8.65**	**10.25**	**50.65**		---
	OBSERVATIONS	**9**	**10**	**10**		**18**
2006	***FULL YEAR: AVERAGES/TOTAL***	**8.20**	**10.36**	**48.67**		**1465.0**
	MEDIAN	**8.25**	**10.25**	**48.92**		---
	OBSERVATIONS	**24**	**25**	**23**		**42**

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/07	Oklahoma Gas & Electric (AR)	5.36	10.00	32.33 *	12/05-YE	5.4 (B)
1/5/07	Puget Sound Energy (WA)	8.40	10.40	44.00	9/05-A	-22.8
1/11/07	Metropolitan Edison (PA)	7.52	10.10	49.00	12/06-YE	58.7 (D)
1/11/07	Pennsylvania Electric (PA)	7.92	10.10	49.00	12/06-YE	50.2 (D)
1/11/07	Wisconsin Public Service (WI)	12.93	10.90	57.46	12/07-A/P	56.7
1/12/07	Portland General Electric (OR)	8.29	10.10	50.00 (Hy)	12/07-A	20.5 (Z)
1/19/07	Wisconsin Power and Light (WI)	9.27	10.80	54.13	12/07-A/P	36.2
3/21/07	Pacific Gas and Electric (CA)	---	---	---	12/07-A	192.2 (B,1)
3/22/07	Rockland Electric (NJ)	7.83	9.75	46.51	12/06-YE	6.4 (B,D)
2007	***1ST QUARTER: AVERAGES/TOTAL***	**8.44**	**10.27**	**47.80**		**403.5**
	MEDIAN	**8.11**	**10.10**	**49.00**		**---**
	OBSERVATIONS	**8**	**8**	**8**		**9**
5/15/07	Appalachian Power (VA)	7.36	10.00	41.11 *	12/05-YE	24.0
5/17/07	Aquila (MPS) (MO)	8.39	10.25	48.17	12/05-YE	45.2
5/17/07	Aquila (L&P) (MO)	8.93	10.25	48.17	12/05-YE	13.6
5/22/07	Monongahela Pow./Potomac Ed. (WV)	8.44	10.50	46.07	12/05-YE	-6.2
5/22/07	Union Electric (MO)	7.94	10.20	52.22	6/06-YE	41.8
5/23/07	Nevada Power (NV)	9.06	10.70	47.29	6/06-YE	120.5
5/24/07	AEP Texas North (TX)	---	---	---	6/06-YE	13.7 (B,D)
5/25/07	Public Service of New Hampshire (NH)	7.55	9.67	47.66	12/05-A	50.1 (B,I,D)
6/15/07	Entergy Arkansas (AR)	5.58	9.90	32.19 *	6/06-YE	-5.7
6/21/07	PacifiCorp (WA)	8.06	10.20	46.00	3/06-A	14.4 (R)
6/22/07	Appalachian Power (WV)	7.67 (E)	10.50 (E)	42.88 (E)	12/06-YE	85.5 (B,Z)
6/28/07	Arizona Public Service (AZ)	8.32	10.75	54.50	9/05-YE	321.7
2007	***2ND QUARTER: AVERAGES/TOTAL***	**7.94**	**10.27**	**46.02**		**718.6**
	MEDIAN	**8.06**	**10.25**	**47.29**		**---**
	OBSERVATIONS	**11**	**11**	**11**		**12**
7/3/07	El Paso Electric (NM)	---	---	---	12/05-YE	5.5 (B)
7/12/07	Granite State Electric (NH)	8.61	9.67	50.00 (Hy)	---	-2.2 (B,D,Z)
7/19/07	Delmarva Power & Light (MD)	7.68	10.00	48.63	9/06-A	14.9 (D,2)
7/19/07	Potomac Electric Power (MD)	7.99	10.00	47.69	9/06-A	10.6 (D,2)
7/27/07	Southwestern Public Service (TX)	---	---	---	9/05-YE	23.0 (B)
8/15/07	Southern Indiana Gas & Electric (IN)	7.32	10.40	47.05 *	3/06-YE	67.3 (B)
2007	***3RD QUARTER: AVERAGES/TOTAL***	**7.90**	**10.02**	**48.34**		**119.1**
	MEDIAN	**7.84**	**10.00**	**48.16**		**---**
	OBSERVATIONS	**4**	**4**	**4**		**6**
10/9/07	Public Service of Oklahoma (OK)	8.01	10.00	46.02	6/06-YE	9.8 (I)
10/18/07	Orange and Rockland Utilities (NY)	7.56	9.10	47.54	6/08-A	0.0 (D)
10/31/07	Electric Transmission Texas (TX)	7.88 (R)	9.96	40.00 (Hy)	6/08-YE	12.0 (R,Tr,3)

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
11/20/07	Kansas City Power & Light (KS)	---	---	---	---	28.0 (B)
11/29/07	Cheyenne Light, Fuel & Power (WY)	8.84	10.90	54.00 (Hy)	9/06-YE	6.7 (B)
11/29/07	Wisconsin Power and Light (WI)	---	---	---	12/08-A	25.8 (4)
12/6/07	Kansas City Power & Light (MO)	8.68	10.75	57.62	12/06-YE	35.3
12/6/07	PPL Electric Utilities (PA)	---	---	---	12/07-YE	55.0 (B,D)
12/13/07	AEP Texas Central (TX)	7.50	9.96	40.00 (Hy)	6/06-YE	40.8 (I,D)
12/14/07	Madison Gas and Electric (WI)	9.08	10.80	57.36	12/08-A/P	16.2
12/14/07	South Carolina Electric & Gas (SC)	8.62	10.70	53.32	3/07-YE	76.9 (B)
12/19/07	Avista Corporation (WA)	8.20	10.20	46.00	12/06-A	30.2 (B)
12/20/07	Duke Energy Carolinas (NC)	8.57	11.00	53.00	12/06-YE	-286.9 (Bp)
12/20/07	Bangor Hydro-Electric (ME)	8.60	10.20	---	---	1.1 (B,D)
12/21/07	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/08-A	0.0
12/21/07	San Diego Gas & Electric (CA)	8.40	11.10	49.00	12/08-A	8.2
12/21/07	Southern California Edison (CA)	8.75	11.50	48.00	12/08-A	-9.6
12/28/07	PacifiCorp (ID)	8.27	10.25	50.40	12/06	11.5 (B)
12/31/07	Georgia Power (GA)	---	11.25	---	7/08-A	99.7 (B)
2007	***4TH QUARTER: AVERAGES/TOTAL***	**8.38**	**10.56**	**49.59**		**160.7**
	MEDIAN	**8.57**	**10.73**	**49.70**		**---**
	OBSERVATIONS	**15**	**16**	**14**		**19**
2007	***FULL YEAR: AVERAGES/TOTAL***	**8.22**	**10.36**	**48.01**		**1401.9**
	MEDIAN	**8.28**	**10.25**	**48.17**		**---**
	OBSERVATIONS	**38**	**39**	**37**		**46**
1/8/08	Northern States Power-Wisconsin (WI)	9.67	10.75	52.51	12/08-A	39.4
1/17/08	Wisconsin Electric Power (WI)	9.26	10.75	54.36	12/08-A/P	148.4 (Z)
1/28/08	Connecticut Light & Power (CT)	7.72	9.40	48.99	12/06-YE	97.9 (D,Z)
1/30/08	Potomac Electric Power (DC)	7.96	10.00	46.55	2/07-A	28.3 (D,5)
1/31/08	Central Vermont Public Service (VT)	8.50	10.21 (R)	50.02	12/06-A	6.4 (B)
2/6/08	Interstate Power & Light (IA)	---	11.70 (6)	---	---	---
2/28/08	Idaho Power (ID)	8.10	---	---	---	32.1 (B)
2/29/08	Fitchburg Gas & Electric (MA)	8.38	10.25	42.80	12/06-YE	2.1 (D)
3/12/08	PacifiCorp (WY)	8.29	10.25	50.80	8/08	23.0 (B,7)
3/25/08	Consolidated Edison of New York (NY)	7.34	9.10	47.98	3/09-A	425.3 (D)
3/31/08	Virginia Electric Power (VA)	---	12.12 (8)	---	---	---
2008	***1ST QUARTER: AVERAGES/TOTAL***	**8.36**	**10.45**	**49.25**		**802.9**
	MEDIAN	**8.29**	**10.25**	**49.51**		**---**
	OBSERVATIONS	**9**	**10**	**8**		**9**
4/22/08	MDU Resources (MT)	8.58	10.25	50.67	12/06-A	4.1 (B,Z)
4/24/08	Public Service Co. of New Mexico (NM)	8.24	10.10	51.37	9/06-YE	34.4
5/1/08	Hawaiian Electric Company (HI)	8.66	10.70	55.79	12/05-A	44.9 (Bp,I)
5/27/08	UNS Electric (AZ)	9.02	10.00	48.85	6/06-YE	4.0
5/30/08	Idaho Power (ID)	--- (9)	---	---	---	8.9

RRA

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
6/10/08	Consumers Energy (MI)	6.93	10.70	41.75 *	12/08-A	221.0 (I)
6/16/08	MidAmerican Energy (IA)	---	11.70 (B,10)	---	---	---
6/27/08	Appalachian Power (WV)	7.65	10.50	41.54	12/07-YE	106.1 (B)
6/27/08	Sierra Pacific Power (NV)	8.41	10.60 (11)	43.49	6/07-YE	87.1
6/30/08	Oncor Electric Delivery (TX)	---	---	---	12/06	--- (D,12)
2008	***2ND QUARTER: AVERAGES/TOTAL***	**8.21**	**10.57**	**47.64**		**510.5**
	MEDIAN	**8.41**	**10.55**	**48.85**		**---**
	OBSERVATIONS	**7**	**8**	**7**		**8**
7/1/08	Central Maine Power (ME)	---	---	---	---	-20.3 (B,D,13)
7/2/08	NorthWestern Corporation (MT)	--- (14)	---	---	---	10.0 (B,I)
7/10/08	Otter Tail Corporation (MN)	8.33	10.43	50.00	12/06-A	3.8 (I)
7/16/08	Orange and Rockland Utilities (NY)	7.69	9.40	48.00	6/09-A	15.6 (B,D)
7/30/08	Empire District Electric (MO)	8.92	10.80	50.78	6/07-YE	22.0
7/31/08	San Diego Gas & Electric (CA)	--- (15)	--- (15)	--- (15)	12/08-A	234.0 (B,Z)
8/11/08	PacifiCorp (UT)	8.29	10.25	50.40	12/08-A	39.4 (R)
8/26/08	Southwestern Public Service (NM)	8.27	10.18	51.23	12/06-YE	13.1
8/27/08	MidAmerican Energy (IA)	---	11.70 (B,16)	---	---	---
9/10/08	Commonwealth Edison (IL)	8.36	10.30	45.04	12/06-YE	273.6 (D)
9/24/08	Central Illinois Light (IL)	8.01	10.65	46.50	12/06-YE	-2.8 (D)
9/24/08	Central Illinois Public Service (IL)	8.20	10.65	47.91	12/06-YE	22.0 (D)
9/24/08	Illinois Power (IL)	8.68	10.65	51.76	12/06-YE	103.9 (D)
9/30/08	Avista Corp. (ID)	8.45	10.20	47.94	12/07-A	23.2 (B)
2008	***3RD QUARTER: AVERAGES/TOTAL***	**8.32**	**10.47**	**48.96**		**737.5**
	MEDIAN	**8.31**	**10.43**	**49.00**		**---**
	OBSERVATIONS	**10**	**11**	**10**		**13**
10/8/08	PacifiCorp (WA)	8.06	---	---	---	20.4 (B)
10/8/08	Puget Sound Energy (WA)	8.25	10.15	46.00	9/07-A	130.2 (B)
11/13/08	NorthWestern Corporation (MT)	8.25 (17)	10.00 (17)	50.00 (17)	---	---
11/17/08	Appalachian Power (VA)	7.69	10.20	---	12/07	167.9 (I,B)
12/1/08	Tucson Electric Power (AZ)	8.03	10.25	42.50	12/06-YE	136.8 (B)
12/17/08	Duke Energy Ohio (OH)	---	---	---	---	98.0 (B,Gn,E,Z)
12/18/08	Madison Gas and Electric (WI)	---	---	---	12/09	-2.7
12/23/08	Detroit Edison (MI)	7.16	11.00	40.68 *	12/09-A	83.6
12/29/08	Portland General Electric (OR)	8.33	10.10 (Bp)	50.00	12/09-A	121.0
12/29/08	Avista Corporation (WA)	8.22	10.20	46.30	12/07-A	32.5 (B)
12/30/08	Wisconsin Power and Light (WI)	---	---	---	12/09	0.0 (B)
12/30/08	Wisconsin Public Service (WI)	---	---	53.41	12/09	48.0 (B,18)
12/31/08	Northern States Power (ND)	8.80	10.75	51.77	12/08	12.8 (I,B)
2008	***4TH QUARTER: AVERAGES/TOTAL***	**8.09**	**10.33**	**47.58**		**848.5**
	MEDIAN	**8.22**	**10.20**	**48.15**		**---**
	OBSERVATIONS	**9**	**8**	**8**		**12**
2008	***YEAR-TO-DATE: AVERAGES/TOTAL***	**8.25**	**10.46**	**48.41**		**2899.4**
	MEDIAN	**8.27**	**10.25**	**48.99**		**---**
	OBSERVATIONS	**35**	**37**	**33**		**42**

RRA

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/14/09	Public Service Oklahoma (OK)	8.31	10.50	44.10	2/08-YE	59.3 (1)
1/21/09	Westar Energy (KS)	---	---	---	---	65.0 (B)
1/21/09	Kansas Gas & Electric (KS)	---	---	---	---	65.0 (B)
1/21/09	Cleveland Electric Illuminating (OH)	8.48	10.50 (E)	49.00	2/08-DC	29.2 (D)
1/21/09	Ohio Edison (OH)	8.48	10.50 (E)	49.00	2/08-DC	68.9 (D)
1/21/09	Toledo Edison (OH)	8.48	10.50 (E)	49.00	2/08-DC	38.5 (D)
1/30/09	Idaho Power (ID)	8.18	10.50	49.27	12/08-YE	27.0 (R)
2/4/09	United Illuminating (CT)	7.59	8.75	50.00	12/07-A	6.8 (D,R,2)
2/4/09	Interstate Power & Light (IA)	---	10.10 (3)	---	---	---
2/5/09	Kentucky Utilities (KY)	---	---	---	---	-8.9 (B)
2/5/09	Louisville Gas & Electric (KY)	---	---	---	---	-13.2 (B)
2/10/09	Union Electric (MO)	8.34	10.76	52.01	3/08-YE	161.7
3/4/09	Indiana Michigan Power (IN)	7.62	10.50	45.80 *	9/07-YE	19.1 (4)
3/11/09	Entergy Texas (TX)	---	---	---	3/07	30.5 (B,I,5)
3/17/09	Southern California Edison (CA)	---	---	---	12/09-A	308.1 (6)
2009	***1ST QUARTER: AVERAGES/TOTAL***	**8.19**	**10.29**	**48.52**		**857.0**
	MEDIAN	**8.33**	**10.50**	**49.00**		**---**
	OBSERVATIONS	**8**	**9**	**8**		**14**
4/2/09	Entergy New Orleans (LA)	---	11.10	---	12/08-YE	-24.7 (B,7)
4/16/09	PacifiCorp (ID)	---	---	---	---	4.4 (B)
4/21/09	PacifiCorp (UT)	8.36	10.61	51.00	12/09-A	45.0 (B)
4/24/09	Consolidated Edison of New York (NY)	7.79	10.00	48.00	3/10-A	523.4 (D)
4/30/09	Tampa Electric (FL)	8.11	11.25	46.11 *	12/09-A	137.9 (Z)
5/4/09	Minnesota Power (MN)	8.45	10.74	54.79	6/09-A	21.1 (I)
5/20/09	Oklahoma Gas & Electric (AR)	6.43	10.25	36.04 *	12/07-YE	13.3 (B)
5/20/09	NorthWestern Corp. (MT)	8.38	10.25	50.00	---	--- (8)
5/20/09	PacifiCorp (WY)	---	---	---	---	18.0 (B)
5/28/09	Public Service New Mexico (NM)	8.77	10.50	50.47	3/08-YE	77.1 (B,Z)
5/29/09	Idaho Power (ID)	---	---	---	---	10.5 (9)
6/2/09	Southwestern Public Service (TX)	---	---	---	12/07	57.4 (B,I)
6/9/09	Public Service Co. of Colorado (CO)	---	---	---	---	112.2 (B)
6/10/09	Kansas City Power & Light (MO)	---	---	---	12/07-YE	95.0 (B)
6/10/09	KCP&L Greater Missouri Oper. (MO)	---	---	---	12/07-YE	63.0 (B)
6/22/09	Central Hudson Gas & Electric (NY)	7.28	10.00	47.00	6/10-A	38.0 (D)
6/24/09	Nevada Power (NV)	8.53	10.50	44.15	6/08-YE	221.0 (Z)
2009	***2ND QUARTER: AVERAGES/TOTAL***	**8.01**	**10.52**	**47.51**		**1412.6**
	MEDIAN	**8.36**	**10.50**	**48.00**		**---**
	OBSERVATIONS	**9**	**10**	**9**		**16**
2009	***YEAR-TO-DATE AVERAGES/TOTAL***	**8.09**	**10.41**	**47.98**		**2269.6**
	MEDIAN	**8.34**	**10.50**	**49.00**		**---**
	OBSERVATIONS	**17**	**19**	**17**		**30**

FOOTNOTES

- A- Average
- B- Order followed stipulation or settlement by the parties. Decision particulars not necssarily precedent-setting or specifically adopted by the regulatory body.
- Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
- Di- Rate change applicable to electric distribution or gas delivery rates only.
- E- Estimated
- G- Return on capital
- Gn- Return applicable to generation assets only.
- Hy- Hypothetical capital structure utilized
- I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
- P- Partial inclusion of CWIP in rate base without AFUDC offset to income
- PBR- Performance Based Ratemaking
- R- Revised
- TD- Rate change applicable to electric transmission and distribution rates only.
- Tr- Rate change applicable to electric transmission rates only.
- YE- Year-end
- Z- Rate change implemented in multiple steps.
- * Capital structure includes cost-free items or tax credit balances at the overall rate of return.
- ** 6/8/05 PSNH case was generation-only case.

Samuel C. Hadaway
Exhibit PPL/217

Docket No. UE-210
Exhibit PPL/217
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Analysts' Consensus Growth Rates for S&P 500 Companies

August 2009

PacifiCorp Oregon
Analysts' Consensus Growth Rates for S&P 500 Companies

No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
1	3M CO	MMM	9.42
2	ABBOTT LABS	ABT	11.19
3	ABERCROMBIE	ANF	10.64
4	ADOBE SYSTEMS	ADBE	14.40
5	ADV MICRO DEV	AMD	12.50
6	AES CORP	AES	11.00
7	AETNA INC-NEW	AET	14.92
8	AFFILIATED COMP	ACS	10.68
9	AFLAC INC	AFL	14.50
10	AGILENT TECH	A	13.00
11	AIR PRODS & CHE	APD	7.25
12	AKAMAI TECH	AKAM	10.88
13	ALCOA INC	AA	(9.10)
14	ALLEGHENY ENGY	AYE	14.00
15	ALLEGHENY TECH	ATI	(4.90)
16	ALLERGAN INC	AGN	15.05
17	ALLSTATE CORP	ALL	9.09
18	ALTERA CORP	ALTR	13.71
19	ALTRIA GROUP	MO	7.00
20	AMAZON.COM INC	AMZN	26.75
21	AMER ELEC PWR	AEP	4.25
22	AMER EXPRESS CO	AXP	11.00
23	AMER INTL GRP	AIG	9.00
24	AMEREN CORP	AEE	4.00
25	AMERICAN TOWER	AMT	19.83
26	AMERIPRISE FINL	AMP	11.50
27	AMERISOURCEBRGN	ABC	11.67
28	AMGEN INC	AMGN	11.12
29	AMPHENOL CORP-A	APH	20.00
30	ANADARKO PETROL	APC	6.25
31	ANALOG DEVICES	ADI	11.42
32	AON CORP	AOC	11.34
33	APACHE CORP	APA	11.40
34	APARTMENT INVT	AIV	5.00
35	APOLLO GROUP	APOL	15.25
36	APPLD MATLS INC	AMAT	11.00
37	APPLE INC	AAPL	18.64
38	ARCHER DANIELS	ADM	18.00
39	ASSURANT INC	AIZ	8.75
40	AT&T INC	T	5.38
41	AUTODESK INC	ADSK	10.00
42	AUTOMATIC DATA	ADP	11.63
43	AUTONATION INC	AN	8.95

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
44	AUTOZONE INC	AZO	12.21
45	AVALONBAY CMMTY	AVB	8.81
46	AVERY DENNISON	AVY	8.67
47	AVON PRODS INC	AVP	12.00
48	BAKER-HUGHES	BHI	8.00
49	BALL CORP	BLL	5.00
50	BANK OF AMER CP	BAC	7.58
51	BANK OF NY MELL	BK	9.97
52	BARD C R INC	BCR	14.17
53	BAXTER INTL	BAX	12.46
54	BB&T CORP	BBT	7.41
55	BECTON DICKINSO	BDX	11.57
56	BED BATH&BEYOND	BBBY	12.11
57	BEMIS	BMS	8.67
58	BEST BUY	BBY	12.45
59	BIG LOTS INC	BIG	12.20
60	BIOGEN IDEC INC	BIIB	9.37
61	BJ SERVICES	BJS	6.00
62	BLACK & DECKER	BDK	6.67
63	BLOCK H & R	HRB	11.00
64	BMC SOFTWARE	BMC	11.73
65	BOEING CO	BA	7.88
66	BOSTON PPTYS	BXP	5.25
67	BOSTON SCIENTIF	BSX	13.82
68	BRISTOL MYRS SQ	BMY	4.52
69	BROADCOM CORP-A	BRCM	17.25
70	BROWN FORMAN B	BF.B	15.40
71	BURLNGTN NSF CP	BNI	10.07
72	CA INC	CA	9.00
73	CABOT OIL & GAS	COG	4.00
74	CAMERON INTL	CAM	18.50
75	CAMPBELL SOUP	CPB	6.33
76	CAPITAL ONE FIN	COF	13.30
77	CARDINAL HEALTH	CAH	10.00
78	CARNIVAL CORP	CCL	12.50
79	CATERPILLAR INC	CAT	8.60
80	CB RICHARD ELLS	CBG	10.00
81	CBS CORP	CBS	5.58
82	CELGENE CORP	CELG	25.99
83	CENTERPOINT EGY	CNP	7.00
84	CENTEX CORP	CTX	12.00
85	CENTURYTEL INC	CTL	3.00
86	CEPHALON INC	CEPH	13.63

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
87	CH ROBINSON WWD	CHRW	13.18
88	CHESAPEAKE ENGY	CHK	10.20
89	CHEVRON CORP	CVX	9.00
90	CHUBB CORP	CB	5.00
91	CIENA CORP	CIEN	10.80
92	CIGNA CORP	CI	12.11
93	CINTAS CORP	CTAS	11.75
94	CISCO SYSTEMS	CSCO	11.05
95	CITIGROUP INC	C	7.00
96	CITRIX SYS INC	CTXS	12.00
97	CLOROX CO	CLX	8.86
98	CME GROUP INC	CME	9.56
99	CMS ENERGY	CMS	6.50
100	COACH INC	COH	13.52
101	COCA COLA CO	KO	8.70
102	COCA-COLA ENTRP	CCE	7.00
103	COGNIZANT TECH	CTSH	18.43
104	COLGATE PALMOLI	CL	10.29
105	COMCAST CORP A	CMCSA	10.50
106	COMERICA INC	CMA	5.44
107	COMP SCIENCE	CSC	9.50
108	CONAGRA FOODS	CAG	15.07
109	CONOCOPHILLIPS	COP	7.00
110	CONSOL EDISON	ED	4.00
111	CONSOL ENERGY	CNX	13.05
112	CONSTELLATN BRD	STZ	10.97
113	CONSTELLATN EGY	CEG	12.00
114	CONVERGYS CORP	CVG	10.13
115	COOPER INDS LTD	CBE	9.00
116	CORNING INC	GLW	13.57
117	COSTCO WHOLE CP	COST	11.61
118	COVENTRY HLTHCR	CVH	13.32
119	CSX CORP	CSX	11.38
120	CUMMINS INC	CMI	9.00
121	CVS CAREMARK CP	CVS	15.53
122	D R HORTON INC	DHI	8.80
123	DANAHER CORP	DHR	12.13
124	DARDEN RESTRNT	DRI	11.99
125	DAVITA INC	DVA	12.95
126	DEAN FOODS CO	DF	9.00
127	DEERE & CO	DE	7.33
128	DELL INC	DELL	10.60
129	DENBURY RES INC	DNR	14.25

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
130	DENTSPLY INTL	XRAY	12.67
131	DEVON ENERGY	DVN	8.40
132	DEVRY INC	DV	20.29
133	DIAMOND OFFSHOR	DO	25.00
134	DIRECTV GRP INC	DTV	20.13
135	DISCOVER FIN SV	DFS	6.00
136	DISNEY WALT	DIS	9.40
137	DOMINION RES VA	D	5.50
138	DOVER CORP	DOV	11.33
139	DOW CHEMICAL	DOW	8.00
140	DR PEPPER SNAPL	DPS	9.00
141	DTE ENERGY CO	DTE	5.00
142	DU PONT (EI) DE	DD	6.00
143	DUKE ENERGY CP	DUK	4.80
144	DUN &BRADST-NEW	DNB	10.00
145	DYNEGY INC	DYN	8.00
146	EASTMAN CHEM CO	EMN	6.50
147	EASTMAN KODAK	EK	10.00
148	EATON CORP	ETN	9.33
149	EBAY INC	EBAY	14.64
150	ECOLAB INC	ECL	13.14
151	EDISON INTL	EIX	3.03
152	EL PASO CORP	EP	8.00
153	ELECTR ARTS INC	ERTS	16.73
154	EMC CORP -MASS	EMC	11.40
155	EMERSON ELEC CO	EMR	10.57
156	ENSCO INTL INC	ESV	22.00
157	ENTERGY CORP	ETR	7.25
158	EOG RES INC	EOG	7.67
159	EQT CORP	EQT	11.50
160	EQUIFAX INC	EFX	9.75
161	EQUITY RES PPTY	EQR	27.69
162	ESTEE LAUDER	EL	12.84
163	EXELON CORP	EXC	6.50
164	EXPEDIA INC	EXPE	16.67
165	EXPEDITORS INTL	EXPD	15.00
166	EXPRESS SCRIPTS	ESRX	16.92
167	EXXON MOBIL CRP	XOM	7.33
168	FAMILY DOLLAR	FDO	12.46
169	FASTENAL	FAST	13.00
170	FEDERATED INVST	FII	9.00
171	FEDEX CORP	FDX	10.33
172	FIDELITY NAT IN	FIS	13.71

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
173	FIFTH THIRD BK	FITB	5.20
174	FIRST HRZN NATL	FHN	7.50
175	FIRSTENERGY CP	FE	7.33
176	FISERV INC	FISV	13.00
177	FLIR SYSTEMS	FLIR	17.83
178	FLOWSERVE CORP	FLS	7.00
179	FLUOR CORP-NEW	FLR	10.25
180	FMC TECH INC	FTI	15.00
181	FORD MOTOR CO	F	5.00
182	FOREST LABS A	FRX	5.20
183	FORTUNE BRANDS	FO	9.00
184	FPL GRP	FPL	9.04
185	FRANKLIN RESOUR	BEN	10.00
186	FREEPT MC COP-B	FCX	7.65
187	FRONTIER COMMUN	FTR	2.93
188	GAMESTOP CORP	GME	16.16
189	GANNETT INC	GCI	3.67
190	GAP INC	GPS	10.06
191	GENL DYNAMICS	GD	9.67
192	GENL ELECTRIC	GE	1.90
193	GENL MILLS	GIS	7.75
194	GENUINE PARTS	GPC	8.33
195	GENWORTH FINL	GNW	10.00
196	GENZYME-GENERAL	GENZ	21.08
197	GILEAD SCIENCES	GILD	16.46
198	GOLDMAN SACHS	GS	11.20
199	GOODRICH CORP	GR	12.85
200	GOODYEAR TIRE	GT	12.00
201	GOOGLE INC-CL A	GOOG	23.46
202	GRAINGER W W	GWW	10.35
203	HALLIBURTON CO	HAL	3.35
204	HARLEY-DAVIDSON	HOG	9.43
205	HARMAN INTL IND	HAR	20.00
206	HARRIS CORP	HRS	13.67
207	HARTFORD FIN SV	HIG	9.50
208	HASBRO INC	HAS	10.00
209	HCP INC	HCP	6.50
210	HEALTH CR REIT	HCN	8.83
211	HEINZ (HJ) CO	HNZ	8.50
212	HERSHEY CO/THE	HSY	8.45
213	HESS CORP	HES	7.50
214	HEWLETT PACKARD	HPQ	10.81
215	HOME DEPOT	HD	11.01

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
216	HONEYWELL INTL	HON	8.86
217	HORMEL FOODS CP	HRL	8.50
218	HOSPIRA INC	HSP	12.69
219	HOST HOTEL&RSRT	HST	(9.20)
220	HUDSON CITY BCP	HCBK	14.50
221	HUMANA INC NEW	HUM	16.41
222	HUNTINGTON BANC	HBAN	(8.42)
223	ILL TOOL WORKS	ITW	10.29
224	IMS HEALTH INC	RX	7.10
225	INTEGRYS ENERGY	TEG	8.25
226	INTEL CORP	INTC	12.91
227	INTERCONTINENTL	ICE	14.60
228	INTERPUBLIC GRP	IPG	9.67
229	INTL BUS MACH	IBM	12.76
230	INTL F & F	IFF	6.33
231	INTL GAME TECH	IGT	13.41
232	INTL PAPER	IP	2.03
233	INTUIT INC	INTU	14.80
234	INTUITIVE SURG	ISRG	21.83
235	INVESCO LTD	IVZ	11.00
236	IRON MOUNTAIN	IRM	18.00
237	ITT CORP	ITT	10.50
238	JABIL CIRCUIT	JBL	19.10
239	JACOBS ENGIN GR	JEC	12.80
240	JANUS CAP GRP	JNS	10.75
241	JDS UNIPHASE CP	JDSU	15.50
242	JOHNSON & JOHNS	JNJ	8.26
243	JOHNSON CONTROL	JCI	11.29
244	JPMORGAN CHASE	JPM	8.20
245	JUNIPER NETWRKS	JNPR	17.42
246	KB HOME	KBH	12.00
247	KELLOGG CO	K	8.80
248	KEYCORP NEW	KEY	5.75
249	KIMBERLY CLARK	KMB	8.32
250	KIMCO REALTY CO	KIM	4.86
251	KING PHARMACEUT	KG	9.50
252	KLA-TENCOR CORP	KLAC	9.33
253	KOHLS CORP	KSS	12.63
254	KRAFT FOODS INC	KFT	10.10
255	KROGER CO	KR	9.00
256	L-3 COMM HLDGS	LLL	10.63
257	LABORATORY CP	LH	11.89
258	LEGG MASON INC	LM	14.00

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
259	LEGGETT & PLATT	LEG	18.97
260	LENNAR CORP -A	LEN	32.38
261	LEXMARK INTL	LXK	3.33
262	LIFE TECHNOLOGS	LIFE	12.05
263	LILLY ELI & CO	LLY	4.10
264	LIMITED INC	LTD	10.44
265	LINCOLN NATL-IN	LNC	9.75
266	LINEAR TEC CORP	LLTC	14.99
267	LOCKHEED MARTIN	LMT	11.16
268	LORILLARD CO	LO	6.00
269	LOWES COS	LOW	9.57
270	LSI CORP	LSI	13.75
271	M&T BANK CORP	MTB	4.72
272	MACYS INC	M	9.67
273	MANITOWOC INC	MTW	10.33
274	MARATHON OIL CP	MRO	9.00
275	MARRIOTT INTL-A	MAR	6.35
276	MARSH &MCLENNAN	MMC	12.00
277	MARSHALL&ILSLEY	MI	7.71
278	MASCO	MAS	11.50
279	MASSEY EGY CPY	MEE	16.50
280	MASTERCARD INC	MA	17.18
281	MATTEL INC	MAT	10.00
282	MBIA INC	MBI	10.00
283	MCAFEE INC	MFE	14.18
284	MCDONALDS CORP	MCD	11.69
285	MCGRAW-HILL COS	MHP	8.00
286	MCKESSON CORP	MCK	12.13
287	MEADWESTVACO CP	MWV	10.00
288	MEDCO HLTH SOL	MHS	16.63
289	MEDTRONIC	MDT	10.65
290	MEMC ELEC MATRL	WFR	17.00
291	MERCK & CO INC	MRK	0.94
292	MEREDITH CORP	MDP	11.00
293	METLIFE INC	MET	10.40
294	METROPCS COMMUN	PCS	40.89
295	MICROCHIP TECH	MCHP	11.92
296	MICRON TECH	MU	9.75
297	MICROSOFT CORP	MSFT	10.62
298	MILLIPORE CORP	MIL	14.05
299	MOLEX INC	MOLX	15.00
300	MOLSON COORS-B	TAP	11.33
301	MONSANTO CO-NEW	MON	19.03

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
302	MONSTER WWD INC	MWW	17.94
303	MOODYS CORP	MCO	12.00
304	MORGAN STANLEY	MS	11.00
305	MOTOROLA INC	MOT	7.14
306	MURPHY OIL	MUR	19.00
307	MYLAN INC	MYL	26.19
308	NABORS IND	NBR	28.00
309	NASDAQ OMX GRP	NDAQ	13.60
310	NATL OILWELL VR	NOV	7.00
311	NATL SEMICON	NSM	12.00
312	NETAPP INC	NTAP	13.78
313	NEWELL RUBBERMD	NWL	9.20
314	NEWMONT MINING	NEM	13.43
315	NEWS CORP INC-A	NWSA	7.95
316	NICOR INC	GAS	4.15
317	NIKE INC-B	NKE	11.63
318	NISOURCE INC	NI	2.75
319	NOBLE ENERGY	NBL	6.00
320	NORDSTROM INC	JWN	11.00
321	NORFOLK SOUTHRN	NSC	13.00
322	NORTHEAST UTIL	NU	8.00
323	NORTHERN TRUST	NTRS	10.49
324	NORTHROP GRUMMN	NOC	10.15
325	NOVELL INC	NOVL	10.75
326	NOVELLUS SYS	NVLS	12.67
327	NUCOR CORP	NUE	5.00
328	NVIDIA CORP	NVDA	11.33
329	NY TIMES A	NYT	7.50
330	NYSE EURONEXT	NYX	11.00
331	O REILLY AUTO	ORLY	15.57
332	OCCIDENTAL PET	OXY	6.50
333	OFFICE DEPOT	ODP	9.90
334	OMNICOM GRP	OMC	10.42
335	ORACLE CORP	ORCL	12.04
336	OWENS-ILLINOIS	OI	5.00
337	PACCAR INC	PCAR	8.75
338	PACTIV CORP	PTV	7.00
339	PALL CORP	PLL	14.67
340	PARKER HANNIFIN	PH	9.00
341	PATTERSON COS	PDCO	12.67
342	PAYCHEX INC	PAYX	12.00
343	PEABODY ENERGY	BTU	11.00
344	PENNEY (JC) INC	JCP	3.61

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
345	PEOPLES UTD FIN	PBCT	9.50
346	PEPCO HLDGS	POM	4.00
347	PEPSI BOTTLING	PBG	7.95
348	PEPSICO INC	PEP	11.53
349	PERKINELMER INC	PKI	12.33
350	PFIZER INC	PFE	(1.50)
351	PG&E CORP	PCG	7.10
352	PHILIP MORRIS	PM	9.67
353	PINNACLE WEST	PNW	6.33
354	PIONEER NAT RES	PXD	13.67
355	PLUM CREEK TMBR	PCL	8.00
356	PNC FINL SVC CP	PNC	8.00
357	POLO RALPH LAUR	RL	13.25
358	PPG INDS INC	PPG	7.50
359	PPL CORP	PPL	9.00
360	PRAXAIR INC	PX	9.00
361	PRECISION CASTP	PCP	15.29
362	PRINCIPAL FINL	PFG	11.00
363	PROCTER & GAMBL	PG	9.56
364	PROGRESS ENERGY	PGN	4.67
365	PROGRESSIVE COR	PGR	7.26
366	PROLOGIS	PLD	10.99
367	PRUDENTIAL FINL	PRU	12.00
368	PUBLIC STORAGE	PSA	4.88
369	PUBLIC SV ENTRP	PEG	5.75
370	PULTE HOMES INC	PHM	11.50
371	QLOGIC CORP	QLGC	10.80
372	QUALCOMM INC	QCOM	15.55
373	QUANTA SERVICES	PWR	11.67
374	QUEST DIAGNOSTC	DGX	12.44
375	QUESTAR	STR	10.00
376	QWEST COMM INTL	Q	1.17
377	RADIOSHACK CORP	RSH	9.48
378	RANGE RESOURCES	RRC	11.63
379	RAYTHEON CO	RTN	10.17
380	RED HAT INC	RHT	18.44
381	REGIONS FINL CP	RF	5.67
382	REPUBLIC SVCS	RSG	12.50
383	REYNOLDS AMER	RAI	12.15
384	ROBT HALF INTL	RHI	12.50
385	ROCKWELL AUTOMT	ROK	8.25
386	ROCKWELL COLLIN	COL	16.85
387	ROWAN COS INC	RDC	12.50

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
388	RYDER SYS	R	1.67
389	SAFEWAY INC	SWY	10.00
390	SALESFORCE.COM	CRM	32.50
391	SANDISK CORP	SNDK	19.67
392	SARA LEE	SLE	6.33
393	SCANA CORP	SCG	4.60
394	SCHERING PLOUGH	SGP	8.50
395	SCHLUMBERGER LT	SLB	9.00
396	SCHWAB(CHAS)	SCHW	16.53
397	SCRIPPS NETWRKS	SNI	11.16
398	SEALED AIR CORP	SEE	8.50
399	SEARS HLDG CP	SHLD	10.00
400	SEMPRA ENERGY	SRE	6.50
401	SHERWIN WILLIAM	SHW	11.50
402	SIGMA ALDRICH	SIAL	8.80
403	SIMON PROPERTY	SPG	5.44
404	SLM CORP	SLM	13.50
405	SMITH INTL	SII	5.00
406	SMUCKER JM	SJM	8.00
407	SNAP-ON INC	SNA	11.33
408	SOUTHN COMPANY	SO	7.33
409	SOUTHWEST AIR	LUV	13.67
410	SOUTHWESTRN ENE	SWN	40.50
411	SPECTRA ENERGY	SE	7.50
412	SPRINT NEXTEL	S	14.50
413	ST JUDE MEDICAL	STJ	14.06
414	STANLEY WORKS	SWK	10.00
415	STAPLES INC	SPLS	13.57
416	STARBUCKS CORP	SBUX	16.10
417	STARWOOD HOTELS	HOT	(6.33)
418	STATE ST CORP	STT	10.89
419	STERICYCLE INC	SRCL	18.75
420	STRYKER CORP	SYK	14.18
421	SUN MICROSYS	JAVA	7.50
422	SUNOCO INC	SUN	5.00
423	SUNTRUST BKS	STI	7.75
424	SUPERVALU INC	SVU	6.50
425	SYMANTEC CORP	SYMC	9.73
426	SYSCO CORP	SYY	9.70
427	T ROWE PRICE	TROW	10.80
428	TARGET CORP	TGT	13.39
429	TECO ENERGY	TE	10.20
430	TELLABS INC	TLAB	8.50

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No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
431	TENET HEALTH	THC	9.33
432	TERADATA CORP	TDC	8.50
433	TERADYNE INC	TER	16.00
434	TESORO CORP	TSO	15.00
435	TEXAS INSTRS	TXN	14.36
436	TEXTRON INC	TXT	10.78
437	THERMO FISHER	TMO	13.98
438	TIFFANY & CO	TIF	8.80
439	TIME WARNER CAB	TWC	10.28
440	TIME WARNER INC	TWX	9.19
441	TITANIUM METALS	TIE	(4.90)
442	TJX COS INC NEW	TJX	12.13
443	TORCHMARK CORP	TMK	8.75
444	TOTAL SYS SVC	TSS	10.60
445	TRAVELERS COS	TRV	2.20
446	TYSON FOODS A	TSN	10.00
447	UNION PAC CORP	UNP	10.80
448	UNITEDHEALTH GP	UNH	13.19
449	UNUM GROUP	UNM	10.00
450	US BANCORP	USB	7.84
451	UTD PARCEL SRVC	UPS	11.43
452	UTD STATES STL	X	7.70
453	UTD TECHS CORP	UTX	8.58
454	V F CORP	VFC	10.87
455	VALERO ENERGY	VLO	(5.68)
456	VARIAN MEDICAL	VAR	16.00
457	VENTAS INC	VTR	4.33
458	VERISIGN INC	VRSN	13.60
459	VERIZON COMM	VZ	5.52
460	VIACOM INC-B	VIA.B	10.57
461	VORNADO RLTY TR	VNO	4.29
462	VULCAN MATLS CO	VMC	(0.73)
463	WALGREEN CO	WAG	12.84
464	WAL-MART STORES	WMT	10.99
465	WASTE MGMT-NEW	WM	10.33
466	WATERS CORP	WAT	12.32
467	WATSON PHARMA	WPI	10.72
468	WELLPOINT INC	WLP	11.71
469	WELLS FARGO-NEW	WFC	11.80
470	WESTERN DIGITAL	WDC	11.00
471	WESTERN UNION	WU	12.64
472	WEYERHAEUSER CO	WY	5.33
473	WHIRLPOOL CORP	WHR	2.60

PacifiCorp Oregon

Analysts' Consensus Growth Rates for S&P 500 Companies

No.	Company Name	Ticker	Long-Term Growth Consensus Estimate (%)
474	WHOLE FOODS MKT	WFMI	16.25
475	WILLIAMS COS	WMB	10.00
476	WINDSTREAM CORP	WIN	3.11
477	WISC ENERGY CP	WEC	8.43
478	WYETH	WYE	3.75
479	WYNDHAM WORLDWD	WYN	15.00
480	WYNN RESRTS LTD	WYNN	(15.66)
481	XCEL ENERGY INC	XEL	5.33
482	XEROX CORP	XRX	7.00
483	XILINX INC	XLNX	12.52
484	XL CAP LTD-A	XL	10.50
485	XTO ENERGY INC	XTO	11.00
486	YAHOO! INC	YHOO	14.85
487	YUM! BRANDS INC	YUM	11.59
488	ZIMMER HOLDINGS	ZMH	10.73
489	ZIONS BANCORP	ZION	7.71
	Average		**10.54**

Source: www.zacks.com (Aug 11, 2009)

Samuel C. Hadaway
Exhibit PPL/218

Docket No. UE-210
Exhibit PPL/218
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Corrections & Updates to Mr. Storm’ s Discounted Cash Flow Analysis

August 2009

PacifiCorp Oregon
Corrections & Updates to Storm Discounted Cash Flow Analysis
Summary Of Results

	Base Case	Case 1	Case 2	Case 3	Case 4
Company	Reproduction of Mr. Storm's Three-Stage DCF Analysis	Base Case with Individual Company Average	Case 1 with No Div Cut in 2015	Case 2 Excluding GDP Growth Adjustment (GDP Growth=5.16%)	Case 3 with Hadaway GDP Growth (GDP Growth=6.2%)
1 Con. Edison		10.3%	10.6%	10.8%	11.5%
2 DTE Energy Co.		11.4%	11.7%	11.9%	12.6%
3 Empire District		11.7%	12.1%	12.3%	12.9%
4 Entergy Corp.		8.7%	8.9%	9.1%	9.8%
5 FirstEnergy		10.3%	10.6%	10.8%	11.5%
6 FPL Group, Inc.		7.9%	8.1%	8.3%	9.0%
7 IDACORP		9.2%	9.4%	9.6%	10.3%
8 Progress Energy		10.4%	10.7%	10.9%	11.5%
9 Southern Co.		9.8%	10.1%	10.3%	11.0%
10 Vectren Corp.		10.1%	10.4%	10.6%	11.2%
11 Wisconsin Energy		9.3%	9.6%	9.8%	10.4%
12 Xcel Energy Inc.		9.8%	10.1%	10.3%	11.0%
Average of "Composite Company"	**9.6%**				
Individual Company Average		**9.9%**	**10.2%**	**10.4%**	**11.1%**
Individual Company Median		**10.0%**	**10.3%**	**10.5%**	**11.1%**

Source: Value Line Investment Survey, Electric Utility (East), May 29, 2009; (Central), Jun 26, 2009; (West), May 8, 2009.

Notes:
Base Case: See Storm workpapers and BaseCase&Case1 backup tab in this spreadsheet.
Case 1: Results calculated for each individual company. Average and median values calculated based on individual company results.
Case 2: Dividend cut contained in Mr. Storm's analysis in 2015 is eliminated and long-term growth is assumed to begin in 2015.
See Case2 backup tab in this spreadsheet.
Case 3: 5% reduction to GDP growth rate does not apply to utilities in comparable group and is eliminated.
See Case3 backup tab in this spreadsheet.
Case 4: See Hadaway Exhibit PPL/204
See Case4 backup tab in this spreadsheet.

PacifiCorp Oregon
Corrections & Updates to Storm Discounted Cash Flow Analysis
Individual Company Average vs. Average of Composite Company

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		2009	2009	2010	2011	2012	2013	2014	2015	2016		2048	
	Company	P0	D1	D2	D3	D4	D5	D6	D7	D8		D40	IRR
1	Con. Edison	-36.71	2.36	2.38	2.40	2.42	2.44	2.46	2.38	2.50	….	318.19	10.31%
2	DTE Energy Co.	-31.33	2.12	2.12	2.27	2.43	2.50	2.58	2.48	2.61	….	309.96	11.38%
3	Empire District	-16.29	1.28	1.28	1.33	1.38	1.40	1.42	1.37	1.44	….	133.25	11.72%
4	Entergy Corp.	-76.59	3.00	3.20	3.38	3.55	3.80	4.05	3.90	4.10	….	477.60	8.68%
5	FirstEnergy	-38.67	2.20	2.20	2.37	2.53	2.65	2.77	2.67	2.80	….	287.13	10.30%
6	FPL Group, Inc.	-56.85	1.89	2.00	2.08	2.16	2.30	2.44	2.35	2.47	….	343.98	7.90%
7	IDACORP	-25.42	1.20	1.20	1.20	1.20	1.20	1.20	1.16	1.22	….	270.38	9.16%
8	Progress Energy	-37.11	2.48	2.50	2.52	2.53	2.56	2.59	2.49	2.62	….	278.24	10.36%
9	Southern Co.	-30.79	1.73	1.80	1.86	1.92	2.00	2.08	2.01	2.11	….	176.26	9.82%
10	Vectren Corp.	-23.24	1.35	1.39	1.43	1.46	1.51	1.56	1.50	1.58	….	178.62	10.08%
11	Wisconsin Energy	-40.14	1.35	1.55	1.70	1.86	2.15	2.44	2.35	2.47	….	295.08	9.28%
12	Xcel Energy Inc.	-17.98	0.97	1.00	1.03	1.07	1.10	1.13	1.09	1.15	….	146.04	9.83%
	Composite Average	-35.93	1.83	1.89	1.96	2.04	2.13	2.23	2.15	2.25	….	267.89	**9.62%**
	Individual Co Average												**9.90%**
	Individual Co Median												**9.96%**

Notes:

(1) Initial price data from Storm workpapers.

(2)-(7) Dividend data from Storm workpapers based on Value Line growth rates.

(8) Shaded area in 2015 indicates dividend cut contained in Mr. Storm's analysis.

(9)-(10) Dividends assumed to grow at long-term GDP rate after 2015 through 2048.

(11) Amount in last year (2048) also includes terminal price.

(12) IRR is the "internal rate of return," which is the return expected if the initial price in column 1 is paid and the dividends and terminal price shown in columns 2-11 are received.

Docket No. UE-210
Exhibit PPL/219
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Updated Gorman ROE Results

August 2009

PacifiCorp Oregon

Summary of Updated Gorman ROE Results

	(1)	(2)
	Summary of Results	
	Gorman Initial ROE	**Updated ROE**
DCF Models		
Constant Growth DCF (Analysts' Growth)	11.68%	**11.68%**
Constant Growth DCF (Sustainable Growth)	10.62%	**10.62%**
Multi-Stage DCF	10.96%	**11.74%**
Average DCF	11.09%	**11.35%**
Risk Premium Models		
Treasury Bond	9.84%	**10.54%**
Current Single-A Utility Bond	10.17%	**10.66%**
Average Risk Premium	10.00%	**10.60%**
Average CAPM	8.60%	**NA**
ROE (Recommended)	10.00%	**NA**
ROE (excluding CAPM)	10.65%	**11.05%**

Notes:
Column 1: Gorman, pages 28, 33, and 39.
Column 2: Constant Growth DCF results not changed; see page 2 of this Exhibit for updated Multi-Stage DCF result; see average of results from pages 3 and 5 of this Exhibit for updated Risk Premium result; CAPM results are not reliable and are excluded as discussed in my testimony.

PacifiCorp Oregon
Gorman Multi-Stage Growth DCF Analysis (with Updated Long-Term GDP Growth)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				First Stage	Second Stage Growth					Third Stage	**Updated**
		Price	Dividend	Growth						Growth	**Cost of**
No.	Company	P_0	D_0	(EPS)	Year 6	Year 7	Year 8	Year 9	Year 10	(GDP)	**Equity**
1	ALLETE	$26.62	$1.76	5.00%	5.20%	5.40%	5.60%	5.80%	6.00%	6.20%	**12.75%**
2	Alliant Energy Co.	$24.08	$1.50	5.75%	5.83%	5.90%	5.98%	6.05%	6.13%	6.20%	**12.64%**
3	Con. Edison	$37.12	$2.36	2.86%	3.42%	3.97%	4.53%	5.09%	5.64%	6.20%	**11.72%**
4	DPL Inc.	$22.34	$1.14	7.72%	7.47%	7.21%	6.96%	6.71%	6.45%	6.20%	**12.13%**
5	DTE Energy Co.	$29.67	$2.12	4.33%	4.64%	4.95%	5.27%	5.58%	5.89%	6.20%	**13.01%**
6	Duke Energy	$14.03	$0.92	4.33%	4.64%	4.95%	5.27%	5.58%	5.89%	6.20%	**12.44%**
7	Edison Internat.	$29.21	$1.24	4.16%	4.50%	4.84%	5.18%	5.52%	5.86%	6.20%	**10.15%**
8	Entergy Corp.	$70.85	$3.00	8.09%	7.78%	7.46%	7.15%	6.83%	6.52%	6.20%	**11.24%**
9	FPL Group, Inc.	$53.92	$1.89	9.61%	9.04%	8.47%	7.91%	7.34%	6.77%	6.20%	**10.78%**
10	IDACORP	$23.66	$1.20	5.00%	5.20%	5.40%	5.60%	5.80%	6.00%	6.20%	**11.20%**
11	NSTAR	$30.82	$1.50	6.36%	6.33%	6.31%	6.28%	6.25%	6.23%	6.20%	**11.41%**
12	PG&E Corp.	$37.34	$1.68	6.88%	6.77%	6.65%	6.54%	6.43%	6.31%	6.20%	**11.17%**
13	Portland General	$17.88	$0.98	6.60%	6.53%	6.47%	6.40%	6.33%	6.27%	6.20%	**12.16%**
14	Progress Energy	$35.36	$2.48	5.13%	5.31%	5.49%	5.67%	5.84%	6.02%	6.20%	**13.20%**
15	Sempra Energy	$45.95	$1.56	6.66%	6.58%	6.51%	6.43%	6.35%	6.28%	6.20%	**9.89%**
16	Southern Co.	$29.60	$1.75	5.39%	5.53%	5.66%	5.80%	5.93%	6.07%	6.20%	**12.18%**
17	Vectren Corp.	$21.84	$1.34	6.53%	6.48%	6.42%	6.37%	6.31%	6.26%	6.20%	**12.84%**
18	Wisconsin Energy	$39.76	$1.35	8.82%	8.38%	7.95%	7.51%	7.07%	6.64%	6.20%	**10.43%**
19	Xcel Energy Inc.	$18.01	$0.95	5.85%	5.91%	5.97%	6.03%	6.08%	6.14%	6.20%	**11.68%**
	Average	$32.00	$1.62	6.06%	6.08%	6.10%	6.13%	6.15%	6.18%	6.20%	**11.74%**

Notes:
Columns 1-3: ICNU-CUB/312.
Columns 4-8: Linear interpolation between columns 3 and 9.
Column 9: PPL/204.
Column 10: The internal rate of return implied by the price in column 1 and dividends for 150 periods. The initial dividend shown in column 2 is assumed to grow for the first five periods at the rate in column 3, then at the rate in columns 4-8 for years 6-10, than at the rate in column 9 for the remaining periods.

PacifiCorp Oregon
Update of Gorman Risk Premium Analysis - Treasury Bond

	(1) TREASURY BOND YIELD	(2) AUTHORIZED ELECTRIC RETURNS	(3) INDICATED RISK PREMIUM
1986	7.78%	13.93%	6.15%
1987	8.59%	12.99%	4.40%
1988	8.96%	12.79%	3.83%
1989	8.45%	12.97%	4.52%
1990	8.61%	12.70%	4.09%
1991	8.14%	12.55%	4.41%
1992	7.67%	12.09%	4.42%
1993	6.59%	11.41%	4.82%
1994	7.37%	11.34%	3.97%
1995	6.88%	11.55%	4.67%
1996	6.71%	11.39%	4.68%
1997	6.61%	11.40%	4.79%
1998	5.58%	11.66%	6.08%
1999	5.87%	10.77%	4.90%
2000	5.94%	11.43%	5.49%
2001	5.49%	11.09%	5.60%
2002	5.43%	11.16%	5.73%
2003	4.96%	10.97%	6.01%
2004	5.05%	10.75%	5.70%
2005	4.65%	10.54%	5.89%
2006	4.91%	10.36%	5.45%
2007	4.84%	10.36%	5.52%
2008	4.28%	10.46%	6.18%
Q1 2009	3.45%	10.31%	6.86%
AVERAGE	6.37%	11.54%	5.17%

INDICATED COST OF EQUITY	
PROJECTED TREASURY BOND YIELD*	4.60%
MOODY'S AVG ANNUAL YIELD DURING STUDY	6.37%
INTEREST RATE DIFFERENCE	-1.77%
INTEREST RATE CHANGE COEFFICIENT	-43.57%
ADUSTMENT TO AVG RISK PREMIUM	0.77%
BASIC RISK PREMIUM	5.17%
INTEREST RATE ADJUSTMENT	0.77%
EQUITY RISK PREMIUM	5.94%
PROJECTED TREASURY BOND YIELD*	4.60%
INDICATED EQUITY RETURN	**10.54%**

Notes:

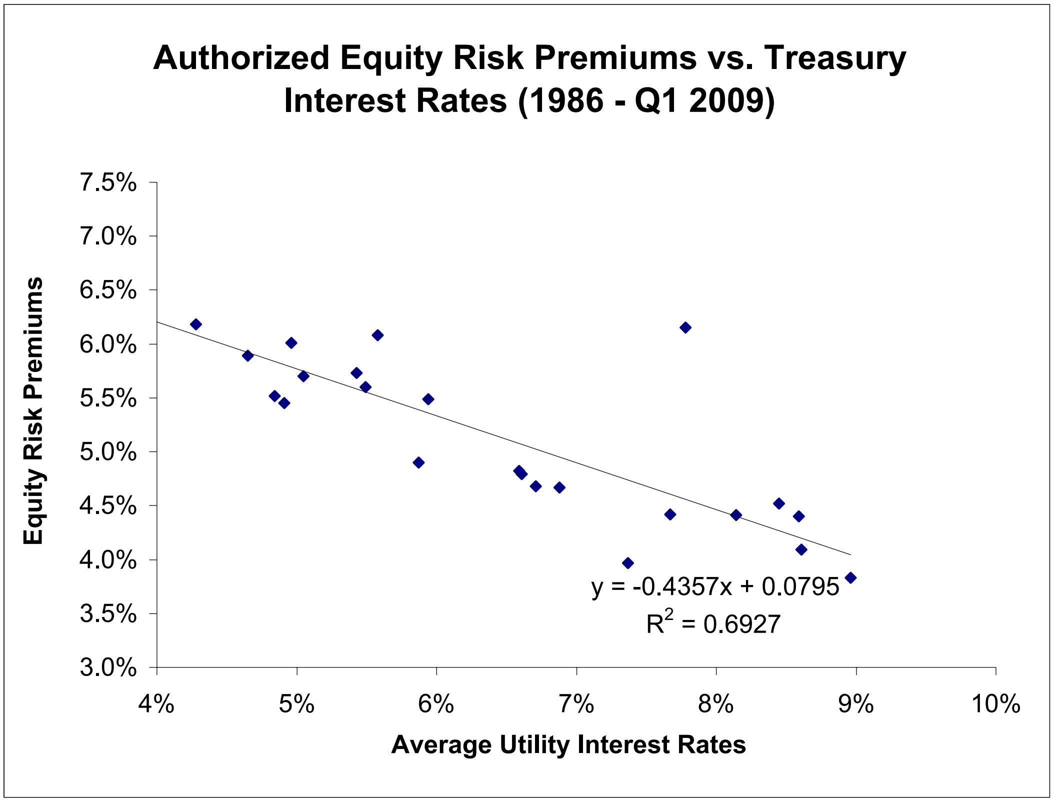
Columns 1-3: ICNU-CUB/314.

*Gorman page 33 for Projected Treasury Bond Yield .

See regression data on next page for derivation of "Interest Rate Change Coefficient."

PacifiCorp Oregon

Update of Gorman Risk Premium Analysis - Treasury Bond



PacifiCorp Oregon
Update of Gorman Risk Premium Analysis - Utility Bond

	(1) MOODY'S "A" RATED PUBLIC UTILITY BOND YIELD	(2) AUTHORIZED ELECTRIC RETURNS	(3) INDICATED RISK PREMIUM
1986	9.58%	13.93%	4.35%
1987	10.10%	12.99%	2.89%
1988	10.49%	12.79%	2.30%
1989	9.77%	12.97%	3.20%
1990	9.86%	12.70%	2.84%
1991	9.36%	12.55%	3.19%
1992	8.69%	12.09%	3.40%
1993	7.59%	11.41%	3.82%
1994	8.31%	11.34%	3.03%
1995	7.89%	11.55%	3.66%
1996	7.75%	11.39%	3.64%
1997	7.60%	11.40%	3.80%
1998	7.04%	11.66%	4.62%
1999	7.62%	10.77%	3.15%
2000	8.24%	11.43%	3.19%
2001	7.76%	11.09%	3.33%
2002	7.37%	11.16%	3.79%
2003	6.58%	10.97%	4.39%
2004	6.16%	10.75%	4.59%
2005	5.65%	10.54%	4.89%
2006	6.07%	10.36%	4.29%
2007	6.07%	10.36%	4.29%
2008	6.53%	10.46%	3.93%
Q1 2009	6.37%	10.31%	3.94%
AVERAGE	7.85%	11.54%	3.69%

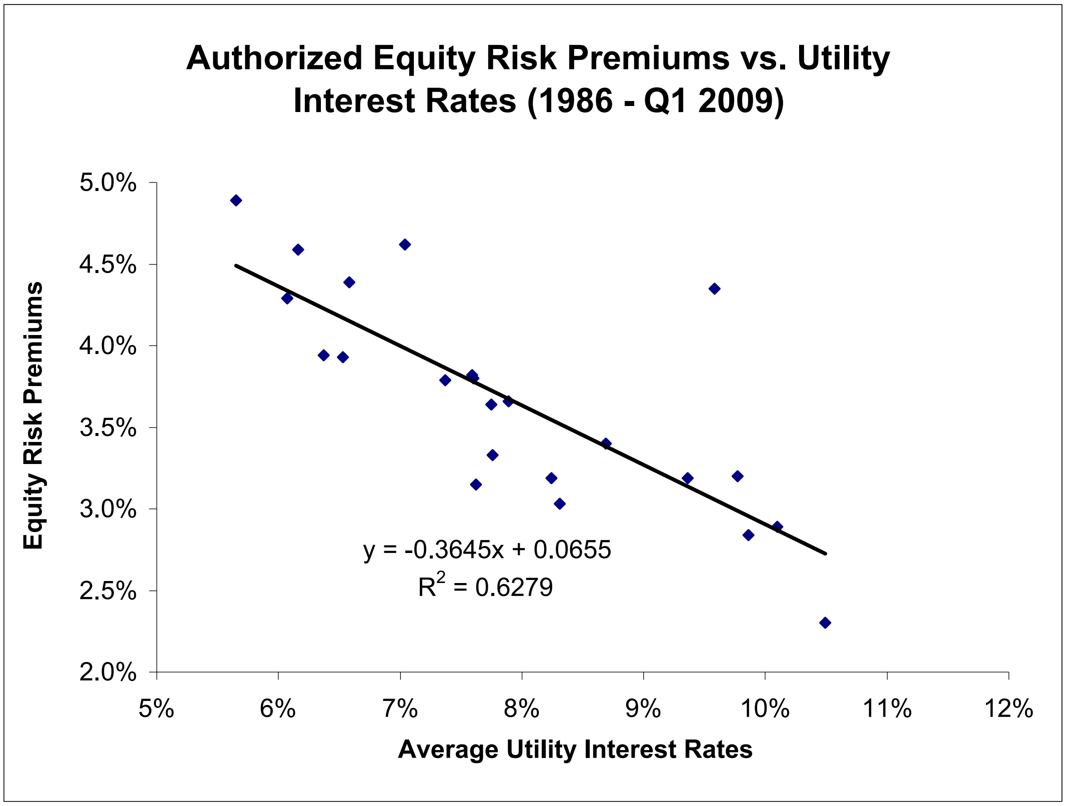
INDICATED COST OF EQUITY

CURRENT "A" UTILITY BOND YIELD*	6.46%
MOODY'S AVG ANNUAL YIELD DURING STUDY	7.85%
INTEREST RATE DIFFERENCE	-1.39%
INTEREST RATE CHANGE COEFFICIENT	-36.45%
ADUSTMENT TO AVG RISK PREMIUM	0.51%
BASIC RISK PREMIUM	3.69%
INTEREST RATE ADJUSTMENT	0.51%
EQUITY RISK PREMIUM	4.20%
CURRENT "A" UTILITY BOND YIELD*	6.46%
INDICATED EQUITY RETURN	**10.66%**

Source:
Columns 1-3: ICNU-CUB/315.
*Gorman page 33 for Current "Baa" Utility Bond Yield.
See regression data on next page for derivation of "Interest Rate Change Coefficient."

PacifiCorp Oregon

Update of Gorman Risk Premium Analysis - Utility Bond



Docket No. UE-210
Exhibit PPL/220
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Updated Discounted Cash Flow Analysis

August 2009

PacifiCorp Oregon
Discounted Cash Flow Analysis
Summary Of DCF Model Results

Company	Constant Growth DCF Model Analysts' Growth Rates	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 ALLETE	11.3%	12.5%	11.9%
2 Alliant Energy Co.	11.0%	12.4%	12.6%
3 Con. Edison	9.7%	12.6%	11.8%
4 DPL Inc.	13.3%	11.3%	11.0%
5 DTE Energy Co.	11.9%	12.9%	12.8%
6 Duke Energy	11.2%	12.9%	12.6%
7 Edison Internat.	7.8%	10.3%	10.3%
8 Entergy Corp.	11.6%	10.4%	10.4%
9 FPL Group, Inc.	13.0%	9.6%	9.6%
10 IDACORP	9.7%	11.0%	10.9%
11 NSTAR	11.9%	11.2%	11.4%
12 PG&E Corp.	11.5%	10.8%	11.1%
13 Portland General	11.4%	11.7%	11.6%
14 Progress Energy	11.9%	13.0%	12.1%
15 Sempra Energy	9.5%	9.6%	9.8%
16 Southern Co.	11.4%	12.1%	11.8%
17 Vectren Corp.	12.1%	12.1%	11.7%
18 Wisconsin Energy	12.0%	9.8%	10.6%
19 Xcel Energy Inc.	11.5%	11.6%	11.3%
GROUP AVERAGE	11.2%	11.5%	11.3%
GROUP MEDIAN	11.5%	11.6%	11.4%

Source: Value Line Investment Survey, Electric Utility (East), May 29, 2009; (Central), Jun 26, 2009; (West), Aug 7, 2009.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Constant Growth DCF Model
Analysts' Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				Analysts' Estimated Growth				
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	Value Line	Zacks	Thomson	Average Growth *(Cols 4-6)*	**ROE** K=Div Yld+G *(Cols 3+7)*
1 ALLETE	28.25	1.78	6.30%	NA	4.00%	6.00%	5.00%	11.3%
2 Alliant Energy Co.	24.87	1.55	6.23%	4.50%	5.30%	4.60%	4.80%	11.0%
3 Con. Edison	36.94	2.37	6.42%	2.50%	4.00%	3.33%	3.28%	9.7%
4 DPL Inc.	22.74	1.16	5.10%	8.00%	7.40%	9.33%	8.24%	13.3%
5 DTE Energy Co.	31.70	2.12	6.69%	7.50%	5.00%	3.00%	5.17%	11.9%
6 Duke Energy	14.38	0.96	6.68%	5.00%	4.80%	3.67%	4.49%	11.2%
7 Edison Internat.	30.49	1.27	4.15%	3.50%	6.30%	1.05%	3.62%	7.8%
8 Entergy Corp.	74.35	3.10	4.17%	6.00%	7.30%	9.02%	7.44%	11.6%
9 FPL Group, Inc.	56.43	1.95	3.45%	10.00%	9.00%	9.59%	9.53%	13.0%
10 IDACORP	24.84	1.20	4.83%	4.50%	5.00%	5.00%	4.83%	9.7%
11 NSTAR	31.31	1.58	5.05%	8.00%	6.40%	6.25%	6.88%	11.9%
12 PG&E Corp.	37.53	1.74	4.64%	6.50%	7.10%	6.92%	6.84%	11.5%
13 Portland General	18.69	1.03	5.51%	3.50%	6.70%	7.60%	5.93%	11.4%
14 Progress Energy	36.58	2.49	6.81%	6.00%	4.70%	4.50%	5.07%	11.9%
15 Sempra Energy	48.35	1.64	3.39%	5.50%	6.50%	6.33%	6.11%	9.5%
16 Southern Co.	30.07	1.77	5.87%	4.50%	7.30%	4.83%	5.54%	11.4%
17 Vectren Corp.	23.23	1.37	5.90%	5.50%	6.80%	6.43%	6.24%	12.1%
18 Wisconsin Energy	40.33	1.45	3.60%	8.00%	8.40%	8.72%	8.37%	12.0%
19 Xcel Energy Inc.	18.19	0.99	5.42%	6.50%	5.30%	6.58%	6.13%	11.5%
GROUP AVERAGE	33.12	1.66	5.27%	5.86%	6.17%	5.93%	5.97%	11.2%
GROUP MEDIAN			5.42%					11.5%

Source: Value Line Investment Survey, Electric Utility (East), May 29, 2009; (Central), Jun 26, 2009; (West), Aug 7, 2009.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Constant Growth DCF Model
Long-Term GDP Growth

		(9)	(10)	(11)	(12)	(13)
	Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	GDP Growth	ROE K=Div Yld+G *(Cols 11+12)*
1	ALLETE	28.25	1.78	6.30%	6.20%	12.5%
2	Alliant Energy Co.	24.87	1.55	6.23%	6.20%	12.4%
3	Con. Edison	36.94	2.37	6.42%	6.20%	12.6%
4	DPL Inc.	22.74	1.16	5.10%	6.20%	11.3%
5	DTE Energy Co.	31.70	2.12	6.69%	6.20%	12.9%
6	Duke Energy	14.38	0.96	6.68%	6.20%	12.9%
7	Edison Internat.	30.49	1.27	4.15%	6.20%	10.3%
8	Entergy Corp.	74.35	3.10	4.17%	6.20%	10.4%
9	FPL Group, Inc.	56.43	1.95	3.45%	6.20%	9.6%
10	IDACORP	24.84	1.20	4.83%	6.20%	11.0%
11	NSTAR	31.31	1.58	5.05%	6.20%	11.2%
12	PG&E Corp.	37.53	1.74	4.64%	6.20%	10.8%
13	Portland General	18.69	1.03	5.51%	6.20%	11.7%
14	Progress Energy	36.58	2.49	6.81%	6.20%	13.0%
15	Sempra Energy	48.35	1.64	3.39%	6.20%	9.6%
16	Southern Co.	30.07	1.77	5.87%	6.20%	12.1%
17	Vectren Corp.	23.23	1.37	5.90%	6.20%	12.1%
18	Wisconsin Energy	40.33	1.45	3.60%	6.20%	9.8%
19	Xcel Energy Inc.	18.19	0.99	5.42%	6.20%	11.6%
	GROUP AVERAGE	33.12	1.66	5.27%	6.20%	11.5%
	GROUP MEDIAN			5.42%		11.6%

Source: Value Line Investment Survey, Electric Utility (East), May 29, 2009; (Central), Jun 26, 2009; (West), Aug 7, 2009.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Low Near-Term Growth
Two-Stage Growth DCF Model

	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
	Next		Annual	CASH FLOWS							ROE=Internal
Company	Year's Div	2013 Div	Change to 2013	Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	Rate of Return *(Yrs 0-150)*
1 ALLETE	1.78	1.92	0.05	-28.25	1.78	1.83	1.87	1.92	2.04	6.20%	11.9%
2 Alliant Energy Co.	1.55	1.92	0.12	-24.87	1.55	1.67	1.80	1.92	2.04	6.20%	12.6%
3 Con. Edison	2.37	2.44	0.02	-36.94	2.37	2.39	2.42	2.44	2.59	6.20%	11.8%
4 DPL Inc.	1.16	1.30	0.05	-22.74	1.16	1.21	1.25	1.30	1.38	6.20%	11.0%
5 DTE Energy Co.	2.12	2.50	0.13	-31.70	2.12	2.25	2.37	2.50	2.66	6.20%	12.8%
6 Duke Energy	0.96	1.10	0.05	-14.38	0.96	1.01	1.05	1.10	1.17	6.20%	12.6%
7 Edison Internat.	1.27	1.50	0.08	-30.49	1.27	1.34	1.42	1.50	1.59	6.20%	10.3%
8 Entergy Corp.	3.10	3.80	0.23	-74.35	3.10	3.33	3.57	3.80	4.04	6.20%	10.4%
9 FPL Group, Inc.	1.95	2.30	0.12	-56.43	1.95	2.06	2.18	2.30	2.44	6.20%	9.6%
10 IDACORP	1.20	1.40	0.07	-24.84	1.20	1.27	1.33	1.40	1.49	6.20%	10.9%
11 NSTAR	1.58	1.95	0.12	-31.31	1.58	1.70	1.83	1.95	2.07	6.20%	11.4%
12 PG&E Corp.	1.74	2.20	0.15	-37.53	1.74	1.89	2.05	2.20	2.34	6.20%	11.1%
13 Portland General	1.03	1.20	0.06	-18.69	1.03	1.09	1.14	1.20	1.27	6.20%	11.6%
14 Progress Energy	2.49	2.56	0.02	-36.58	2.49	2.51	2.54	2.56	2.72	6.20%	12.1%
15 Sempra Energy	1.64	2.10	0.15	-48.35	1.64	1.79	1.95	2.10	2.23	6.20%	9.8%
16 Southern Co.	1.77	2.00	0.08	-30.07	1.77	1.84	1.92	2.00	2.12	6.20%	11.8%
17 Vectren Corp.	1.37	1.51	0.05	-23.23	1.37	1.42	1.46	1.51	1.60	6.20%	11.7%
18 Wisconsin Energy	1.45	2.15	0.23	-40.33	1.45	1.68	1.92	2.15	2.28	6.20%	10.6%
19 Xcel Energy Inc.	0.99	1.10	0.04	-18.19	0.99	1.02	1.06	1.10	1.17	6.20%	11.3%
GROUP AVERAGE											11.3%
GROUP MEDIAN											11.4%

Source: Value Line Investment Survey, Electric Utility (East), May 29, 2009; (Central), Jun 26, 2009; (West), Aug 7, 2009.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Discounted Cash Flow Analysis
Column Descriptions

Column 1: Three-month Average Price per Share (May 2009-Jul 2009)

Column 2: Average of Estimated 2009 & 2010 Div per Share from Value Line

Column 3: Column 2 Divided by Column 1

Column 4: "Est'd 06-08 to 12-14" Earnings Growth Reported by Value Line

Column 5: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com

Column 6: "Next 5 Years (per annum) Growth Estimate Reported by Thomson Financial Network (at Yahoo Finance)

Column 7: Average of Columns 4-6

Column 8: Column 3 Plus Column 7

Column 9: See Column 1

Column 10: See Column 2

Column 11: Column 10 Divided by Column 9

Column 12: Average of GDP Growth During the Last 10 year, 20 year, 30 year, 40 year, 50 year, and 60 year growth periods. See Exhibit PPL/204

Column 13: Column 11 Plus Column 12

Column 14: See Column 2

Column 15: Estimated 2013 Dividends per Share from Value Line

Column 16: (Column 15 Minus Column 14) Divided by Three

Column 17: See Column 1

Column 18: See Column 14

Column 19: Column 18 Plus Column 16

Column 20: Column 19 Plus Column 19

Column 21: Column 20 Plus Column 16

Column 22: Column 21 Increased by the Growth Rate Shown in Column 23

Column 23: See Column 12

Column 24: The Internal Rate of Return of the Cash Flows in Columns 17-22 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 23

Samuel C. Hadaway
Exhibit PPL/221

Docket No. UE-210
Exhibit PPL/221
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Samuel C. Hadaway

Updated Risk Premium Analysis

August 2009

PacifiCorp Oregon

Risk Premium Analysis

(Based on Projected Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
AVERAGE	9.15%	12.34%	3.19%

INDICATED COST OF EQUITY

PROJECTED SINGLE-A UTILITY BOND YIELD*	7.53%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.15%
INTEREST RATE DIFFERENCE	-1.62%
INTEREST RATE CHANGE COEFFICIENT	-41.34%
ADUSTMENT TO AVG RISK PREMIUM	0.67%
BASIC RISK PREMIUM	3.19%
INTEREST RATE ADJUSTMENT	0.67%
EQUITY RISK PREMIUM	3.86%
PROJECTED SINGLE-A UTILITY BOND YIELD*	7.53%
INDICATED EQUITY RETURN	**11.39%**

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Projected single-A bond yield is 183 basis points over projected long-term Treasury bond rate of 5.7% from Exhibit PPL/215, p. 2. The single-A spread is for 3 months ended July 2009 from Exhibit PPL/215, p. 1.

PacifiCorp Oregon

Risk Premium Analysis

(Based on Current Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
AVERAGE	9.15%	12.34%	3.19%

INDICATED COST OF EQUITY

CURRENT SINGLE-A UTILITY BOND YIELD*	6.22%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.15%
INTEREST RATE DIFFERENCE	-2.93%
INTEREST RATE CHANGE COEFFICIENT	-41.34%
ADUSTMENT TO AVG RISK PREMIUM	1.21%
BASIC RISK PREMIUM	3.19%
INTEREST RATE ADJUSTMENT	1.21%
EQUITY RISK PREMIUM	4.40%
CURRENT SINGLE-A UTILITY BOND YIELD*	6.22%
INDICATED EQUITY RETURN	**10.62%**

(1) Moody's Investors Service

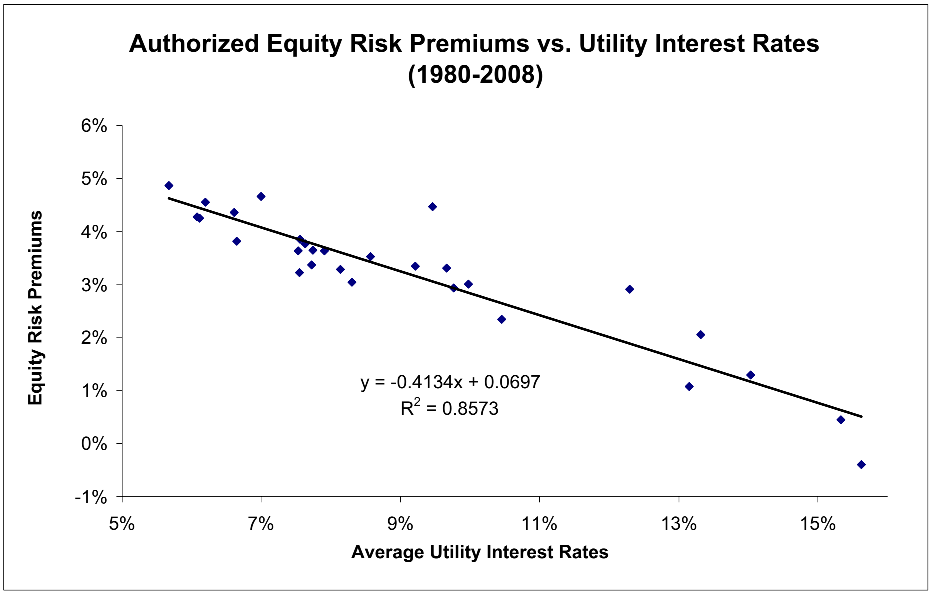
(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Current single-A utility bond yield is three month average of Moody's Single-A Public Utility Bond Yield Average through July 2009 from Exhibit PPL/215, p. 1.

PacifiCorp Oregon

Risk Premium Analysis

Regression Analysis & Interest Rate Change Coefficient



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.925929671
R Square	0.857345755
Adjusted R Square	0.852062265
Standard Error	0.004864141
Observations	29

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.003839258	0.003839258	162.2688162	6.25236E-13
Residual	27	0.000638816	2.36599E-05		
Total	28	0.004478074			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.069723958	0.003102577	22.47291965	5.19996E-19	0.063357996	0.07608992	0.063357996	0.07608992
X Variable 1	-0.413428393	0.032455086	-12.73847778	6.25236E-13	-0.480020728	-0.346836058	-0.480020728	-0.346836058

Bruce N. Williams
Exhibit PPL/307

Docket No. UE-210
Exhibit PPL/307
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Bruce N. Williams

August 2009

Q. Are you the same Bruce N. Williams who previously provided testimony in this docket?

A. Yes, as Exhibit PPL/300.

Purpose and Summary

Q. Please explain the purpose of your reply testimony.

A. My reply testimony has four primary sections. First, I explain the Company's updated capital structure and rate of return recommendations. Second, I respond to the testimony of the joint witness for the Industrial Customers of Northwest Utilities and the Citizens' Utility Board ("ICNU-CUB"), Mr. Michael P. Gorman concerning the Company's capital structure. Third, I discuss Public Utility Commission of Oregon Staff ("Staff") witness Mr. Jorge Ordonez's proposed adjustments to the cost of debt and preferred stock. Fourth, I address Staff witness Mr. Dustin Ball's proposed adjustments to the Company's FAS 87 pension expense and FAS 106 Post Retirement Benefits.

Q. Are there items concerning the cost of capital in your direct testimony with which the parties agreed?

A. Yes. Staff is not proposing any direct adjustments to the Company's capital structure. Staff does, however, make an incorrect downward adjustment to its return on equity estimate based upon the allegation that PacifiCorp has higher equity than average in Staff's comparable group and therefore has less risk. Dr. Samuel C. Hadaway addresses this issue. Additionally, Mr. Gorman accepts the cost of long-term debt and preferred stock as filed in my direct testimony.

Q. Please summarize your testimony.

A. I provide an update to three components of the Company' s cost of capital. I explain why the Company' s equity ratio is now projected to be 51.0 percent instead of 51.2 percent; the Company' s cost of debt is now projected to be 5.96 percent instead of 5.98 percent; resulting in a weighted average cost of capital of 8.53 percent instead of 8.55 percent.

I demonstrate that Mr. Gorman' s proposal to reduce the Company' s equity in its capital structure from 51.2 percent to 50.5 percent is based on a calculation of retained earnings that is flawed because it relies on mismatched time periods and cost components. Additionally, Mr. Gorman improperly focused on Oregon financial forecasts instead of the Company-wide data properly used to calculate retained earnings for the Company' s capital structure.

With respect to Staff' s adjustments to long-term debt, I show that Staff' s proposal to substitute seven-year maturities for the Company' s proposed thirty-year maturities for new long-term debt is inconsistent with the Company' s actual approach to debt financing and Oregon Commission precedent. Nevertheless, because the amount of new long-term debt is small, the Company proposes to compromise this point by using ten-year maturities. On Staff' s proposal to re-price the variable-rate tax-exempt debt, I explain how Staff' s proposal relies on an improper exclusion of certain months from the period used to calculate the rate and the use of an interest rate from April 2009, instead of a time period closer to the rate effective date.

I respond to Staff' s adjustment to the Company' s pension expense by showing that the Company's long-term rate of return for its pension plan is the result of a calculation based upon a detailed review of plan assets. I contrast this to Staff's proposed rate of return, which is based upon generalized industry data without any attempt to determine plan comparability. Similarly, I show that the Company derived its proposed 6.3 percent discount rate for 2010 in consultation with its actuary. I also show that the actuary's most recent assessment further demonstrates the unreasonableness of Staff's proposal to use for 2010 the Company's 2009 discount rate of 6.9 percent.

Update to Capital Structure and Rate of Return Recommendation

Q. Is the Company proposing an update to the capital structure?

A. Yes. At the time the direct testimony in this docket was prepared, the Company anticipated receiving a $200 million capital contribution during the fourth quarter of 2009, while paying no dividends to its common shareholder. The Company now expects to receive a capital contribution of $125 million during the fourth quarter of 2009, with no change in the expectations on dividend payments. The resulting impact is to reduce the common equity component of the capital structure to 51.0 percent.

Q. What is the new proposed overall cost of capital including this adjustment and other changes discussed in this testimony?

A. The Company's updated rate of return is 8.53 percent, a slight reduction from its initial 8.55 percent recommendation. Including proposed adjustments to the cost of long-term debt discussed below and the adjusted common equity component, the proposed capital structure and costs from which this rate of return is derived are:

Overall Cost of Capital

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	48.7%	5.96%	2.90%
Preferred Stock	0.3%	5.41%	0.02%
Common Stock Equity	51.0%	11.00%	5.61%
			8.53%

Reply to ICNU-CUB Capital Structure Adjustment

Q. Please describe the adjustment that Mr. Gorman is proposing to the Company' s capital structure.

A. Mr. Gorman proposes to reduce the common equity component of the Company' s capital structure from 51.2 percent to 50.5 percent based on his projection of an increase in retained earnings during 2009 for PacifiCorp. Mr. Gorman calculates this increase by using the Company' s forecast Oregon jurisdictional return on equity during 2010 if rate relief is not granted in this docket. This produces a lower increase in retained earnings than the Company expects on a total company basis during 2009. The lower retained earnings result in reduced common equity as a percentage of the total capitalization.

Q. Do you agree with Mr. Gorman' s adjustment?

A. No, for several reasons. First, he is using inconsistent time periods for the basis of his adjustments. He uses a projected return on equity for the Oregon jurisdiction during 2010 and then applies that rate to the beginning 2009 common equity level. Clearly, this is an inappropriate and inconsistent mismatch of returns, capital structure balances and periods of time.

Second, he is applying the Oregon jurisdictional return to the Company' s entire operations which include five other states. The Company finances its operations in all six state jurisdictions with one aggregate capital structure – there are not six individual capital structures or six individual credit ratings. The Company's increase or decrease in retained earnings will be an aggregate of its financial results for all of the jurisdictions in which it operates, rather than just one.

Further, Mr. Gorman compares the forecasted 2010 return on equity for the Oregon jurisdiction, absent any rate relief, which is calculated using a 13 month average for capital structure, to his calculated 2009 total -company ROE. However, Mr. Gorman merely divides the increase in retained earnings into the beginning common equity level in order to produce his assessment of the Company's ROE. This results in his calculation overstating the 2009 return on equity as the amount of common equity is increasing throughout the time period due to all earnings being retained (no dividends are being paid) and capital contributions also being received. For instance, if he had calculated return on equity on the ending 2009 capital structure, the result would be a 2009 total company return on equity of 8.8 percent and not the 10 percent he cites.

Projected 2009 Increase in Retained Earnings	$590,595,729
Divided by 12/31/09 Common Equity	6,736,223,000
Equals ROE on ending equity	8.8%

Q. Do you believe that Mr. Gorman's reference to the Company's capital structure in its Washington general rate case is a valid comparison to this case?

A. No, primarily for the reason that the cases have different test periods and the

Washington jurisdiction employs different ratemaking principles to calculate the allowable capital structure. The Washington case is utilizing an average capital structure during the 12 months ending June 30, 2009. That end date will then exclude any increase in retained earnings or capital contributions received during the second half of 2009. This Oregon case is using a measurement date of December 31, 2009. Again, Mr. Gorman is attempting to compare non-comparable time periods.

Q. Mr. Gorman attempted to support his proposed return on equity as reasonable by stating that the Company's credit ratios would support its current ratings. Did his model accurately reflect adjustments that the rating agencies make when calculating PacifiCorp's financial metrics?

A. No, Mr. Gorman did not include a substantial amount of debt and interest adjustments that Standard & Poor's makes during its analysis of PacifiCorp. For example, Mr. Gorman failed to include a number of adjustments that resulted in $575 million of debt and $44 million of corresponding interest being excluded from his ratio calculations. These adjustments are clearly stated in Standard & Poor's April 1, 2009 credit report on PacifiCorp, which Mr. Gorman was certainly aware of since he cites the report on page 9 of his opening testimony. (ICNU-CUB/300, Gorman/9, lines 15-30)

Cost of Debt and Preferred Stock

Q. Can you please summarize the adjustments that Staff witness Mr. Ordonez proposes to the Company's cost of long-term debt and preferred stock.

A. Mr. Ordonez proposes two adjustments to the cost of long-term debt and one adjustment to the cost of preferred stock. The first adjustment to the cost of long-term debt is to assume a shorter maturity for the pro forma debt that is included in the cost of debt calculation. Mr. Ordonez' s second adjustment is to the Company' s variable rate, tax-exempt Pollution Control Revenue Bonds (" PCRBs"). Finally, Mr. Ordonez proposes to exclude certain costs from the cost of preferred stock calculation.

Q. Do you agree with these adjustments?

A. No. The proposed adjustments should not be accepted as they are inappropriate and inconsistent with the facts.

Cost of Long-Term Debt

Q. Please describe Mr. Ordonez' s proposed changes to the Company' s cost of long-term debt.

A. Mr. Ordonez' s first adjustment is to change the pro-forma test period debt issuance from a thirty-year maturity with an interest rate determined from forward rates and historical credit spreads to a seven-year maturity based on treasury rates and credit spreads during April 2009.

Q. Do you agree with this adjustment?

A. No. It is inconsistent with the Company' s practice of issuing longer term maturities. In Docket UE 116, the Commission rejected a similar Staff proposal to price PacifiCorp' s pro-forma test period debt issuance assuming a seven-year maturity date, recognizing that it was more likely that PacifiCorp would use a mix of ten- and thirty-year maturity dates.

Q. Have you determined the impact on the cost of long-term debt from this adjustment?

A. Yes. The adjustment essentially has no impact on the cost of debt in this docket due to the relatively small amount of pro-forma debt for which the rate is being determined, i.e. $14.6 million. However, the Company believes this adjustment is inconsistent with the proposed tenor of the issuance and contrary to Commission precedent.

Q. Given the immateriality of the adjustment, does PacifiCorp have a compromise position?

A. Yes. The Company is agreeable to compromise using a maturity of ten years for purposes of this docket. This position, however, should not be seen as setting a precedent for future determinations of cost of long-term debt.

Q. Please describe Mr. Ordonez' s proposed adjustment concerning variable rate tax-exempt debt.

A. As background, I will first summarize how the Company determines the coupon rate for its variable rate debt. As discussed in my direct testimony, the Company' s debt portfolio includes securities which are variable rate and on average have been trading at 85 percent of the London Interbank Offer Rate (" LIBOR") for the period January 2000 through December 2008. The Company then applied that 85 percent factor to the forward 30-day LIBOR rate at December 31, 2009 (that date is the end of the quarter prior to when the new rates in this docket are to be effective). The Company then added the respective credit enhancement and remarketing fees for each variable rate series. This method is consistent with the Company's past practices when determining the cost of debt in previous Oregon general rate cases as well as the other states that regulate PacifiCorp.

Mr. Ordonez generally followed the same process but made two significant changes. The first change is to exclude the time period between June and December 2008 when calculating the relationship of the average variable rate to LIBOR. By excluding that period, Mr. Ordonez calculates the relationship at 81 percent rather than the 85 percent in my direct testimony.

Q. Why did Mr. Ordonez remove this time period from the analysis?

A. Mr. Ordonez stated that it was removed "due to adverse market conditions." (Staff/900, Ordonez/9, line 5)

Q. Did the Company similarly remove time periods when rates were low in order to avoid including "favorable market conditions"?

A. No. The Company included all rates during the entire period of January 2000 to December 2008. To selectively remove periods for whatever reason is arbitrary and inappropriate when one is determining the average rate.

Q. What was Mr. Ordonez's second adjustment to the variable-rate tax exempt debt?

A. Rather than use a forward rate for 30-day LIBOR at December 31, 2009, Mr. Ordonez uses the 30-day LIBOR rate on April 14, 2009.

Q. Does the Company's use of a forward rate for 30-day LIBOR from December 31, 2009 better align with Commission precedent than use of a rate from April 14, 2009?

A. Yes. The Commission has previously determined that the cost of debt should be measured at the effective date of final rates in the proceeding. PacifiCorp set its long-term debt costs as of December 31, 2009, as a reasonable approximation of the costs of debt in February 2010, when new rates from this case will go into effect. Use of a 30-day LIBOR rate from December 31, 2009 better matches the Company's costs when the rates will be effective with customers' prices. There is no similar rationale justifying the use of Staff's April 14, 2009 30-day LIBOR rate.

Summary and Update on Long-Term Debt Costs

Q. Please summarize the adjustments to the cost of long-term debt you are proposing.

A. As I mentioned earlier, the Company is willing to use a 10-year maturity as the basis for determining the interest rate on the pro-forma series of long-term debt, even though a 30-year maturity is much more consistent with the actual maturities of the Company's recent long-term debt

Q. How did you determine the proposed new cost of the pro-forma long-term debt?

A. Using a current forward rate for the 10-year Treasury at December 31, 2009 and the average credit spread for a new issuance of 10-year long-term debt, which was provided to Staff in response to data request OPUC 334, results in the following:

10 Year Treasury Rate	3.91%
Average credit spread	1.34%
Pro-forma coupon rate	5.25%

This is the coupon rate for the pro-forma debt that the Company' s uses in its updated cost of long-term debt.

Q. Are there any other adjustments you are proposing?

A. Yes, we have also updated the variable-rate PCRBs to reflect current forward rates at December 31, 2009, for 30-day LIBOR of 1.42 percent. Applying the 85 percent factor that I discussed above produces a coupon rate of 1.21 percent for the variable-rate PCRBs. I have also included this rate in the updated cost of long-term debt.

Q. What is the Company' s updated cost of long-term debt?

A. The updated cost of long-term debt is 5.96 percent at December 31, 2009, as shown in Exhibit PPL/308. This updated cost includes both the adjustment for the pro-forma cost of long-term debt and the adjustment for the variable-rate PCRBs.

Cost of Preferred Stock

Q. Please explain Staff' s proposed adjustment to the cost of preferred stock.

A. Mr. Ordonez cites three reasons for excluding certain unrecovered costs associated with quarterly income debt securities (" QUIDS") that were redeemed prior to final maturity. These costs approximate $152,000 annually for PacifiCorp as a whole, which the Company is amortizing over the original life of these securities. Mr. Ordonez states that these costs should be excluded because:

i) The QUIDS are no longer outstanding and no specific replacement debt has been identified;

ii) the expenses are non-recurring; and

iii) in previous rate cases the Company did not identify new debt issuances used to specifically refund the QUIDS.

Q. Can you please provide some background on these securities and their subsequent redemption?

A. The Company issued two separate series of QUIDS during 1995 totaling $175.8 million. The first series bore a coupon rate of 8.55 percent with a maturity of 2025 while the second series had a coupon rate of 8.375 percent and a 2035 maturity. The Company incurred normal and reasonable expenses associated with the issuances of the two series. At the time of issuance and during their life, these securities were treated as preferred stock for regulatory accounting purposes. Initially, the rating agencies viewed QUIDS similar to traditional preferred stock and they received favorable equity treatment by the credit rating agencies. However, the rating agencies subsequently revised their view and later considered these types of securities as debt securities in their ratings analysis.

During November 2000, the Company redeemed the entirety of both series of QUIDS with cash generated from the sale of a subsidiary. The QUIDS were relatively high cost, especially when viewed as debt consistent with the revised rating agency treatment, and had par call features which allowed the Company to redeem the securities without paying a premium. No additional expense was incurred in the redemption. No replacement debt or preferred stock was issued and following Federal Energy Regulatory Commission accounting guidelines, the

Company continues to amortize the issuance costs related to these two series over their original life.

Q. Should the " non-recurring" nature of these unamortized issuance expenses preclude them from being recovered?

A. No. Securities issuance or redemption costs are almost always " non-recurring" during the life of a security. The Company must pay underwriter fees, legal and accounting fees, etc., up front in order to issue any long-term security. For accounting and rate-making purposes, these costs are recovered over the expected life of the securities. In Order No. 01-787, UE 116, the Commission was clear that the non-recurring nature of the issuance costs did not preclude their recovery as a part of the overall cost of capital, but only limited their recovery as some other type of expense.

Q. Has the Commission previously commented on the recovery of the QUIDS expenses?

A. Yes. In Order No. 01-787 the Commission stated that if " given persuasive evidence as to how customers specifically benefited from PacifiCorp' s decision to redeem the QUIDS, we would be inclined to allow the expense." In that case, decided less than one year after the redemption, PacifiCorp was unable to satisfy the Commission' s requirement of specific and demonstrable proof of customer benefit. However, the Company has since developed that evidence.

Q. Has the Company demonstrated in this docket that retiring the QUIDS benefited Oregon customers?

A. Yes. Redeeming the QUIDS has provided Oregon customers with an approximate $500,000 annual benefit through lower revenue requirement. The Company' s overall cost of capital in this case would be higher absent the QUIDS being redeemed. See Exhibit PPL/309 (response to Staff data request 120.) The Company has provided the evidence in this docket that Oregon customers have and will continue to benefit from the QUIDS redemption and the Commission should allow recovery of the unamortized issuance costs.

Pension Expense and Post-Retirement Benefits

Q. Please summarize the adjustments that Mr. Ball proposes to make to the Company' s pension expense and post-retirement benefits.

A. Mr. Ball proposes to increase the estimated long-term rate of return from 7.75 percent to 8.25 percent and to increase the discount rate from 6.30 percent to 6.90 percent. The impact of these adjustments results in reduced pension and post retirement benefit expense for a total adjustment of $2.7 million to the Company' s revenue requirement.

<u>Estimated Long-Term Rate of Return</u>

Q. How did the Company determine the rate of 7.75 percent as the estimated long-term rate of return for its pension investment?

A. The Company performed a " bottoms-up" analysis utilizing the asset allocation targets for the investment portfolio and a specific return for each asset class. The return for each asset class, which was provided by the Company' s investment consultant, is then weighted by the amount of the portfolio allocated to that asset class. The Company calculated that, based on its asset allocation targets and the projected return for each asset class, the weighted average return for the investment portfolio is 7.74 percent, which was rounded to 7.75 percent. The table below illustrates the calculations that the Company undertook.

Pension Investment Return Projections

	PacifiCorp			
Asset Class	**Allocation**	**Nominal Index Return**	**Active Alpha***	**Projected Return**
Fixed Income				
Domestic	23.00%	5.40%	0.20%	5.60%
Global	12.00%	5.35%	0.30%	5.65%
TOTAL	35.00%	5.38%	0.23%	5.62%
Equity				
Domestic				
Large Cap	34.50%	8.30%	0.40%	8.70%
Small Cap	7.50%	8.90%	0.75%	9.65%
Total Domestic	42.00%	8.41%	0.46%	8.87%
International				
Developed	11.25%	8.40%	0.40%	8.80%
Developing	3.75%	8.90%	0.75%	9.65%
Total International	15.00%	8.53%	0.49%	9.01%
Total Public Equity	57.00%	8.44%	0.47%	8.91%
Private Equity	8.00%	10.80%	1.00%	11.80%
Total Equity	65.00%	8.73%	0.53%	9.25%
Composite Return	100.00%	**7.56%**	0.43%	**7.99%**
	Less	Trustee & other administrative costs		-0.25%
		Investment Return Net of Expenses		**7.74%**

*Net of investment manager fees

In addition, the expected long-term rate of return was then reviewed and was accepted by both the Company' s actuary and its independent external auditors.

Q. How did Mr. Ball determine his proposed rate?

A. Mr. Ball' s proposed adjustment was selected based on industry data with the goal of moving the Company' s estimated long term rate of return close to the mid-point of such data.

Q. Did Mr. Ball undertake an analysis of asset allocation and projected asset class returns for the companies in the data set from which he selected the mid-point?

A. No, it appears that he undertook no analysis of underlying assumptions or asset allocations of the industry group to determine if they were comparable to the Company' s.

Q. Would the Company' s independent external auditors find it acceptable if the Company selected its estimated long-term rate of return in a manner similar to Mr. Ball' s approach?

A. No, the auditors would not accept the determination of the Company' s estimated long-term rate of return based on general industry data. Generally accepted accounting principles in the United States require that the expected long-term rate of return on plan assets be determined based on the average return of the funds invested for purposes of funding benefits, and requires consideration of returns being earned or expected to be earned by such plan assets. During the annual financial statement audit, the Company' s independent external auditors request information supporting the Company' s calculation of the expected long-term rate of return. In determining the expected long-term rate of return in this manner, the Company considers asset allocation targets and asset class return expectations of the underlying portfolio of investments.

Discount Rate

Q. Does Mr. Ball propose to also change the discount rate that is used in the calculation of pension and post-retirement benefits?

A. Yes. Mr. Ball adjusts the discount rate used by the Company in determining pension and post-retirement benefits from a rate of 6.30 percent to 6.90 percent. The impact of the higher discount rate is to reduce the level of future pension obligations (discounting a future cash flow at a higher rate results in a lower present value) and thus reduce each of the retirement obligation expenses.

Q. On what basis did Mr. Ball propose this higher discount rate?

A. Mr. Ball proposes to use the rate determined on December 31, 2008 which the Company used for purposes of determining expense during 2009.

Q. Do you agree with Mr. Ball' s proposed adjustments?

A. No. The actual discount rate that will be used to determine pension and post-retirement benefit expense during 2010 will not be determined until interest rates on the measurement date, December 31, 2009, are known. As such, the Company' s projections were originally determined in consultation with Hewitt Associates, the Company' s actuary, during the 2008 planning process at which time the discount rate was 6.30 percent. There was no better data available than assuming the discount rate would stay constant in the calculation of projected

2009 and subsequent pension and post-retirement expense. Then when the 2009 discount rate become known, the 2009 assumptions were appropriately updated.

Q. What is the Company' s most recent information on its discount rate forecast?

A. The Company recently received an update from its actuary that indicates the discount rate of 6.30 percent would be too high today. Hewitt Associates has estimated that as of July 31, 2009 (the last data known and available), the discount rate if measured on that date would be 6.15 percent, a rate slightly below the 6.30 percent that the Company has used. This estimate is well below the 6.90 percent that Staff is proposing.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/308
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Bruce N. Williams

Pro Forma Cost of Long-Term Debt
December 31, 2009 – Updated for Reply Testimony

August 2009

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary (Reply Testimony)
December 31, 2009

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	**$5,633,973,000**	**($59,159,033)**	**($32,177,777)**	**$5,542,636,190**	**$358,754,817**	**6.209%**	**6.368%**	**23.5**	**18.7**	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$13,757,532	3.125%	3.435%	28.0	11.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$6,979,572	1.890%	2.066%	27.8	8.2	5
6	**Total Pollution Control Revenue Bonds**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$20,737,104**	**2.560%**	**2.808%**	**27.9**	**10.0**	6
7											7
8	**Total Cost of Long Term Debt**	**$6,372,343,000**	**($74,014,074)**	**($49,349,200)**	**$6,248,979,725**	**$379,491,921**	**5.786%**	**5.955%**	**24.0**	**17.7**	8
9											9

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail (Reply Testimony)
December 31, 2009

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	19	1	$4,422,000	$412,000	$0	$0	$412,000	$100.000	7.978%	$32,869	3
4	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	2	$19,772,000	$3,590,000	$0	$0	$3,590,000	$100.000	8.493%	$304,899	4
5	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	20	2	$16,203,000	$4,247,000	$0	$0	$4,247,000	$100.000	8.797%	$373,609	5
6	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	21	3	$28,218,000	$9,301,000	$0	$0	$9,301,000	$100.000	8.734%	$812,349	6
7	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	21	3	$46,946,000	$17,918,000	$0	$0	$17,918,000	$100.000	8.294%	$1,486,119	7
8	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	22	4	$18,750,000	$8,318,000	$0	$0	$8,318,000	$100.000	8.635%	$718,259	8
9	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	5	$19,609,000	$9,585,000	$0	$0	$9,585,000	$100.000	8.470%	$811,850	9
10	**8.506%**	**Subtotal - Amortizing FMBs**			**21**	**3**		**$53,371,000**	**$0**	**$0**	**$53,371,000**		**8.506%**	**$4,539,954**	10
11															11
12	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	2	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	$98.932	7.051%	$35,255,000	12
13	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	4	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.961%	$11,922,000	13
14	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	5	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	14
15	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	22	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	15
16	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	25	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	16
17	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	25	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	17
18	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	27	$350,000,000	$350,000,000	($4,048,711)	$0	$345,951,289	$98.843	6.185%	$21,647,500	18
19	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	27	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	19
20	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	28	$600,000,000	$600,000,000	($5,873,367)	$0	$594,126,633	$99.021	6.323%	$37,938,000	20
21	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	9	$500,000,000	$500,000,000	($3,827,364)	$0	$496,172,636	$99.235	5.752%	$28,760,000	21
22	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	29	$300,000,000	$300,000,000	($3,874,418)	$0	$296,125,582	$98.709	6.448%	$19,344,000	22
23	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	9	$350,000,000	$350,000,000	($4,795,000)	$0	$345,205,000	$98.630	5.681%	$19,883,500	23
24	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	29	$650,000,000	$650,000,000	($12,285,000)	$0	$637,715,000	$98.110	6.139%	$39,903,500	24
25	5.250%	Pro Forma Series	12/31/09	12/31/19	10	10	$14,602,000	$14,602,000	($113,166)	$0	$14,488,835	$99.225	5.351%	$781,353	25
26	**6.034%**	**Subtotal - Bullet FMBs**			**23**	**20**		**$5,064,602,000**	**($54,901,811)**	**($7,263,815)**	**$5,002,436,374**		**6.154%**	**$311,672,853**	26
27															27
28	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	2	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	28
29	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.022%	$1,804,400	29
30	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	30
31	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	31
32	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	2	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	32
33	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	2	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	33
34	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	2	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	34
35	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	2	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.925%	$297,750	35
36	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	12	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	36
37	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	12	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	37
38	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	12	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	38
39	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	12	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	39
40	**8.766%**	**Subtotal - Series C MTNs**			**23**	**4**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,383,170**	40
41															41
42	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	3	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	42
43	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	13	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	43
44	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	13	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	44
45	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	45
46	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	46
47	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	13	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	47
48	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	48
49	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	49
50	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	13	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	50
51	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	13	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	51
52	**8.100%**	**Subtotal - Series E MTNs**			**29**	**12**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	52
53															53
54	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	54
55	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	55
56	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	56
57	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	57
58	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	58
59	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	59

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail (Reply Testimony)
December 31, 2009

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
60	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	60
61	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	61
62	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	62
63	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	63
64	**7.044%**	**Subtotal - Series F MTNs**			**30**	**14**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	64
65															65
66	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	16	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	66
67	**6.710%**	**Subtotal - Series G MTNs**			**30**	**16**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	67
68															68
69	**6.209%**	**Total First Mortgage Bonds**			**23**	**19**		**$5,633,973,000**	**($59,159,033)**	**($32,177,777)**	**$5,542,636,190**		**6.368%**	**$358,754,817**	69
70															70
71		**Pollution Control Revenue Bonds**													71
72	1.889%	Moffat 94 due May 2013	11/17/94	05/01/13	18	3	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	2.041%	$829,769	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	4	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	5	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	3.645%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	6	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	4.125%	$1,856,250	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	7	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	12	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	14	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	14	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	79
80	1.829%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	15	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	1.955%	$183,086	80
81	1.830%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	15	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	1.990%	$162,981	81
82	1.796%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	15	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	1.986%	$2,421,728	82
83	1.937%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	15	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	2.088%	$314,453	83
84	1.809%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	15	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	1.933%	$410,956	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	16	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	16	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.442%	$977,240	86
87	**3.125%**	**Subtotal - Secured PCRBs**			**28**	**12**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**3.435%**	**$13,757,532**	87
88															88
89	1.774%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	4	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	1.979%	$227,585	89
90	1.774%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	6	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	1.879%	$1,315,300	90
91	1.775%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	6	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	2.185%	$983,250	91
92	1.802%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	7	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	1.920%	$960,000	92
93	1.774%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	8	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	1.910%	$859,500	93
94	1.774%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	8	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	1.919%	$790,628	94
95	1.313%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	11	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.418%	$318,837	95
96	1.313%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	11	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.454%	$135,731	96
97	1.313%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	11	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.486%	$93,692	97
98	1.772%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	16	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	1.890%	$461,160	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	21	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	99
100	**1.890%**	**Subtotal - Unsecured PCRBs**			**28**	**8**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**2.066%**	**$6,979,572**	100
101															101
102	**2.560%**	**Total PCRB Obligations**			**28**	**10**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.808%**	**$20,737,104**	102
103															103
104	**5.786%**	**Total Long-Term Debt**			**24**	**18**		**$6,372,343,000**	**($74,014,074)**	**($49,349,200)**	**$6,248,979,725**		**5.955%**	**$379,491,921**	104
105															105

Docket No. UE-210
Exhibit PPL/309
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Bruce N. Williams

OPUC Data Request 120

August 2009

OPUC Data Request 120

Regarding Exhibit PPL/306, please provide a qualitative and quantitative cost-benefit analysis demonstrating that the refunding of the QUIDS securities was cost effective. Please provide this analysis in electronic format, with cell references and formulae intact.

Response to OPUC Data Request 120

During November 2000, PacifiCorp redeemed all of the 8.55% and 8 3/8% QUIDS with cash received following the sale of its Australian subsidiary. The QUIDS had par call options which allowed the Company to redeem these higher cost securities without paying a premium. No replacement debt or preferred stock was issued.

If, however, the Company had elected to not call the QUIDS for redemption at that time, it is likely that the Company's next subsequent long-term debt issuance, which occurred in November 2001, would have been reduced by the principal amount of the QUIDS ($175,825,925).

Please refer to Attachments OPUC 120 -1 to OPUC 120 -3, which show that the Company's weighted average cost of capital in this case would be higher than filed. The Company estimates that redeeming the QUIDS provides Oregon customers with an approximate $500,000 annual benefit through lower revenue requirements.

Please refer to non-confidential Attachment OPUC 120 -1, Attachment OPUC 120 -2 and Attachment OPUC 120 -3 on the enclosed CD.

PacifiCorp

UE 210 WACC (December 31, 2009)
(Exhibit PPL/300 Williams/5 (lines 7-15)

	% of Tot	Costs	WACC
LTD	48.5%	5.98%	2.90%
Pfd	0.3%	5.41%	0.02%
CSE	51.2%	11.00%	5.63%
	100.0%		$\boxed{8.55\%}$

Proforma WACC
(No QUIDS Redemp in 2000)

	% of Tot	Costs	WACC
LTD	48.5%	6.02%	2.92%
Pfd	0.3%	5.05%	0.02%
CSE	51.2%	11.00%	5.63%
	100.0%		$\boxed{8.57\%}$

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
(assumes no QUIDS redemption in Nov 2000)
December 31, 2009

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	$5,458,147,075	($57,205,020)	($32,177,777)	$5,368,764,278	$346,011,309	6.180%	6.339%	23.7	19.0	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$14,310,270	3.260%	3.573%	28.0	11.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$7,809,876	2.131%	2.311%	27.8	8.2	5
6	**Total Pollution Control Revenue Bonds**	$738,370,000	($14,855,042)	($17,171,423)	$706,343,535	$22,120,146	2.743%	2.996%	27.9	10.0	6
7											7
8	**Total QUIDS***	$175,825,925	($6,844,160)	$0	$168,981,765	$15,455,318	8.431%	8.790%	37.0	22.5	8
9											9
10	**Total Cost of Long Term Debt**	$6,372,343,000	($78,904,221)	($49,349,200)	$6,244,089,578	$383,586,773	5.844%	6.020%	24.6	18.1	10
11											11
12	**subsequent changes in accounting and rating agency treatement of QUIDS would have necessitated their treatment as Long-Term Debt if still outstanding as of 12/31/09.*										12
13											13

Exhibit PPL/309
Williams/3

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
(assumes no QUIDS redemption in Nov 2000)
December 31, 2009

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	19	1	$4,422,000	$412,000	$0	$0	$412,000	$100.000	7.978%	$32,869	3
4	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	2	$19,772,000	$3,590,000	$0	$0	$3,590,000	$100.000	8.493%	$304,899	4
5	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	20	2	$16,203,000	$4,247,000	$0	$0	$4,247,000	$100.000	8.797%	$373,609	5
6	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	21	3	$28,218,000	$9,301,000	$0	$0	$9,301,000	$100.000	8.734%	$812,349	6
7	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	21	3	$46,946,000	$17,918,000	$0	$0	$17,918,000	$100.000	8.294%	$1,486,119	7
8	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	22	4	$18,750,000	$8,318,000	$0	$0	$8,318,000	$100.000	8.635%	$718,259	8
9	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	5	$19,609,000	$9,585,000	$0	$0	$9,585,000	$100.000	8.470%	$811,850	9
10	**8.506%**	**Subtotal - Amortizing FMBs**			**21**	**3**		**$53,371,000**	**$0**	**$0**	**$53,371,000**		**8.506%**	**$4,539,954**	10
11															11
12	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	2	$390,108,797	$390,108,797	($4,165,464)	$0	$385,943,333	$98.932	7.051%	$27,506,571	12
13	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	4	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.961%	$11,922,000	13
14	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	5	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	14
15	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	22	$234,065,278	$234,065,278	($2,887,827)	$0	$231,177,451	$98.766	7.807%	$18,273,476	15
16	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	25	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	16
17	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	25	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	17
18	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	27	$350,000,000	$350,000,000	($4,048,711)	$0	$345,951,289	$98.843	6.185%	$21,647,500	18
19	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	27	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	19
20	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	28	$600,000,000	$600,000,000	($5,873,367)	$0	$594,126,633	$99.021	6.323%	$37,938,000	20
21	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	9	$500,000,000	$500,000,000	($3,827,364)	$0	$496,172,636	$99.235	5.752%	$28,760,000	21
22	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	29	$300,000,000	$300,000,000	($3,874,418)	$0	$296,125,582	$98.709	6.448%	$19,344,000	22
23	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	9	$350,000,000	$350,000,000	($4,795,000)	$0	$345,205,000	$98.630	5.681%	$19,883,500	23
24	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	29	$650,000,000	$650,000,000	($12,285,000)	$0	$637,715,000	$98.110	6.139%	$39,903,500	24
25	6.320%	Pro Forma Series	12/31/09	12/31/39	30	30	$14,602,000	$14,602,000	($146,020)	$0	$14,455,980	$99.000	6.395%	$933,798	25
26	**5.996%**	**Subtotal - Bullet FMBs**			**23**	**20**		**$4,888,776,075**	**($52,947,798)**	**($7,263,815)**	**$4,828,564,463**		**6.115%**	**$298,929,345**	26
27															27
28	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	2	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	28
29	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.022%	$1,804,400	29
30	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	30
31	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	31
32	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	2	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	32
33	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	2	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	33
34	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	2	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	34
35	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	2	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.925%	$297,750	35
36	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	12	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	36
37	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	12	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	37
38	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	12	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	38
39	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	12	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	39
40	**8.766%**	**Subtotal - Series C MTNs**			**23**	**4**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,383,170**	40
41															41
42	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	3	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	42
43	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	13	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	43
44	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	13	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	44
45	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	45
46	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	46
47	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	13	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	47
48	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	48
49	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	49
50	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	13	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	50
51	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	13	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	51
52	**8.100%**	**Subtotal - Series E MTNs**			**29**	**12**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	52
53															53
54	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	54
55	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	55
56	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	56
57	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	57
58	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	58
59	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	59
60	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	60
61	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	61
62	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	62
63	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	63
64	**7.044%**	**Subtotal - Series F MTNs**			**30**	**14**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	64
65															65
66	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	16	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	66
67	**6.710%**	**Subtotal - Series G MTNs**			**30**	**16**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	67
68															68
69	**6.180%**	**Total First Mortgage Bonds**			**24**	**19**		**$5,458,147,075**	**($57,205,020)**	**($32,177,777)**	**$5,368,764,278**		**6.339%**	**$346,011,309**	69

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
(assumes no QUIDS redemption in Nov 2000)
December 31, 2009

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
70															70
71		**Pollution Control Revenue Bonds**													71
72	2.139%	Moffat 94 due May 2013	11/17/94	05/01/13	18	3	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	2.295%	$933,032	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	4	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	5	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	3.645%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	6	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	4.125%	$1,856,250	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	7	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	12	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	14	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	14	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	79
80	2.079%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	15	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	2.209%	$206,873	80
81	2.080%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	15	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	2.246%	$183,947	81
82	2.046%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	15	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	2.242%	$2,733,895	82
83	2.187%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	15	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	2.344%	$353,006	83
84	2.059%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	15	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	2.187%	$464,956	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	16	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	16	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.442%	$977,240	86
87	**3.260%**	**Subtotal - Secured PCRBs**			**28**	**12**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**3.573%**	**$14,310,270**	87
88															88
89	2.024%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	4	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	2.236%	$257,140	89
90	2.024%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	6	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	2.132%	$1,492,400	90
91	2.025%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	6	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	2.447%	$1,101,150	91
92	2.052%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	7	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	2.174%	$1,087,000	92
93	2.024%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	8	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	2.165%	$974,250	93
94	2.024%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	8	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	2.174%	$895,688	94
95	1.563%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	11	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.672%	$375,949	95
96	1.563%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	11	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.708%	$159,442	96
97	1.563%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	11	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.742%	$109,833	97
98	2.022%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	16	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	2.144%	$523,136	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	21	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	99
100	**2.131%**	**Subtotal - Unsecured PCRBs**			**28**	**8**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**2.311%**	**$7,809,876**	100
101															101
102	**2.743%**	**Total PCRB Obligations**			**28**	**10**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.996%**	**$22,120,146**	102
103															103
104	8.375%	Series A QUIDS	05/31/95	06/30/35	40	26	$120,000,000	$120,000,000	($4,323,604)	$0	$115,676,396	$96.397	8.699%	$10,438,800	104
105	8.550%	Series B QUIDS	10/05/95	12/31/25	30	16	$55,825,925	$55,825,925	($2,520,556)	$0	$53,305,369	$95.485	8.986%	$5,016,518	105
106	**8.431%**	**Subtotal - QUIDS**			**37**	**22**		**$175,825,925**	**($6,844,160)**	**$0**	**$168,981,765**		**8.790%**	**$15,455,318**	106
107															107
108	**5.844%**	**Total Long-Term Debt**			**25**	**18**		**$6,372,343,000**	**($78,904,221)**	**($49,349,200)**	**$6,244,089,578**		**6.020%**	**$383,586,773**	108
109															109

Exhibit PPL/309
Williams/5

Exhibit PPL/309
Williams/6

PACIFICORP
Electric Operations
Pro Forma Cost of Preferred Stock
(assumes no QUIDS redemption in Nov 2000*)
December 31, 2009

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.000%	126,243	$12,624,300	($98,049)	$12,526,251	99.223%	5.039%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.520%	2,065	$206,500	($9,676)	$196,824	95.314%	4.742%	$9,793	4
5	7.00% Series	(b)	None	7.000%	18,046	$1,804,600	(c)	$1,804,600	100.000%	7.000%	$126,322	5
6	6.00% Series	(b)	None	6.000%	5,930	$593,000	(c)	$593,000	100.000%	6.000%	$35,580	6
7	5.00% Series	(b)	100.00%	5.000%	41,908	$4,190,800	(c)	$4,190,800	100.000%	5.000%	$209,540	7
8	5.40% Series	(b)	101.00%	5.400%	65,959	$6,595,900	(c)	$6,595,900	100.000%	5.400%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.720%	69,890	$6,989,000	($30,349)	$6,958,651	99.566%	4.741%	$331,320	9
10	4.56% Series	Feb-65	102.34%	4.560%	84,592	$8,459,200	($49,071)	$8,410,129	99.420%	4.587%	$387,990	10
11												11
12												12
13												13
14												14
15	**Total Cost of Preferred Stock**			**5.026%**	**414,633**	**$41,463,300**	**($187,146)**	**$41,276,155**		**5.048%**	**$2,092,879**	15
16												16
17												17
18	(a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company											18
19	and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.											19
20	(b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.											20
21	(c) Original issue expense/premium has been fully amortized or expensed.											21
22												22
23	*subsequent changes in accounting and rating agency treatment for QUIDS would have necessitated their treatment as Long-term Debt if still outstanding as of 12/31/09.											23

Gregory N. Duvall
Exhibit PPL/615

Docket No. UE-210
Exhibit PPL/615
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Gregory N. Duvall

August 2009

Q. Are you the same Gregory N. Duvall who previously provided testimony in this docket?

A. Yes, as Exhibits PPL/600, PPL/605, and PPL/614.

Purpose and Summary

Q. Please explain the purpose of your reply testimony.

A. The purpose of my reply testimony is to:

- Respond to the adjustments and criticisms of the Company's monthly coincident peak forecasts[1] presented by the Staff of the Oregon Public Utility Commission ("Staff") witness Mr. Robert Clark. Monthly coincident peak forecast values are primarily used to develop the System Capacity ("SC") and related allocation factors which are used to allocate a significant portion of the Company's costs.
- Respond to the proposals on changes in methodology and the inclusion of variable costs of new resources in stand-alone Transition Adjustment Mechanism ("TAM") filings presented by Staff witness Ms. Kelcey Brown and Industrial Customers of Northwest Utilities ("ICNU") witness Mr. Randall Falkenberg.
- Respond to the proposal on line losses presented by Fred Meyer Stores witness Mr. Kevin C. Higgins.
- Respond to Staff witness Mr. Michael Dougherty's recommendation concerning the sale of Renewable Energy Certificates ("RECs").

[1] Each jurisdiction's monthly coincident peak load represents that jurisdiction's contribution to the system monthly coincident peak load.

Q. Please summarize your reply testimony with regard to the load forecast changes proposed by Staff witness Mr. Robert Clark.

A. In my reply testimony, I demonstrate the following:

- First, although Mr. Clark prepared forecast models for monthly coincident peak loads for all 12 months in Utah and Oregon for a total of 24 forecast models, he selectively excluded half of those forecast models in his testimony. Had he used all of his forecast models consistently, Oregon's SC factor would <u>increase</u> by 0.27 percent as compared to the Company's filing, rather than decrease as proposed by Mr. Clark.
- Second, Mr. Clark's proposed load reductions in Oregon for the three months of January, February and September cause monthly peak load to shift to another hour or another day. Because of this, Mr. Clark's new hourly load forecast for these three months is not appropriate for use in calculating the SC factor since that hour is no longer the peak hour. Mr. Clark has not attempted to calculate a new SC allocation factor using the new hour of monthly system coincident peak load. Had he done so, he would have found that the SC factor would again have <u>increased</u> by 0.12 percent as compared to what Mr. Clark proposed.
- Third, three of the nine coincident peak load forecasts sponsored by Mr. Clark for Utah loads exceed Utah's monthly peak load for the respective month. This is impossible by definition.
- Fourth, three of the 12 peak load forecast models are developed without any consideration of the temperature on the day of the peak load. One month is

modeled solely using the temperature from two days prior to the peak load day. This is like using only Wednesday' s weather to predict Friday' s load. Two other months rely solely on the prior day' s temperature, which would be like using only Thursday' s weather to predict Friday' s load. In fact, only three of Mr. Clark' s 12 proposed forecast models fully take into account the temperature on the peak day.

- Fifth, Mr. Clark' s proposal is incomplete since it only addresses 12 out of 72 monthly peak loads.
- Sixth, Mr. Clark uses unconventional statistical modeling methods with incorrect specification.
- Finally, Mr. Clark makes no attempt to adjust energy sales or hourly loads to be consistent with the proposed changes to peak loads

Based on these reasons, I recommend the Commission reject Staff witness Mr. Clark' s recommendation to change the SC allocation factor based on his proposed load forecasts changes. I will discuss the above objections in detail in the remainder of my testimony.

Q. Please summarize your testimony on the TAM-related issues.

A. With regard to allowing methodology changes in stand-alone TAMs, I recommend that any solution be fair and balanced. For inclusion of the variable costs of new resources in a stand-alone TAM, I adopt ICNU' s recommendation to allow exclusion of variable costs of selected new resources that the Company has not owned or purchased for more than six months prior to the stand-alone TAM filing. On the issue of line losses, I demonstrate that distribution losses are not avoided when customers choose direct access and therefore should not be included in the calculation of the transition credit.

Q. Please summarize your testimony on the sale of RECs.

A. I recommend that the Commission reject Staff's proposal to place any gain on the sales of RECs into the property sales balancing account. I explain that the Oregon-allocated RECs are being banked for future compliance with Oregon's Renewable Portfolio Standard. As such, Staff's recommended approach is unnecessary.

Q. How is your testimony organized?

A. I have divided my testimony into three sections. Section I addresses the load forecast, Section II addresses the TAM-related issues, and Section III addresses the issue related to RECs. In Section I, I first summarize Staff's proposed changes. Second, I provide a brief review of the Company's peak forecasting methodology. Third, I discuss the Company's specific objections to Staff's proposal. Finally, I discuss methodology concerns. In Section II, I address the three TAM-related issues. In Section III, I address the RECs-related issue.

SECTION I – LOAD FORECAST

Summary of Staff Proposal

Q. Please summarize Staff's proposed changes to the Company's coincident peak load forecasts.

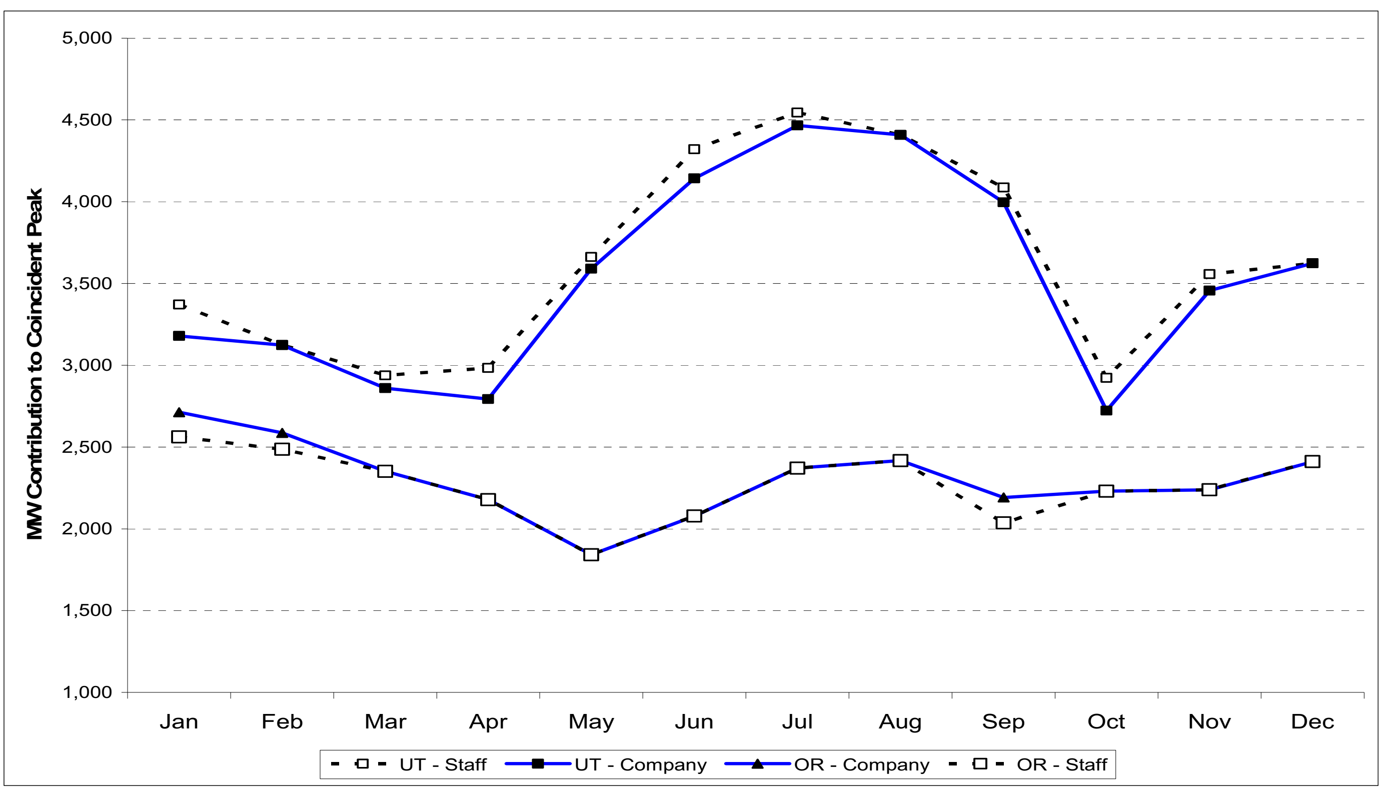
A. Staff proposed changes to 12 out of 72 monthly coincident peak load forecast values that make up the SC factor[2]; three in Oregon and nine in Utah. Staff accepted the remaining 60 monthly peak forecasts presented by the Company. Staff also accepted the Company's energy sales forecast and hourly load forecast. The differences between Staff's proposal and the Company's forecast are illustrated in Table 1 and Chart 1.

Table 1

Table 1
OPUC Staff's Proposed Monthly CP forecast Change (in MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	SUM of CPs	Change in SC factor
OR	-151.3	-100.9	0.0	0.0	0.0	0.0	0.0	0.0	-155.6	0.0	0.0	0.0	-407.8	-0.60%
CA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.01%
WA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.06%
UT	191.2	0.0	78.4	189.8	71.3	178.6	78.0	0.0	89.7	200.5	100.7	0.0	1,178.3	0.84%
WY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.11%
ID	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.04%

Chart 1 - 2010 Coincident Peak Overview



2 The SC factor is defined as the sum of the 12 monthly coincident peaks ("12 CP"). Since the Company has six jurisdictions, all 72 monthly peaks (6 jurisdictions and 12 months) are required to determine the SC factor.

Q. How did Staff prepare its partial peak load forecast?

A. Staff prepared its partial peak load forecast in two basic steps. First, Staff specified its models using regression analysis. As I demonstrate later in my testimony, the models are seriously flawed primarily because they do not include important explanatory variables and use only temperatures from a single year. In addition, each of Staff' s 12 forecasts uses a different methodology and/or input assumptions. Second, when using the model to forecast loads in the test period, Staff again uses only one single monthly temperature from an arbitrary historic year. For each monthly forecast, Staff then uses the lowest single monthly temperature for winter months and the highest single monthly temperature for summer months with few exceptions regardless of what day that low or high temperature occurred. Both the specification and use of the model are illogical and are not consistent with the traditional use of normalized weather data to forecast loads.

Review of the Company' s Peak Forecast Methodology

Q. How does the Company forecast monthly coincident peak loads?

A. First, monthly non-coincident peak loads are forecast directly for each jurisdiction based on specific information applicable to each jurisdiction. The primary drivers of the peak model are the average daily temperature on the day of the peak and historical trends in peak loads. Other inputs include the average daily temperature from one and two days prior to the monthly peak and economic and demographic variables. Second, monthly coincident peak loads are forecast by applying historical relationships between non-coincident and coincident peak loads experienced in each jurisdiction.

Q. Does Staff accept the Company's peak forecast?

A. Yes, for the vast majority of monthly peak loads. Specifically, Staff accepted the Company's method of forecasting coincident peaks for 60 of the 72 monthly coincident peak forecasts. The Company's monthly peak loads are used by Staff to forecast all of the monthly coincident peak loads for California, Idaho, Washington and Wyoming, nine months in Oregon and three months in Utah. For the remaining 12 monthly coincident peak loads, three in Oregon and nine in Utah, Staff attempts to forecast monthly coincident peak loads using various alternative methods.

Q. Has the Company's load forecasting and peak methodology been reviewed by any independent experts?

A. Yes. The Company's load forecasting methodology was developed by ITRON, a leading expert in the field of utility load forecasting techniques. In addition, it has been independently reviewed by GDS Associates, Atlanta, Georgia who concluded that "the methodology and models currently used by PacifiCorp meet or exceed industry standards."

Specific Critique of Staff's Proposed Peak Forecast Methodologies

Q. Please describe more specifically the problems with Staff's proposed forecast methodology.

A. Staff's proposal is incomplete, results in unintended consequences, uses temperature inappropriately, both to develop the models and in the use of the models to forecast load in the test period, ignores important explanatory variables, and is inconsistent with the energy and hourly load forecasts.

Q. Please indicate why you claim that Staff' s proposal is incomplete.

A. Mr. Clark selectively presents 12 monthly peak forecasting models, each of which reduce Oregon' s SC and related allocation factors by either lowering Oregon' s peak load forecast or raising Utah' s peak load forecast. Staff' s work papers, however, include forecast models for all 24 months which include the remaining nine months in Oregon and three months in Utah. No models were developed for Wyoming, Idaho, Washington or California. Coincident peak forecasts for these missing months are displayed in Table 2 and are based on Staff' s own regression models from their work papers. The Company corrected Staff' s use of temperature for forecasting test period loads, where needed, based on the mapping provided by Staff in Mr. Clark' s opening testimony. Had Mr. Clark correctly included all 24 forecasts in his testimony, Oregon' s SC allocation factor would have increased by 0.88 percent to 27.49 percent, as compared to the 26.61 percent resulting from the selective application of only 12 of the 24 monthly forecasts included in Staff' s testimony. This corrected SC factor for Oregon is 0.27 percent higher than the respective SC factor included in the Company' s filing.

Table 2

	OPUC Staff's Proposed Monthly CP forecast Change (in MW)												SC Factor	SC Factor	Change in SC Factor
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Staff's methodology used for 12 months for OR and UT	Staff's Proposal: Changes to CP for three months in Oregon and nine Months in Utah	Impact of Including all 12 Months for Oregon and Utah
OR	-151.3	-100.9	-3.7	195.8	93.9	5.6	265.1	-23.9	-155.6	49.9	536.0	149.0	27.49%	26.61%	0.88%
CA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.78%	1.80%	-0.02%
WA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.91%	8.01%	-0.10%
UT	191.2	13.7	78.4	189.8	71.3	178.6	78.0	37.0	89.7	200.5	100.7	27.1	42.11%	42.59%	-0.48%
WY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.94%	15.14%	-0.20%
ID	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.78%	5.85%	-0.08%

Q. Do Staff’ s forecasts produce any unintended consequences?

A. Yes. In all three months that Staff presented new forecasts for Oregon - January, February and September - the reduction in Oregon load shifted the monthly peak load to another hour or day. As a result, a different hour would need to be used for the development of the SC factor, negating the effect that all three of Staff’ s adjustments to Oregon load would have on the SC factor.

The other significant unintended consequence is that for three of the nine months in Utah - April, June and November - Staff’ s forecasts of load at the time of monthly system coincident peak exceeds Utah’ s non-coincident peak load for that month. This is an impossible outcome by definition and makes these three forecasts unusable for determining the SC allocation factor.

Q. What do you conclude from these unintended consequences?

A. Half of Staff’ s proposed forecasts have serious unintended consequences that make them unable to be reliably used in the calculation of the SC factor. At a minimum, these six forecasts should be rejected.

Q. Please explain what temperature should drive the forecast for the peak day.

A. One of the most important determinants of peak load is temperature. Because there is typically a “ build up” effect, the temperature on the peak day and the temperatures before the peak days are all important determinants of the peak. However, the temperature on the peak day is the key temperature. It is obvious that the importance of temperature declines with the time span before the peak.

Q. Please explain how Staff chose temperatures to estimate the regression equations.

A. Staff’ s criteria for choosing the temperature is based on the correlation between coincident peak load and temperatures on the peak day, one day and two days prior to peak days. Staff generally chose the temperature with the highest correlation to the peak load to be used in the estimation of the regression. As a result, Staff used the temperature associated with the peak day, or a day prior to peak day, or two days prior to peak, or on occasion, a combination of the above. By doing that Staff has ignored the importance of the temperature of the peak day in a number of cases.

Q. What were the results of Staff’ s temperature selections for specifying their models?

A. The results of Staff’ s method are shown in Table 3 and are compared to those used by the Company. As a result of their correlation analysis, Staff did not select to use the temperature on the day of peak load in developing forecast models for January in Oregon, and for January and March in Utah, and only placed a 16.6 percent weighting on the temperature on the day of the peak load for the model for October in Utah. For January in Oregon, Staff relies completely on the temperature on the day before the peak load. Yet in Utah, for the same month of January, Staff relies completely on the temperature from two days before the peak load. Staff did not use the temperature on the day of the January coincident peak to develop their models in either Utah or Oregon. In fact, 75 percent of Staff's regressions failed to fully account for the temperature on the day of the load they were seeking to forecast.

Table 3-Summary of Weights Applied to Temperature Variables Used in Estimation of Regression Equations

Weights Applied to Temperature on Utah Coincident Peak Day, 1 Day Prior, and 2 Days Prior

Utah	PPL Proposed			Staff Proposed		
	Peak Day	1 Day Prior	2 Days Prior	Peak Day	1 Day Prior	2 Days Prior
January	100.0%	66.0%	33.0%	0.0%	0.0%	100.0%
March	100.0%	66.0%	33.0%	0.0%	100.0%	0.0%
April	100.0%	66.0%	33.0%	100.0%	0.0%	0.0%
May	100.0%	66.0%	33.0%	100.0%	0.0%	0.0%
June	100.0%	66.0%	33.0%	67.0%	0.0%	33.0%
July	100.0%	66.0%	33.0%	100.0%	0.0%	0.0%
September	100.0%	66.0%	33.0%	62.9%	37.1%	0.0%
October	100.0%	66.0%	33.0%	16.6%	0.0%	83.4%
November	100.0%	66.0%	33.0%	79.8%	0.0%	20.2%

Weights Applied to Temperature on Oregon Coincident Peak Day, 1 Day Prior, and 2 Days Prior

Oregon	PPL Proposed			Staff Proposed		
	Peak Day	1 Day Prior	2 Days Prior	Peak Day	1 Day Prior	2 Days Prior
January	100.0%	75.0%	25.0%	0.0%	100.0%	0.0%
February	100.0%	75.0%	25.0%	67.1%	0.0%	32.9%
September	100.0%	75.0%	25.0%	98.6%	0.0%	1.4%

Q. Has the Company analyzed the use of the correlation approach to determine the choice of the temperature variable?

A. Yes. The Company looked at Staff’s January regressions for Oregon and Utah. In the Oregon regressions, the Company found that the correlation between peak loads and temperature is actually highest using the temperature that occurred 14 days after the peak day. In Utah, the Company found 19 days with a higher correlation than the day chosen by Staff.

Q. Is the Company proposing to use a day with a higher correlation as a measure of peak producing temperatures?

A. No. The Company performed this correlation analysis simply to highlight that correlating temperature and load as Staff has done is not a useful method of specifying a load forecasting model.

Q. Do you have further concerns about Staff' s choice of temperature used in estimation of the regression equations?

A. Yes. The Company used the average 20 years of temperatures that occurred on the day of coincident peak as the basis of the temperature it used to forecast coincident peak load. Staff has misinterpreted this mapping and picked a single year and a single temperature to create its coincident peak models. Because of this, Staff' s model is highly dependent on that one temperature data point that could easily have come from a year with extreme weather conditions. In any event, Staff did not use normal weather either in the creation of its models or in using them to predict loads in the test period.

Methodology Concerns

Q. What concerns do you have regarding Staff' s choice of statistical modeling techniques?

A. Staff' s structure of regression equations is incorrectly specified, and varies by state and across months. Moreover, Staff' s use of a two-step regression analysis technique (where first the coincident peak variable is regressed on a time trend variable, and second any unexplained variation from the first step is regressed on a temperature variable) gives the variable used in the first set of regressions (the time trend variable) a privileged position over the variables used in second set of regression equations creating the undesirable case of omitted variable bias leading to incorrect estimation of regression equation (Gary King, " How Not to Lie with Statistics: Avoiding Common Mistakes in Quantitative Political Science"). In the econometrics literature, it is recommended that all relevant explanatory variables should be included in a full multiple regression equation, if they are believed that they are theoretically relevant to explain variations in the dependent variable (R. J. Wonnacott and T. H. Wonnacott, " Econometrics" Second Edition, page 410). Moreover, Staff changed the structure of the equations used for regression analysis across months by applying inconsistent weights to temperatures as previously described. When using one chosen variable, Staff only used temperature for Oregon assuming that historic time trend will have no impact on the future peak forecast. This approach is illogical and would result in the same forecast both for 2010 and all years beyond 2010.

Q. Does Staff' s method include all relevant explanatory variables that you believe could explain the forecast of peak load?

A. No. Staff' s approach does not recognize that Oregon' s coincident peak load is not only dependent on temperatures in the Company' s Oregon service territory on the coincident peak day, but for a multi-jurisdictional utility such as the Company, is also affected by the temperatures in other jurisdictions on the day of system coincident peak. Staff also ignores other relevant variables that would help explain the coincident peak load. For example, monthly jurisdictional kilowatt-hour sales are an important determinant of peak load. To test this hypothesis, the Company expanded Staff' s model to include monthly jurisdictional sales. The results of this test confirmed that sales are a statistically significant determinant of peak, and inclusion of sales improved the predictive power of temperature in Staff' s model.

Q. Did you test the accuracy of Staff's forecast models compared to the Company's model?

A. Yes. The Company used Staff's regression equations to develop monthly coincident peak forecasts for 2008 and compared them to results using the Company's model. When Staff's forecasts for 2008 were compared with actual 2008 monthly coincident peak data, the Mean Absolute Percent Error (MAPE)[3] was 10 percent for Oregon. The Company's forecast was more accurate with a MAPE of only 4 percent. For Utah, the MAPE associated with Staff's forecast was 5 percent compared to a MAPE value of only 2 percent with Company's forecast.

Q. Do you have any other concerns with Staff's proposal?

A. Yes. Staff's peak load forecast is not coordinated with the energy or hourly forecasts. Staff did not make any attempt to coordinate these three forecasts. Changing one hour per month without changing the hourly or energy forecasts consistently results in additional unintended consequences. Either the peak load needs to be restored to that forecast by the Company, or the hourly curve must be changed to better reflect the hourly load patterns experienced over recent history. Changing the hourly loads curve would also result in a change in the energy forecast.

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[3] Mean Absolute Percent Error ("MAPE") is a common measure of forecast accuracy in a fitted time series value in statistics. A lower MAPE indicates a better forecast.

Q. Please summarize your recommendation regarding Staff witness Clark's partial peak load forecast.

A. For all of the reasons discussed in detail above, I recommend the Commission reject Staff witness Clark's proposal to change the SC allocation factor based on his proposed load forecasts changes.

SECTION II – TAM-RELATED ISSUES

Changes in Methodology in the Calculation of Net Power Costs

Q. What is Staff's position on whether changes in methodologies used to calculate net power costs should be permitted in stand-alone TAM proceedings?

A. Staff proposes two standards; one for the Company, and the other for Staff and Intervenors. Staff recommends that the Company be allowed to make limited changes in methodologies in stand-alone TAM proceedings, but only if the Company can "sufficiently demonstrate" the changes are necessary due to an error that the Company has discovered in its modeling. Staff proposes this "sufficient demonstration" be done prior to the Company making a stand-alone TAM filing and requires the "consent" of Staff and Intervenors before being allowed in the filing. In Staff's proposal, this limited ability to make methodological changes in a stand-alone TAM is only applicable to the Company. Staff and Intervenors would have an unlimited ability to suggest changes or adjustments associated with existing modeling methodologies.

Q. What is ICNU's position on whether changes in methodologies used to calculate net power costs should be permitted in stand-alone TAM proceedings?

A. ICNU makes three recommendations on this issue. First, they recommend that parties be precluded from addressing issues that have already been decided by the Commission in a prior general rate or TAM case. Second, ICNU recommends that new "types" of costs or revenues should not be allowed in a stand-alone TAM proceeding. Third, ICNU proposes that "black box settlements" should not be the basis of a Commission-approved methodology. ICNU claims that 87 percent of the dollar value of their proposed adjustments to net power costs in UE 207 concern the proper methodology to apply. They conclude that limiting methodological changes in future cases could well result in unfair, unjust and unreasonable rates.

Q. How do you respond to these two proposals?

A. Staff and ICNU have made substantially different proposals regarding the inclusion of methodological changes in a stand-alone TAM. Additionally, each of Staff and ICNU's proposals are materially different than the Company's proposal. These three proposals range from not allowing methodological changes on the one hand, to allowing an unlimited number of methodological changes. After reviewing the proposals from Staff and ICNU presented in their reply testimony, I have concluded that the Company is agreeable to any outcome on this issue as long as it is symmetrical and is based on sound regulatory policy that promotes a fair and balanced outcome.

Q. Are the proposals from Staff and ICNU symmetrical?

A. The proposal from ICNU is symmetrical, but Staff's proposal is not. Staff's proposal is inconsistent with a balanced approach to ratemaking. For example, Staff's proposal requires the Company to attain the "consent" of Staff and intervenors in advance of making its TAM filing if it wants to include methodological changes in the filing. There are no reciprocal requirements placed on Staff or intervenors to seek the consent of the Company for proposing methodological changes under Staff's proposal. Indeed, Staff provides no rationale for applying a different standard to the Company than to other parties.

Q. Please identify the benefits of allowing methodological changes in a stand-alone TAM.

A. Allowing methodological changes in stand-alone TAM filings would not require parties to spend time arguing over what constitutes a methodological change. As ICNU has pointed out, many of the adjustments in the current TAM are considered by ICNU to be methodological changes. The forecast of net power costs would likely be more accurate if methodological changes are allowed simply by the nature of being more inclusive.

Q. What are the benefits of not allowing methodological changes in a stand-alone TAM?

A. Not allowing methodological changes in the TAM has the potential to streamline the stand-alone TAM proceedings if parties could agree what constitutes a methodological change.

Including Variable Costs of New Generation Resources

Q. What does Staff propose regarding the inclusion of the variable costs of new generation resources in a stand-alone TAM?

A. Staff recommends including new facilities that are used and useful as of January 1 of a test year into net power costs. They incorrectly indicate that this is consistent with the treatment agreed to by the Company in its sur-surrebuttal testimony in UE 170, and further observe that the Company can request a general rate case to recover the fixed costs of resources at their discretion.

Q. What does ICNU recommend on this issue?

A. ICNU recommends that the Company be required to reflect the variable costs of the new resource in a stand-alone TAM so long as the Company has had the opportunity to file a GRC but chose not to do so. ICNU indicates that the Company raises a seemingly valid concern; however they disagree with the solution. ICNU proposes to modify and limit the Company' s proposal to exclude new resources from the TAM unless the Company acquired or completed the resource two years prior to the TAM filing date. They specifically propose to shorten the two years to six months, and recommend the exclusion only apply to a new resource acquired outside of any IRP or RFP process, such as Chehalis which is referred to by ICNU as " an unpredictable event accompanying a special opportunity."

Q. How does the Company respond to these proposals?

A. The Company believes ICNU' s proposal reflects a reasonable balance and supports their recommendation. The Company believes, though, that the prudence of the resource would need to be established by the Commission prior to the inclusion of the variable costs in rates.

Treatment of Line Losses in Calculating Schedules 294 and 295

Q. Has Mr. Higgins proposes adjustments to line losses that the Company applied in the calculations of Schedules 294 and 295?

A. Yes. Mr. Higgins states that the line loss factor that the Company uses is " unusually low for retail delivery" and may have been applied incorrectly.

Q. Do you agree with Mr. Higgins statement?

A. No. Mr. Higgins correctly states that " it is necessary to make a line loss adjustment in order to subtract one price from the other on an ' apples-to-apples' basis." However, Mr. Higgins incorrectly determined the point where the line loss adjustments should be made.

Q. Please explain.

A. When a customer becomes a direct access customer, they still remain a distribution customer of the Company and the Company still incurs distribution line losses in order to serve the direct access customer. The only line losses that the Company no longer incurs are the losses at the transmission level. The Company still incurs losses on its distribution system to deliver the energy to that customer from the transmission substation. As a result, only the transmission level line losses should be removed from the cost-of-service price.

Q. What is the 4.48 percent to which Mr. Higgins refers?

A. The 4.48 percent is the Company' s line loss factor at the transmission level that is currently in the Company' s Open Access Transmission Tariff.

Q. What is your recommendation on this adjustment?

A. The Commission should reject Mr. Higgins' s recommendation because it incorrectly determines the impact of line losses on the Company' s system when customers choose direct access.

SECTION III – SALES OF RECS

Q. Staff witness Dougherty proposes that the Company be required to place the gain on the sale of RECs in the property sales balancing account for refund to customers in the future. Do you agree with this recommendation?

A. No. PacifiCorp is not planning to sell any Oregon-allocated eligible RECs in the future due to its need to bank the RECs for future compliance with the Oregon RPS. As such, Staff' s recommendation with respect to RPS-eligible RECs is unnecessary.

Q. Does this conclude your reply testimony?

A. Yes.

R. Bryce Dalley
Exhibit PPL/706

Docket No. UE-210
Exhibit PPL/706
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of R. Bryce Dalley

August 2009

Q. Are you the same R. Bryce Dalley who previously provided testimony in this docket?

A. Yes, I am.

Purpose and Summary

Q. What is the purpose of your reply testimony?

A. The purpose of my testimony is to respond to adjustments proposed by the witnesses for the staff of the Public Utility Commission of Oregon (" Staff"), Citizens' Utility Board of Oregon (" CUB") and Industrial Customers of Northwest Utilities (" ICNU").

Q. Please summarize your testimony.

A. My testimony explains and supports the Company' s revised overall base revenue increase of $82.7 million, excluding net power costs (" NPC") and new tariff riders. This is a reduction from the $92.1 million request included in the Company' s initial filing. My testimony also provides:

- A detailed calculation of the $82.7 million requested base revenue increase, including a summary of the differences between the $92.1 million initial request and the current amount. The revised request includes the impact of adjustments proposed by other parties that the Company has accepted; and
- The Company' s response to certain revenue requirement adjustments proposed by intervening parties in this case which the Company contests.

Required Revenue Increase

Q. What price increase is required to achieve the requested return on equity in this case?

A. As shown on Page 1 of Exhibit PPL/707, an overall base price increase of $82.7

million, excluding NPC and new tariff riders, is required to produce the 11 percent return on equity requested in this rate case proceeding. As addressed in my direct testimony, NPC-related items are recovered separately through the Company's Transition Adjustment Mechanism ("TAM") filing.

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue increase of $82.7 million was calculated using the same Revised Protocol allocation methodology included in the Company's original filing and incorporates certain adjustments proposed by other parties. In support of the revised calculation, Exhibit PPL/708 shows the revised revenue requirement requested by the Company. This Exhibit updates Tabs 1, 2, and 11 of my original Exhibit PPL/702 and adds a new section, Tab 12, containing backup pages for each new adjustment made to the Company's filing. All adjustments included in Tab 12 are incremental to the revenue requirement in the Company's original filing made April 2, 2009.

Revenue Requirement Adjustments

Q. Is the Company incorporating any adjustments proposed by the intervening parties into its revenue requirement calculation?

A. Yes. The Company incorporated the following new adjustments, including some proposed by intervening parties, into its Oregon revenue requirement calculation. Each is described further in my testimony.

Original Price Change Request	**$**	**92.1**	**million**
Reply Adjustments			
Allocation Factors		(0.1)	
Cost of Capital and Capital Structure		(1.0)	
Rate Base		(0.1)	
Insurance Low Claims Bonus		(0.1)	
Workers Compensation Expense		(0.4)	
FAS 112 (Post-Employment Benefits)		(0.2)	
401(k) Expense		(1.9)	
Challenge Grants		(0.1)	
Transition Plan - Oregon Regulatory Asset		(3.6)	
MEHC CIC Severance Regulatory Asset		(2.8)	
Grid West Regulatory Asset		(0.4)	
Wind Interconnection Rate Base		(0.6)	
Other Wind Plant Additions		(0.3)	
August 2009 - NPC Update/ECD		2.3	
Subtotal		(9.3)	
Reply Price Change Request	**$**	**82.7**	**million**

<u>Allocation Factors</u>

Q. Please describe the Company's adjustment to its originally-proposed allocation factors.

A. The Company has updated allocation factors to reflect two changes. First, allocation factors that rely on the NPC study developed using the Generation and Regulation Initiative Decision ("GRID") model have been updated to reflect changes in NPC as filed in the Company's August 2009 TAM update. Second, allocation factors calculated based on plant-in-service balances have been updated to reflect plant levels included in the Company's revised revenue requirement. Both of these changes are consistent with the Commission-approved Revised Protocol allocation methodology.

Q. Have you reflected these changes to allocation factors in your revised revenue requirement?

A. Yes. I have included a proposed adjustment reflecting these changes as Adjustment 12.1 of Exhibit PPL/708.

<u>Cost of Capital and Capital Structure</u>

Q. Please explain the changes to cost of capital and capital structure.

A. Cost of capital and capital structure have been updated to the amounts shown in the table below. The reply testimony of Company witness Mr. Bruce N. Williams addresses the changes in capital structure and cost of debt. The Company has not made any changes to the cost of common equity as addressed in the reply testimony of Company witness Dr. Samuel C. Hadaway.

	Capital Structure	Embedded Cost	Weighted Cost
Long-Term Debt	48.7%	5.96%	2.90%
Preferred Stock	0.3%	5.41%	0.02%
Common Stock	51.0%	11.00%	5.61%
	100.000%		8.53%

Q. Have you reflected these changes to cost of capital and capital structure in your revised revenue requirement?

A. Yes. I have included a proposed adjustment reflecting these changes as Adjustment 12.2 of Exhibit PPL/708.

<u>Rate Base</u>

Q. Please describe Staff witness Ms. Deborah Garcia’ s proposed adjustment to the Company’ s rate base.

A. Ms. Garcia proposes to disallow approximately $269 million of Company investment, or $116.6 million on an Oregon-allocated basis. Ms. Garcia’ s adjustment is broken down into three separate categories, one of which removes approximately $400,000 of Oregon-allocated rate base for two distinct projects that should not be included in rate base. The Company accepts this aspect of Ms. Garcia’ s adjustment, but contests the balance of this adjustment as discerned later in my testimony.

Q. Has an adjustment to rate base been reflected in your revised revenue requirement?

A. Yes. Adjustment 12.3 of Exhibit PPL/708 reflects the Company's acceptance of Ms. Garcia's approximately $400,000 of proposed adjustments to Oregon-allocated rate base balances.

Q. Does Adjustment 12.3 of Exhibit PPL/708 reflect any additional components not proposed by Ms. Garcia?

A. Yes. Adjustment 12.3 includes two other aspects not included in Ms. Garcia's adjustment. First, this adjustment includes an update to reflect the final amount of liquidated damages related to the Goodnoe Hills wind resource. At the time of the Company's filing, the final amount of liquidated damages was unknown. In the Company's response to OPUC Data Request 310, the Company provided the final amount of liquidated damages and agreed to make an adjustment in its reply testimony reflecting this change. This adjustment reduces Oregon-allocated rate base by approximately $538,000. Second, this adjustment reflects the impact of accumulated depreciation and depreciation expense associated with the rate base changes described above.

<u>Insurance Low Claims Bonus</u>

Q. Please describe Staff witness Mr. Dustin Ball's proposed adjustment related to insurance low claims bonuses.

A. Mr. Ball proposes a reduction of $122,918, on an Oregon-allocated basis, to the Company's insurance expense for a potential low claims bonus in the test period ending December 31, 2010 ("Test Period"). In support of his adjustment, Mr. Ball cites low claims bonuses that were received by the Company in recent policy years. His proposal includes 50 percent of the Company's recent low claims bonus as a reduction to insurance expenses in the Test Period.

Q. Do you accept Mr. Ball's proposed adjustment to insurance expense for low claims bonuses?

A. Yes. While it is not certain that the Company will receive a low claims bonus in the Test Period, for purposes of this proceeding, the Company accepts Mr. Ball's adjustment reflecting a low claims bonus for the Test Period.

Q. Has an adjustment to insurance expense for low claims bonuses been reflected in your revised revenue requirement?

A. Yes. Adjustment 12.4 of Exhibit PPL/708 reflects the Company's acceptance of Mr. Ball's proposed adjustment.

Worker's Compensation Insurance Expense

Q. Please describe Staff witness Mr. Ball's proposed adjustment related to worker's compensation insurance expense.

A. Mr. Ball proposes that the Company's worker's compensation insurance costs be reduced by $512,931 on an Oregon-allocated basis. Mr. Ball splits this adjustment amount between operations and maintenance ("O&M") expense and rate base.

Q. Do you address Mr. Ball's proposed adjustment to worker's compensation insurance in your reply testimony?

A. No. Company witness Mr. Erich D. Wilson addresses Mr. Ball's proposed adjustment in his reply testimony.

Q. Has an adjustment to worker' s compensation insurance expense been reflected in your revised revenue requirement?

A. As detailed in Mr. Wilson' s reply testimony, the Company accepts Mr. Ball' s adjustment to worker' s compensation insurance O&M expense. Adjustment 12.5 of Exhibit PPL/708 reflects the Company' s acceptance of Mr. Ball' s proposed adjustment.

FAS 112 (Post-Employment Benefits)

Q. Please describe Staff witness Mr. Ball' s proposed adjustment related to FAS 112 (Post-Employment Benefits) expense.

A. Mr. Ball proposes an adjustment to FAS 112 (Post-Employment Benefits) of $316,596 on an Oregon-allocated basis, split between O&M expense and rate base. The basis of Mr. Ball' s adjustment is to escalate actual 2008 expenses to develop projected Test Period levels instead of escalating budgeted 2008 expenses as filed in the Company' s direct position.

Q. Do you accept Mr. Ball' s proposed adjustment?

A. Yes. The Company accepts the level of FAS 112 (Post-Employment Benefits) expense proposed by Mr. Ball as a reasonable projection for the Test Period.

Q. Has an adjustment to FAS 112 (Post-Employment Benefits) been reflected in your revised revenue requirement?

A. Yes. Adjustment 12.6 of Exhibit PPL/708 reflects the Company' s acceptance of Mr. Ball' s proposed adjustment to FAS 112 (Post Employment Benefits) O&M expense.

401(k) Expense

Q. Please explain Staff witness Mr. Ball' s adjustment to the Company' s 401(k) expense.

A. Mr. Ball proposes an adjustment of $2.6 million to the Company' s Test Period 401(k) expense on an Oregon-allocated basis, split between rate base and O&M expenses.

Q. Do you address Mr. Ball' s proposed adjustment to 401(k) expenses in your reply testimony?

A. No. Company witness Mr. Wilson addresses Mr. Ball' s proposed adjustment to 401(k) expenses in his reply testimony.

Q. Has an adjustment to 401(k) expense been reflected in your revised revenue requirement?

A. Yes. As detailed in Mr. Wilson' s reply testimony, the Company accepts Mr. Ball' s adjustment to 401(k) O&M expenses. Adjustment 12.7 of Exhibit PPL/708 reflects the Company' s acceptance of Mr. Ball' s proposed adjustment.

Challenge Grants

Q. Please describe Staff witness Mr. Ball' s proposed adjustments to challenge grant expenses.

A. Mr. Ball proposes to disallow challenge grant expenses from regulated results, reducing Oregon' s revenue requirement by approximately $58,000. Mr. Ball claims that these costs relate to civic activities, are discretionary, and require customers to support causes in which they may not believe.

Q. Do you accept Mr. Ball' s proposed adjustment?

A. Yes. The Company accepts Mr. Ball' s adjustment, as I have been informed that it complies with prior Oregon Commission practice.

Q. Has an adjustment been reflected in your revised revenue requirement to reflect this treatment?

A. Yes. Adjustment 12.8 of Exhibit PPL/708 reflects the removal of the challenge grant expenses from the Test Period.

<u>Regulatory Asset Amortization</u>

Q. Please describe Staff witness Mr. Ball's adjustment related to regulatory asset amortizations.

A. Mr. Ball proposes adjustments to two regulatory assets included in the base historical period used in this proceeding, the 12 months ended June 2008 ("Base Period"). First, he proposes removing the amortization expense related to the "98 Early Retirement Oregon" regulatory asset since this asset was fully amortized by December 2007. Second, he proposes to move the "Transition Plan-Oregon" regulatory asset from base rates to a separate tariff rider to ensure that the amortization of this asset terminates once it is fully amortized.

Q. Do you accept Mr. Ball's adjustment to the 98 Early Retirement Oregon regulatory asset?

A. In principle, yes. I agree with Mr. Ball's recommendation that the amortization related to this regulatory asset should not be included in the Test Period because it was fully amortized in December 2007. However, the Company's revenue requirement in this proceeding does not include any amortization expense for this regulatory asset during the Test Period.

Q. Did the Company make an adjustment to remove the amortization expense related to this regulatory asset in its filed revenue requirement?

A. Yes. The Base Period used in this case included approximately $1.8 million of amortization expense related to the 98 Early Retirement regulatory asset. As explained in my direct testimony, the Company developed O&M expense levels for the Test Period by escalating the Base Period expense for inflation using the Global Insight inflationary indices. This escalation process results in amortization expense for this regulatory asset of approximately $2.0 million. However, the Company made a final O&M adjustment in its original filing to true-up the overall level of O&M expenses included in the Test Period to the level included in the Company's 2010 budget. By following this process, the amortization expense related to the 98 Early Retirement regulatory asset was removed from the Test Period, since the Company's 2010 budget does not include any amortization expense for this item. This adjustment was included on page 4.20 of Exhibit PPL/702.

Q. Would the Commission's acceptance of Mr. Ball's proposed adjustment remove the amortization expense associated with this asset twice?

A. Yes. Any additional adjustment related to the amortization expense of this asset is unnecessary since it has already been removed from the Company's revenue requirement.

Q. Do you accept Mr. Ball's adjustment to the "Transition Plan-Oregon" regulatory asset?

A. Again, in principle, yes. I accept Mr. Ball's recommendation to move the balance and associated amortization of this asset out of base rates to be recovered through a separate tariff rider. However, I do not agree with the amount of amortization Mr. Ball asserts is included in the Test Period.

Q. How has Mr. Ball determined the amount of amortization included in the Test Period?

A. Mr. Ball calculates the amount of amortization included in the Test Period by taking the amortization expense included in the Base Period of approximately $3.9 million, multiplied by the Global Insight inflationary index of 7.1 percent, resulting in a total escalated amount of approximately $4.2 million.

Q. Is this consistent with how the O&M expense was developed in the Company's original filing?

A. No. As explained above, the Company developed the O&M expenses in this case by escalating the Base Year for inflation using Global Insight inflationary indices. This treatment is consistent with Mr. Ball's proposal. However, the Company made a final O&M adjustment, page 4.20 of Exhibit PPL/702, in its original filing to true-up the overall level of O&M expenses included in the Test Period to the level included in the Company's 2010 budget. As a result of this process, the amortization expense related to the Transition Plan-Oregon regulatory asset in the Test Period equals the amount of amortization expense included in the Company's 2010 budget.

Q. What is the level of amortization expense included in the Company's 2010 budget and the revenue requirement for the Test Period?

A. The Company's 2010 budget and the revenue requirement for the Test Period include approximately $2.3 million of amortization expense related to this asset. This amount reflects seven months of amortization expense, January 2010 through July 2010. The

Company' s 2010 budget does not reflect any amortization expense related to this asset from August 2010 through December 2010, since the asset is scheduled to be fully amortized at the end of July 2010.

Q. Has an adjustment been reflected in your revised revenue requirement related to the Transition Plan-Oregon regulatory asset?

A. Yes. Adjustment 12.9 of Exhibit PPL/708 reflects the removal of the amortization expense, balance, and associated accumulated deferred tax balance related to this asset as included in the Company' s original filing. The Company accepts Mr. Ball' s proposal to establish a separate tariff rider to recover the remaining balance associated with this asset beginning in February 2010 of $1,945,215 on an Oregon-allocated basis. The rate associated with this tariff rider is discussed in the reply testimony of Company witness Mr. William R. Griffith.

MEHC Change-in-Control (" CIC") Severance Regulatory Asset

Q. Please describe Staff witness Mr. Ball' s proposed adjustment to the MidAmerican Energy Holdings Company (" MEHC") CIC severance regulatory asset.

A. Mr. Ball does not take issue with the Company' s calculation of the MEHC CIC Severance regulatory asset as filed on page 4.3 of Exhibit PPL/702. However, he proposes to move the Commission-approved regulatory asset out of base rates to a separate tariff rider.

Q. Do you accept Mr. Ball' s proposal with respect to this regulatory asset?

A. Yes.

Q. Has an adjustment been made to the revised revenue requirement to reflect this treatment?

A. Yes. Adjustment 12.10 of Exhibit PPL/708 reflects the removal of the amortization expense, balance, and associated tax entries associated with the MEHC CIC severance regulatory asset as included in the Test Period. The Company accepts Mr. Ball' s proposal to establish a separate tariff rider to recover the remaining balance associated with this asset beginning in February 2010 of $4,605,029 on an Oregon-allocated basis. The rate associated with this tariff rider is discussed in the reply testimony of Company witness Mr. Griffith.

<u>Grid West Regulatory Asset</u>

Q. Please describe Staff witness Mr. Ball' s proposed adjustment to the Grid West regulatory asset.

A. Mr. Ball does not take issue with the Company' s calculation of the Grid West regulatory asset as filed on page 4.10 of Exhibit PPL/702. However, he again proposes to move the Commission-approved regulatory asset out of base rates to a separate tariff rider.

Q. Do you accept Mr. Ball' s proposal with respect to this regulatory asset?

A. Yes.

Q. Has an adjustment been made to the revised revenue requirement to reflect this treatment?

A. Yes. Adjustment 12.11 of Exhibit PPL/708 reflects the removal of the amortization expense, balance, and associated tax entries associated with the Grid West asset as included in the Test Period. The Company accepts Mr. Ball' s proposal to establish a separate tariff rider to recover the remaining balance associated with this asset beginning in February 2010 of $1,041,140 on an Oregon-allocated basis. The rate associated with this tariff rider is discussed in the reply testimony of Company witness Mr. Griffith.

Wind Interconnection Rate Base

Q. Please describe Staff witness Mr. Ed Durrenberger's proposed adjustment related to the interconnection costs associated with Seven Mile Hill II and Glenrock III.

A. Mr. Durrenberger removes approximately $4.5 million of Oregon-allocated interconnection rate base related to Seven Mile Hill and Glenrock III wind resources because of an alleged double count. Mr. Durrenberger asserts that the plant additions to rate base for these two facilities already include expenses for the interconnections and the Company's proposal would result in a double count of these expenses.

Q. Do you accept Mr. Durrenberger's proposed adjustment?

A. Yes.

Q. Has an adjustment been made to the revised revenue requirement related to the wind interconnection balances?

A. Yes. Adjustment 12.12 of Exhibit PPL/708 reflects the Company's acceptance of Mr. Durrenberger's proposed adjustment to wind interconnection capital additions. This adjustment also removes the associated depreciation expense and accumulated reserve associated with these capital additions.

<u>Other Wind Plant Additions</u>

Q. Please describe Staff witness Mr. Durrenberger's proposed adjustment related to the Company's new wind facilities.

A. Mr. Durrenberger removes approximately $2 million of Oregon-allocated rate base associated with certain cost components included as capital additions for the Company's High Plains, Seven Mile Hill II, and Glenrock III wind resources. He asserts that cost categories "Capital Surcharge" and "Contingencies" are not appropriate additions to rate base.

Q. Do you accept Mr. Durrenberger's proposed adjustment related to forecast contingency capital amounts?

A. Yes. For purposes of this proceeding and these specific resources, the Company accepts Mr. Durrenberger's proposed adjustment related to forecast contingencies for High Plains, Seven Mile Hill II, and Glenrock III wind resources.

Q. Has an adjustment been made to the revised revenue requirement related to these contingency capital amounts?

A. Yes. Adjustment 12.13 of Exhibit PPL/708 reflects the Company's acceptance of Mr. Durrenberger's proposed adjustment related to contingencies. This adjustment also removes the depreciation expense and accumulated reserve associated with these capital additions.

Q. Do you accept Mr. Durrenberger's proposed adjustment related to capital surcharges?

A. No. Capital surcharges or overhead construction costs are appropriate charges to be capitalized as part of rate base. The Code of Federal Regulations ("C.F.R.") clearly provides for the inclusion of capital surcharge and other similar overhead construction costs in capital projects. The relevant regulation, 18 C.F.R. § 367.52, states:

> 4. Overhead Construction Costs.
> A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

The Company's inclusion of capital surcharge amounts for its wind facilities is in compliance with Federal Energy Regulatory Commission ("FERC") regulations. As such, the Commission should reject Mr. Durrenberger's proposed adjustment removing these construction overhead amounts from rate base.

August 2009 NPC Update/Embedded Cost Differential ("ECD")

Q. Does your revised revenue requirement model reflect updates to NPC as filed in the Company's August 2009 TAM update?

A. Yes. Adjustments 12.14 and 12.15 of Exhibit PPL/708 reflect updated NPC as reported in the Company's August 2009 TAM update. As discussed previously, the Company is seeking to recover its NPC through the TAM (Docket UE 207) and not in this proceeding. However, an update of NPC is required to properly calculate the ECD, which is included as part of the non-NPC revenue requirement. The update to the ECD has been calculated in accordance with the Commission-approved allocation methodology.

Q. Is the Company making any other adjustments to revenue requirement at this time?

A. No.

Contested Adjustments

Q. Do you address any specific adjustments proposed by the intervening parties to which the Company is opposed?

A. Yes. I address several adjustments proposed by intervening parties to which the Company is opposed.

<u>Rate Base</u>

Q. Please describe Staff witness Ms. Deborah Garcia's proposed rate base adjustment.

A. As discussed previously in my testimony, Ms. Garcia's proposed adjustment disallows approximately $269 million of Company investment, or $116.6 million on an Oregon-allocated basis. This adjustment is comprised of three separate categories. First, she removes $36.4 million of Oregon-allocated rate base balances for capital projects scheduled to be placed into service subsequent to the rate effective date, February 2, 2010. Second, she removes approximately $400,000 of Oregon-allocated rate base for two distinct projects that should not be included in rate base. Third, she removes $79.8 million of Oregon-allocated rate base balances, representing 50 percent of the balances associated with projects that have designated in-service dates as "monthly" or "various."

Q. Please describe the aspects of Ms. Garcia's proposed rate base adjustment to which the Company is opposed.

A. The Company does not agree with Ms. Garcia's first and third categories of adjustments. Specifically, the Company opposes her proposal to remove all capital projects with in-service dates subsequent to the rate effective date and 50 percent of all capital amounts associated with projects that are placed into service in multiple months. In addition to my testimony on the Company's objections to these proposals, Company witness Mr. Richard A. Vail explains the invalidity of Ms. Garcia's adjustment as it relates to distribution plant.

Q. Why is the Company opposed to the first and third categories of Ms. Garcia's proposed adjustments?

A. Ms. Garcia's proposed adjustments are inappropriate for three fundamental reasons. First, her proposals are inconsistent with Commission precedent. Second, her proposals ignore the matching principle regarding the costs, revenues and balances included in the Test Period. Third, the overall level of Oregon net plant in service proposed by Staff produces a level of rate base in the Test Period that is less than the level of rate base actually experienced by the Company in the 12-months ended June 2009 - a patently unreasonable result.

Q. How is Ms. Garcia's proposal contrary to Commission precedent?

A. With respect to Ms. Garcia's first category of adjustments - capital projects with in-service dates subsequent to the rate effective date - Ms. Garcia's proposal applies an improper "known and measurable" standard that the Commission has rejected.

Q. What "known and measurable" standard does Ms. Garcia apply?

A. Ms. Garcia argues that proposed rate base additions must be excluded if there is "no guarantee" that the project will be completed by the forecasted date. Ms. Garcia argues that it is "a simple reality that no entity can foresee unexpected changes in costs, delays, or whether there would be a logical reason to scrap a proposed project." Essentially, Ms. Garcia is defining "known and measurable" to mean that the Company must be absolutely certain the project will be in service on the forecasted date to be included in rates.

Q. Does the Commission use the "known and measurable" standard advocated by Ms. Garcia?

A. No. In fact, as I understand Commission policy, the standard Ms. Garcia proposes was rejected by the Commission in Order No. 00-191. In that order, the Commission stated that revenues and expenses are included in the Test Period if they are "reasonably certain." Ms. Garcia's interpretation of "known and measurable" is more restrictive than the Commission's "reasonably certain" standard and should be rejected. PacifiCorp asked Staff to provide citations to past orders where the Commission has used the "known and measurable" policy advocated by Ms. Garcia in Data Request 3.16. Staff could not cite to any orders where the Commission did so. See Exhibit PPL/709.

Q. Is the Company reasonably certain that the rate base items that the Company included in the Test Period will be in service on the forecasted date?

A. Yes. The Company plans plant additions not only for regulatory purposes, but for its own facility management and engineering purposes. Based on the Company's best judgment and extensive review of plant additions, the Company's forecasted in-service dates included in its filing are reasonably certain. In fact, the Company's revenue requirement is calculated based on a 13-month average rate base designed to ensure that customers' rates only reflect the portion of the investment that is used and useful in the Test Period. In addition, because in this case the Test Period begins on January 1, 2010, but the rate effective period starts a month later, the Company's recovery on its rate base in the Test Period lags by a month. This lag provides additional reassurance that the Company will not be prematurely recovering on new projects included in rate base.

Q. Are you concerned about the policy implications of Ms. Garcia's interpretation of "known and measurable"?

A. Yes. Application of Ms. Garcia's standard requiring a "guarantee" before including projects in rate base would undermine the Commission's ability to use a forecast Test Period. Ms. Garcia is correct that no entity can foresee all changes in the Test Period, but requiring an entity to foresee all changes that will occur in the Test Period is incompatible with a forecast test period. This incompatibility is why in Order No. 00-191 the Commission rejected a restrictive "known and measurable" standard in favor of the "reasonably certain" standard.

Q. How else are Ms. Garcia's proposed adjustments contrary to Commission precedent?

A. Both the first category of adjustments - removal of all capital projects with in-service dates subsequent to the rate effective date, and the third category of adjustments - removal of 50 percent of all capital amounts associated with projects that are placed into service in multiple months are contrary to the Commission's interpretation of the "used and useful" standard.

Q. What do you mean by the Commission's interpretation of the "used and useful" standard?

A. It is my understanding that the Commission has found that the "used and useful" requirement in ORS 757.355 was not intended to apply to routine, smaller projects relating to operating plant. See Order No. 02-227. The Commission's recent order reviewing the validity of Order No. 02-227, Order No. 08-487, did not change this policy.

Q. Has the Company reflected this policy in its filing?

A. Yes. As discussed in my direct testimony, the Company did not include in rate base projects greater than $20 million on a total-company basis that will be placed into service during 2010. The projects under $20 million included in the Company's filing that will be placed into service in the Test Period primarily relate to existing infrastructure or operating plant that is already in service. Additionally, the use of a 13-month average rate base approach ensures that projects are not reflected in rate base until the in-service date. Therefore, the projects classified in Ms. Garcia's first and third categories of adjustments are appropriately included in rate base, consistent with the Commission's interpretation of ORS 757.355.

Q. Please describe the matching principle and how it has been applied in the Company's original filing.

A. In general, the matching principle states that the costs incurred during a period should be matched against the revenue generated in the same period. In the context of a general rate case, this principle requires a time period "matching" of revenues, costs and rate base balances used in the calculation of the revenue requirement. As described in my direct testimony, the Company's filed revenue requirement closely adheres to the matching principle by including costs, revenues and rate base balances on a consistent calendar year 2010 basis. To summarize, costs, revenues, and rate base balances are included in the Company's filed position at projected levels for the rate effective period.

Q. Is Ms. Garcia's adjustment consistent with this matching principle?

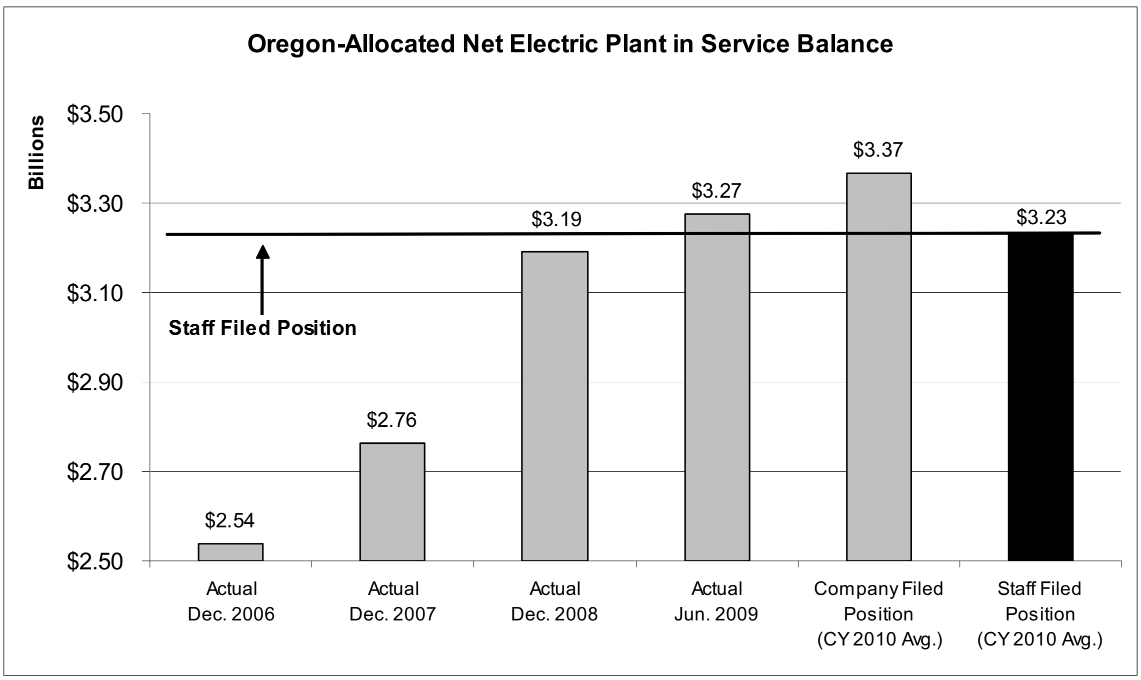
A. No. Ms. Garcia's rate base adjustment explicitly removes all projects identified to be placed into service after February 2010, effectively using a 2009 rate base level while other aspects of Staff's filed position remain at a calendar year 2010 Test Period level. This treatment allows customers to receive the benefits of plant additions that will be in service in the Test Period without bearing the costs of such additions. This result is contrary to the matching principle and Commission policy.

Q. Are there other aspects of Staff's filed position that are inconsistent with the matching principle?

A. Yes. Staff's proposed adjustments significantly limit the amount of capital additions included in the Test Period, while ignoring the fact that accumulated depreciation on existing plant balances continues to increase through the end of the Test Period. In other words, Staff includes the reduction to rate base for increases in accumulated depreciation on existing rate base through 2010, while substantially restricting or eliminating the additions to rate base for the same period. This treatment further exacerbates the mismatch in Staff's filed position.

Q. Do the overall level of plant balances proposed by Staff reflect a reasonable level for the Test Period?

A. No. The chart below shows actual Oregon-allocated plant-in-service balances from December 2006 through June 2009 compared to the Company's and Staff's filed positions for the Test Period. Staff's position in this rate case produces Oregon-allocated net plant-in-service balances for the Test Period that are less than June 2009 actual levels.



Q. Is it reasonably certain that an average Test Period net plant balance will be less than actual June 2009 levels?

A. No. In order for a decline in net plant-in-service to occur from the June 2009 actual level to the levels proposed by Staff for the Test Period, the Company would effectively have to discontinue making capital investments into the system. There is no reasonable possibility of this occurring.

Depreciation and Amortization

Q. Please describe Staff witness Ms. Ming Peng' s proposed adjustments to depreciation and amortization expense and reserve.

A. Ms. Peng' s adjustments attempt to reflect the depreciation and amortization impacts of Ms. Garcia' s proposed rate base adjustments discussed in detail above.

Q. Do you agree with Ms. Peng' s proposed adjustments?

A. Yes, in principle. Modifications to the capital amounts included in the case require adjustments to the levels of depreciation and amortization expense and reserve. However, because the Company does not agree with the majority of Ms. Garcia' s proposed adjustments to the Company' s capital additions, Ms. Peng' s adjustment is unnecessary.

Q. Has the Company appropriately adjusted depreciation expense and reserve for the adjustments included in its revised revenue requirement?

A. Yes. For each of the capital adjustments made from the Company' s original filing, the appropriate adjustments to depreciation and amortization expense and reserve have also been considered. These impacts are included as part of the individual adjustments as discussed earlier in my testimony. As a result, no additional adjustment to the level of depreciation and amortization expense or reserve is necessary.

Q. Do you have concerns with Ms. Peng' s modeling of the depreciation and amortization expense and reserve?

A. Yes. Ms. Peng' s workpapers contain several errors and inconsistencies, some of which were identified and agreed to by Staff in Company Data Request 3.21. See

PPL/709. I also have concerns about the integrity of the final result given that Ms. Peng' s methodology of calculating the depreciation and amortization impacts appears to be done on a project-by-project basis.

<u>**Uncollectible Expense**</u>

Q. Please describe Staff witness Mr. Paul Rossow' s proposed adjustment related to the Company' s level of uncollectible expense.

A. Mr. Rossow proposes a reduction of approximately $963,000 to Oregon-allocated uncollectible expenses using a three-year average of net write-off levels (2006-2008). He then uses this average, escalated for inflation, to determine the level for the Test Period.

Q. Do you agree with Staff' s proposed adjustment?

A. No. Mr. Rossow' s use of historical averaging to determine the Test Period level of uncollectible expense is inappropriate in the current environment.

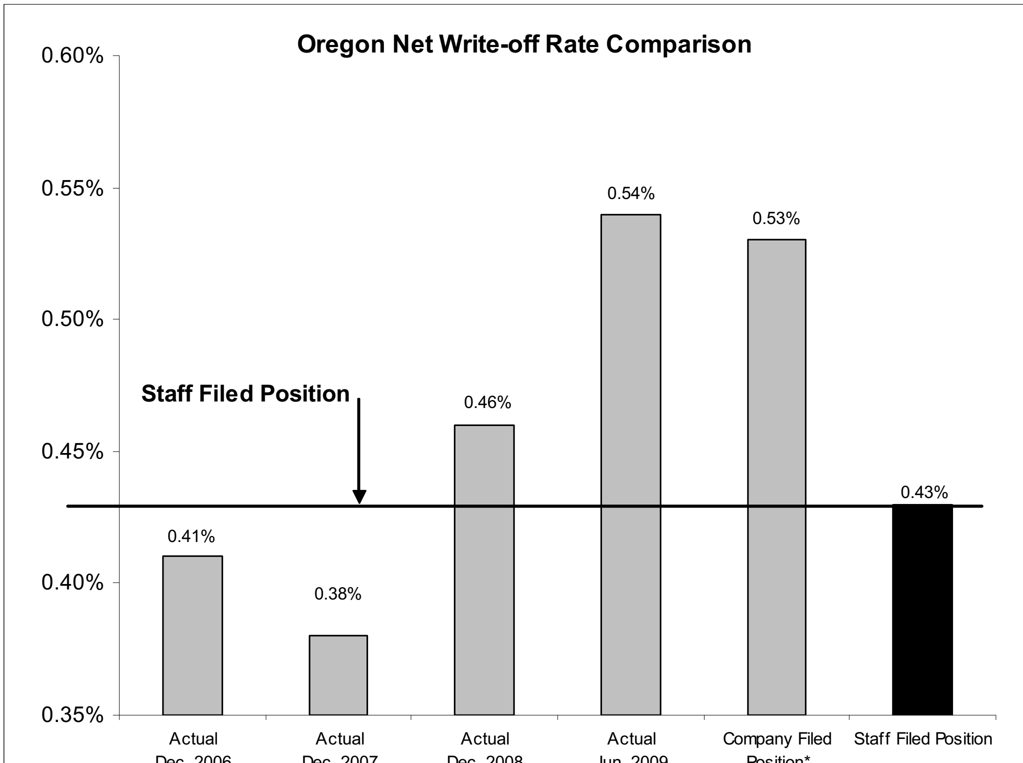
Q. Why is it inappropriate to use a three-year historical average methodology?

A. Mr. Rossow' s method fails to account for the steep downturn in recent economic conditions. Staff acknowledged in response to Data Request 3.8b that the write-off level has been trending upward since 2006. See PPL/709. Nevertheless, Staff stated that " [n]o consideration was given to the upward trending of the write-off levels from 2006 to the present." In addition, Staff uses a historical average that places equal weight on years during which the economy was relatively healthy - 2006 and 2007. Mr. Rossow' s method produces a forecast of 2010 uncollectible expense that is below the actual levels seen in both the 12-months ended December 2008 and June 2009.

Failure to recognize the current conditions affecting the Company and its customers significantly undermines the validity of this adjustment.

Q. How does the Company' s proposed uncollectible expense compare with that proposed by Staff?

A. The chart below shows the Company' s actual Oregon write-off rates (net write-offs as a percentage of associated revenues) compared to the Company and Staff filed positions. As shown below, Staff proposes a 2010 write-off rate below the actual rates experienced from 2008 to the present. On the other hand, at 0.53 percent, the Company' s proposed uncollectible rate is below the actual write-off rate for the year ended June 2009. This comparison demonstrates that the Company' s forecast rate is conservative.



Net Write-off rate is determined by dividing net w rite-off amounts (w rite-offs less recoveries) by revenues.

*The Company's filed position, as seen in PPL/702 is based on uncollectible expense as recorded in FERC account 904.

Adjustment to Revenue Sensitive Uncollectible Rate

Q. Please describe Staff witness Mr. Rossow's proposed adjustment to the Company's revenue sensitive uncollectible rate.

A. Mr. Rossow has applied his proposed uncollectible rate of 0.43 percent in the gross-up factor used to determine the price increase.

Q. Should the Commission accept Staff's proposed adjustment to the uncollectible rate used in the revenue requirement gross-up factor?

A. No. For the same reasons described above, this adjustment is inappropriate and should be rejected by the Commission.

Non-Captive Insurance Expense

Q. Please describe Staff witness Mr. Ball's proposed adjustment related to non-captive insurance expense.

A. Mr. Ball proposes to reduce the Company's non-captive insurance expense by approximately $1.0 million, on a total-company basis. The basis of his adjustment is the Company's response to OPUC Data Request No. 91, in which the Company provided its calendar year 2010 projection of non-captive insurance expenses.

Q. Do you agree with the Test Period level of non-captive insurance expense proposed by Mr. Ball?

A. Yes. The Company's response to OPUC Data Request 91 presented the forecast of non-captive insurance expense of approximately $13.8 million for the Test Period on a total-Company basis. This figure is consistent with the Company's budget for the same period.

Q. Does an adjustment need to be made to the Company' s filed revenue requirement to arrive at this level of non-captive insurance expense for the Test Period?

A. No. The Company' s filed revenue requirement already reflects non-captive insurance expense at the level proposed by Mr. Ball. As explained in my direct testimony, the Company developed O&M expense levels for the Test Period by escalating the Base Period for inflation using the Global Insight inflationary indices. This process results in non-captive insurance expense of approximately $14.8 million referenced by Mr. Ball in his direct testimony. However, the Company made a final O&M adjustment in its original filing to true-up the overall level of O&M expenses included in the Test Period to the level included in the Company' s 2010 budget. This adjustment (" Budget True-Up") was included in Exhibit PPL/702, page 4.20 and resulted in a reduction of approximately $40.5 million O&M expenses on a total company basis.

Q. Was non-captive insurance specifically itemized in this additional true-up adjustment contained in the Company' s original filing?

A. No. The Company' s 2010 budget was not developed at a FERC account level of detail. As a result, the true-up to budget adjustment shown on page 4.20 of Exhibit PPL/702 was done at a total O&M expense level prorated to various FERC functions. However, the ultimate impact of the adjustment reduces the total level of O&M expense included in the Test Period to the level contained in the Company' s 2010 budget. The non-captive insurance expense included in the Test Period is therefore already at the budgeted level of approximately $13.8 million proposed by Mr. Ball.

Q. Should the Commission accept Mr. Ball' s proposed adjustment?

A. No. The Commission should reject Mr. Ball' s proposed adjustment. Acceptance of his adjustment would result in a double count of the adjustments already reflected in the Company' s original filing. If the Commission were to accept this proposed adjustment, then the Budget True-Up adjustment included in Exhibit PPL/702, page 4.20, of approximately $40.5 million on a total-company basis would need to be reduced by an equal amount, or approximately $1.0 million.

<u>Uninsured Losses Expense</u>

Q. Please describe Mr. Ball' s proposed adjustment to uninsured losses expense?

A. Mr. Ball proposes to reduce the Company' s uninsured losses expense by approximately $12.8 million, on a total-company basis. The basis of his adjustment is the Company' s response to OPUC Data Request No. 91, in which the Company provided its calendar year 2010 projection of uninsured losses expense.

Q. Do you agree with Mr. Ball' s proposed adjustment to uninsured losses expense?

A. No. Similar to the adjustment Mr. Ball proposes to non-captive insurance expense described above, Mr. Ball fails to recognize that the Company' s original filing already reflects the Company' s 2010 budget as reported in OPUC Data Request 91.

Q. What is your recommendation to the Commission regarding Mr. Ball' s proposed adjustment?

A. I recommend the Commission reject Mr. Ball' s proposed adjustment to uninsured losses. No adjustment is necessary to arrive at the forecasted levels proposed by Mr. Ball. If the Commission were to accept this proposed adjustment, then the Budget

True-Up adjustment of approximately $40.5 million on a total-company basis would need to be reduced by an equal amount, or approximately $12.8 million.

Partial Reversal of Budget True-Up Adjustment

Q. Has Staff witness Mr. Ball attempted to reflect any reduction to the Budget True-Up adjustment?

A. Yes. Mr. Ball attempts to reverse a portion of the Budget True-Up adjustment. As discussed above, this adjustment reduces the overall level of O&M expense included in the Test Period to the level of O&M included in the Company's 2010 budget. Since several of Mr. Ball's adjustments reduce O&M expenses in the escalated Base Period, he has somewhat arbitrarily reversed the administrative and general ("A&G") and transmission categories of the Budget True-Up adjustment, only partially restating the Budget True-Up adjustment.

Q. Do you agree with Mr. Ball's approach?

A. No. The Company's Budget True-Up adjustment should be reduced on a dollar-for-dollar basis for any O&M adjustments Mr. Ball has proposed. Mr. Ball's approach results in an improper double count of a portion of the Budget True-Up adjustment.

Q. How does Mr. Ball's methodology result in a double count?

A. The Budget True-Up adjustment was prorated among FERC functional categories based on relationships in the Base Period. Mr. Ball's proposed adjustments impact all categories of O&M, not just the A&G and transmission portions. Removing only the A&G and transmission portions of the Budget True-Up adjustment, as Mr. Ball does, does not fully offset the portion of the Budget True-Up adjustment related to Mr.

Ball' s proposed adjustments. As a result, Mr. Ball' s adjustments remove O&M costs that are then removed again through the Budget True-Up adjustment.

Q. How do you propose the Commission handle the Budget True-Up adjustment?

A. After the Commission has determined the appropriate level of O&M costs in this proceeding, the Budget True-Up adjustment needs to be recalculated using the new Test Period O&M costs. If total O&M costs are higher than the Company' s 2010 target used to calculate the Budget True-Up adjustment, the revised adjustment will reduce Test Period O&M costs to the 2010 budget. If total Test Period O&M is lower than the 2010 target used to calculate the Budget True-Up adjustment, the Budget True-Up adjustment should be completely eliminated.

Meals and Entertainment Expenses

Q. Please describe Staff' s proposed adjustments to meals and entertainment, onsite meals, offsite rentals, catering, and other employee expenses.

A. Staff witnesses Mr. Ball and Mr. Michael Dougherty propose adjustments to reduce expenses incurred for meals and entertainment, onsite meals, offsite rentals, catering, and other employee expenses by 50 percent. The impact of these adjustments is a reduction to Oregon-allocated O&M expense of $136,909.

Adjustment Summary by Category/Witness

	Staff 202 Ball 10	Staff 202 Ball 12	Staff 302 Dougherty 1	Adj. TOTAL
Meals & Entertainment	31,299	2,389	51,933	85,620
On-site Meals	12,723	967	18,233	31,924
Off-site Rentals	-	-	7	7
Catering	-	-	4,462	4,462
Other Employee Expenses	-	-	14,896	14,896
Adj. TOTAL	44,022	3,356	89,531	**136,909**

In Mr. Dougherty' s testimony, he insists that this is a routine adjustment that promotes cost sharing between customers and shareholders.

Q. Does the Company agree with Staff' s proposed adjustment?

A. No. The majority of this adjustment removes meals and entertainment and on-site meals expenses. The main purpose of these types of expenses is providing meals to employees when required to work overtime on a project, travel for Company business, or work offsite. The Company believes that such expenses are important to maintain a productive and safe work environment and should be allowed.

Q. Should the Commission accept Staff' s proposed adjustments to meals and entertainment and other miscellaneous expenses?

No.

<u>FERC Proceeding ER07-882 Legal Fees Amortization</u>

Q. Please describe Staff witness Mr. Ball' s proposed adjustments to legal fees associated with FERC proceeding ER07-882.

A. Mr. Ball proposes to amortize approximately $176,000 of Oregon-allocated legal fees associated with FERC proceeding ER07-882 (" FERC Litigation") over a 10-year period.

Q. Please provide a brief summary of the legal fees associated with FERC Litigation.

A. PacifiCorp owns and operates a 47-mile transmission line segment that runs between its Malin substation located in southern Oregon and a point in northern California known as Indian Springs (the " Malin Line"). PacifiCorp leased the full capacity of the Malin Line to a group of California utilities from its original construction in 1967 until the lease expiration in 2007. Upon lease expiration, PacifiCorp was required to litigate its right to terminate the lease. Ultimately, the litigation resulted in a settlement agreement whereby PacifiCorp agreed to lease the Malin Line to the California utilities under new stipulated terms.

Q. Do you agree with Mr. Ball' s proposed adjustment?

A. No. PacifiCorp incurs legal fees on a regular basis that are related to one-time agreements. For example, PacifiCorp enters into power purchase agreements with qualifying facilities on a regular basis with terms of up to 20 years. The legal costs associated with these contracts are expensed in the period in which they are incurred and are not amortized over the life of the contract. Establishing a policy requiring the Company to amortize legal expenses in the manner proposed by Mr. Ball would be highly burdensome while providing very little benefit to customers. Mr. Ball has not presented a basis for changing Commission policy on this issue. As such, the Commission should reject Mr. Ball' s proposed adjustment.

<u>Enhanced Reliability Standards</u>

Q. Please describe Staff witness Mr. Ball' s proposed adjustment to costs associated with enhanced reliability standards.

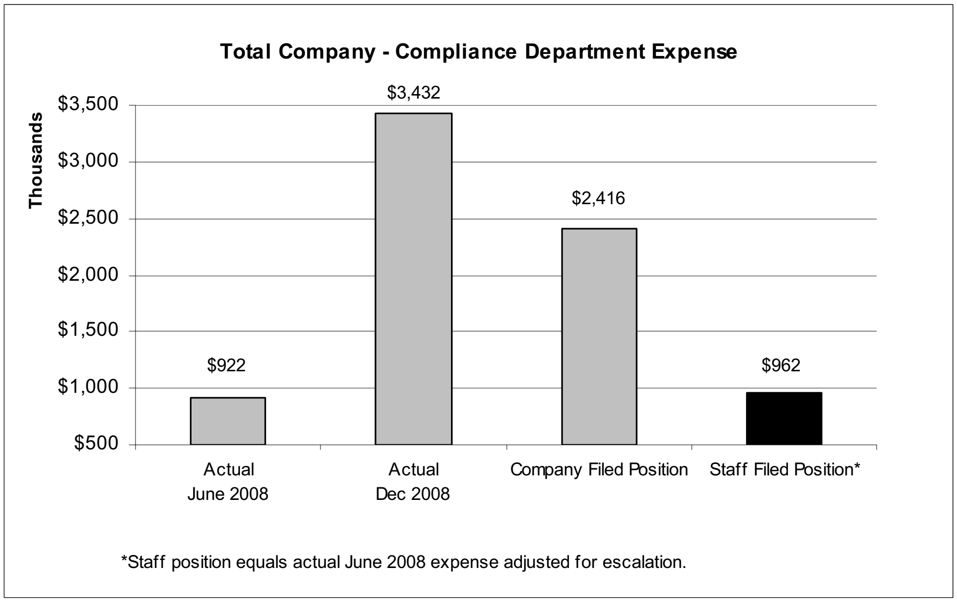
A. Mr. Ball' s proposed adjustment removes $388,236 of Oregon-allocated O&M expense related to compliance with mandatory enhanced reliability standards. Mr. Ball states, " PacifiCorp has not met its burden of proof to demonstrate why additional funding is necessary." He asserts that the level of expense included in the Base Period, adjusted for inflation, is sufficient to allow the Company to recover the additional costs associated with the new mandatory standards. Mr. Ball also states that significant costs related to compliance of these standards are labeled as " planning" costs and are nonrecurring in nature.

Q. Do you agree with Mr. Ball' s proposed adjustment?

A. No. As discussed in detail by Company witness Mr. Richard P. Reiten, the Company has incurred and continues to incur considerable costs due to the enhanced reliability standards imposed by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council. The original cost estimate to comply with these standards was $2.4 million (total-company basis) for the Test Period, of which approximately $922,000 (total-company basis) was included in the Company' s Base Period.

Q. Are the costs included in the Company' s filing related to compliance with the enhanced reliability standards conservative?

A. Yes. In the 12-months ended December 2008, the Company actually incurred approximately $3.4 million on a total-company basis in compliance with these new standards - significantly more than the Company proposed for the Test Period in this proceeding. The chart below compares actual data for June 2008 and December 2008 to Staff' s proposal and the Company' s request.



*Staff position equals actual June 2008 expense adjusted for escalation.

Q. Are these costs one-time "planning" costs as claimed by Mr. Ball?

A. No. PacifiCorp's obligation to comply with the mandatory reliability standards will continue indefinitely. While there was an initial planning effort to ensure that compliance could be achieved, the continued effort to maintain compliance with the standards is higher than anticipated and will impose ongoing expenses that the Company will be required to incur.

Q. Should the Commission accept Mr. Ball's proposed adjustment?

A. No. The Commission should reject Mr. Ball's proposed adjustment. Limiting compliance expenses to the level included in the Base Period, escalated for inflation, does not provide the recovery necessary to maintain compliance with these mandatory reliability standards.

Construction Work in Progress ("CWIP") Write-off Expenses

Q. Please summarize Staff's proposed adjustment to CWIP write-off expenses.

A. Staff witnesses Mr. Dougherty and Mr. Ball propose to disallow a total of approximately $1.3 million of Oregon-allocated CWIP write-off expenses (also referred to as AUC expense by Mr. Ball). In his testimony, Mr. Dougherty argues that the Company should not be allowed to recover these expenses through customer rates because they are related to projects not placed in service or used for providing utility service to Oregon customers. For projects labeled " New Revenue," he suggests that one way for the Company to recover these expenses is to " attempt to bill and recover the write-off amounts from specific sources of new revenue." Staff/300, Dougherty/5, lines 17-19. For other types of projects, such as those listed as " Mandated, Public Accommodations and Other (Replace, Upgrade, Temporary Connections)," Mr. Dougherty simply states that the Company should not be allowed to recover these costs because the projects were never placed in service.

Q. What are these costs?

A. The majority of the distribution expenses in Mr. Dougherty' s adjustment are attributable to expirations of service estimates provided by the Company or when customers indicate they no longer wish to pursue a project for which an estimate was provided by the Company.

Q. Do you agree with Staff' s rationale that expenses must be related to a project placed in service and used for providing utility service to Oregon customers in order to justify recovery of the expenses?

A. No. Providing an estimate is a necessary customer service for any person requesting, relocating or upgrading service in Oregon. PacifiCorp' s Customer Guarantee No. 4 in the Oregon tariff requires that for Residential and Schedule 23 customers, " [a]n estimate for new supply will be supplied to the Applicant or Customer within 15 working days after the initial meeting and all necessary information is provided and any required payment is made." If PacifiCorp fails to meet this requirement, a qualifying customer's account is automatically credited $50. *See* Oregon Rule 25, General Rules and Regulations, Customer Guarantees. The Company's Customer Guarantee Program was approved by the Commission as part of the MEHC acquisition of PacifiCorp in Docket UM 1209.

Q. Why is providing estimates to customers a necessary activity?

A. Many customers need this information prior to proceeding with a project. To make educated decisions, customers and applicants must be informed of what requirements (including costs) are necessary to make changes to their current service or receive new service. To that end, the Company must prepare estimates to provide customers and applicants with the necessary information.

Q. Please explain the process for providing customers with electric service request estimates.

A. PacifiCorp provides thousands of estimates annually for customers or applicants requesting new electric service or a redesign (relocating/adding capacity) of existing service at their homes or businesses. To provide an estimate, a PacifiCorp estimator typically begins by traveling to the home or business of the customer to discuss the requested service and assess the proposed connection. Depending on the complexity of the connection, the estimator may develop drawings and perform calculations in order to provide the customer with an accurate estimate. All of the estimator's time required for an estimate is recorded as CWIP.

Once an estimate and contract are presented to a customer, the customer has 90 days to sign the contract and pay any applicable advance costs. Estimates must be recalculated if the contract is not signed in 90 days or the project has not commenced within 150 days of the contract. If the customer elects to proceed, the project costs, including the expenses related to the original estimate are capitalized and included in rate base. For various reasons, customers may decide not to go forward with the service connection or redesign. In those cases, all estimator time and expenses are credited from CWIP and debited to O&M expense as part of the Company's routine operations.

Q. What are some of the reasons a customer might cancel a project after an estimate has been provided?

A. The following are typical reasons that customers elect to cancel a project after an estimate has been provided:

- Customers may be unfamiliar with the costs associated with bringing electric service to their site. Once an estimate has been provided, a customer may decide that it is unable to pay to complete the job. For example, applicants may not realize that an upgraded transformer or larger pole is required for their service or the costs associated with necessary trenching.
- A customer may not be able to obtain easements or rights of way from neighboring properties.
- A customer may face unexpected economic hardship.
- A customer may be unable to obtain financing for a project. Often, a written estimate is required by financial institutions prior to approving funding.

Q. Does PacifiCorp require a customer to advance the costs of providing estimates in Oregon?

A. For customers requesting service under 1000 kW, the Company generally provides the initial estimate at no charge. For other customers or applicants, the Company may require a customer to advance estimated engineering, design and estimation costs, which are then applied to the costs for a line extension under Oregon Rule 13(I)(C).

Q. Please explain why PacifiCorp does not require all customers to advance estimate costs as allowed under its line extension tariff?

A. The Company does not require all customers to advance estimation costs for several reasons. First, as a matter of policy, the Company strives to provide customers with the necessary information to make informed decisions in a prompt and professional manner. Second, charging customers a fee prior to the commencement of any estimate would require additional administrative expense, including additional employee time to administer the fees, computer system changes, accounting, processing and refunds. Finally, requiring the estimating fee in advance would add another step to the line extension process, further delaying the timeframe to receive the estimate and deliver service upon execution of a line extension contract.

Q. Staff suggests that one way PacifiCorp could recover estimation expenses associated with New Revenue projects is to attempt to bill and recover the costs through separate charges. Are there any challenges associated with this approach?

A. Yes, for the same reasons identified above—it would be administratively burdensome and possibly result in delays in the timeframe to receive the estimate. Additionally, attempting to recover estimation costs after a job is cancelled would be very difficult because the Company would have no leverage to collect the costs. Moreover, the Company would likely spend more money attempting to collect the costs associated with the cancelled job than was actually incurred to perform the estimate.

Q. Staff also provides an alternate recommendation to share Oregon New Revenue CWIP costs equally between shareholders and customers. Do you believe this approach is equitable?

A. No. Providing estimates is a cost of doing business. All customers are eligible to receive this service; therefore, it is reasonable for the costs to be spread across all customers.

Q. Should there be a distinction between costs associated with projects Mr. Dougherty classifies as New Revenue versus Mandated, Public Administration and Other, as suggested by Mr. Dougherty?

A. No. The Company's process for providing customers with electric service estimates and the reasons supporting the Company's recovery of costs related to this service are the same for both types of projects.

Q. Should the Commission accept Staff's proposed adjustment?

A. No. As discussed previously these costs are incurred as part of providing electric service to customers.

<u>Property Tax Adjustment</u>

Q. Does Staff make an adjustment to property taxes in addition to the property tax adjustment addressed by Company witness Mr. Norman K. Ross?

A. Yes. Staff makes an additional adjustment to property tax expenses related to rate base adjustments proposed in other Staff adjustments. In her direct testimony, Ms. Garcia states this adjustment aligns Staff's proposed rate base reductions with the amount of property taxes the Company will actually pay.

Q. Is it correct to adjust property taxes for Staff's proposed rate base removals?

A. No. This methodology is flawed as addressed in the reply testimony of Mr. Ross. In addition, Staff's proposed calculation is inconsistent with the Revised Protocol methodology of allocating property taxes to Oregon.

Q. Please explain how Staff's calculation is inconsistent with the Revised Protocol allocation methodology?

A. Staff applied a property tax rate to Oregon-allocated rate base amounts effectively allocating property taxes using several allocation factors instead of applying the rate to total company amounts and then allocating using the Gross Plant – System ("GPS") factor. This results in an overstatement of Staff's adjustment by $329,000.

Adjustment to Oregon's Allocation of Labor

Q. Please describe ICNU-CUB witness Ms. Ellen Blumenthal's proposed adjustment to Oregon's allocated share of labor and benefit expenses.

A. Ms. Blumenthal's proposed adjustment reduces Oregon's allocated share of wages and employee benefits from the Company's initial filing of 29.5 percent to 19.7 percent. The impact of this adjustment is a reduction to Oregon revenue requirement of approximately $47 million.

Q. Do you agree with Ms. Blumenthal's proposed adjustment to Oregon's allocated share of labor and benefit expenses?

A. No. Ms. Blumenthal's adjustment appears to stem from a misplaced reliance on the data presented in the Company's responses to ICNU Data Requests 9.8 and 9.33. In these responses, the Company provided Oregon-allocated figures for wages as requested but noted in the written response that the data provided did not reflect the allocation of FERC 707 expenses and did not reflect the final allocation of other accounts.

Q. Has the Company provided supplemental responses to ICNU Data Requests 9.8 and 9.33 clarifying this information?

A. Yes. Upon receiving Ms. Blumenthal's direct testimony, the Company became aware that Ms. Blumenthal had misinterpreted the data contained in the Company's original data responses. As a result, the Company provided a supplemental response explaining that the original response did not provide an accurate view of the final allocation of wage expenses, and providing clarifying information. The narrative portions of the Company's original and supplemental responses to these data requests are provided as Exhibit PPL/710.

Q. What additional information did the supplemental response provide?

A. The Company's second supplemental response to ICNU Data Request 9.8 explained in greater detail the implications of the fact that the original response did not reflect the allocation of FERC 707 expenses and did not reflect the final allocation of other accounts.

In 2007, the Company began using FERC 707 as a temporary labor clearing account, which is by far the largest account for labor costs. As explained in the second supplemental response, the numbers provided in the original response showed the FERC 707 costs as allocated to "Other" instead of system-allocated to all states.

The effect of this treatment was to reflect FERC 707 costs in total expense but to assign none of the expense to Oregon. Ms. Blumenthal incorrectly calculated Oregon allocation ratios of 19.90 percent and 18.86 percent in 2007 and 2008, respectively.

Q. Did the supplemental response explain the method which the Company used to derive the Oregon-allocated share of labor costs applied in this case?

A. Yes. The Test Period projection of 29.5 percent for the Oregon-allocated share of labor and benefit expenses as filed in Exhibit PPL/702 is based on actual data for the 12-month period ended June 2008, including all labor allocation activity processing.

Q. Is the Company's proposed 2010 Oregon-allocated share reasonable when compared with actual historical data?

A. Yes. The table below reflects Oregon's final labor allocation percentages for 2006, 2007, and 2008 as reported in the Company's annual Results of Operations Reports filed with the Commission and provided to other parties. The table also shows the Oregon-allocated share applied in both the Company's and ICNU-CUB's filed positions. This demonstrates that Ms. Blumenthal's "declining trend" analysis is mistaken. However, the Company's allocation of labor and benefit expenses in this case is slightly less than the actual Oregon-allocation for calendar year 2008.

Year	Final Oregon Alloc. %
2006 - Actual	30.59%
2007 - Actual	30.10%
2008 - Actual	30.37%
2010 Company Filed Position	29.50%
2010 ICNU/CUB Filed Position	19.68%

Q. What factors contribute to changes in the labor allocation?

A. Consistent with the Commission-approved Revised Protocol allocation methodology, labor expenses are allocated to states based on the type of work identified. For example, generation and transmission labor expenses are primarily allocated using the system generation (" SG") factor, while distribution labor expenses are primarily situs assigned. Allocation factors change as each state' s contribution to total system energy and coincident peaks changes. The Company' s filing has been prepared in accordance with the Commission-approved methodology of allocating labor costs to Oregon.

Q. Should the Commission accept Ms. Blumenthal' s adjustment related to Oregon' s allocated share of labor expenses?

A. No. The Commission should reject Ms. Blumenthal' s proposed adjustment as it clearly does not provide an accurate view of Oregon' s overall labor allocation. Acceptance of this adjustment would be a deviation from the Commission-approved allocation methodology and would result in a level of Oregon-allocated labor and benefit expenses to levels not experienced by the Company since the late 1980' s.

Increase in Employee Levels

Q. Please describe ICNU-CUB witness Ellen Blumenthal' s proposed adjustment related to alleged increases to employee levels.

A. Ms. Blumenthal' s proposed adjustment removes approximately $7.3 million Oregon-allocated expenses related to salary and benefit expenses for 311 full time equivalents (FTEs). Ms. Blumenthal asserts that the Company' s filing includes 311 additional FTEs above actual 2008 calendar year levels.

Q. What is the basis of Ms. Blumenthal' s assertion that the Company' s filing includes 311 additional FTEs?

A. Ms. Blumenthal references the Company' s response to OPUC Data Request 165 in which the Company provided actual full and part-time headcount of 5,802 as of December 2008 and a projected headcount of 6,113 for calendar year 2010.

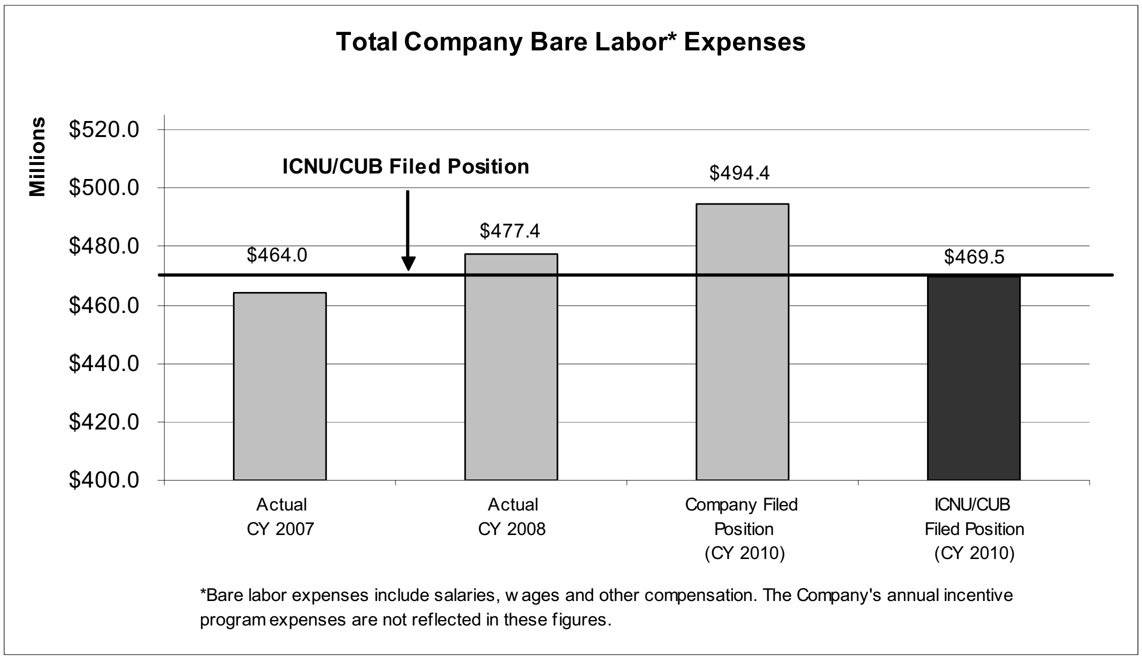
Q. Do you agree with Ms. Blumenthal' s assertion that the Company' s budget includes higher projected employee levels than the historical period?

A. Yes, in part. The Company' s projected number of employees for calendar year 2010 includes 6,113 of full- and part-time employees. However, while the budgeted headcount may show additional employees, the costs related to those additional employees have not been included in the Company' s filing, because the majority of the 311 full- and part-time employee increases will remain unfilled during the Test Period. As stated in the direct testimony of Mr. Reiten, " The Company has proactively and aggressively controlled operations and maintenance (" O&M") expenses and administrative and general (" A&G") expenses." Part of the process of controlling costs includes setting aggressive (low) total O&M targets for each of the Company' s business units. As provided in the Company' s response to OPUC Data Request 279, in 2008 the Company' s actual employee levels were 263 FTEs less than the Company' s budget. In 2007, actual employee levels were 388 FTEs less than the budget.

Q. Does the Company' s revenue requirement reflect a reasonable level of costs?

A. Yes. Bare labor expenses (wages, salaries, and other compensation) for calendar year 2007 were approximately $464 million and for 2008 were approximately $477.4

million, as reported in the Company' s annual Results of Operations Reports filed with the Commission and provided to other parties. The adjustment proposed by ICNU-CUB would result in a bare labor of approximately $469.5 millio, which is below the actual level for 2008. This is clearly not a reasonable result. On the other hand, the Company' s revenue requirement reflects an annual increase to bare labor expenses of approximately 1.8 percent. The chart below reflects these figures.



Q. What do you recommend with respect to ICNU-CUB' s adjustment related to the level of employees?

A. I recommend the Commission reject the adjustment because the increase in employees cited by Ms. Blumenthal was not used as a basis for calculating labor costs in the Company' s filing. In addition, ICNU-CUB' s position on total bare labor costs for the Test Period results in a level of costs less than actual 2008 amounts.

Pensions, Benefits and Payroll Taxes

Q. Please describe ICNU-CUB witness Ms. Blumenthal's proposed adjustment related to pensions and benefit expenses and payroll taxes.

A. Ms. Blumenthal's adjustment reduces 401(k) expenses to the corrected level as provided in the Company's response to OPUC Data Request 206. She also reduces a pro-rata share of pension, benefit, and payroll tax expenses in connection with her salary adjustment discussed above and her incentive adjustment discussed in the reply testimony of Mr. Wilson.

Q. Do you agree with Ms. Blumenthal's proposed adjustment?

A. Yes, in part. As explained in the reply testimony of Mr. Wilson, the Company accepts the correction to 401(k) expense as provided in the Company's response to OPUC Data Request 206. The Company's acceptance of Mr. Ball's proposed adjustment to 401(k) expenses includes this correction. The Company has reflected this adjustment as part of Adjustment 12.7 of Exhibit PPL/708.

Ms. Blumenthal's adjustment to pensions, benefits and payroll taxes is unnecessary since her adjustments to salaries and incentives are inappropriate as explained above and in the reply testimony of Mr. Wilson.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/707
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Oregon Results of Operations Summary
December 2010

August 2009

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2010

	(1) NPC-Related Results	(2) (3) - (1) Non-NPC Related Results	(3) Ref. Page 1.1 Total Adjusted Results	(4) TAM NPC-Related Under Recovery	(5) GRC Requested Non-NPC Related Price Change	(6) (3) + (4) + (5) Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	252,395,751	696,945,552	949,341,303	19,969,132	82,748,845	1,052,059,280
3 Interdepartmental		-	-			-
4 Special Sales	185,483,438	963,190	186,446,628			186,446,628
5 Other Operating Revenues		42,876,160	42,876,160			42,876,160
6 Total Operating Revenues	437,879,189	740,784,902	1,178,664,091	19,969,132	82,748,845	1,281,382,068
7						
8 Operating Expenses:						
9 Steam Production	169,775,591	80,783,699	250,559,290			250,559,290
10 Nuclear Production		-	-			-
11 Hydro Production		9,911,805	9,911,805			9,911,805
12 Other Power Supply	249,222,139	12,213,053	261,435,192			261,435,192
13 Transmission	38,850,591	13,705,242	52,555,833			52,555,833
14 Distribution		70,710,593	70,710,593			70,710,593
15 Customer Accounting		31,710,902	31,710,902		545,609	32,256,512
16 Customer Service & Info		3,695,469	3,695,469			3,695,469
17 Sales		-	-			-
18 Administrative & General		49,670,470	49,670,470			49,670,470
19						
20 Total O&M Expenses	457,848,321	272,401,234	730,249,555	-		730,249,555
21						
22 Depreciation		147,845,235	147,845,235			147,845,235
23 Amortization		16,476,351	16,476,351			16,476,351
24 Taxes Other Than Income		51,966,873	51,966,873		2,376,074	54,342,947
25 Income Taxes - Federal	(6,671,887)	30,430,290	23,758,403	6,671,887	26,671,053	57,101,342
26 Income Taxes - State	(906,599)	5,744,726	4,838,128	906,599	3,624,153	9,368,880
27 Income Taxes - Def Net		17,114,105	17,114,105			17,114,105
28 Investment Tax Credit Adj.		-	-			-
29 Misc Revenue & Expense		(2,076,505)	(2,076,505)			(2,076,505)
30						
31 Total Operating Expenses:	450,269,836	539,902,308	990,172,144	7,578,485	33,216,889	1,030,967,519
32						
33 Operating Rev For Return:	(12,390,647)	200,882,594	188,491,947	12,390,647	49,531,955	250,414,549
34						
35 Rate Base:						
36 Electric Plant In Service		5,543,234,819	5,543,234,819			5,543,234,819
37 Plant Held for Future Use		(0)	(0)			(0)
38 Misc Deferred Debits		20,133,708	20,133,708			20,133,708
39 Elec Plant Acq Adj		18,568,147	18,568,147			18,568,147
40 Nuclear Fuel		-	-			-
41 Prepayments		12,201,019	12,201,019			12,201,019
42 Fuel Stock		41,007,740	41,007,740			41,007,740
43 Material & Supplies		49,319,573	49,319,573			49,319,573
44 Working Capital		12,584,036	12,584,036			12,584,036
45 Weatherization Loans		(696)	(696)			(696)
46 Misc Rate Base		1,206,251	1,206,251			1,206,251
47						
48 Total Electric Plant:	-	5,698,254,596	5,698,254,596			5,698,254,596
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec		(2,041,168,235)	(2,041,168,235)			(2,041,168,235)
52 Accum Prov For Amort		(141,105,146)	(141,105,146)			(141,105,146)
53 Accum Def Income Tax		(551,004,650)	(551,004,650)			(551,004,650)
54 Unamortized ITC		(4,172,305)	(4,172,305)			(4,172,305)
55 Customer Adv For Const		(3,499,244)	(3,499,244)			(3,499,244)
56 Customer Service Deposits		-	-			-
57 Misc Rate Base Deductions		(21,182,496)	(21,182,496)			(21,182,496)
58						
59 Total Rate Base Deductions	-	(2,762,132,076)	(2,762,132,076)			(2,762,132,076)
60						
61 Total Rate Base:	-	2,936,122,520	2,936,122,520			2,936,122,520
62						
63 Return on Rate Base			6.420%			8.529%
64						
65 Return on Equity			6.865%			11.000%

Ref. Page 1.1

Exhibit PPL/707
Dalley/2

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2010

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	949,341,303	102,717,977	1,052,059,280
3	Interdepartmental	-		
4	Special Sales	186,446,628		
5	Other Operating Revenues	42,876,160		
6	Total Operating Revenues	1,178,664,091		
7				
8	Operating Expenses:			
9	Steam Production	250,559,290		
10	Nuclear Production	-		
11	Hydro Production	9,911,805		
12	Other Power Supply	261,435,192		
13	Transmission	52,555,833		
14	Distribution	70,710,593		
15	Customer Accounting	31,710,902	545,609	32,256,512
16	Customer Service & Info	3,695,469		
17	Sales	-		
18	Administrative & General	49,670,470		
19				
20	Total O&M Expenses	730,249,555		
21				
22	Depreciation	147,845,235		
23	Amortization	16,476,351		
24	Taxes Other Than Income	51,966,873	2,376,074	54,342,947
25	Income Taxes - Federal	23,758,403	33,342,940	57,101,342
26	Income Taxes - State	4,838,128	4,530,752	9,368,880
27	Income Taxes - Def Net	17,114,105		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	(2,076,505)		
30				
31	Total Operating Expenses:	990,172,144	40,795,375	1,030,967,519
32				
33	Operating Rev For Return:	188,491,947	61,922,602	250,414,549
34				
35	Rate Base:			
36	Electric Plant In Service	5,543,234,819		
37	Plant Held for Future Use	(0)		
38	Misc Deferred Debits	20,133,708		
39	Elec Plant Acq Adj	18,568,147		
40	Nuclear Fuel	-		
41	Prepayments	12,201,019		
42	Fuel Stock	41,007,740		
43	Material & Supplies	49,319,573		
44	Working Capital	12,584,036		
45	Weatherization Loans	(696)		
46	Misc Rate Base	1,206,251		
47				
48	Total Electric Plant:	5,698,254,596	-	5,698,254,596
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(2,041,168,235)		
52	Accum Prov For Amort	(141,105,146)		
53	Accum Def Income Tax	(551,004,650)		
54	Unamortized ITC	(4,172,305)		
55	Customer Adv For Const	(3,499,244)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(21,182,496)		
58				
59	Total Rate Base Deductions	(2,762,132,076)	-	(2,762,132,076)
60				
61	Total Rate Base:	2,936,122,520	-	2,936,122,520
62				
63	Return on Rate Base	6.420%		8.529%
64				
65	Return on Equity	6.865%		11.000%
66				
67	TAX CALCULATION:			
68	Operating Revenue	234,202,582	99,796,294	333,998,876
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	85,221,543	-	85,221,543
72	Schedule "M" Additions	252,520,086	-	252,520,086
73	Schedule "M" Deductions	289,540,060	-	289,540,060
74	Income Before Tax	111,961,065	99,796,294	211,757,359
75				
76	State Income Taxes	4,838,128	4,530,752	9,368,880
77	Taxable Income	107,122,937	95,265,542	202,388,479
78				
79	Federal Income Taxes + Other	23,758,403	33,342,940	57,101,342

Ref. Page 2.2

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2010

Exhibit PPL/707
Dalley/3

		Total Company Filed Results December 2010	Oregon Allocated Filed Results December 2010	Tab 12 - Reply Adjustments	Oregon Allocated Reply Results December 2010
1	Operating Revenues:				
2	General Business Revenues	3,553,650,952	949,341,303	-	949,341,303
3	Interdepartmental	-	-	-	-
4	Special Sales	755,003,589	201,716,768	(15,270,140)	186,446,628
5	Other Operating Revenues	185,918,747	42,876,105	55	42,876,160
6	Total Operating Revenues	4,494,573,288	1,193,934,176	(15,270,085)	1,178,664,091
7					
8	Operating Expenses:				
9	Steam Production	984,803,361	251,950,077	(1,390,787)	250,559,290
10	Nuclear Production	-	-	-	-
11	Hydro Production	36,878,549	9,911,805	-	9,911,805
12	Other Power Supply	1,123,036,510	275,007,872	(13,572,680)	261,435,192
13	Transmission	190,741,324	51,260,023	1,295,810	52,555,833
14	Distribution	218,255,971	70,710,593	-	70,710,593
15	Customer Accounting	94,717,057	31,710,902	-	31,710,902
16	Customer Service & Info	34,210,049	3,695,469	-	3,695,469
17	Sales	-	-	-	-
18	Administrative & General	186,328,399	57,051,637	(7,381,167)	49,670,470
19					
20	Total O&M Expenses	2,868,971,219	751,298,378	(21,048,823)	730,249,555
21					
22	Depreciation	515,917,994	148,046,103	(200,868)	147,845,235
23	Amortization	66,908,040	16,475,737	614	16,476,351
24	Taxes Other Than Income	130,014,866	51,964,717	2,156	51,966,873
25	Income Taxes - Federal	64,951,362	20,969,445	2,788,958	23,758,403
26	Income Taxes - State	14,798,811	4,470,103	368,025	4,838,128
27	Income Taxes - Def Net	110,991,798	17,791,779	(677,674)	17,114,105
28	Investment Tax Credit Adj.	(1,874,204)	-	-	-
29	Misc Revenue & Expense	(9,703,584)	(2,076,510)	4	(2,076,505)
30					
31	Total Operating Expenses:	3,760,976,302	1,008,939,751	(18,767,607)	990,172,144
32					
33	Operating Rev For Return:	733,596,986	184,994,425	3,497,522	188,491,947
34					
35	Rate Base:				
36	Electric Plant In Service	19,643,024,026	5,550,442,483	(7,207,665)	5,543,234,819
37	Plant Held for Future Use	(1)	(0)	-	(0)
38	Misc Deferred Debits	199,791,016	32,822,514	(12,688,806)	20,133,708
39	Elec Plant Acq Adj	69,085,936	18,568,147	-	18,568,147
40	Nuclear Fuel	-	-	-	-
41	Prepayments	40,665,612	12,200,450	569	12,201,019
42	Fuel Stock	163,868,998	41,007,391	349	41,007,740
43	Material & Supplies	166,165,361	49,318,208	1,365	49,319,573
44	Working Capital	46,730,027	12,866,739	(282,703)	12,584,036
45	Weatherization Loans	14,588,989	(696)	(0)	(696)
46	Misc Rate Base	4,314,182	1,206,251	-	1,206,251
47					
48	Total Electric Plant:	20,348,234,146	5,718,431,486		5,718,431,486
49					
50	Rate Base Deductions:				
51	Accum Prov For Deprec	(6,893,735,360)	(2,041,423,829)	255,594	(2,041,168,235)
52	Accum Prov For Amort	(474,413,197)	(141,099,147)	(5,999)	(141,105,146)
53	Accum Def Income Tax	(2,072,535,947)	(548,748,369)	(2,256,282)	(551,004,650)
54	Unamortized ITC	(6,481,996)	(4,172,305)	-	(4,172,305)
55	Customer Adv For Const	(18,748,968)	(3,499,244)	-	(3,499,244)
56	Customer Service Deposits	-	-	-	-
57	Misc Rate Base Deductions	(80,990,630)	(21,181,866)	(630)	(21,182,496)
58					
59	Total Rate Base Deductions	(9,546,906,098)	(2,760,124,760)	(2,007,316)	(2,762,132,076)
60					
61	Total Rate Base:	10,801,328,048	2,958,306,726	(22,184,206)	2,936,122,520
62					
63	Return on Rate Base	6.792%	6.253%	0.166%	6.420%
64					
65	Return on Equity	7.569%	6.517%	0.347%	6.865%
66					
67	TAX CALCULATION:				
68	Operating Revenue		228,225,751	5,976,831	234,202,582
69	Other Deductions				
70	Interest (AFUDC)		-		-
71	Interest		85,799,770	(578,227)	85,221,543
72	Schedule "M" Additions		252,518,382	1,705	252,520,086
73	Schedule "M" Deductions		291,319,775	(1,779,715)	289,540,060
74	Income Before Tax		103,624,588	8,336,477	111,961,065
75					
76	State Income Taxes		4,470,103	368,025	4,838,128
77	Taxable Income		99,154,485	7,968,452	107,122,937
78					
79	Federal Income Taxes + Other		20,969,445	2,788,958	23,758,403
	APPROXIMATE REVISED PROTOCOL PRICE CHANGE		112,628,901	(9,910,923)	**102,717,977**

PacifiCorp
Normalized Results of Operations
Tab 12 Adjustment Summary
Twelve Months Ending Dec 31, 2010

		12.1	12.2	12.3	12.4	12.5	12.6	12.7
	Total Adjustments	Allocation Factors	Cost of Capital and Capital Structure	Rate Base	Insurance Low Claims Bonus	Workers Compensation Expense	FAS 112 (Post-Employment Benefits)	401(k) Expense
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	(15,270,140)	-	-	-	-	-	-	-
5 Other Operating Revenues	55	55	-	-	-	-	-	-
6 Total Operating Revenues	(15,270,085)	55	-	-	-	-	-	-
7								
8 Operating Expenses:								
9 Steam Production	(1,390,787)	5,606	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-	-
12 Other Power Supply	(13,572,680)	(66,469)	8,273	11,298	-	-	-	-
13 Transmission	1,295,810	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	(7,381,167)	3,394	-	-	(122,925)	(366,510)	(226,221)	(1,865,575)
19								
20 Total O&M Expenses	(21,048,823)	(57,469)	8,273	11,298	(122,925)	(366,510)	(226,221)	(1,865,575)
21								
22 Depreciation	(200,868)	252	-	(33,815)	-	-	-	-
23 Amortization	614	614	-	-	-	-	-	-
24 Taxes Other Than Income	2,156	2,156	-	-	-	-	-	-
25 Income Taxes - Federal	2,788,958	46,591	(24,657)	15,691	40,958	122,118	75,375	621,595
26 Income Taxes - State	368,025	(78,355)	(3,487)	2,897	5,934	17,693	10,921	90,059
27 Income Taxes - Def Net	(677,674)	(1,888)	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	4	4	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(18,767,607)	(88,095)	(19,871)	(3,928)	(76,033)	(226,699)	(139,925)	(1,153,920)
32								
33 Operating Rev For Return:	3,497,522	88,150	19,871	3,928	76,033	226,699	139,925	1,153,920
34								
35 Rate Base:								
36 Electric Plant In Service	(7,207,665)	32,919	-	(933,488)	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	(12,688,806)	422	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	569	569	-	-	-	-	-	-
42 Fuel Stock	349	349	-	-	-	-	-	-
43 Material & Supplies	1,365	1,365	-	-	-	-	-	-
44 Working Capital	(282,703)	(746)	(396)	262	(1,071)	(3,192)	(1,970)	(16,250)
45 Weatherization Loans	(0)	(0)	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(20,176,890)	34,878	(396)	(933,226)	(1,071)	(3,192)	(1,970)	(16,250)
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	255,594	(10,742)	-	64,614	-	-	-	-
52 Accum Prov For Amort	(5,999)	(5,999)	-	-	-	-	-	-
53 Accum Def Income Tax	(2,256,282)	(1,692)	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	(630)	(630)	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	(2,007,316)	(19,063)	-	64,614	-	-	-	-
60								
61 Total Rate Base:	(22,184,206)	15,815	(396)	(868,612)	(1,071)	(3,192)	(1,970)	(16,250)
62								
63 Return on Rate Base	0.166%	0.003%	0.001%	0.002%	0.003%	0.008%	0.005%	0.039%
64								
65 Return on Equity	0.347%	0.006%	0.023%	0.004%	0.005%	0.015%	0.009%	0.077%
66								
67 TAX CALCULATION:								
68 Operating Revenue	5,976,831	54,497	(8,273)	22,516	122,925	366,510	226,221	1,865,575
69 Other Deductions								
70 Interest (AFUDC)		-	-	-	-	-	-	-
71 Interest	(578,227)	459	65,663	(25,212)	(31)	(93)	(57)	(472)
72 Schedule "M" Additions	1,705	1,705	-	-	-	-	-	-
73 Schedule "M" Deductions	(1,779,715)	982	-	-	-	-	-	-
74 Income Before Tax	8,336,477	54,761	(73,936)	47,728	122,956	366,603	226,278	1,866,046
75								
76 State Income Taxes	368,025	(78,355)	(3,487)	2,897	5,934	17,693	10,921	90,059
77 Taxable Income	7,968,452	133,116	(70,449)	44,830	117,022	348,910	215,358	1,775,987
78								
79 Federal Income Taxes + Other	2,788,958	46,591	(24,657)	15,691	40,958	122,118	75,375	621,595
APPROXIMATE REVISED PROTOCOL PRICE CHANGE	(9,910,923)	(143,981)	(1,003,683)	(129,404)	(126,276)	(376,502)	(232,389)	(1,916,436)
Approximate Price Change Due to:								
Net Power Costs/TAM	(602,513)	(46,254)						
Embedded Cost Differential	2,203,205	(16,400)	8,273	11,298				
General Rate Case	(11,511,615)	(81,326)	(1,011,956)	(140,702)	(126,276)	(376,502)	(232,389)	(1,916,436)

PacifiCorp
Normalized Results of Operations
Tab 12 Adjustment Summary
Twelve Months Ending Dec 31, 2010

	12.8	12.9	12.10	12.11	12.12	12.13	12.14	12.15
	Challenge Grants	Transition Plan - Oregon Regulatory Asset	MEHC CIC Severance Regulatory Asset	Grid West Regulatory Asset	Wind Interconnection Rate Base	Other Wind Plant Additions	August 2009 - Net Power Cost Update	Embedded Cost Differential
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	(15,270,140)	-
5 Other Operating Revenues	-	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	(15,270,140)	-
7								
8 Operating Expenses:								
9 Steam Production	-	-	-	-	-	-	(1,396,393)	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	24,167	(14,782,211)	1,232,262
13 Transmission	-	-	-	-	-	-	1,295,810	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	(58,280)	(2,274,947)	(2,125,400)	(344,703)	-	-	-	-
19								
20 Total O&M Expenses	(58,280)	(2,274,947)	(2,125,400)	(344,703)	-	24,167	(14,882,793)	1,232,262
21								
22 Depreciation	-	-	-	-	(91,032)	(76,273)	-	-
23 Amortization	-	-	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	19,418	873,288	1,465,648	5,374	71,660	34,519	(154,153)	(424,467)
26 Income Taxes - State	2,813	49,690	212,345	306	10,589	6,339	59,598	(19,318)
27 Income Taxes - Def Net	-	-	(806,610)	130,824	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(36,048)	(1,351,969)	(1,254,017)	(208,199)	(8,783)	(11,247)	(14,977,349)	788,477
32								
33 Operating Rev For Return:	36,048	1,351,969	1,254,017	208,199	8,783	11,247	(292,792)	(788,477)
34								
35 Rate Base:								
36 Electric Plant In Service	-	-	-	-	(4,423,967)	(1,883,129)	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	(8,108,022)	(3,719,449)	(861,756)	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-	-
44 Working Capital	(508)	(19,039)	(6,300)	(4,774)	1,158	575	(224,202)	(6,249)
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(508)	(8,127,061)	(3,725,750)	(866,531)	(4,422,809)	(1,882,554)	(224,202)	(6,249)
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	-	-	-	-	140,341	61,380	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-	-
53 Accum Def Income Tax	-	(1,170,062)	(1,411,568)	327,041	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	-	(1,170,062)	(1,411,568)	327,041	140,341	61,380	-	-
60								
61 Total Rate Base:	(508)	(9,297,123)	(5,137,318)	(539,490)	(4,282,467)	(1,821,173)	(224,202)	(6,249)
62								
63 Return on Rate Base	0.001%	0.066%	0.054%	0.008%	0.010%	0.004%	-0.009%	-0.027%
64								
65 Return on Equity	0.002%	0.129%	0.105%	0.016%	0.019%	0.009%	-0.019%	-0.053%
66								
67 TAX CALCULATION:								
68 Operating Revenue	58,280	2,274,947	2,125,400	344,703	91,032	52,106	(387,347)	(1,232,262)
69 Other Deductions								
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	(15)	(269,851)	(149,112)	(15,659)	(124,299)	(52,860)	(6,508)	(181)
72 Schedule "M" Additions	-	-	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	(2,125,400)	344,703	-	-	-	-
74 Income Before Tax	58,295	2,544,798	4,399,911	15,659	215,332	104,966	(380,839)	(1,232,080)
75								
76 State Income Taxes	2,813	49,690	212,345	306	10,589	6,339	59,598	(19,318)
77 Taxable Income	55,481	2,495,108	4,187,566	15,353	204,743	98,627	(440,437)	(1,212,763)
78								
79 Federal Income Taxes + Other	19,418	873,288	1,465,648	5,374	71,660	34,519	(154,153)	(424,467)
APPROXIMATE REVISED PROTOCOL PRICE CHANGE	(59,869)	(3,557,983)	(2,806,986)	(421,688)	(620,436)	(276,310)	453,967	1,307,051
Approximate Price Change Due to:								
Net Power Costs/TAM							(556,258)	
Embedded Cost Differential						24,167	943,605	1,232,262
General Rate Case	(59,869)	(3,557,983)	(2,806,986)	(421,688)	(620,436)	(300,476)	66,620	74,790

R. Bryce Dalley
Exhibit PPL/708

Docket No. UE-210
Exhibit PPL/708
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Oregon Results of Operations
December 2010

August 2009

Docket No. UE-210
Exhibit PPL/708
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Oregon Results of Operations
December 2010

August 2009

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2010

	(1) NPC-Related Results	(2) (3) - (1) Non-NPC Related Results	(3) Ref. Page 1.1 Total Adjusted Results	(4) TAM NPC-Related Under Recovery	(5) GRC Requested Non-NPC Related Price Change	(6) (3) + (4) + (5) Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	252,395,751	696,945,552	949,341,303	19,969,132	82,748,845	1,052,059,280
3 Interdepartmental		-	-			-
4 Special Sales	185,483,438	963,190	186,446,628			186,446,628
5 Other Operating Revenues		42,876,160	42,876,160			42,876,160
6 Total Operating Revenues	437,879,189	740,784,902	1,178,664,091	19,969,132	82,748,845	1,281,382,068
7						
8 Operating Expenses:						
9 Steam Production	169,775,591	80,783,699	250,559,290			250,559,290
10 Nuclear Production		-	-			-
11 Hydro Production		9,911,805	9,911,805			9,911,805
12 Other Power Supply	249,222,139	12,213,053	261,435,192			261,435,192
13 Transmission	38,850,591	13,705,242	52,555,833			52,555,833
14 Distribution		70,710,593	70,710,593			70,710,593
15 Customer Accounting		31,710,902	31,710,902		545,609	32,256,512
16 Customer Service & Info		3,695,469	3,695,469			3,695,469
17 Sales		-	-			-
18 Administrative & General		49,670,470	49,670,470			49,670,470
19						
20 Total O&M Expenses	457,848,321	272,401,234	730,249,555	-		730,249,555
21						
22 Depreciation		147,845,235	147,845,235			147,845,235
23 Amortization		16,476,351	16,476,351			16,476,351
24 Taxes Other Than Income		51,966,873	51,966,873		2,376,074	54,342,947
25 Income Taxes - Federal	(6,671,887)	30,430,290	23,758,403	6,671,887	26,671,053	57,101,342
26 Income Taxes - State	(906,599)	5,744,726	4,838,128	906,599	3,624,153	9,368,880
27 Income Taxes - Def Net		17,114,105	17,114,105			17,114,105
28 Investment Tax Credit Adj.		-	-			-
29 Misc Revenue & Expense		(2,076,505)	(2,076,505)			(2,076,505)
30						
31 Total Operating Expenses:	450,269,836	539,902,308	990,172,144	7,578,485	33,216,889	1,030,967,519
32						
33 Operating Rev For Return:	(12,390,647)	200,882,594	188,491,947	12,390,647	49,531,955	250,414,549
34						
35 Rate Base:						
36 Electric Plant In Service		5,543,234,819	5,543,234,819			5,543,234,819
37 Plant Held for Future Use		(0)	(0)			(0)
38 Misc Deferred Debits		20,133,708	20,133,708			20,133,708
39 Elec Plant Acq Adj		18,568,147	18,568,147			18,568,147
40 Nuclear Fuel		-	-			-
41 Prepayments		12,201,019	12,201,019			12,201,019
42 Fuel Stock		41,007,740	41,007,740			41,007,740
43 Material & Supplies		49,319,573	49,319,573			49,319,573
44 Working Capital		12,584,036	12,584,036			12,584,036
45 Weatherization Loans		(696)	(696)			(696)
46 Misc Rate Base		1,206,251	1,206,251			1,206,251
47						
48 Total Electric Plant:	-	5,698,254,596	5,698,254,596			5,698,254,596
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec		(2,041,168,235)	(2,041,168,235)			(2,041,168,235)
52 Accum Prov For Amort		(141,105,146)	(141,105,146)			(141,105,146)
53 Accum Def Income Tax		(551,004,650)	(551,004,650)			(551,004,650)
54 Unamortized ITC		(4,172,305)	(4,172,305)			(4,172,305)
55 Customer Adv For Const		(3,499,244)	(3,499,244)			(3,499,244)
56 Customer Service Deposits		-	-			-
57 Misc Rate Base Deductions		(21,182,496)	(21,182,496)			(21,182,496)
58						
59 Total Rate Base Deductions	-	(2,762,132,076)	(2,762,132,076)			(2,762,132,076)
60						
61 Total Rate Base:	-	2,936,122,520	2,936,122,520			2,936,122,520
62						
63 Return on Rate Base			6.420%			8.529%
64						
65 Return on Equity			6.865%			11.000%

Ref. Page 1.1

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2010

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	949,341,303	102,717,977	1,052,059,280
3 Interdepartmental	-		
4 Special Sales	186,446,628		
5 Other Operating Revenues	42,876,160		
6 Total Operating Revenues	1,178,664,091		
7			
8 Operating Expenses:			
9 Steam Production	250,559,290		
10 Nuclear Production	-		
11 Hydro Production	9,911,805		
12 Other Power Supply	261,435,192		
13 Transmission	52,555,833		
14 Distribution	70,710,593		
15 Customer Accounting	31,710,902	545,609	32,256,512
16 Customer Service & Info	3,695,469		
17 Sales	-		
18 Administrative & General	49,670,470		
19			
20 Total O&M Expenses	730,249,555		
21			
22 Depreciation	147,845,235		
23 Amortization	16,476,351		
24 Taxes Other Than Income	51,966,873	2,376,074	54,342,947
25 Income Taxes - Federal	23,758,403	33,342,940	57,101,342
26 Income Taxes - State	4,838,128	4,530,752	9,368,880
27 Income Taxes - Def Net	17,114,105		
28 Investment Tax Credit Adj.	-		
29 Misc Revenue & Expense	(2,076,505)		
30			
31 Total Operating Expenses:	990,172,144	40,795,375	1,030,967,519
32			
33 Operating Rev For Return:	188,491,947	61,922,602	250,414,549
34			
35 Rate Base:			
36 Electric Plant In Service	5,543,234,819		
37 Plant Held for Future Use	(0)		
38 Misc Deferred Debits	20,133,708		
39 Elec Plant Acq Adj	18,568,147		
40 Nuclear Fuel	-		
41 Prepayments	12,201,019		
42 Fuel Stock	41,007,740		
43 Material & Supplies	49,319,573		
44 Working Capital	12,584,036		
45 Weatherization Loans	(696)		
46 Misc Rate Base	1,206,251		
47			
48 Total Electric Plant:	5,698,254,596	-	5,698,254,596
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(2,041,168,235)		
52 Accum Prov For Amort	(141,105,146)		
53 Accum Def Income Tax	(551,004,650)		
54 Unamortized ITC	(4,172,305)		
55 Customer Adv For Const	(3,499,244)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(21,182,496)		
58			
59 Total Rate Base Deductions	(2,762,132,076)	-	(2,762,132,076)
60			
61 Total Rate Base:	2,936,122,520	-	2,936,122,520
62			
63 Return on Rate Base	6.420%		8.529%
64			
65 Return on Equity	6.865%		11.000%
66			
67 TAX CALCULATION:			
68 Operating Revenue	234,202,582	99,796,294	333,998,876
69 Other Deductions			
70 Interest (AFUDC)	-	-	-
71 Interest	85,221,543	-	85,221,543
72 Schedule "M" Additions	252,520,086	-	252,520,086
73 Schedule "M" Deductions	289,540,060	-	289,540,060
74 Income Before Tax	111,961,065	99,796,294	211,757,359
75			
76 State Income Taxes	4,838,128	4,530,752	9,368,880
77 Taxable Income	107,122,937	95,265,542	202,388,479
78			
79 Federal Income Taxes + Other	23,758,403	33,342,940	57,101,342

Ref. Page 2.2

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2010

Net Rate Base	$ 2,936,122,520	Ref. Page 1.1
Return on Rate Base Requested	8.529%	Ref. Page 2.1
Revenues Required to Earn Requested Return	250,414,549	
Less Current Operating Revenues	(188,491,947)	
Increase to Current Revenues	61,922,602	
Net to Gross Bump-up	165.88%	
Price Change Required for Requested Return	$ 102,717,977	
Requested Price Change	$ 102,717,977	
Uncollectible Percent	0.531%	Ref. Page 1.3
Increased Uncollectible Expense	$ 545,609	
Requested Price Change	$ 102,717,977	
Franchise Tax	2.250%	Ref. Page 1.3
Revenue Tax	0.000%	Ref. Page 1.3
Resource Supplier Tax	0.063%	Ref. Page 1.3
Gross Receipts	0.000%	Ref. Page 1.3
Increase Taxes Other Than Income	$ 2,376,074	
Requested Price Change	$ 102,717,977	
Uncollectible Expense	(545,609)	
Taxes Other Than Income	(2,376,074)	
Income Before Taxes	$ 99,796,294	
State Effective Tax Rate	4.54%	Ref. Page 2.1
State Income Taxes	$ 4,530,752	
Taxable Income	$ 95,265,542	
Federal Income Tax Rate	35.00%	Ref. Page 2.1
Federal Income Taxes	$ 33,342,940	
Operating Income	100.000%	
Net Operating Income	60.284%	Ref. Page 1.3
Net to Gross Bump-Up	165.88%	

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2010

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.531%	See Note (1) Below
Taxes Other - Franchise Tax	2.250%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.063%	
Taxes Other - Gross Receipts	0.000%	
Sub-Total	97.156%	
State Income Tax @ 4.54%	4.411%	
Sub-Total	92.745%	
Federal Income Tax @ 35.00%	32.461%	
Net Operating Income	60.284%	

(1) Uncollectible Accounts =	5,042,637	Pg 2.12, Oregon Situs from Account 904
	949,341,303	Pg. 2.2, General Business Revenues

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2010

	Total Company Filed Results December 2010	Oregon Allocated Filed Results December 2010	Tab 12 - Reply Adjustments	Oregon Allocated Reply Results December 2010
1 Operating Revenues:				
2 General Business Revenues	3,553,650,952	949,341,303	-	949,341,303
3 Interdepartmental	-	-	-	-
4 Special Sales	755,003,589	201,716,768	(15,270,140)	186,446,628
5 Other Operating Revenues	185,918,747	42,876,105	55	42,876,160
6 Total Operating Revenues	4,494,573,288	1,193,934,176	(15,270,085)	1,178,664,091
7				
8 Operating Expenses:				
9 Steam Production	984,803,361	251,950,077	(1,390,787)	250,559,290
10 Nuclear Production	-	-	-	-
11 Hydro Production	36,878,549	9,911,805	-	9,911,805
12 Other Power Supply	1,123,036,510	275,007,872	(13,572,680)	261,435,192
13 Transmission	190,741,324	51,260,023	1,295,810	52,555,833
14 Distribution	218,255,971	70,710,593	-	70,710,593
15 Customer Accounting	94,717,057	31,710,902	-	31,710,902
16 Customer Service & Info	34,210,049	3,695,469	-	3,695,469
17 Sales	-	-	-	-
18 Administrative & General	186,328,399	57,051,637	(7,381,167)	49,670,470
19				
20 Total O&M Expenses	2,868,971,219	751,298,378	(21,048,823)	730,249,555
21				
22 Depreciation	515,917,994	148,046,103	(200,868)	147,845,235
23 Amortization	66,908,040	16,475,737	614	16,476,351
24 Taxes Other Than Income	130,014,866	51,964,717	2,156	51,966,873
25 Income Taxes - Federal	64,951,362	20,969,445	2,788,958	23,758,403
26 Income Taxes - State	14,798,811	4,470,103	368,025	4,838,128
27 Income Taxes - Def Net	110,991,798	17,791,779	(677,674)	17,114,105
28 Investment Tax Credit Adj.	(1,874,204)	-	-	-
29 Misc Revenue & Expense	(9,703,584)	(2,076,510)	4	(2,076,505)
30				
31 Total Operating Expenses:	3,760,976,302	1,008,939,751	(18,767,607)	990,172,144
32				
33 Operating Rev For Return:	733,596,986	184,994,425	3,497,522	188,491,947
34				
35 Rate Base:				
36 Electric Plant In Service	19,643,024,026	5,550,442,483	(7,207,665)	5,543,234,819
37 Plant Held for Future Use	(1)	(0)	-	(0)
38 Misc Deferred Debits	199,791,016	32,822,514	(12,688,806)	20,133,708
39 Elec Plant Acq Adj	69,085,936	18,568,147	-	18,568,147
40 Nuclear Fuel	-	-	-	-
41 Prepayments	40,665,612	12,200,450	569	12,201,019
42 Fuel Stock	163,868,998	41,007,391	349	41,007,740
43 Material & Supplies	166,165,361	49,318,208	1,365	49,319,573
44 Working Capital	46,730,027	12,866,739	(282,703)	12,584,036
45 Weatherization Loans	14,588,989	(696)	(0)	(696)
46 Misc Rate Base	4,314,182	1,206,251	-	1,206,251
47				
48 Total Electric Plant:	20,348,234,146	5,718,431,486		5,718,431,486
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	(6,893,735,360)	(2,041,423,829)	255,594	(2,041,168,235)
52 Accum Prov For Amort	(474,413,197)	(141,099,147)	(5,999)	(141,105,146)
53 Accum Def Income Tax	(2,072,535,947)	(548,748,369)	(2,256,282)	(551,004,650)
54 Unamortized ITC	(6,481,996)	(4,172,305)	-	(4,172,305)
55 Customer Adv For Const	(18,748,968)	(3,499,244)	-	(3,499,244)
56 Customer Service Deposits	-	-	-	-
57 Misc Rate Base Deductions	(80,990,630)	(21,181,866)	(630)	(21,182,496)
58				
59 Total Rate Base Deductions	(9,546,906,098)	(2,760,124,760)	(2,007,316)	(2,762,132,076)
60				
61 Total Rate Base:	10,801,328,048	2,958,306,726	(22,184,206)	2,936,122,520
62				
63 Return on Rate Base	6.792%	6.253%	0.166%	6.420%
64				
65 Return on Equity	7.569%	6.517%	0.347%	6.865%
66				
67 TAX CALCULATION:				
68 Operating Revenue		228,225,751	5,976,831	234,202,582
69 Other Deductions				
70 Interest (AFUDC)		-		-
71 Interest		85,799,770	(578,227)	85,221,543
72 Schedule "M" Additions		252,518,382	1,705	252,520,086
73 Schedule "M" Deductions		291,319,775	(1,779,715)	289,540,060
74 Income Before Tax		103,624,588	8,336,477	111,961,065
75				
76 State Income Taxes		4,470,103	368,025	4,838,128
77 Taxable Income		99,154,485	7,968,452	107,122,937
78				
79 Federal Income Taxes + Other		20,969,445	2,788,958	23,758,403
APPROXIMATE REVISED PROTOCOL PRICE CHANGE		112,628,901	(9,910,923)	**102,717,977**

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DEC 31, 2010
FILE:	OR JAM Dec 2010 GRC - REPLY
PREPARED BY:	Revenue Requirement Department
DATE:	8/25/2009
TIME:	10:00:10 AM
TYPE OF RATE BASE:	Thirteen Month Average
ALLOCATION METHOD:	**REVISED PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincidental Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	35.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.659
FEDERAL/STATE COMBINED RATE	37.95%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	48.70%	5.96%	2.90%
PREFERRED	0.30%	5.41%	0.02%
COMMON	51.00%	11.00%	5.61%
	100.00%		8.53%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see the testimony of Mr. Bruce Williams.
For information and support regarding return on common equity, see the testimony of Mr. Sam Hadaway.

REVISED PROTOCOL
Thirteen Month Average

RESULTS OF OPERATIONS SUMMARY

Description of Account Summary:	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
Operating Revenues					
General Business Revenues	2.3	3,553,650,952	949,341,303	3,553,650,952	949,341,303
Interdepartmental	2.3	0	0	0	0
Special Sales	2.3	755,003,589	201,716,768	698,188,446	186,446,628
Other Operating Revenues	2.4	185,918,747	42,876,105	185,918,747	42,876,160
Total Operating Revenues	2.4	4,494,573,288	1,193,934,176	4,437,758,145	1,178,664,091
Operating Expenses:					
Steam Production	2.5	984,803,361	251,950,077	979,214,271	250,559,290
Nuclear Production	2.6	0	0	0	0
Hydro Production	2.7	36,878,549	9,911,805	36,878,549	9,911,805
Other Power Supply	2.9	1,123,036,510	275,007,872	1,061,844,380	261,435,192
Transmission	2.10	190,741,324	51,260,023	195,562,060	52,555,833
Distribution	2.12	218,255,971	70,710,593	218,255,971	70,710,593
Customer Accounting	2.12	94,717,057	31,710,902	94,717,057	31,710,902
Customer Service & Infor	2.13	34,210,049	3,695,469	34,210,049	3,695,469
Sales	2.13	0	0	0	0
Administrative & General	2.14	186,328,399	57,051,637	166,846,953	49,670,470
Total O & M Expenses	2.14	2,868,971,219	751,298,378	2,787,529,290	730,249,555
Depreciation	2.16	515,917,994	148,046,103	515,169,709	147,845,235
Amortization	2.17	66,908,040	16,475,737	66,908,040	16,476,351
Taxes Other Than Income	2.17	130,014,866	51,964,717	130,014,866	51,966,873
Income Taxes - Federal	2.20	64,951,362	20,969,445	76,293,804	23,758,403
Income Taxes - State	2.20	14,798,811	4,470,103	16,298,694	4,838,128
Income Taxes - Def Net	2.19	110,991,798	17,791,779	108,268,235	17,114,105
Investment Tax Credit Adj.	2.17	(1,874,204)	0	(1,874,204)	0
Misc Revenue & Expense	2.4	(9,703,584)	(2,076,510)	(9,703,584)	(2,076,505)
Total Operating Expenses	2.20	3,760,976,302	1,008,939,751	3,688,904,850	990,172,144
Operating Revenue for Return		733,596,986	184,994,425	748,853,295	188,491,947
Rate Base:					
Electric Plant in Service	2.30	19,643,024,026	5,550,442,483	19,616,084,429	5,543,234,819
Plant Held for Future Use	2.31	(1)	(0)	(1)	(0)
Misc Deferred Debits	2.33	199,791,016	32,822,514	177,659,062	20,133,708
Elec Plant Acq Adj	2.31	69,085,936	18,568,147	69,085,936	18,568,147
Nuclear Fuel	2.31	0	0	0	0
Prepayments	2.32	40,665,612	12,200,450	40,665,612	12,201,019
Fuel Stock	2.32	163,868,998	41,007,391	163,868,998	41,007,740
Material & Supplies	2.32	166,165,361	49,318,208	166,165,361	49,319,573
Working Capital	2.33	46,730,027	12,866,739	45,741,716	12,584,036
Weatherization Loans	2.31	14,588,989	(696)	14,588,989	(696)
Miscellaneous Rate Base	2.34	4,314,182	1,206,251	4,314,182	1,206,251
Total Electric Plant		20,348,234,146	5,718,431,486	20,298,174,284	5,698,254,596
Rate Base Deductions:					
Accum Prov For Depr	2.38	(6,893,735,360)	(2,041,423,829)	(6,892,744,441)	(2,041,168,235)
Accum Prov For Amort	2.39	(474,413,197)	(141,099,147)	(474,413,197)	(141,105,146)
Accum Def Income Taxes	2.35	(2,072,535,947)	(548,748,369)	(2,078,374,146)	(551,004,650)
Unamortized ITC	2.35	(6,481,996)	(4,172,305)	(6,481,996)	(4,172,305)
Customer Adv for Const	2.34	(18,748,968)	(3,499,244)	(18,748,968)	(3,499,244)
Customer Service Deposits	2.34	0	0	0	0
Misc. Rate Base Deductions	2.34	(80,990,630)	(21,181,866)	(80,990,630)	(21,182,496)
Total Rate Base Deductions		(9,546,906,098)	(2,760,124,760)	(9,551,753,378)	(2,762,132,076)
Total Rate Base		10,801,328,048	2,958,306,726	10,746,420,905	2,936,122,520
Return on Rate Base		6.792%	6.253%	6.968%	6.420%
Return on Equity		7.569%	6.517%	7.940%	6.865%
Net Power Costs		1,100,545,209	272,967,396	1,095,399,869	272,364,883
100 Basis Points in Equity:					
Revenue Requirement Impact		89,127,624	24,410,596	88,328,171	24,132,903
Rate Base Decrease		(757,185,756)	(223,882,627)	(732,867,552)	(216,085,841)

REVISED PROTOCOL
Thirteen Month Average

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
70	Sales to Ultimate Customers								
71	440	Residential Sales							
72			0	S		1,377,975,739	471,582,657	1,377,975,739	471,582,657
73									
74					B1	1,377,975,739	471,582,657	1,377,975,739	471,582,657
75									
76	442	Commercial & Industrial Sales							
77			0	S		2,137,089,745	473,034,023	2,137,089,745	473,034,023
78			P	SE		-	-	-	-
79			PT	SG		-	-	-	-
80									
81									
82					B1	2,137,089,745	473,034,023	2,137,089,745	473,034,023
83									
84	444	Public Street & Highway Lighting							
85			0	S		19,754,238	4,724,623	19,754,238	4,724,623
86			0	SO		-	-	-	-
87					B1	19,754,238	4,724,623	19,754,238	4,724,623
88									
89	445	Other Sales to Public Authority							
90			0	S		18,831,230	-	18,831,230	-
91									
92					B1	18,831,230	-	18,831,230	-
93									
94	448	Interdepartmental							
95			DPW	S		-	-	-	-
96			GP	SO		-	-	-	-
97					B1	-	-	-	-
98									
99	**Total Sales to Ultimate Customers**				**B1**	**3,553,650,952**	**949,341,303**	**3,553,650,952**	**949,341,303**
100									
101									
102									
103	447	Sales for Resale-Non NPC							
104			WSF	S		8,065,896	963,190	8,065,896	963,190
105						8,065,896	963,190	8,065,896	963,190
106									
107	447NPC	Sales for Resale-NPC							
108			WSF	SG		746,937,693	200,753,578	690,122,550	185,483,438
109			WSF	SE		0	0	0	0
110			WSF	SG		-	-	-	-
111						746,937,693	200,753,578	690,122,550	185,483,438
112									
113		Total Sales for Resale			B1	755,003,589	201,716,768	698,188,446	186,446,628
114									
115	449	Provision for Rate Refund							
116			WSF	S		-	-	-	-
117			WSF	SG		-	-	-	-
118									
119									
120					B1	-	-	-	-
121									
122	**Total Sales from Electricity**				**B1**	**4,308,654,541**	**1,151,058,071**	**4,251,839,398**	**1,135,787,931**
123	450	Forfeited Discounts & Interest							
124			CUST	S		7,330,567	2,699,352	7,330,567	2,699,352
125			CUST	SO		-	-	-	-
126					B1	7,330,567	2,699,352	7,330,567	2,699,352
127									
128	451	Misc Electric Revenue							
129			CUST	S		6,969,143	1,911,077	6,969,143	1,911,077
130			GP	SG		-	-	-	-
131			GP	SO		13,522	3,821	13,522	3,821
132					B1	6,982,665	1,914,898	6,982,665	1,914,898
133									
134	453	Water Sales							
135			P	SG		82,483	22,169	82,483	22,169
136					B1	82,483	22,169	82,483	22,169
137									
138	454	Rent of Electric Property							
139			DPW	S		11,755,137	5,808,234	11,755,137	5,808,234
140			T	SG		5,438,329	1,461,653	5,438,329	1,461,653
141			GP	SO		2,640,177	746,023	2,640,177	746,078
142					B1	19,833,643	8,015,911	19,833,643	8,015,965
143									
144									

REVISED PROTOCOL
Thirteen Month Average

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
456	Other Electric Revenue							
		DMSC	S		29,796,569	(2,230,667)	29,796,569	(2,230,667)
		CUST	CN		-	-	-	-
		OTHSE	SE		16,351,827	4,088,267	16,351,827	4,088,267
		OTHSO	SO		3,287	929	3,287	929
		OTHSGR	SG		105,537,708	28,365,247	105,537,708	28,365,247
				B1	151,689,390	30,223,776	151,689,390	30,223,776
Total Other Electric Revenues				**B1**	**185,918,747**	**42,876,105**	**185,918,747**	**42,876,160**
Total Electric Operating Revenues				**B1**	**4,494,573,288**	**1,193,934,176**	**4,437,758,145**	**1,178,664,091**
Summary of Revenues by Factor								
	S				3,617,568,263	958,492,488	3,617,568,263	958,492,488
	CN				-	-	-	-
	SE				16,351,827	4,088,267	16,351,827	4,088,267
	SO				2,656,987	750,773	2,656,987	750,828
	SG				857,996,212	230,602,648	801,181,069	215,332,508
	DGP				-	-	-	-
Total Electric Operating Revenues					4,494,573,288	1,193,934,176	4,437,758,145	1,178,664,091
Miscellaneous Revenues								
41160	Gain on Sale of Utility Plant - CR							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
		G	SO		-	-	-	-
		T	SG		-	-	-	-
		P	SG		-	-	-	-
				B1	-	-	-	-
41170	Loss on Sale of Utility Plant							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
				B1	-	-	-	-
4118	Gain from Emission Allowances							
		P	S		-	-	-	-
		P	SE		(8,321,159)	(2,080,448)	(8,321,159)	(2,080,448)
				B1	(8,321,159)	(2,080,448)	(8,321,159)	(2,080,448)
41181	Gain from Disposition of NOX Credits							
		P	SE		-	-	-	-
				B1	-	-	-	-
4194	Impact Housing Interest Income							
		P	SG		-	-	-	-
				B1	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant							
		DPW	S		269,721	444,952	269,721	444,952
		T	SG		-	-	-	-
		T	SG		(356,472)	(95,809)	(356,472)	(95,809)
		PTD	CN		669	207	669	207
		PTD	SO		217,731	61,523	217,731	61,528
		P	SG		(1,514,073)	(406,936)	(1,514,073)	(406,936)
				B1	(1,382,425)	3,938	(1,382,425)	3,942
Total Miscellaneous Revenues					**(9,703,584)**	**(2,076,510)**	**(9,703,584)**	**(2,076,505)**
Miscellaneous Expenses								
4311	Interest on Customer Deposits							
		CUST	S		-	-	-	-
				B1	-	-	-	-
Total Miscellaneous Expenses					-	-	-	-
Net Misc Revenue and Expense				**B1**	**(9,703,584)**	**(2,076,510)**	**(9,703,584)**	**(2,076,505)**

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
500	Operation Supervision & Engineering							
		P	SG		21,356,608	5,739,991	21,356,608	5,739,991
		P	SSGCH		1,380,389	379,874	1,380,389	380,069
				B2	22,736,997	6,119,865	22,736,997	6,120,059
501	Fuel Related-Non NPC							
		P	SE		14,245,212	3,561,573	14,245,212	3,561,573
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SSECT		-	-	-	-
		P	SSECH		1,757,497	446,484	1,757,497	446,551
				B2	16,002,709	4,008,057	16,002,709	4,008,124
501NPC	Fuel Related-NPC							
		P	SE		625,282,635	156,332,531	619,447,910	154,873,739
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SSECT		-	-	-	-
		P	SSECH		54,964,905	13,963,575	55,207,439	14,027,286
				B2	680,247,540	170,296,106	674,655,349	168,901,025
	Total Fuel Related				696,250,250	174,304,163	690,658,059	172,909,149
502	Steam Expenses							
		P	SG		33,876,171	9,104,859	33,876,171	9,104,859
		P	SSGCH		2,987,357	822,101	2,987,357	822,522
				B2	36,863,528	9,926,961	36,863,528	9,927,382
503	Steam From Other Sources-Non-NPC							
		P	SE		1,303	326	1,303	326
				B2	1,303	326	1,303	326
503NPC	Steam From Other Sources-NPC							
		P	SE		3,494,899	873,791	3,498,000	874,566
				B2	3,494,899	873,791	3,498,000	874,566
505	Electric Expenses							
		P	SG		2,894,693	778,003	2,894,693	778,003
		P	SSGCH		1,497,829	412,193	1,497,829	412,404
				B2	4,392,522	1,190,196	4,392,522	1,190,407
506	Misc. Steam Expense							
		P	SG		43,539,798	11,702,141	43,539,798	11,702,141
		P	SE		-	-	-	-
		P	SSGCH		1,928,578	530,732	1,928,578	531,004
				B2	45,468,376	12,232,873	45,468,376	12,233,145
507	Rents							
		P	SG		685,858	184,337	685,858	184,337
		P	SSGCH		6,080	1,673	6,080	1,674
				B2	691,938	186,010	691,938	186,011
510	Maint Supervision & Engineering							
		P	SG		18,569,334	4,990,858	18,569,334	4,990,858
		P	SSGCH		1,869,532	514,483	1,869,532	514,747
				B2	20,438,866	5,505,342	20,438,866	5,505,605
511	Maintenance of Structures							
		P	SG		24,345,886	6,543,416	24,345,886	6,543,416
		P	SSGCH		1,100,539	302,861	1,100,539	303,016
				B2	25,446,425	6,846,277	25,446,425	6,846,432
512	Maintenance of Boiler Plant							
		P	SG		80,008,202	21,503,712	80,008,202	21,503,712
		P	SSGCH		5,824,299	1,602,810	5,824,299	1,603,631
				B2	85,832,500	23,106,521	85,832,500	23,107,342
513	Maintenance of Electric Plant							
		P	SG		25,528,277	6,861,205	25,528,277	6,861,205
		P	SSGCH		3,732,120	1,027,056	3,732,120	1,027,582
				B2	29,260,397	7,888,261	29,260,397	7,888,787
514	Maintenance of Misc. Steam Plant							
		P	SG		9,755,987	2,622,105	9,755,987	2,622,105
		P	SSGCH		4,169,373	1,147,385	4,169,373	1,147,972
				B2	13,925,360	3,769,490	13,925,360	3,770,078
Total Steam Power Generation				**B2**	**984,803,361**	**251,950,077**	**979,214,271**	**250,559,290**

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517	Operation Super & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
518	Nuclear Fuel Expense							
		P	SE		-	-	-	-
				B2	-	-	-	-
519	Coolants and Water							
		P	SG		-	-	-	-
				B2	-	-	-	-
520	Steam Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
523	Electric Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
524	Misc. Nuclear Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
528	Maintenance Super & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
529	Maintenance of Structures							
		P	SG		-	-	-	-
				B2	-	-	-	-
530	Maintenance of Reactor Plant							
		P	SG		-	-	-	-
				B2	-	-	-	-
531	Maintenance of Electric Plant							
		P	SG		-	-	-	-
				B2	-	-	-	-
532	Maintenance of Misc Nuclear							
		P	SG		-	-	-	-
				B2	-	-	-	-
Total Nuclear Power Generation				**B2**	**-**	**-**	**-**	**-**
535	Operation Super & Engineering							
		P	DGP		-	-	-	-
		P	SG		7,961,270	2,139,741	7,961,270	2,139,741
		P	SG		815,453	219,168	815,453	219,168
				B2	8,776,722	2,358,909	8,776,722	2,358,909
536	Water For Power							
		P	DGP		-	-	-	-
		P	SG		245,842	66,075	245,842	66,075
		P	SG		9,005	2,420	9,005	2,420
				B2	254,847	68,495	254,847	68,495

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
537	Hydraulic Expenses							
		P	DGP		-	-	-	-
		P	SG		3,580,615	962,358	3,580,615	962,358
		P	SG		397,666	106,880	397,666	106,880
				B2	3,978,281	1,069,238	3,978,281	1,069,238
538	Electric Expenses							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
539	Misc. Hydro Expenses							
		P	DGP		-	-	-	-
		P	SG		11,261,488	3,026,737	11,261,488	3,026,737
		P	SG		5,657,841	1,520,651	5,657,841	1,520,651
				B2	16,919,329	4,547,388	16,919,329	4,547,388
540	Rents (Hydro Generation)							
		P	DGP		-	-	-	-
		P	SG		155,264	41,730	155,264	41,730
		P	SG		9,458	2,542	9,458	2,542
				B2	164,722	44,272	164,722	44,272
541	Maint Supervision & Engineering							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
542	Maintenance of Structures							
		P	DGP		-	-	-	-
		P	SG		897,600	241,247	897,600	241,247
		P	SG		67,746	18,208	67,746	18,208
				B2	965,346	259,455	965,346	259,455
543	Maintenance of Dams & Waterways							
		P	DGP		-	-	-	-
		P	SG		877,446	235,830	877,446	235,830
		P	SG		420,785	113,094	420,785	113,094
				B2	1,298,231	348,924	1,298,231	348,924
544	Maintenance of Electric Plant							
		P	DGP		-	-	-	-
		P	SG		1,233,021	331,398	1,233,021	331,398
		P	SG		901,909	242,405	901,909	242,405
				B2	2,134,930	573,803	2,134,930	573,803
545	Maintenance of Misc. Hydro Plant							
		P	DGP		-	-	-	-
		P	SG		1,606,564	431,794	1,606,564	431,794
		P	SG		779,578	209,526	779,578	209,526
				B2	2,386,142	641,321	2,386,142	641,321
Total Hydraulic Power Generation				**B2**	**36,878,549**	**9,911,805**	**36,878,549**	**9,911,805**

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
546	Operation Super & Engineering							
		P	SG		480,567	129,162	480,567	129,162
		P	SSGCT		-	-	-	-
				B2	480,567	129,162	480,567	129,162
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SSECT		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		458,583,217	114,654,511	426,442,274	106,618,665
		P	SSECT		17,499,425	4,123,302	12,469,820	2,903,754
				B2	476,082,642	118,777,814	438,912,094	109,522,419
548	Generation Expense							
		P	SG		13,838,307	3,719,306	13,838,307	3,719,306
		P	SSGCT		1,536,918	386,800	1,536,918	385,797
				B2	15,375,225	4,106,106	15,375,225	4,105,102
549	Miscellaneous Other							
		P	SG		29,384,944	7,897,757	29,384,944	7,897,757
		P	SSGCT		-	-	-	-
				B2	29,384,944	7,897,757	29,384,944	7,897,757
550	Rents							
		P	SG		1,851,930	497,741	1,851,930	497,741
		P	SSGCT		1	0	1	0
				B2	1,851,931	497,741	1,851,931	497,741
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		483,098	129,842	483,098	129,842
		P	SSGCT		153,503	38,633	153,503	38,532
				B2	636,602	168,474	636,602	168,374
553	Maint of Generation & Electric Plant							
		P	SG		9,056,012	2,433,974	9,056,012	2,433,974
		P	SSGCT		792,994	199,575	792,994	199,057
				B2	9,849,006	2,633,549	9,849,006	2,633,031
554	Maintenance of Misc. Other							
		P	SG		135,872	36,518	135,872	36,518
		P	SSGCT		160,105	40,294	160,105	40,189
				B2	295,977	76,812	295,977	76,708
Total Other Power Generation				**B2**	**533,956,894**	**134,287,416**	**496,786,346**	**125,030,295**
555	Purchased Power-Non NPC							
		DMSC	S		-	-	-	-
					-	-	-	-
555NPC	Purchased Power-NPC							
		P	SG		492,312,478	132,318,254	464,956,956	124,965,942
		P	SE		55,596,693	13,900,229	58,930,634	14,733,777
	Seasonal Co	P	SSGC		-	-	-	-
			DGP		-	-	-	-
					547,909,171	146,218,483	523,887,590	139,699,720
	Total Purchased Power			B2	547,909,171	146,218,483	523,887,590	139,699,720
556	System Control & Load Dispatch							
		P	SG		2,305,070	619,531	2,305,070	619,531
				B2	2,305,070	619,531	2,305,070	619,531

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557	Other Expenses							
		P	S		2,904,957	(57,199)	2,904,957	(57,199)
		P	SG		34,766,943	9,344,271	34,766,943	9,344,271
		P	SGCT		1,193,039	321,868	1,193,039	321,868
		P	SE		-	-	-	-
		P	SSGCT		435	109	435	109
		P	TROJP		-	-	-	-
				B2	38,865,374	9,609,050	38,865,374	9,609,049
Embedded Cost Differentials								
Company Owned Hyd		P	DGP		(62,223,795)	(33,740,893)	(62,796,647)	(34,051,523)
Company Owned Hyd		P	SG		62,223,795	16,723,817	62,796,647	16,877,782
Mid-C Contract		P	MC		(43,182,719)	(26,638,696)	(37,511,140)	(23,154,241)
Mid-C Contract		P	SG		43,182,719	11,606,169	37,511,140	10,081,826
Existing QF Contracts		P	S		41,789,560	27,554,727	41,501,243	27,876,994
Existing QF Contracts		P	SG		(41,789,560)	(11,231,732)	(41,501,243)	(11,154,241)
					-	(15,726,608)	-	(13,523,403)
Total Other Power Supply				**B2**	**589,079,615**	**140,720,456**	**565,058,034**	**136,404,897**
Total Production Expense				**B2**	**2,144,718,419**	**536,869,753**	**2,077,937,200**	**521,906,287**
Summary of Production Expense by Factor								
		S			44,694,517	27,497,529	44,406,200	27,819,795
		SG			945,671,539	254,167,044	913,505,608	245,521,844
		SE			1,157,203,960	289,322,961	1,122,565,333	280,662,647
		SNPPH			-	-	-	-
		TROJP			-	-	-	-
		SGCT			1,193,039	321,868	1,193,039	321,868
		DGP			(62,223,795)	(33,740,893)	(62,796,647)	(34,051,523)
		DEU			-	-	-	-
		DEP			-	-	-	-
		SNPPS			-	-	-	-
		SNPPO			-	-	-	-
		DGU			-	-	-	-
		MC			(43,182,719)	(26,638,696)	(37,511,140)	(23,154,241)
		SSGCT			2,643,955	665,412	2,643,955	663,685
		SSECT			17,499,425	4,123,302	12,469,820	2,903,754
		SSGC			-	-	-	-
		SSGCH			24,496,095	6,741,169	24,496,095	6,744,621
		SSECH			56,722,402	14,410,059	56,964,936	14,473,837
Total Production Expense by Factor					2,144,718,419	536,869,753	2,077,937,200	521,906,287
560	Operation Supervision & Engineering							
		T	SG		9,501,988	2,553,838	9,501,988	2,553,838
				B2	9,501,988	2,553,838	9,501,988	2,553,838
561	Load Dispatching							
		T	SG		8,825,146	2,371,924	8,825,146	2,371,924
				B2	8,825,146	2,371,924	8,825,146	2,371,924
562	Station Expense							
		T	SG		1,932,042	519,273	1,932,042	519,273
				B2	1,932,042	519,273	1,932,042	519,273
563	Overhead Line Expense							
		T	SG		(1,042,959)	(280,315)	(1,042,959)	(280,315)
				B2	(1,042,959)	(280,315)	(1,042,959)	(280,315)
564	Underground Line Expense							
		T	SG		-	-	-	-
				B2	-	-	-	-

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570	565	Transmission of Electricity by Others							
571			T	SG		-	-	-	-
572			T	SE		-	-	-	-
573						-	-	-	-
575	565NPC	Transmission of Electricity by Others-NPC							
576			T	SG		139,465,900	37,484,088	144,294,464	38,781,856
577			T	SE		282,748	70,692	274,920	68,735
578						139,748,649	37,554,781	144,569,385	38,850,591
580		Total Transmission of Electricity by Others			B2	139,748,649	37,554,781	144,569,385	38,850,591
582	566	Misc. Transmission Expense							
583			T	SG		414,452	111,392	414,452	111,392
585					B2	414,452	111,392	414,452	111,392
587	567	Rents - Transmission							
588			T	SG		1,466,576	394,170	1,466,576	394,170
590					B2	1,466,576	394,170	1,466,576	394,170
592	568	Maint Supervision & Engineering							
593			T	SG		45,666	12,274	45,666	12,274
595					B2	45,666	12,274	45,666	12,274
597	569	Maintenance of Structures							
598			T	SG		3,847,214	1,034,011	3,847,214	1,034,011
600					B2	3,847,214	1,034,011	3,847,214	1,034,011
602	570	Maintenance of Station Equipment							
603			T	SG		9,986,383	2,684,028	9,986,383	2,684,028
605					B2	9,986,383	2,684,028	9,986,383	2,684,028
607	571	Maintenance of Overhead Lines							
608			T	SG		15,455,764	4,154,028	15,455,764	4,154,028
610					B2	15,455,764	4,154,028	15,455,764	4,154,028
612	572	Maintenance of Underground Lines							
613			T	SG		-	-	-	-
615					B2	-	-	-	-
617	573	Maint of Misc. Transmission Plant							
618			T	SG		560,403	150,619	560,403	150,619
620					B2	560,403	150,619	560,403	150,619
622	**Total Transmission Expense**				**B2**	**190,741,324**	**51,260,023**	**195,562,060**	**52,555,833**
624	Summary of Transmission Expense by Factor								
625		SE				282,748	70,692	274,920	68,735
626		SG				190,458,575	51,189,331	195,287,139	52,487,098
627		SNPT				-	-	-	-
628	Total Transmission Expense by Factor					190,741,324	51,260,023	195,562,060	52,555,833
629	580	Operation Supervision & Engineering							
630			DPW	S		180,211	(21)	180,211	(21)
631			DPW	SNPD		19,953,814	5,666,616	19,953,814	5,666,616
632					B2	20,134,025	5,666,595	20,134,025	5,666,595
634	581	Load Dispatching							
635			DPW	S		-	-	-	-
636			DPW	SNPD		13,428,189	3,813,426	13,428,189	3,813,426
637					B2	13,428,189	3,813,426	13,428,189	3,813,426
639	582	Station Expense							
640			DPW	S		4,486,859	1,215,958	4,486,859	1,215,958
641			DPW	SNPD		(39,602)	(11,247)	(39,602)	(11,247)
642					B2	4,447,257	1,204,711	4,447,257	1,204,711

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	FERC		BUS			DECEMBER 2010 Original Filing		DECEMBER 2010 Reply Results	
	ACCT	DESCRIP	FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
644	583	Overhead Line Expenses							
645			DPW	S		767,907	588,926	767,907	588,926
646			DPW	SNPD		234,474	66,587	234,474	66,587
647					B2	1,002,381	655,514	1,002,381	655,514
648									
649	584	Underground Line Expense							
650			DPW	S		(298,343)	(216,863)	(298,343)	(216,863)
651			DPW	SNPD		-	-	-	-
652					B2	(298,343)	(216,863)	(298,343)	(216,863)
653									
654	585	Street Lighting & Signal Systems							
655			DPW	S		-	-	-	-
656			DPW	SNPD		240,336	68,252	240,336	68,252
657					B2	240,336	68,252	240,336	68,252
658									
659	586	Meter Expenses							
660			DPW	S		5,748,833	2,376,254	5,748,833	2,376,254
661			DPW	SNPD		1,306,640	371,068	1,306,640	371,068
662					B2	7,055,474	2,747,322	7,055,474	2,747,322
663									
664	587	Customer Installation Expenses							
665			DPW	S		15,800,935	5,807,463	15,800,935	5,807,463
666			DPW	SNPD		-	-	-	-
667					B2	15,800,935	5,807,463	15,800,935	5,807,463
668									
669	588	Misc. Distribution Expenses							
670			DPW	S		4,362,553	1,649,755	4,362,553	1,649,755
671			DPW	SNPD		(1,962,885)	(557,433)	(1,962,885)	(557,433)
672					B2	2,399,668	1,092,322	2,399,668	1,092,322
673									
674	589	Rents							
675			DPW	S		3,637,999	1,868,519	3,637,999	1,868,519
676			DPW	SNPD		266,503	75,683	266,503	75,683
677					B2	3,904,502	1,944,202	3,904,502	1,944,202
678									
679	590	Maint Supervision & Engineering							
680			DPW	S		86,537	277,517	86,537	277,517
681			DPW	SNPD		6,115,842	1,736,817	6,115,842	1,736,817
682					B2	6,202,379	2,014,334	6,202,379	2,014,334
683									
684	591	Maintenance of Structures							
685			DPW	S		1,590,773	473,352	1,590,773	473,352
686			DPW	SNPD		185,341	52,634	185,341	52,634
687					B2	1,776,114	525,987	1,776,114	525,987
688									
689	592	Maintenance of Station Equipment							
690			DPW	S		10,701,003	3,313,499	10,701,003	3,313,499
691			DPW	SNPD		1,963,050	557,480	1,963,050	557,480
692					B2	12,664,053	3,870,979	12,664,053	3,870,979
693	593	Maintenance of Overhead Lines							
694			DPW	S		89,465,468	30,842,053	89,465,468	30,842,053
695			DPW	SNPD		1,434,376	407,343	1,434,376	407,343
696					B2	90,899,843	31,249,397	90,899,843	31,249,397
697									
698	594	Maintenance of Underground Lines							
699			DPW	S		24,194,370	6,193,419	24,194,370	6,193,419
700			DPW	SNPD		6,747	1,916	6,747	1,916
701					B2	24,201,117	6,195,335	24,201,117	6,195,335
702									
703	595	Maintenance of Line Transformers							
704			DPW	S		45,399	54,401	45,399	54,401
705			DPW	SNPD		1,103,194	313,292	1,103,194	313,292
706					B2	1,148,593	367,693	1,148,593	367,693
707									
708	596	Maint of Street Lighting & Signal Sys.							
709			DPW	S		4,165,978	858,984	4,165,978	858,984
710			DPW	SNPD		-	-	-	-
711					B2	4,165,978	858,984	4,165,978	858,984
712									

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
597	Maintenance of Meters							
		DPW	S		4,240,115	1,235,413	4,240,115	1,235,413
		DPW	SNPD		1,753,521	497,977	1,753,521	497,977
				B2	5,993,636	1,733,389	5,993,636	1,733,389
598	Maint of Misc. Distribution Plant							
		DPW	S		3,113,289	1,118,212	3,113,289	1,118,212
		DPW	SNPD		(23,454)	(6,661)	(23,454)	(6,661)
				B2	3,089,835	1,111,551	3,089,835	1,111,551
Total Distribution Expense				**B2**	**218,255,971**	**70,710,593**	**218,255,971**	**70,710,593**
Summary of Distribution Expense by Factor								
	S				172,289,885	57,656,840	172,289,885	57,656,840
	SNPD				45,966,086	13,053,753	45,966,086	13,053,753
Total Distribution Expense by Factor					218,255,971	70,710,593	218,255,971	70,710,593
901	Supervision							
		CUST	S		(1,200,094)	(1,022,122)	(1,200,094)	(1,022,122)
		CUST	CN		2,465,894	763,639	2,465,894	763,639
				B2	1,265,800	(258,482)	1,265,800	(258,482)
902	Meter Reading Expense							
		CUST	S		27,938,931	10,232,031	27,938,931	10,232,031
		CUST	CN		774,937	239,983	774,937	239,983
				B2	28,713,868	10,472,014	28,713,868	10,472,014
903	Customer Receipts & Collections							
		CUST	S		6,130,492	2,139,103	6,130,492	2,139,103
		CUST	CN		50,946,680	15,777,196	50,946,680	15,777,196
				B2	57,077,172	17,916,299	57,077,172	17,916,299
904	Uncollectible Accounts							
		CUST	S		12,403,730	5,042,637	12,403,730	5,042,637
		P	SG		-	-	-	-
		CUST	CN		3,912	1,212	3,912	1,212
				B2	12,407,643	5,043,849	12,407,643	5,043,849
905	Misc. Customer Accounts Expense							
		CUST	S		(5,563)	5,686	(5,563)	5,686
		CUST	CN		(4,741,863)	(1,468,463)	(4,741,863)	(1,468,463)
				B2	(4,747,426)	(1,462,777)	(4,747,426)	(1,462,777)
Total Customer Accounts Expense				**B2**	**94,717,057**	**31,710,902**	**94,717,057**	**31,710,902**
Summary of Customer Accts Exp by Factor								
	S				45,267,497	16,397,335	45,267,497	16,397,335
	CN				49,449,560	15,313,567	49,449,560	15,313,567
	SG				-	-	-	-
Total Customer Accounts Expense by Factor					94,717,057	31,710,902	94,717,057	31,710,902
907	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		300,605	93,092	300,605	93,092
				B2	300,605	93,092	300,605	93,092
908	Customer Assistance							
		CUST	S		26,207,568	1,198,841	26,207,568	1,198,841
		CUST	CN		4,406,674	1,364,661	4,406,674	1,364,661
				B2	30,614,242	2,563,502	30,614,242	2,563,502

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
778	909	Informational & Instructional Adv							
779			CUST	S		63,348	38,033	63,348	38,033
780			CUST	CN		3,165,386	980,259	3,165,386	980,259
781					B2	3,228,735	1,018,292	3,228,735	1,018,292
782									
783	910	Misc. Customer Service							
784			CUST	S		-	-	-	-
785			CUST	CN		66,467	20,583	66,467	20,583
786									
787					B2	66,467	20,583	66,467	20,583
788									
789	**Total Customer Service Expense**				**B2**	**34,210,049**	**3,695,469**	**34,210,049**	**3,695,469**
790									
791									
792	Summary of Customer Service Exp by Factor								
793		S				26,270,916	1,236,874	26,270,916	1,236,874
794		CN				7,939,133	2,458,595	7,939,133	2,458,595
795									
796	Total Customer Service Expense by Factor				B2	34,210,049	3,695,469	34,210,049	3,695,469
797									
798									
799	911	Supervision							
800			CUST	S		-	-	-	-
801			CUST	CN		-	-	-	-
802					B2	-	-	-	-
803									
804	912	Demonstration & Selling Expense							
805			CUST	S		-	-	-	-
806			CUST	CN		-	-	-	-
807					B2	-	-	-	-
808									
809	913	Advertising Expense							
810			CUST	S		-	-	-	-
811			CUST	CN		-	-	-	-
812					B2	-	-	-	-
813									
814	916	Misc. Sales Expense							
815			CUST	S		-	-	-	-
816			CUST	CN		-	-	-	-
817					B2	-	-	-	-
818									
819	**Total Sales Expense**				**B2**	**-**	**-**	**-**	**-**
820									
821									
822	Total Sales Expense by Factor								
823		S				-	-	-	-
824		CN				-	-	-	-
825	Total Sales Expense by Factor					-	-	-	-
826									
827	**Total Customer Service Exp Including Sales**				**B2**	**34,210,049**	**3,695,469**	**34,210,049**	**3,695,469**
828	920	Administrative & General Salaries							
829			PTD	S		2,424,643	-	2,424,643	-
830			CUST	CN		-	-	-	-
831			PTD	SO		79,928,673	22,585,092	79,928,673	22,586,740
832					B2	82,353,315	22,585,092	82,353,315	22,586,740
833									
834	921	Office Supplies & expenses							
835			PTD	S		(1,072,317)	-	(1,072,317)	-
836			CUST	CN		-	-	-	-
837			PTD	SO		13,148,058	3,715,189	13,148,058	3,715,460
838					B2	12,075,742	3,715,189	12,075,742	3,715,460
839									
840	922	A&G Expenses Transferred							
841			PTD	S		-	-	-	-
842			CUST	CN		-	-	-	-
843			PTD	SO		(22,825,213)	(6,449,620)	(22,825,213)	(6,450,090)
844					B2	(22,825,213)	(6,449,620)	(22,825,213)	(6,450,090)
845									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
846	923	Outside Services							
847			PTD	S		2,615	-	2,615	-
848			CUST	CN		-	-	-	-
849			PTD	SO		10,961,217	3,097,263	10,961,217	3,097,489
850					B2	10,963,832	3,097,263	10,963,832	3,097,489
851									
852	924	Property Insurance							
853			PTD	SO		35,497,167	10,030,277	35,062,167	9,908,085
854					B2	35,497,167	10,030,277	35,062,167	9,908,085
855									
856	925	Injuries & Damages							
857			PTD	SO		8,915,624	2,519,248	8,915,624	2,519,432
858					B2	8,915,624	2,519,248	8,915,624	2,519,432
859									
860	926	Employee Pensions & Benefits							
861			LABOR	S		-	-	-	-
862			CUST	CN		-	-	-	-
863			LABOR	SO		-	-	-	-
864					B2	-	-	-	-
865									
866	927	Franchise Requirements							
867			DMSC	S		-	-	-	-
868			DMSC	SO		-	-	-	-
869					B2	-	-	-	-
870									
871	928	Regulatory Commission Expense							
872			DMSC	S		8,644,967	2,814,219	8,644,967	2,814,219
873			CUST	CN		-	-	-	-
874			DMSC	SO		-	-	-	-
875			FERC	SG		940,372	252,743	940,372	252,743
876					B2	9,585,339	3,066,961	9,585,339	3,066,961
877									
878	929	Duplicate Charges							
879			LABOR	S		-	-	-	-
880			LABOR	SO		(5,040,682)	(1,424,323)	(5,040,682)	(1,424,427)
881					B2	(5,040,682)	(1,424,323)	(5,040,682)	(1,424,427)
882									
883	930	Misc General Expenses							
884			PTD	S		9,811,918	6,483,144	7,192,268	3,863,494
885			CUST	CN		5,413	1,676	5,413	1,676
886			LABOR	SO		12,568,569	3,551,445	(3,858,227)	(1,090,282)
887					B2	22,385,900	10,036,265	3,339,454	2,774,889
888									
889	931	Rents							
890			PTD	S		976,500	966,793	976,500	966,793
891			PTD	SO		5,770,404	1,630,518	5,770,404	1,630,637
892					B2	6,746,904	2,597,311	6,746,904	2,597,430
893									
894	935	Maintenance of General Plant							
895			G	S		33,985	33,985	33,985	33,985
896			CUST	CN		-	-	-	-
897			G	SO		25,636,488	7,243,989	25,636,488	7,244,518
898					B2	25,670,473	7,277,974	25,670,473	7,278,503
899									
900	**Total Administrative & General Expense**				**B2**	**186,328,399**	**57,051,637**	**166,846,953**	**49,670,470**
901									
902	Summary of A&G Expense by Factor								
903		S				20,822,310	10,298,140	18,202,661	7,678,491
904		SO				164,560,303	46,499,078	147,698,508	41,737,560
905		SG				940,372	252,743	940,372	252,743
906		CN				5,413	1,676	5,413	1,676
907	Total A&G Expense by Factor					186,328,399	57,051,637	166,846,953	49,670,470
908									
909	**Total O&M Expense**				**B2**	**2,868,971,219**	**751,298,378**	**2,787,529,290**	**730,249,555**

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
910	403SP	Steam Depreciation							
911			P	SG		33,824,536	9,090,981	33,824,536	9,090,981
912			P	SG		33,287,871	8,946,743	33,287,871	8,946,743
913			P	SG		72,063,748	19,368,490	72,019,253	19,356,531
914			P	SSGCH		11,794,624	3,245,805	11,794,624	3,247,467
915					B3	150,970,779	40,652,019	150,926,284	40,641,722
916									
917	403NP	Nuclear Depreciation							
918			P	SG		-	-	-	-
919					B3	-	-	-	-
920									
921	403HP	Hydro Depreciation							
922			P	SG		3,895,145	1,046,894	3,895,145	1,046,894
923			P	SG		1,006,937	270,633	1,006,937	270,633
924			P	SG		8,551,973	2,298,504	8,551,973	2,298,504
925			P	SG		3,745,825	1,006,761	3,745,825	1,006,761
926					B3	17,199,881	4,622,792	17,199,881	4,622,792
927									
928	403OP	Other Production Depreciation							
929			P	SG		120,601	32,414	120,601	32,414
930			P	SG		94,721,127	25,458,087	94,356,334	25,360,042
931			P	SSGCT		2,675,997	673,476	2,675,997	671,728
932			P	SSGCH		-	-	-	-
933					B3	97,517,725	26,163,977	97,152,932	26,064,184
934									
935	403TP	Transmission Depreciation							
936			T	SG		11,223,679	3,016,575	11,223,679	3,016,575
937			T	SG		12,539,264	3,370,163	12,539,264	3,370,163
938			T	SG		41,441,498	11,138,183	41,102,797	11,047,151
939					B3	65,204,440	17,524,922	64,865,739	17,433,889
940									
941									
942									
943	403	Distribution Depreciation							
944	360	Land & Land Rights	DPW	S		274,790	59,166	274,790	59,166
945	361	Structures	DPW	S		918,368	233,902	918,368	233,902
946	362	Station Equipment	DPW	S		14,731,487	3,761,906	14,731,487	3,761,906
947	363	Storage Battery Eq	DPW	S		116,607	-	116,607	-
948	364	Poles & Towers	DPW	S		48,478,788	15,783,591	48,478,788	15,783,591
949	365	OH Conductors	DPW	S		17,420,828	6,521,785	17,420,828	6,521,785
950	366	UG Conduit	DPW	S		6,843,411	2,096,675	6,843,411	2,096,675
951	367	UG Conductor	DPW	S		15,252,200	3,285,318	15,252,200	3,285,318
952	368	Line Trans	DPW	S		25,485,735	9,967,097	25,485,735	9,967,097
953	369	Services	DPW	S		10,472,952	3,821,583	10,472,952	3,821,583
954	370	Meters	DPW	S		6,443,332	2,153,361	6,443,332	2,153,361
955	371	Inst Cust Prem	DPW	S		438,695	106,738	438,695	106,738
956	372	Leased Property	DPW	S		808	-	808	-
957	373	Street Lighting	DPW	S		2,282,280	605,513	2,282,280	605,513
958					B3	149,160,279	48,396,637	149,160,279	48,396,637
959									
960	403GP	General Depreciation							
961			G-SITUS	S		13,131,350	4,302,300	13,131,350	4,302,300
962			G-DGP	SG		351,467	94,463	351,467	94,463
963			G-DGU	SG		645,213	173,413	645,213	173,413
964			P	SE		20,839	5,210	20,839	5,210
965			CUST	CN		1,395,670	432,212	1,395,670	432,212
966			G-SG	SG		4,543,437	1,221,134	4,543,437	1,221,134
967			PTD	SO		15,653,446	4,423,125	15,653,150	4,423,364
968			G-SG	SSGCT		3,346	842	3,346	840
969			G-SG	SSGCH		120,122	33,057	120,122	33,074
970					B3	35,864,890	10,685,757	35,864,594	10,686,011
971									
972	403GV0	General Vehicles							
973			G-SG	SG		-	-	-	-
974					B3	-	-	-	-
975									
976	403MP	Mining Depreciation							
977			P	SE		-	-	-	-
978					B3	-	-	-	-
979									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
980	403EP	Experimental Plant Depreciation							
981			P	SG		-	-	-	-
982			P	SG		-	-	-	-
983					B3	-	-	-	-
984	4031	ARO Depreciation							
985			P	S		-	-	-	-
986					B3	-	-	-	-
987									
988									
989	**Total Depreciation Expense**				**B3**	**515,917,994**	**148,046,103**	**515,169,709**	**147,845,235**
990									
991	Summary	S				162,291,630	52,698,937	162,291,630	52,698,937
992		DGP				-	-	-	-
993		DGU				-	-	-	-
994		SG				321,962,320	86,533,440	321,214,331	86,332,403
995		SO				15,653,446	4,423,125	15,653,150	4,423,364
996		CN				1,395,670	432,212	1,395,670	432,212
997		SE				20,839	5,210	20,839	5,210
998		SSGCH				11,914,746	3,278,862	11,914,746	3,280,541
999		SSGCT				2,679,343	674,318	2,679,343	672,568
1000	Total Depreciation Expense By Factor					515,917,994	148,046,103	515,169,709	147,845,235
1001									
1002	404GP	Amort of LT Plant - Capital Lease Gen							
1003			I-SITUS	S		1,066,457	688,163	1,066,457	688,163
1004			I-SG	SG		-	-	-	-
1005			PTD	SO		1,620,301	457,841	1,620,301	457,875
1006			I-DGU	SG		-	-	-	-
1007			CUST	CN		232,291	71,936	232,291	71,936
1008			I-DGP	SG		-	-	-	-
1009					B4	2,919,049	1,217,940	2,919,049	1,217,973
1010									
1011	404SP	Amort of LT Plant - Cap Lease Steam							
1012			P	SG		-	-	-	-
1013			P	SG		-	-	-	-
1014					B4	-	-	-	-
1015									
1016	404IP	Amort of LT Plant - Intangible Plant							
1017			I-SITUS	S		82,963	19,205	82,963	19,205
1018			P	SE		241,417	60,359	241,417	60,359
1019			I-SG	SG		4,623,011	1,242,521	4,623,011	1,242,521
1020			PTD	SO		28,143,727	7,952,449	28,143,727	7,953,029
1021			CUST	CN		5,764,343	1,785,105	5,764,343	1,785,105
1022			I-SG	SG		7,701,547	2,069,936	7,701,547	2,069,936
1023			I-SG	SG		309,688	83,234	309,688	83,234
1024			I-DGP	SG		-	-	-	-
1025			I-SG	SSGCT		-	-	-	-
1026			I-SG	SSGCH		-	-	-	-
1027			I-DGU	SG		15,942	4,285	15,942	4,285
1028					B4	46,882,637	13,217,093	46,882,637	13,217,674
1029									
1030	404MP	Amort of LT Plant - Mining Plant							
1031			P	SE		-	-	-	-
1032					B4	-	-	-	-
1033									
1034	404OP	Amort of LT Plant - Other Plant							
1035			P	SSGCT		-	-	-	-
1036					B4	-	-	-	-
1037									
1038									
1039	404HP	Amortization of Other Electric Plant							
1040			P	SG		2,279	613	2,279	613
1041			P	SG		38,493	10,346	38,493	10,346
1042			P	SG		-	-	-	-
1043					B4	40,772	10,958	40,772	10,958
1044									
1045	**Total Amortization of Limited Term Plant**				**B4**	**49,842,458**	**14,445,991**	**49,842,458**	**14,446,605**
1046									
1047									
1048	405	Amortization of Other Electric Plant							
1049			GP	S		-	-	-	-
1050									
1051					B4	-	-	-	-
1052									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1053	406	Amortization of Plant Acquisition Adj							
1054			P	S		-	-	-	-
1055			P	SG		-	-	-	-
1056			P	SG		-	-	-	-
1057			P	SG		5,479,353	1,472,679	5,479,353	1,472,679
1058			P	SO		-	-	-	-
1059					B4	5,479,353	1,472,679	5,479,353	1,472,679
1060	407	Amort of Prop Losses, Unrec Plant, etc							
1061			DPW	S		9,239,399	(67,953)	9,239,399	(67,953)
1062			GP	SO		-	-	-	-
1063			P	SG-P		0	0	0	0
1064			P	SE		-	-	-	-
1065			P	SG		333,105	89,528	333,105	89,528
1066			P	TROJP		2,013,725	535,491	2,013,725	535,491
1067					B4	11,586,229	557,066	11,586,229	557,066
1068									
1069	**Total Amortization Expense**				**B4**	**66,908,040**	**16,475,737**	**66,908,040**	**16,476,351**
1070									
1071									
1072									
1073	Summary of Amortization Expense by Factor								
1074		S				10,388,819	639,414	10,388,819	639,414
1075		SE				241,417	60,359	241,417	60,359
1076		TROJP				2,013,725	535,491	2,013,725	535,491
1077		DGP				-	-	-	-
1078		DGU				-	-	-	-
1079		SO				29,764,028	8,410,290	29,764,028	8,410,904
1080		SSGCT				-	-	-	-
1081		SSGCH				-	-	-	-
1082		CN				5,996,634	1,857,041	5,996,634	1,857,041
1083		SG				18,503,417	4,973,142	18,503,417	4,973,142
1084	Total Amortization Expense by Factor					66,908,040	16,475,737	66,908,040	16,476,351
1085	408	Taxes Other Than Income							
1086			DMSC	S		24,709,924	22,233,321	24,709,924	22,233,321
1087			GP	GPS		95,786,000	27,065,827	95,786,000	27,067,802
1088			GP	SO		8,776,746	2,480,006	8,776,746	2,480,187
1089			P	SE		742,196	185,563	742,196	185,563
1090			P	SG		-	-	-	-
1091			DMSC	OPRV-ID		-	-	-	-
1092			GP	EXCTAX		-	-	-	-
1093			GP	SG		-	-	-	-
1094									
1095									
1096									
1097	**Total Taxes Other Than Income**				**B5**	**130,014,866**	**51,964,717**	**130,014,866**	**51,966,873**
1098									
1099									
1100	41140	Deferred Investment Tax Credit - Fed							
1101			PTD	DGU		(1,874,204)	-	(1,874,204)	-
1102									
1103					B7	(1,874,204)	-	(1,874,204)	-
1104									
1105	41141	Deferred Investment Tax Credit - Idaho							
1106			PTD	DGU		-	-	-	-
1107									
1108					B7	-	-	-	-
1109									
1110	**Total Deferred ITC**				**B7**	**(1,874,204)**	**-**	**(1,874,204)**	**-**
1111									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1112									
1113	427	Interest on Long-Term Debt							
1114			GP	S		311,423,068	85,799,770	310,067,820	85,221,543
1115			GP	SNP		-	-	-	-
1116					B6	311,423,068	85,799,770	310,067,820	85,221,543
1117									
1118	428	Amortization of Debt Disc & Exp							
1119			GP	SNP		-	-	-	-
1120					B6	-	-	-	-
1121									
1122	429	Amortization of Premium on Debt							
1123			GP	SNP		-	-	-	-
1124					B6	-	-	-	-
1125									
1126	431	Other Interest Expense							
1127			NUTIL	OTH		-	-	-	-
1128			GP	SO		-	-	-	-
1129			GP	SNP		-	-	-	-
1130					B6	-	-	-	-
1131									
1132	432	AFUDC - Borrowed							
1133			GP	SNP		-	-	-	-
1134						-	-	-	-
1135									
1136		Total Elec. Interest Deductions for Tax			B6	311,423,068	85,799,770	310,067,820	85,221,543
1137									
1138		Non-Utility Portion of Interest							
1139		427	NUTIL	NUTIL		-	-	-	-
1140		428	NUTIL	NUTIL		-	-	-	-
1141		429	NUTIL	NUTIL		-	-	-	-
1142		431	NUTIL	NUTIL		-	-	-	-
1143									
1144		Total Non-utility Interest				-	-	-	-
1145									
1146		Total Interest Deductions for Tax			B6	311,423,068	85,799,770	310,067,820	85,221,543
1147									
1148									
1149	419	Interest & Dividends							
1150			GP	S		-	-	-	-
1151			GP	SNP		-	-	-	-
1152		Total Operating Deductions for Tax			B6	-	-	-	-
1153									
1154									
1155	41010	Deferred Income Tax - Federal-DR							
1156			GP	S		433,985,852	148,994,697	433,985,852	148,994,697
1157			P	TROJD		-	-	-	-
1158			PT	DGP		-	-	-	-
1159			LABOR	SO		7,492,129	2,117,018	7,492,129	2,117,172
1160			GP	SNP		24,441,083	6,706,023	24,441,083	6,706,346
1161			P	SE		12,670,465	3,167,857	12,670,465	3,167,857
1162			PT	SG		7,703,789	2,070,538	7,703,789	2,070,538
1163			GP	GPS		-	-	-	-
1164			DITEXP	DITEXP		-	-	-	-
1165			CUST	BADDEBT		-	-	-	-
1166			CUST	CN		-	-	-	-
1167			P	IBT		-	-	-	-
1168			DPW	SNPD		-	-	-	-
1169					B7	486,293,317	163,056,133	486,293,317	163,056,610
1170									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1171									
1172									
1173	41110	Deferred Income Tax - Federal-CR							
1174			GP	S		(308,442,276)	(127,149,682)	(308,311,452)	(127,018,858)
1175			P	SE		(12,276,927)	(3,069,465)	(12,276,927)	(3,069,465)
1176			PT	DGP		-	-	-	-
1177			GP	SNP		(42,656,054)	(11,703,757)	(42,656,054)	(11,704,320)
1178			PT	SG		(524,056)	(140,850)	(524,056)	(140,850)
1179			GP	GPS		-	-	-	-
1180			LABOR	SO		(10,733,616)	(3,032,950)	(13,588,003)	(3,839,782)
1181			PT	SNPD		-	-	-	-
1182			P	SG		-	-	-	-
1183			P	SGCT		(356,221)	(96,104)	(356,221)	(96,104)
1184			DITEXP	DITEXP		-	-	-	-
1185			P	TROJD		(633,784)	(168,217)	(633,784)	(168,217)
1186			P	IBT		321,415	96,672	321,415	95,091
1187									
1188									
1189					B7	(375,301,519)	(145,264,354)	(378,025,082)	(145,942,505)
1190									
1191	**Total Deferred Income Taxes**				**B7**	**110,991,798**	**17,791,779**	**108,268,235**	**17,114,105**
1192	SCHMAF	Additions - Flow Through							
1193			SCHMAF	S		-	-	-	-
1194			SCHMAF	SNP		-	-	-	-
1195			SCHMAF	SO		-	-	-	-
1196			SCHMAF	SE		-	-	-	-
1197			SCHMAF	TROJP		-	-	-	-
1198			SCHMAF	SG		-	-	-	-
1199					B6	-	-	-	-
1200									
1201	SCHMAP	Additions - Permanent							
1202			P	S		-	-	-	-
1203			P	SE		45,000	11,251	45,000	11,251
1204			LABOR	SNP		-	-	-	-
1205			SCHMAP-SO	SO		9,738,000	2,751,624	9,738,000	2,751,824
1206			SCHMAP	SG		-	-	-	-
1207			DPW	BADDEBT		-	-	-	-
1208					B6	9,783,000	2,762,874	9,783,000	2,763,075
1209									
1210	SCHMAT	Additions - Temporary							
1211			SCHMAT-SITUS	S		40,918,848	40,918,848	40,918,848	40,918,848
1212			P	SG		-	-	-	-
1213			DPW	CIAC		-	-	-	-
1214			SCHMAT-SNP	SNP		112,397,708	30,839,126	112,397,708	30,840,609
1215			P	TROJD		1,670,005	443,249	1,670,005	443,249
1216			P	SG		-	-	-	-
1217			SCHMAT-SE	SE		32,349,419	8,087,969	32,349,419	8,087,969
1218			P	SG		0	0	0	0
1219			SCHMAT-GPS	GPS		-	-	-	-
1220			SCHMAT-SO	SO		1,020,000	288,217	1,020,000	288,238
1221			SCHMAT-SNP	SNPD		-	-	-	-
1222			CUST	SGCT		938,633	253,232	938,633	253,232
1223			P	TAXDEPR		641,909,357	168,924,866	641,909,357	168,924,866
1224			BOOKDEPR	SCHMDEXP		-	-	-	-
1225					B6	831,203,970	249,755,507	831,203,970	249,757,011
1226									
1227	TOTAL SCHEDULE - M ADDITIONS				B6	840,986,970	252,518,382	840,986,970	252,520,086
1228									

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1229	SCHMDF	Deductions - Flow Through							
1230			SCHMDF	S		-	-	-	-
1231			SCHMDF	DGP		-	-	-	-
1232			SCHMDF	DGU		-	-	-	-
1233					B6	-	-	-	-
1234	SCHMDP	Deductions - Permanent							
1235			SCHMDP	S		-	-	-	-
1236			P	SE		274,060	68,520	274,060	68,520
1237			PTD	SNP		381,063	104,554	381,063	104,559
1238			SCHMDP	IBT		-	-	-	-
1239			P	SG		18,776,377	5,046,505	18,776,377	5,046,505
1240			SCHMDP-SO	SO		13,700,500	3,871,290	13,700,500	3,871,572
1241					B6	33,132,000	9,090,869	33,132,000	9,091,157
1242									
1243	SCHMDT	Deductions - Temporary							
1244			GP	S		(344,703)	(344,703)	-	-
1245			DPW	BADDEBT		-	-	-	-
1246			SCHMDT-SNP	SNP		64,401,683	17,670,215	64,401,683	17,671,064
1247			SCHMDT	CN		-	-	-	-
1248			SCHMDT	TROJD		-	-	-	-
1249			CUST	DGP		-	-	-	-
1250			P	SE		33,386,450	8,347,246	33,386,450	8,347,246
1251			SCHMDT-SG	SG		18,148,261	4,877,687	18,148,261	4,877,687
1252			SCHMDT-GPS	GPS		-	-	-	-
1253			SCHMDT-SO	SO		(7,521,243)	(2,125,245)	(15,042,487)	(4,250,799)
1254			TAXDEPR	TAXDEPR		964,446,362	253,803,705	964,446,362	253,803,705
1255			DPW	SNPD		-	-	-	-
1256					B6	1,072,516,810	282,228,906	1,065,340,270	280,448,903
1257									
1258	TOTAL SCHEDULE - M DEDUCTIONS				B6	1,105,648,810	291,319,775	1,098,472,269	289,540,060
1259									
1260	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(264,661,840)**	**(38,801,393)**	**(257,485,299)**	**(37,019,974)**
1261									
1262									
1263									
1264	40911	State Income Taxes							
1265			IBT	IBT		15,394,967	4,630,331	16,894,850	4,998,356
1266			IBT	IBT		-	-	-	-
1267		REC	P	SG		(596,156)	(160,228)	(596,156)	(160,228)
1268			IBT	IBT		-	-	-	-
1269	**Total State Tax Expense**					**14,798,811**	**4,470,103**	**16,298,694**	**4,838,128**
1270									
1271									
1272	Calculation of Taxable Income:								
1273		Operating Revenues				4,494,573,288	1,193,934,176	4,437,758,145	1,178,664,091
1274		Operating Deductions:							
1275		O & M Expenses				2,868,971,219	751,298,378	2,787,529,290	730,249,555
1276		Depreciation Expense				515,917,994	148,046,103	515,169,709	147,845,235
1277		Amortization Expense				66,908,040	16,475,737	66,908,040	16,476,351
1278		Taxes Other Than Income				130,014,866	51,964,717	130,014,866	51,966,873
1279		Interest & Dividends (AFUDC-Equity)				-	-	-	-
1280		Misc Revenue & Expense				(9,703,584)	(2,076,510)	(9,703,584)	(2,076,505)
1281		Total Operating Deductions				3,572,108,535	965,708,425	3,489,918,321	944,461,509
1282		Other Deductions:							
1283		Interest Deductions				311,423,068	85,799,770	310,067,820	85,221,543
1284		Interest on PCRBS				-	-	-	-
1285		Schedule M Adjustments				(264,661,840)	(38,801,393)	(257,485,299)	(37,019,974)
1286									
1287		Income Before State Taxes				346,379,845	103,624,588	380,286,705	111,961,065
1288									
1289		State Income Taxes				14,798,811	4,470,103	16,298,694	4,838,128
1290									
1291	Total Taxable Income					331,581,034	99,154,485	363,988,011	107,122,937
1292									
1293	Tax Rate					35.0%	35.0%	35.0%	35.0%
1294									
1295	Federal Income Tax - Calculated					116,053,362	34,704,070	127,395,804	37,493,028
1296									
1297	Adjustments to Calculated Tax:								
1298	40910	PMI	P	SE		-	-	-	-
1299	40910	REC	P	SG		(51,102,000)	(13,734,625)	(51,102,000)	(13,734,625)
1300	40910		P	SO		-	-	-	-
1301	40910	IRS Settle	LABOR	S		-	-	-	-
1302	**Federal Income Tax Expense**					**64,951,362**	**20,969,445**	**76,293,804**	**23,758,403**
1303									
1304	**Total Operating Expenses**					**3,760,976,302**	**1,008,939,751**	**3,688,904,850**	**990,172,144**

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1305	310	Land and Land Rights							
1306			P	SG		2,329,517	626,102	2,329,517	626,102
1307			P	SG		34,798,446	9,352,738	34,798,446	9,352,738
1308			P	SG		56,316,727	15,136,182	56,316,727	15,136,182
1309			P	S		-	-	-	-
1310			P	SSGCH		1,246,363	342,991	1,246,363	343,167
1311					B8	94,691,053	25,458,012	94,691,053	25,458,188
1312									
1313	311	Structures and Improvements							
1314			P	SG		234,885,474	63,129,897	234,885,474	63,129,897
1315			P	SG		327,384,549	87,990,766	327,384,549	87,990,766
1316			P	SG		187,548,390	50,407,163	187,548,390	50,407,163
1317			P	SSGCH		54,824,863	15,087,452	54,824,863	15,095,178
1318					B8	804,643,277	216,615,278	804,643,277	216,623,004
1319									
1320	312	Boiler Plant Equipment							
1321			P	SG		702,863,691	188,907,860	702,863,691	188,907,860
1322			P	SG		637,562,010	171,356,803	637,562,010	171,356,803
1323			P	SG		1,627,091,950	437,311,618	1,625,623,297	436,916,890
1324			P	SSGCH		319,011,617	87,789,958	319,011,617	87,834,914
1325					B8	3,286,529,269	885,366,239	3,285,060,616	885,016,466
1326									
1327	314	Turbogenerator Units							
1328			P	SG		146,508,558	39,376,935	146,508,558	39,376,935
1329			P	SG		144,894,564	38,943,144	144,894,564	38,943,144
1330			P	SG		429,185,110	115,351,585	429,185,110	115,351,585
1331			P	SSGCH		66,682,853	18,350,695	66,682,853	18,360,092
1332					B8	787,271,085	212,022,359	787,271,085	212,031,756
1333									
1334	315	Accessory Electric Equipment							
1335			P	SG		88,063,697	23,668,778	88,063,697	23,668,778
1336			P	SG		139,206,770	37,414,442	139,206,770	37,414,442
1337			P	SG		67,451,626	18,128,895	67,451,626	18,128,895
1338			P	SSGCH		64,602,266	17,778,131	64,602,266	17,787,235
1339					B8	359,324,359	96,990,246	359,324,359	96,999,350
1340									
1341									
1342									
1343	316	Misc Power Plant Equipment							
1344			P	SG		4,915,806	1,321,215	4,915,806	1,321,215
1345			P	SG		5,295,901	1,423,373	5,295,901	1,423,373
1346			P	SG		12,528,029	3,367,144	12,528,029	3,367,144
1347			P	SSGCH		3,162,939	870,421	3,162,939	870,866
1348					B8	25,902,675	6,982,153	25,902,675	6,982,599
1349									
1350	317	Steam Plant ARO							
1351			P	S		-	-	-	-
1352					B8	-	-	-	-
1353									
1354	SP	Unclassified Steam Plant - Account 300							
1355			P	SG		11,881	3,193	11,881	3,193
1356					B8	11,881	3,193	11,881	3,193
1357									
1358									
1359	**Total Steam Production Plant**				**B8**	**5,358,373,599**	**1,443,437,480**	**5,356,904,946**	**1,443,114,557**
1360									
1361									
1362	Summary of Steam Production Plant by Factor								
1363		S				-	-	-	-
1364		DGP				-	-	-	-
1365		DGU				-	-	-	-
1366		SG				4,848,842,698	1,303,217,833	4,847,374,045	1,302,823,105
1367		SSGCH				509,530,901	140,219,647	509,530,901	140,291,452
1368	Total Steam Production Plant by Factor					5,358,373,599	1,443,437,480	5,356,904,946	1,443,114,557
1369	320	Land and Land Rights							
1370			P	SG		-	-	-	-
1371			P	SG		-	-	-	-
1372					B8	-	-	-	-
1373									
1374	321	Structures and Improvements							
1375			P	SG		-	-	-	-
1376			P	SG	B8	-	-	-	-
1377						-	-	-	-

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
322	Reactor Plant Equipment							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
323	Turbogenerator Units							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
324	Land and Land Rights							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
325	Misc. Power Plant Equipment							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300							
		P	SG		-	-	-	-
				B8	-	-	-	-
Total Nuclear Production Plant				B8	-	-	-	-
Summary of Nuclear Production Plant by Factor								
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				-	-	-	-
Total Nuclear Plant by Factor					-	-	-	-
330	Land and Land Rights							
		P	SG		10,626,875	2,856,173	10,626,875	2,856,173
		P	SG		5,307,562	1,426,507	5,307,562	1,426,507
		P	SG		3,122,699	839,284	3,122,699	839,284
		P	SG		635,700	170,856	635,700	170,856
				B8	19,692,835	5,292,821	19,692,835	5,292,821
331	Structures and Improvements							
		P	SG		21,454,741	5,766,366	21,454,741	5,766,366
		P	SG		5,324,128	1,430,960	5,324,128	1,430,960
		P	SG		50,447,986	13,558,847	50,447,986	13,558,847
		P	SG		7,100,646	1,908,432	7,100,646	1,908,432
				B8	84,327,501	22,664,605	84,327,501	22,664,605
332	Reservoirs, Dams & Waterways							
		P	SG		150,171,432	40,361,402	150,171,432	40,361,402
		P	SG		20,072,400	5,394,836	20,072,400	5,394,836
		P	SG		152,326,189	40,940,533	152,326,189	40,940,533
		P	SG		57,298,078	15,399,938	57,298,078	15,399,938
				B8	379,868,099	102,096,709	379,868,099	102,096,709
333	Water Wheel, Turbines, & Generators							
		P	SG		32,795,206	8,814,330	32,795,206	8,814,330
		P	SG		9,262,626	2,489,505	9,262,626	2,489,505
		P	SG		35,586,529	9,564,550	35,586,529	9,564,550
		P	SG		17,469,186	4,695,173	17,469,186	4,695,173
				B8	95,113,547	25,563,558	95,113,547	25,563,558
334	Accessory Electric Equipment							
		P	SG		4,695,199	1,261,923	4,695,199	1,261,923
		P	SG		3,917,006	1,052,769	3,917,006	1,052,769
		P	SG		37,034,307	9,953,668	37,034,307	9,953,668
		P	SG		4,646,577	1,248,855	4,646,577	1,248,855
				B8	50,293,088	13,517,215	50,293,088	13,517,215

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Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1451									
1452									
1453	335	Misc. Power Plant Equipment							
1454			P	SG		1,290,121	346,744	1,290,121	346,744
1455			P	SG		194,397	52,248	194,397	52,248
1456			P	SG		982,272	264,004	982,272	264,004
1457			P	SG		12,963	3,484	12,963	3,484
1458					B8	2,479,753	666,480	2,479,753	666,480
1459									
1460	336	Roads, Railroads & Bridges							
1461			P	SG		4,638,282	1,246,626	4,638,282	1,246,626
1462			P	SG		828,976	222,803	828,976	222,803
1463			P	SG		8,022,513	2,156,202	8,022,513	2,156,202
1464			P	SG		592,158	159,154	592,158	159,154
1465					B8	14,081,929	3,784,784	14,081,929	3,784,784
1466									
1467	337	Hydro Plant ARO							
1468			P	S		-	-	-	-
1469					B8	-	-	-	-
1470									
1471	HP	Unclassified Hydro Plant - Acct 300							
1472			P	S		-	-	-	-
1473			P	SG		-	-	-	-
1474			P	SG		-	-	-	-
1475			P	SG		-	-	-	-
1476					B8	-	-	-	-
1477									
1478	**Total Hydraulic Production Plant**				**B8**	**645,856,753**	**173,586,171**	**645,856,753**	**173,586,171**
1479									
1480	Summary of Hydraulic Plant by Factor								
1481		S				-	-	-	-
1482		SG				645,856,753	173,586,171	645,856,753	173,586,171
1483		DGP				-	-	-	-
1484		DGU				-	-	-	-
1485	Total Hydraulic Plant by Factor					645,856,753	173,586,171	645,856,753	173,586,171
1486									
1487	340	Land and Land Rights							
1488			P	SG		21,542,917	5,790,065	21,542,917	5,790,065
1489			P	SG		-	-	-	-
1490			P	SSGCT		-	-	-	-
1491					B8	21,542,917	5,790,065	21,542,917	5,790,065
1492									
1493	341	Structures and Improvements							
1494			P	SG		94,013,356	25,267,861	94,013,356	25,267,861
1495			P	SG		166,099	44,642	166,099	44,642
1496			P	SSGCT		4,121,643	1,037,306	4,121,643	1,034,614
1497					B8	98,301,098	26,349,809	98,301,098	26,347,117
1498									
1499	342	Fuel Holders, Producers & Accessories							
1500			P	SG		6,788,799	1,824,618	6,788,799	1,824,618
1501			P	SG		121,339	32,612	121,339	32,612
1502			P	SSGCT		2,284,126	574,852	2,284,126	573,361
1503					B8	9,194,264	2,432,082	9,194,264	2,430,590
1504									
1505	343	Prime Movers							
1506			P	S		-	-	-	-
1507			P	SG		721,334	193,872	721,334	193,872
1508			P	SG		2,295,253,336	616,892,579	2,286,246,836	614,471,913
1509			P	SSGCT		55,116,485	13,871,323	55,116,485	13,835,327
1510					B8	2,351,091,155	630,957,774	2,342,084,655	628,501,111
1511									
1512	344	Generators							
1513			P	S		-	-	-	-
1514			P	SG		-	-	-	-
1515			P	SG		211,954,059	56,966,647	211,954,059	56,966,647
1516			P	SSGCT		15,873,643	3,994,965	15,873,643	3,984,598
1517					B8	227,827,702	60,961,612	227,827,702	60,951,245

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Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1518									
1519	345	Accessory Electric Plant							
1520			P	SG		117,692,887	31,632,181	117,692,887	31,632,181
1521			P	SG		156,586	42,085	156,586	42,085
1522			P	SSGCT		3,166,402	796,897	3,166,402	794,829
1523					B8	121,015,875	32,471,164	121,015,875	32,469,096
1524									
1525									
1526									
1527	346	Misc. Power Plant Equipment							
1528			P	SG		6,827,441	1,835,003	6,827,441	1,835,003
1529			P	SG		11,813	3,175	11,813	3,175
1530					B8	6,839,254	1,838,178	6,839,254	1,838,178
1531									
1532	347	Other Production ARO							
1533			P	S		-	-	-	-
1534					B8	-	-	-	-
1535									
1536	OP	Unclassified Other Prod Plant-Acct 300							
1537			P	S		-	-	-	-
1538			P	SG		-	-	-	-
1539						-	-	-	-
1540									
1541	**Total Other Production Plant**				**B8**	**2,835,812,265**	**760,800,684**	**2,826,805,765**	**758,327,403**
1542									
1543	Summary of Other Production Plant by Factor								
1544		S				-	-	-	-
1545		DGU				-	-	-	-
1546		SG				2,755,249,966	740,525,341	2,746,243,466	738,104,674
1547		SSGCT				80,562,299	20,275,343	80,562,299	20,222,729
1548	Total of Other Production Plant by Factor					2,835,812,265	760,800,684	2,826,805,765	758,327,403
1549									
1550	Experimental Plant								
1551	103	Experimental Plant							
1552			P	SG		-	-	-	-
1553	**Total Experimental Production Plant**				**B8**	-	-	-	-
1554									
1555	**Total Production Plant**				**B8**	**8,840,042,618**	**2,377,824,335**	**8,829,567,465**	**2,375,028,130**
1556	350	Land and Land Rights							
1557			T	SG		21,186,150	5,694,177	21,186,150	5,694,177
1558			T	SG		48,528,905	13,043,058	48,528,905	13,043,058
1559			T	SG		18,513,504	4,975,853	18,513,504	4,975,853
1560					B8	88,228,560	23,713,088	88,228,560	23,713,088
1561									
1562	352	Structures and Improvements							
1563			T	S		-	-	-	-
1564			T	SG		7,693,994	2,067,906	7,693,994	2,067,906
1565			T	SG		18,325,554	4,925,338	18,325,554	4,925,338
1566			T	SG		40,896,271	10,991,643	40,896,271	10,991,643
1567					B8	66,915,819	17,984,887	66,915,819	17,984,887
1568									
1569	353	Station Equipment							
1570			T	SG		133,425,635	35,860,653	133,425,635	35,860,653
1571			T	SG		194,993,000	52,408,043	194,993,000	52,408,043
1572			T	SG		733,387,634	197,111,745	733,387,634	197,111,745
1573					B8	1,061,806,268	285,380,440	1,061,806,268	285,380,440
1574									
1575	354	Towers and Fixtures							
1576			T	SG		156,322,773	42,014,691	156,322,773	42,014,691
1577			T	SG		126,427,452	33,979,760	126,427,452	33,979,760
1578			T	SG		144,741,622	38,902,038	144,741,622	38,902,038
1579					B8	427,491,847	114,896,488	427,491,847	114,896,488
1580									
1581	355	Poles and Fixtures							
1582			T	SG		61,706,653	16,584,826	61,706,653	16,584,826
1583			T	SG		112,585,212	30,259,397	112,585,212	30,259,397
1584			T	SG		695,439,242	186,912,399	678,979,123	182,488,432
1585					B8	869,731,107	233,756,622	853,270,988	229,332,655
1586									

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1587	356	Clearing and Grading							
1588			T	SG		197,851,415	53,176,296	197,851,415	53,176,296
1589			T	SG		157,949,575	42,451,924	157,949,575	42,451,924
1590			T	SG		348,529,943	93,673,989	348,529,943	93,673,989
1591					B8	704,330,934	189,302,209	704,330,934	189,302,209
1592									
1593	357	Underground Conduit							
1594			T	SG		6,371	1,712	6,371	1,712
1595			T	SG		91,651	24,633	91,651	24,633
1596			T	SG		3,111,560	836,291	3,111,560	836,291
1597					B8	3,209,582	862,636	3,209,582	862,636
1598									
1599	358	Underground Conductors							
1600			T	SG		-	-	-	-
1601			T	SG		1,087,552	292,300	1,087,552	292,300
1602			T	SG		6,402,623	1,720,826	6,402,623	1,720,826
1603					B8	7,490,175	2,013,126	7,490,175	2,013,126
1604									
1605	359	Roads and Trails							
1606			T	SG		1,863,032	500,725	1,863,032	500,725
1607			T	SG		440,513	118,396	440,513	118,396
1608			T	SG		9,087,840	2,442,528	9,087,840	2,442,528
1609					B8	11,391,385	3,061,649	11,391,385	3,061,649
1610									
1611	TP	Unclassified Trans Plant - Acct 300							
1612			T	SG		14,015,206	3,766,851	14,015,206	3,766,851
1613					B8	14,015,206	3,766,851	14,015,206	3,766,851
1614									
1615	TS0	Unclassified Trans Sub Plant - Acct 300							
1616			T	SG		-	-	-	-
1617					B8	-	-	-	-
1618									
1619	**Total Transmission Plant**				**B8**	**3,254,610,882**	**874,737,995**	**3,238,150,763**	**870,314,028**
1620	Summary of Transmission Plant by Factor								
1621		DGP				-	-	-	-
1622		DGU				-	-	-	-
1623		SG				3,254,610,882	874,737,995	3,238,150,763	870,314,028
1624	Total Transmission Plant by Factor					3,254,610,882	874,737,995	3,238,150,763	870,314,028
1625	360	Land and Land Rights							
1626			DPW	S		46,296,912	8,935,528	46,296,912	8,935,528
1627					B8	46,296,912	8,935,528	46,296,912	8,935,528
1628									
1629	361	Structures and Improvements							
1630			DPW	S		56,432,102	14,747,335	56,432,102	14,747,335
1631					B8	56,432,102	14,747,335	56,432,102	14,747,335
1632									
1633	362	Station Equipment							
1634			DPW	S		704,538,436	175,817,518	704,538,436	175,817,518
1635					B8	704,538,436	175,817,518	704,538,436	175,817,518
1636									
1637	363	Storage Battery Equipment							
1638			DPW	S		1,457,805	-	1,457,805	-
1639					B8	1,457,805	-	1,457,805	-
1640									
1641	364	Poles, Towers & Fixtures							
1642			DPW	S		1,286,017,326	406,460,463	1,286,017,326	406,460,463
1643					B8	1,286,017,326	406,460,463	1,286,017,326	406,460,463
1644									
1645	365	Overhead Conductors							
1646			DPW	S		608,761,234	216,663,023	608,761,234	216,663,023
1647					B8	608,761,234	216,663,023	608,761,234	216,663,023
1648									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1649	366	Underground Conduit							
1650			DPW	S		273,151,285	78,912,761	273,151,285	78,912,761
1651					B8	273,151,285	78,912,761	273,151,285	78,912,761
1652									
1653									
1654									
1655									
1656	367	Underground Conductors							
1657			DPW	S		658,701,909	141,854,929	658,701,909	141,854,929
1658					B8	658,701,909	141,854,929	658,701,909	141,854,929
1659									
1660	368	Line Transformers							
1661			DPW	S		985,594,730	357,264,059	985,594,730	357,264,059
1662					B8	985,594,730	357,264,059	985,594,730	357,264,059
1663									
1664	369	Services							
1665			DPW	S		518,926,428	201,106,275	518,926,428	201,106,275
1666					B8	518,926,428	201,106,275	518,926,428	201,106,275
1667									
1668	370	Meters							
1669			DPW	S		183,724,863	59,552,063	183,724,863	59,552,063
1670					B8	183,724,863	59,552,063	183,724,863	59,552,063
1671									
1672	371	Installations on Customers' Premises							
1673			DPW	S		8,825,713	2,436,751	8,825,713	2,436,751
1674					B8	8,825,713	2,436,751	8,825,713	2,436,751
1675									
1676	372	Leased Property							
1677			DPW	S		-	-	-	-
1678					B8	-	-	-	-
1679									
1680	373	Street Lights							
1681			DPW	S		60,630,069	21,113,867	60,630,069	21,113,867
1682					B8	60,630,069	21,113,867	60,630,069	21,113,867
1683									
1684	DP	Unclassified Dist Plant - Acct 300							
1685			DPW	S		25,991,196	5,406,560	25,991,196	5,406,560
1686					B8	25,991,196	5,406,560	25,991,196	5,406,560
1687									
1688	DS0	Unclassified Dist Sub Plant - Acct 300							
1689			DPW	S		-	-	-	-
1690					B8	-	-	-	-
1691									
1692									
1693	**Total Distribution Plant**				**B8**	**5,419,050,009**	**1,690,271,132**	**5,419,050,009**	**1,690,271,132**
1694									
1695	Summary of Distribution Plant by Factor								
1696		S				5,419,050,009	1,690,271,132	5,419,050,009	1,690,271,132
1697									
1698	Total Distribution Plant by Factor					5,419,050,009	1,690,271,132	5,419,050,009	1,690,271,132

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	FERC		BUS			DECEMBER 2010 Original Filing		DECEMBER 2010 Reply Results	
	ACCT	DESCRIP	FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
1699	389	Land and Land Rights							
1700			G-SITUS	S		8,555,822	2,236,138	8,555,822	2,236,138
1701			CUST	CN		1,128,506	349,476	1,128,506	349,476
1702			G-DGU	SG		332	89	332	89
1703			G-SG	SG		1,228	330	1,228	330
1704			PTD	SO		5,598,055	1,581,818	5,598,055	1,581,933
1705					B8	15,283,942	4,167,851	15,283,942	4,167,966
1706									
1707	390	Structures and Improvements							
1708			G-SITUS	S		106,735,983	31,776,208	106,735,983	31,776,208
1709			G-DGP	SG		358,127	96,254	358,127	96,254
1710			G-DGU	SG		1,573,572	422,927	1,573,572	422,927
1711			CUST	CN		12,096,722	3,746,120	12,096,722	3,746,120
1712			G-SG	SG		4,094,596	1,100,500	4,094,596	1,100,500
1713			PTD	SO		101,791,533	28,762,784	101,791,533	28,764,883
1714					B8	226,650,534	65,904,792	226,650,534	65,906,891
1715									
1716	391	Office Furniture & Equipment							
1717			G-SITUS	S		16,060,987	5,541,584	16,060,987	5,541,584
1718			G-DGP	SG		273,446	73,494	273,446	73,494
1719			G-DGU	SG		281,018	75,529	281,018	75,529
1720			CUST	CN		7,359,187	2,278,997	7,359,187	2,278,997
1721			G-SG	SG		4,562,299	1,226,204	4,562,299	1,226,204
1722			P	SE		119,144	29,788	119,144	29,788
1723			PTD	SO		65,265,588	18,441,809	65,265,588	18,443,155
1724			G-SG	SSGCH		74,351	20,461	74,351	20,471
1725			G-SG	SSGCT		-	-	-	-
1726					B8	93,996,019	27,687,865	93,996,019	27,689,221
1727									
1728	392	Transportation Equipment							
1729			G-SITUS	S		71,113,051	19,740,286	71,113,051	19,740,286
1730			PTD	SO		8,216,935	2,321,823	8,216,935	2,321,992
1731			G-SG	SG		15,384,774	4,134,948	15,384,774	4,134,948
1732			CUST	CN		-	-	-	-
1733			G-DGU	SG		1,024,238	275,283	1,024,238	275,283
1734			P	SE		757,992	189,512	757,992	189,512
1735			G-DGP	SG		155,978	41,922	155,978	41,922
1736			G-SG	SSGCH		390,994	107,599	390,994	107,654
1737			G-DGU	SSGCT		44,655	11,238	44,655	11,209
1738					B8	97,088,616	26,822,612	97,088,616	26,822,807
1739									
1740	393	Stores Equipment							
1741			G-SITUS	S		8,959,725	2,536,913	8,959,725	2,536,913
1742			G-DGP	SG		335,531	90,180	335,531	90,180
1743			G-DGU	SG		673,399	180,989	673,399	180,989
1744			PTD	SO		494,538	139,739	494,538	139,750
1745			G-SG	SG		3,179,843	854,643	3,179,843	854,643
1746			G-DGU	SSGCT		53,971	13,583	53,971	13,548
1747					B8	13,697,006	3,816,047	13,697,006	3,816,022

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1748									
1749	394	Tools, Shop & Garage Equipment							
1750			G-SITUS	S		31,502,852	9,951,080	31,502,852	9,951,080
1751			G-DGP	SG		2,809,419	755,084	2,809,419	755,084
1752			G-SG	SG		18,990,165	5,103,965	18,990,165	5,103,965
1753			PTD	SO		4,158,799	1,175,133	4,158,799	1,175,219
1754			P	SE		7,106	1,777	7,106	1,777
1755			G-DGU	SG		4,445,795	1,194,891	4,445,795	1,194,891
1756			G-SG	SSGCH		1,820,646	501,030	1,820,646	501,287
1757			G-SG	SSGCT		3,789	954	3,789	951
1758					B8	63,738,571	18,683,914	63,738,571	18,684,254
1759									
1760	395	Laboratory Equipment							
1761			G-SITUS	S		27,522,297	10,965,818	27,522,297	10,965,818
1762			G-DGP	SG		60,181	16,175	60,181	16,175
1763			G-DGU	SG		779,179	209,419	779,179	209,419
1764			PTD	SO		5,541,354	1,565,796	5,541,354	1,565,910
1765			P	SE		42,438	10,610	42,438	10,610
1766			G-SG	SG		5,966,976	1,603,737	5,966,976	1,603,737
1767			G-SG	SSGCH		253,001	69,624	253,001	69,660
1768			G-SG	SSGCT		14,022	3,529	14,022	3,520
1769					B8	40,179,448	14,444,709	40,179,448	14,444,849
1770									
1771	396	Power Operated Equipment							
1772			G-SITUS	S		93,113,598	27,920,155	93,113,598	27,920,155
1773			G-DGP	SG		981,699	263,850	981,699	263,850
1774			G-SG	SG		27,310,124	7,340,110	27,310,124	7,340,110
1775			PTD	SO		1,717,832	485,400	1,717,832	485,436
1776			G-DGU	SG		2,084,384	560,218	2,084,384	560,218
1777			P	SE		73,823	18,457	73,823	18,457
1778			P	SSGCT		-	-	-	-
1779			G-SG	SSGCH		982,722	270,439	982,722	270,577
1780					B8	126,264,183	36,858,629	126,264,183	36,858,803
1781	397	Communication Equipment							
1782			COM_EQ	S		130,012,302	52,135,234	130,012,302	52,135,234
1783			COM_EQ	SG		4,302,717	1,156,436	4,302,717	1,156,436
1784			COM_EQ	SG		7,667,838	2,060,876	7,667,838	2,060,876
1785			COM_EQ	SO		48,379,756	13,670,454	48,375,431	13,670,229
1786			COM_EQ	CN		1,710,149	529,600	1,710,149	529,600
1787			COM_EQ	SG		59,888,434	16,096,145	59,888,434	16,096,145
1788			COM_EQ	SE		(220,377)	(55,098)	(220,377)	(55,098)
1789			COM_EQ	SSGCH		620,984	170,891	620,984	170,978
1790			COM_EQ	SSGCT		(308)	(78)	(308)	(77)
1791					B8	252,361,495	85,764,460	252,357,170	85,764,323
1792									
1793	398	Misc. Equipment							
1794			G-SITUS	S		1,145,225	464,639	1,145,225	464,639
1795			G-DGP	SG		18,689	5,023	18,689	5,023
1796			G-DGU	SG		19,234	5,170	19,234	5,170
1797			CUST	CN		197,260	61,088	197,260	61,088
1798			PTD	SO		3,278,843	926,488	3,278,843	926,556
1799			P	SE		1,668	417	1,668	417
1800			G-SG	SG		1,499,233	402,947	1,499,233	402,947
1801			G-SG	SSGCT		-	-	-	-
1802					B8	6,160,152	1,865,771	6,160,152	1,865,839
1803									
1804	399	Coal Mine							
1805			P	SE		469,345,489	117,345,284	469,345,489	117,345,284
1806	MP		P	SE		-	-	-	-
1807					B8	469,345,489	117,345,284	469,345,489	117,345,284
1808									
1809	399L	WIDCO Capital Lease							
1810			P	SE	Tab 8	-	-	-	-
1811						-	-	-	-
1812									
1813		Remove Capital Leases				-	-	-	-
1814					Tab 8	-	-	-	-
1815									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1816	1011390	General Capital Leases							
1817			G-SITUS	S		7,269,922	5,882,166	7,269,922	5,882,166
1818			P	SG		12,411,745	3,335,890	12,411,745	3,335,890
1819			PTD	SO		12,902,451	3,645,788	12,902,451	3,646,055
1820					B9	32,584,118	12,863,845	32,584,118	12,864,111
1821									
1822		Remove Capital Leases				(32,584,118)	(12,863,845)	(32,584,118)	(12,864,111)
1823						-	-	-	-
1824									
1825	1011346	General Gas Line Capital Leases							
1826			P	SG		-	-	-	-
1827					B9	-	-	-	-
1828									
1829		Remove Capital Leases				-	-	-	-
1830						-	-	-	-
1831									
1832	GP	Unclassified Gen Plant - Acct 300							
1833			G-SITUS	S		-	-	-	-
1834			PTD	SO		150,944	42,652	150,944	42,655
1835			CUST	CN		-	-	-	-
1836			G-SG	SG		-	-	-	-
1837			G-DGP	SG		-	-	-	-
1838			G-DGU	SG		-	-	-	-
1839					B8	150,944	42,652	150,944	42,655
1840									
1841	399G	Unclassified Gen Plant - Acct 300							
1842			G-SITUS	S		-	-	-	-
1843			PTD	SO		-	-	-	-
1844			G-SG	SG		-	-	-	-
1845			G-DGP	SG		-	-	-	-
1846			G-DGU	SG		-	-	-	-
1847					B8	-	-	-	-
1848									
1849	**Total General Plant**				**B8**	**1,404,916,399**	**403,404,585**	**1,404,912,074**	**403,408,915**
1850									
1851	Summary of General Plant by Factor								
1852		S				501,991,764	169,150,222	501,991,764	169,150,222
1853		DGP				-	-	-	-
1854		DGU				-	-	-	-
1855		SG				181,134,195	48,683,228	181,134,195	48,683,228
1856		SO				257,496,626	72,759,684	257,492,301	72,763,772
1857		SE				470,127,282	117,540,747	470,127,282	117,540,747
1858		CN				22,491,824	6,965,280	22,491,824	6,965,280
1859		DEU				-	-	-	-
1860		SSGCT				116,128	29,226	116,128	29,150
1861		SSGCH				4,142,697	1,140,044	4,142,697	1,140,627
1862		Less Capital Leases				(32,584,118)	(12,863,845)	(32,584,118)	(12,864,111)
1863	Total General Plant by Factor					1,404,916,399	403,404,585	1,404,912,074	403,408,915
1864	301	Organization							
1865			I-SITUS	S		-	-	-	-
1866			PTD	SO		-	-	-	-
1867			I-SG	SG		-	-	-	-
1868					B8	-	-	-	-
1869	302	Franchise & Consent							
1870			I-SITUS	S		2,449,200	-	2,449,200	-
1871			I-SG	SG		32,307,638	8,683,286	32,307,638	8,683,286
1872			I-SG	SG		103,288,545	27,760,743	103,288,545	27,760,743
1873			I-SG	SG		9,240,742	2,483,623	9,240,742	2,483,623
1874			I-DGP	SG		-	-	-	-
1875			I-DGU	SG		574,477	154,401	574,477	154,401
1876					B8	147,860,601	39,082,054	147,860,601	39,082,054
1877									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
1878	303	Miscellaneous Intangible Plant							
1879			I-SITUS	S		2,058,482	540,701	2,058,482	540,701
1880			I-SG	SG		57,371,530	15,419,680	57,371,530	15,419,680
1881			PTD	SO		396,534,278	112,046,938	396,534,278	112,055,116
1882			P	SE		3,628,256	907,133	3,628,256	907,133
1883			CUST	CN		116,718,484	36,145,444	116,718,484	36,145,444
1884			P	SG		232,487	62,485	232,487	62,485
1885			I-DGP	SSGCT		-	-	-	-
1886					B8	576,543,518	165,122,381	576,543,518	165,130,559
1887	303	Less Non-Utility Plant							
1888			I-SITUS	S		-	-	-	-
1889						576,543,518	165,122,381	576,543,518	165,130,559
1890	IP	Unclassified Intangible Plant - Acct 300							
1891			I-SITUS	S		-	-	-	-
1892			I-SG	SG		-	-	-	-
1893			I-DGU	SG		-	-	-	-
1894			PTD	SO		-	-	-	-
1895						-	-	-	-
1896									
1897	**Total Intangible Plant**				**B8**	**724,404,119**	**204,204,435**	**724,404,119**	**204,212,613**
1898									
1899	Summary of Intangible Plant by Factor								
1900		S				4,507,682	540,701	4,507,682	540,701
1901		DGP				-	-	-	-
1902		DGU				-	-	-	-
1903		SG				203,015,418	54,564,219	203,015,418	54,564,219
1904		SO				396,534,278	112,046,938	396,534,278	112,055,116
1905		CN				116,718,484	36,145,444	116,718,484	36,145,444
1906		SSGCT				-	-	-	-
1907		SSGCH				-	-	-	-
1908		SE				3,628,256	907,133	3,628,256	907,133
1909	Total Intangible Plant by Factor					724,404,119	204,204,435	724,404,119	204,212,613
1910	Summary of Unclassified Plant (Account 106)								
1911		DP				25,991,196	5,406,560	25,991,196	5,406,560
1912		DS0				-	-	-	-
1913		GP				150,944	42,652	150,944	42,655
1914		HP				-	-	-	-
1915		NP				-	-	-	-
1916		OP				-	-	-	-
1917		TP				14,015,206	3,766,851	14,015,206	3,766,851
1918		TS0				-	-	-	-
1919		IP				-	-	-	-
1920		MP							
1921		SP				11,881	3,193	11,881	3,193
1922	Total Unclassified Plant by Factor					40,169,227	9,219,255	40,169,227	9,219,258
1923									
1924	**Total Electric Plant In Service**				**B8**	**19,643,024,026**	**5,550,442,483**	**19,616,084,429**	**5,543,234,819**

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Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
	Thirteen Month Average								
1925	Summary of Electric Plant by Factor								
1926		S				5,925,549,455	1,859,962,055	5,925,549,455	1,859,962,055
1927		SE				473,755,539	118,447,880	473,755,539	118,447,880
1928		DGU				-	-	-	-
1929		DGP				-	-	-	-
1930		SG				11,888,709,913	3,195,314,786	11,861,774,641	3,188,075,425
1931		SO				654,030,905	184,806,622	654,026,580	184,818,888
1932		CN				139,210,308	43,110,724	139,210,308	43,110,724
1933		DEU				-	-	-	-
1934		SSGCH				513,673,598	141,359,691	513,673,598	141,432,079
1935		SSGCT				80,678,427	20,304,570	80,678,427	20,251,879
1936		Less Capital Leases				(32,584,118)	(12,863,845)	(32,584,118)	(12,864,111)
1937						19,643,024,026	5,550,442,483	19,616,084,429	5,543,234,819
1938	105	Plant Held For Future Use							
1939			DPW	S		-	-	-	-
1940			P	SG		-	-	-	-
1941			T	SG		(8,923,303)	(2,398,306)	(8,923,303)	(2,398,306)
1942			P	SG		8,923,302	2,398,305	8,923,302	2,398,305
1943			P	SE		0	0	0	0
1944			G	SG		-	-	-	-
1945									
1946									
1947	**Total Plant Held For Future Use**				**B10**	**(1)**	**(0)**	**(1)**	**(0)**
1948									
1949	114	Electric Plant Acquisition Adjustments							
1950			P	S		-	-	-	-
1951			P	SG		142,633,069	38,335,325	142,633,069	38,335,325
1952			P	SG		14,560,711	3,913,465	14,560,711	3,913,465
1953	**Total Electric Plant Acquisition Adjustment**				**B15**	**157,193,780**	**42,248,790**	**157,193,780**	**42,248,790**
1954									
1955	115	Accum Provision for Asset Acquisition Adjustments							
1956			P	S		-	-	-	-
1957			P	SG		(76,874,453)	(20,661,458)	(76,874,453)	(20,661,458)
1958			P	SG		(11,233,390)	(3,019,185)	(11,233,390)	(3,019,185)
1959					B15	(88,107,844)	(23,680,643)	(88,107,844)	(23,680,643)
1960									
1961	120	Nuclear Fuel							
1962			P	SE		-	-	-	-
1963	**Total Nuclear Fuel**				**B15**	**-**	**-**	**-**	**-**
1964									
1965	124	Weatherization							
1966			DMSC	S		3,832,460	0	3,832,460	0
1967			DMSC	SO		(2,464)	(696)	(2,464)	(696)
1968					B16	3,829,995	(696)	3,829,995	(696)
1969									
1970	182W	Weatherization							
1971			DMSC	S		10,758,993	-	10,758,993	-
1972			DMSC	SG		-	-	-	-
1973			DMSC	SGCT		-	-	-	-
1974			DMSC	SO		-	-	-	-
1975					B16	10,758,993	-	10,758,993	-
1976									
1977	186W	Weatherization							
1978			DMSC	S		-	-	-	-
1979			DMSC	CN		-	-	-	-
1980			DMSC	CNP		-	-	-	-
1981			DMSC	SG		-	-	-	-
1982			DMSC	SO		-	-	-	-
1983					B16	-	-	-	-
1984									
1985	**Total Weatherization**				**B16**	**14,588,989**	**(696)**	**14,588,989**	**(696)**

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
151	Fuel Stock							
		P	DEU		-	-	-	-
		P	SE		157,240,837	39,313,195	157,240,837	39,313,195
		P	SSECT		-	-	-	-
		P	SSECH		9,197,039	2,336,464	9,197,039	2,336,814
Total Fuel Stock				**B13**	**166,437,876**	**41,649,659**	**166,437,876**	**41,650,008**
152	Fuel Stock - Undistributed							
		P	SE		-	-	-	-
					-	-	-	-
25316	DG&T Working Capital Deposit							
		P	SE		(874,000)	(218,517)	(874,000)	(218,517)
				B13	(874,000)	(218,517)	(874,000)	(218,517)
25317	DG&T Working Capital Deposit							
		P	SE		(1,694,878)	(423,752)	(1,694,878)	(423,752)
				B13	(1,694,878)	(423,752)	(1,694,878)	(423,752)
25319	Provo Working Capital Deposit							
		P	SE		-	-	-	-
					-	-	-	-
	Total Fuel Stock			B13	163,868,998	41,007,391	163,868,998	41,007,740
154	Materials and Supplies							
		MSS	S		87,961,713	28,381,534	87,961,713	28,381,534
		MSS	SG		3,189,612	857,268	3,189,612	857,268
		MSS	SE		4,414,212	1,103,637	4,414,212	1,103,637
		MSS	SO		(2,573)	(727)	(2,573)	(727)
		MSS	SNPPS		74,840,075	20,175,688	74,840,075	20,177,057
		MSS	SNPPH		(21,081)	(5,666)	(21,081)	(5,666)
		MSS	SNPD		(3,943,599)	(1,119,929)	(3,943,599)	(1,119,929)
		MSS	SNPT		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SSGCT		-	-	-	-
		MSS	SNPP		-	-	-	-
		MSS	SSGCH		-	-	-	-
Total Materials and Supplies				**B13**	**166,438,361**	**49,391,804**	**166,438,361**	**49,393,174**
163	Stores Expense Undistributed							
		MSS	SO		-	-	-	-
				B13	-	-	-	-
25318	Provo Working Capital Deposit							
		MSS	SNPPS		(273,000)	(73,596)	(273,000)	(73,601)
				B13	(273,000)	(73,596)	(273,000)	(73,601)
	Total Materials & Supplies			B13	166,165,361	49,318,208	166,165,361	49,319,573
165	Prepayments							
		DMSC	S		7,286,323	2,900,866	7,286,323	2,900,866
		GP	GPS		165,217	46,685	165,217	46,688
		PT	SG		3,015,461	810,462	3,015,461	810,462
		P	SE		2,785,261	696,368	2,785,261	696,368
		PTD	SO		27,413,349	7,746,069	27,413,349	7,746,634
Total Prepayments				**B15**	**40,665,612**	**12,200,450**	**40,665,612**	**12,201,019**

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
2047	182M	Misc Regulatory Assets							
2048			DDS2	S		103,089,835	7,683,233	94,120,056	(1,286,545)
2049			DEFSG	SG		5,765,516	1,549,591	5,765,516	1,549,591
2050			P	SGCT		10,195,361	2,750,587	10,195,361	2,750,587
2051			DEFSG	SG-P		(2,739,971)	(736,419)	(2,739,971)	(736,419)
2052			P	SE		-	-	-	-
2053			P	SSGCT		-	-	-	-
2054			DDSO2	SO		20,232,450	5,716,994	7,070,274	1,997,962
2055					B11	136,543,190	16,963,986	114,411,235	4,275,176
2056									
2057	186M	Misc Deferred Debits							
2058			LABOR	S		3,734,884	-	3,734,884	-
2059			P	SG		-	-	-	-
2060			P	SG		-	-	-	-
2061			DEFSG	SG		51,826,605	13,929,377	51,826,605	13,929,377
2062			LABOR	SO		228,017	64,430	228,017	64,435
2063			P	SE		7,458,319	1,864,721	7,458,319	1,864,721
2064			P	SNPPS		-	-	-	-
2065			GP	EXCTAX		-	-	-	-
2066	**Total Misc. Deferred Debits**				**B11**	**63,247,826**	**15,858,528**	**63,247,826**	**15,858,533**
2067									
2068	Working Capital								
2069	CWC	Cash Working Capital							
2070			CWC	S		44,417,996	11,891,415	43,429,685	11,608,463
2071			CWC	SO		-	-	-	-
2072			CWC	SE		-	-	-	-
2073					B14	44,417,996	11,891,415	43,429,685	11,608,463
2074									
2075	OWC	Other Work. Cap.							
2076	131	Cash	GP	SNP		(0)	(0)	(0)	(0)
2077	135	Working Funds	GP	SG		2,462	662	2,462	662
2078	141	Notes Receivabl	GP	SO		465,829	131,627	465,829	131,637
2079	143	Other A/R	GP	SO		15,882,714	4,487,908	15,882,714	4,488,236
2080	232	A/P	PTD	S		-	-	-	-
2081	232	A/P	PTD	SO		(4,260,318)	(1,203,819)	(4,260,318)	(1,203,907)
2082	232	A/P	P	SE		(1,133,268)	(283,338)	(1,133,268)	(283,338)
2083	253	Deferred Hedge	P	SG		2	0	2	0
2084	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2085	2533	Other Msc. Df. Crd.	P	SE		(5,726,145)	(1,431,645)	(5,726,145)	(1,431,645)
2086	230	Asset Retir. Oblig.	P	SE		(2,435,214)	(608,850)	(2,435,214)	(608,850)
2087	230	Asset Retir. Oblig.	P	S		-	-	-	-
2088	254105	ARO Reg Liability	P	S		(15,182)	-	(15,182)	-
2089	254105	ARO Reg Liability	P	SE		(468,849)	(117,221)	(468,849)	(117,221)
2090	2533	Cholla Reclamatior	P	SSECH		-	-	-	-
2091					B14	2,312,031	975,324	2,312,031	975,573
2092									
2093	**Total Working Capital**				**B14**	**46,730,027**	**12,866,739**	**45,741,716**	**12,584,036**
2094	Miscellaneous Rate Base								
2095	18221	Unrec Plant & Reg Study Costs							
2096			P	S		-	-	-	-
2097									
2098					B15	-	-	-	-
2099									
2100	18222	Nuclear Plant - Trojan							
2101			P	S		(887,941)	(175,546)	(887,941)	(175,546)
2102			P	TROJP		2,111,016	561,363	2,111,016	561,363
2103			P	TROJD		3,091,107	820,434	3,091,107	820,434
2104					B15	4,314,182	1,206,251	4,314,182	1,206,251
2105									
2106									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
2107									
2108	1869	Misc Deferred Debits-Trojan							
2109			P	S		-	-	-	-
2110			P	SNPPN		-	-	-	-
2111					B15	-	-	-	-
2112									
2113	**Total Miscellaneous Rate Base**				**B15**	**4,314,182**	**1,206,251**	**4,314,182**	**1,206,251**
2114									
2115	**Total Rate Base Additions**				**B15**	**705,210,119**	**167,989,002**	**682,089,854**	**155,019,777**
2116	235	Customer Service Deposits							
2117			CUST	S		-	-	-	-
2118			CUST	CN		-	-	-	-
2119	**Total Customer Service Deposits**				B15	-	-	-	-
2120									
2121	2281	Prop Ins	PTD	SO		-	-	-	-
2122	2282	Inj & Dam	PTD	SO		(8,160,389)	(2,305,845)	(8,160,389)	(2,306,013)
2123	2283	Pen & Ben	PTD	SO		(20,008,719)	(5,653,775)	(20,008,719)	(5,654,188)
2124	2283	Pen & Ben	PTD	SG		-	-	-	-
2125	254	Ins Prov	PTD	SE		(593,553)	(148,400)	(593,553)	(148,400)
2126					B15	(28,762,661)	(8,108,020)	(28,762,661)	(8,108,601)
2127									
2128	22844	Accum Hydro Relicensing Obligation							
2129			P	S		-	-	-	-
2130			P	SG		-	-	-	-
2131					B15	-	-	-	-
2132									
2133	22842	Prv-Trojan	P	TROJD		(2,423,023)	(643,113)	(2,423,023)	(643,113)
2134	230	ARO	P	TROJP		(2,289,329)	(608,780)	(2,289,329)	(608,780)
2135	254105	ARO	P	TROJP		(806,253)	(214,399)	(806,253)	(214,399)
2136	254		P	S		(1,962,062)	-	(1,962,062)	-
2137					B15	(7,480,668)	(1,466,292)	(7,480,668)	(1,466,292)
2138									
2139	252	Customer Advances for Construction							
2140			DPW	S		(11,656,541)	(1,593,020)	(11,656,541)	(1,593,020)
2141			DPW	SE		-	-	-	-
2142			T	SG		(7,092,427)	(1,906,223)	(7,092,427)	(1,906,223)
2143			DPW	SO		-	-	-	-
2144			CUST	CN		-	-	-	-
2145	**Total Customer Advances for Construction**				**B19**	**(18,748,968)**	**(3,499,244)**	**(18,748,968)**	**(3,499,244)**
2146									
2147	25398	SO2 Emissions							
2148			P	SE		(15,485,355)	(3,871,633)	(15,485,355)	(3,871,633)
2149					B19	(15,485,355)	(3,871,633)	(15,485,355)	(3,871,633)
2150									
2151	25399	Other Deferred Credits							
2152			P	S		(2,288,113)	(497,650)	(2,288,113)	(497,650)
2153			LABOR	SO		(2,369,925)	(669,659)	(2,369,925)	(669,708)
2154			P	SG		(22,249,141)	(5,979,876)	(22,249,141)	(5,979,876)
2155			P	SE		(2,354,768)	(588,737)	(2,354,768)	(588,737)
2156					B19	(29,261,947)	(7,735,922)	(29,261,947)	(7,735,971)

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	FERC		BUS			DECEMBER 2010 Original Filing		DECEMBER 2010 Reply Results	
	ACCT	DESCRIP	FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
2157									
2158	190	Accumulated Deferred Income Taxes							
2159			P	S		404,598	811,860	404,598	811,860
2160			CUST	CN		112,198	34,745	112,198	34,745
2161			LABOR	SO		16,003,271	4,521,973	11,008,093	3,110,735
2162			P	DGP		368	200	368	200
2163			PTD	IBT		279,522	84,071	279,522	82,697
2164			P	SG		-	-	-	-
2165			P	SG		-	-	-	-
2166			CUST	BADDEBT		2,839,496	1,154,288	2,839,496	1,154,288
2167			P	TROJD		137	36	137	36
2168			P	SG		43,162,092	11,600,625	43,162,092	11,600,625
2169			P	SE		17,698,217	4,424,890	17,698,217	4,424,890
2170			PTD	SNP		(0)	(0)	(0)	(0)
2171			DPW	SNPD		2,124,838	603,426	2,124,838	603,426
2172			P	SSGCT		-	-	-	-
2173	**Total Accum Deferred Income Taxes**				**B19**	**82,624,735**	**23,236,115**	**77,629,558**	**21,823,502**
2174									
2175	281	Accumulated Deferred Income Taxes							
2176			P	S		-	-	-	-
2177			PT	DGP		-	-	-	-
2178			T	SNPT		-	-	-	-
2179					B19	-	-	-	-
2180									
2181	282	Accumulated Deferred Income Taxes							
2182			GP	S		(2,034,306,714)	(546,068,247)	(2,034,306,714)	(546,068,247)
2183			ACCMDIT	DITBAL		(0)	(0)	(0)	(0)
2184			PT	SNP		(10,033,814)	(2,753,028)	(10,033,814)	(2,753,161)
2185			LABOR	SO		(14,601,543)	(4,125,893)	(14,601,543)	(4,126,194)
2186			PTD	GPS		-	-	-	-
2187			P	SE		(16,282,707)	(4,070,986)	(16,282,707)	(4,070,986)
2188			P	SG		(18,321,980)	(4,924,377)	(18,321,980)	(4,924,377)
2189					B19	(2,093,546,757)	(561,942,532)	(2,093,546,757)	(561,942,966)
2190									
2191	283	Accumulated Deferred Income Taxes							
2192			GP	S		(31,640,118)	(2,086,432)	(32,483,139)	(2,929,453)
2193			P	SG		(3,955,748)	(1,063,182)	(3,955,748)	(1,063,182)
2194			P	SE		(12,019,040)	(3,004,988)	(12,019,040)	(3,004,988)
2195			LABOR	SO		8,723,992	2,465,100	8,723,992	2,465,280
2196			GP	GPS		(14,031,408)	(3,964,793)	(14,031,408)	(3,965,082)
2197			PTD	SNP		(7,943,838)	(2,179,591)	(7,943,838)	(2,179,696)
2198			P	TROJD		1,447,558	384,207	1,447,558	384,207
2199			P	SSGCT		-	-	-	-
2200			P	SGCT		(2,195,324)	(592,272)	(2,195,324)	(592,272)
2201			P	SSGCH		-	-	-	-
2202					B19	(61,613,926)	(10,041,951)	(62,456,947)	(10,885,187)
2203									
2204	**Total Accum Deferred Income Tax**				**B19**	**(2,072,535,947)**	**(548,748,369)**	**(2,078,374,146)**	**(551,004,650)**
2205	255	Accumulated Investment Tax Credit							
2206			PTD	S		-	-	-	-
2207			PTD	ITC84		(1,454,405)	(1,032,278)	(1,454,405)	(1,032,278)
2208			PTD	ITC85		(2,704,876)	(1,830,931)	(2,704,876)	(1,830,931)
2209			PTD	ITC86		(1,356,447)	(876,373)	(1,356,447)	(876,373)
2210			PTD	ITC88		(207,432)	(126,948)	(207,432)	(126,948)
2211			PTD	ITC89		(457,318)	(257,725)	(457,318)	(257,725)
2212			PTD	ITC90		(301,518)	(48,049)	(301,518)	(48,049)
2213			PTD	DGU		-	-	-	-
2214	**Total Accumlated ITC**				**B19**	(6,481,996)	(4,172,305)	(6,481,996)	(4,172,305)
2215									
2216	**Total Rate Base Deductions**					**(2,178,757,541)**	**(577,601,784)**	**(2,184,595,740)**	**(579,858,695)**
2217									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
2218									
2219									
2220	108SP	Steam Prod Plant Accumulated Depr							
2221			P	S		-	-	-	-
2222			P	SG		(890,379,750)	(239,306,334)	(890,379,750)	(239,306,334)
2223			P	SG		(955,852,887)	(256,903,473)	(955,852,887)	(256,903,473)
2224			P	SG		(625,642,326)	(168,153,163)	(625,561,165)	(168,131,349)
2225			P	SSGCH		(164,118,231)	(45,164,288)	(164,118,231)	(45,187,416)
2226					B17	(2,635,993,193)	(709,527,257)	(2,635,912,032)	(709,528,572)
2227									
2228	108NP	Nuclear Prod Plant Accumulated Depr							
2229			P	SG		-	-	-	-
2230			P	SG		-	-	-	-
2231			P	SG		-	-	-	-
2232					B17	-	-	-	-
2233									
2234									
2235	108HP	Hydraulic Prod Plant Accum Depr							
2236			P	S		-	-	-	-
2237			P	SG		(150,623,290)	(40,482,847)	(150,623,290)	(40,482,847)
2238			P	SG		(29,520,221)	(7,934,116)	(29,520,221)	(7,934,116)
2239			P	SG		(53,881,756)	(14,481,737)	(53,881,756)	(14,481,737)
2240			P	SG		(16,189,375)	(4,351,199)	(16,189,375)	(4,351,199)
2241					B17	(250,214,643)	(67,249,900)	(250,214,643)	(67,249,900)
2242									
2243	108OP	Other Production Plant - Accum Depr							
2244			P	S		-	-	-	-
2245			P	SG		(1,341,258)	(360,488)	(1,341,258)	(360,488)
2246			P	SG		-	-	-	-
2247			P	SG		(232,570,848)	(62,507,797)	(232,183,834)	(62,403,780)
2248			P	SSGCT		(21,911,899)	(5,514,630)	(21,911,899)	(5,500,320)
2249					B17	(255,824,005)	(68,382,916)	(255,436,991)	(68,264,588)
2250									
2251	108EP	Experimental Plant - Accum Depr							
2252			P	SG		-	-	-	-
2253			P	SG		-	-	-	-
2254						-	-	-	-
2255									
2256	**Total Production Plant Accum Depreciation**				**B17**	**(3,142,031,840)**	**(845,160,072)**	**(3,141,563,666)**	**(845,043,059)**
2257									
2258	Summary of Prod Plant Depreciation by Factor								
2259		S				-	-	-	-
2260		DGP				-	-	-	-
2261		DGU				-	-	-	-
2262		SG				(2,956,001,710)	(794,481,154)	(2,955,533,536)	(794,355,324)
2263		SSGCH				(164,118,231)	(45,164,288)	(164,118,231)	(45,187,416)
2264		SSGCT				(21,911,899)	(5,514,630)	(21,911,899)	(5,500,320)
2265	Total of Prod Plant Depreciation by Factor					(3,142,031,840)	(845,160,072)	(3,141,563,666)	(845,043,059)
2266									
2267									
2268	108TP	Transmission Plant Accumulated Depr							
2269			T	SG		(393,223,544)	(105,686,236)	(393,223,544)	(105,686,236)
2270			T	SG		(394,382,155)	(105,997,635)	(394,382,155)	(105,997,635)
2271			T	SG		(400,910,908)	(107,752,360)	(400,388,744)	(107,612,019)
2272	**Total Trans Plant Accum Depreciation**				**B17**	**(1,188,516,606)**	**(319,436,231)**	**(1,187,994,442)**	**(319,295,890)**

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108360	Land and Land Rights							
		DPW	S		(5,302,229)	(1,602,022)	(5,302,229)	(1,602,022)
				B17	(5,302,229)	(1,602,022)	(5,302,229)	(1,602,022)
108361	Structures and Improvements							
		DPW	S		(12,207,271)	(2,891,139)	(12,207,271)	(2,891,139)
				B17	(12,207,271)	(2,891,139)	(12,207,271)	(2,891,139)
108362	Station Equipment							
		DPW	S		(193,896,184)	(50,927,189)	(193,896,184)	(50,927,189)
				B17	(193,896,184)	(50,927,189)	(193,896,184)	(50,927,189)
108363	Storage Battery Equipment							
		DPW	S		(653,513)	-	(653,513)	-
				B17	(653,513)	-	(653,513)	-
108364	Poles, Towers & Fixtures							
		DPW	S		(650,324,680)	(254,217,371)	(650,324,680)	(254,217,371)
				B17	(650,324,680)	(254,217,371)	(650,324,680)	(254,217,371)
108365	Overhead Conductors							
		DPW	S		(239,104,064)	(111,511,075)	(239,104,064)	(111,511,075)
				B17	(239,104,064)	(111,511,075)	(239,104,064)	(111,511,075)
108366	Underground Conduit							
		DPW	S		(113,096,837)	(30,131,046)	(113,096,837)	(30,131,046)
				B17	(113,096,837)	(30,131,046)	(113,096,837)	(30,131,046)
108367	Underground Conductors							
		DPW	S		(259,139,566)	(49,257,652)	(259,139,566)	(49,257,652)
				B17	(259,139,566)	(49,257,652)	(259,139,566)	(49,257,652)
108368	Line Transformers							
		DPW	S		(338,323,984)	(145,890,557)	(338,323,984)	(145,890,557)
				B17	(338,323,984)	(145,890,557)	(338,323,984)	(145,890,557)
108369	Services							
		DPW	S		(149,366,555)	(54,920,796)	(149,366,555)	(54,920,796)
				B17	(149,366,555)	(54,920,796)	(149,366,555)	(54,920,796)
108370	Meters							
		DPW	S		(83,109,895)	(30,602,765)	(83,109,895)	(30,602,765)
				B17	(83,109,895)	(30,602,765)	(83,109,895)	(30,602,765)
108371	Installations on Customers' Premises							
		DPW	S		(7,615,655)	(2,335,549)	(7,615,655)	(2,335,549)
				B17	(7,615,655)	(2,335,549)	(7,615,655)	(2,335,549)
108372	Leased Property							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108373	Street Lights							
		DPW	S		(26,942,772)	(7,478,090)	(26,942,772)	(7,478,090)
				B17	(26,942,772)	(7,478,090)	(26,942,772)	(7,478,090)
108D00	Unclassified Dist Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
Total Distribution Plant Accum Depreciation				B17	**(2,079,083,205)**	**(741,765,252)**	**(2,079,083,205)**	**(741,765,252)**
Summary of Distribution Plant Depr by Factor								
	S				(2,079,083,205)	(741,765,252)	(2,079,083,205)	(741,765,252)
Total Distribution Depreciation by Factor					(2,079,083,205)	(741,765,252)	(2,079,083,205)	(741,765,252)

REVISED PROTOCOL
Thirteen Month Average

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
108GP	General Plant Accumulated Depr							
		G-SITUS	S		(163,165,354)	(50,628,900)	(163,165,354)	(50,628,900)
		G-DGP	SG		(7,296,953)	(1,961,193)	(7,296,953)	(1,961,193)
		G-DGU	SG		(13,863,584)	(3,726,099)	(13,863,584)	(3,726,099)
		G-SG	SG		(44,960,094)	(12,083,872)	(44,960,094)	(12,083,872)
		CUST	CN		(5,819,925)	(1,802,318)	(5,819,925)	(1,802,318)
		PTD	SO		(78,231,519)	(22,105,535)	(78,230,939)	(22,106,984)
		P	SE		(262,896)	(65,729)	(262,896)	(65,729)
		G-SG	SSGCT		(33,832)	(8,514)	(33,832)	(8,492)
		G-SG	SSGCH		(2,363,052)	(650,297)	(2,363,052)	(650,630)
				B17	(315,997,209)	(93,032,457)	(315,996,629)	(93,034,218)
108MP	Mining Plant Accumulated Depr.							
		P	S		-	-	-	-
		P	SE		(168,106,499)	(42,029,817)	(168,106,499)	(42,029,817)
				B17	(168,106,499)	(42,029,817)	(168,106,499)	(42,029,817)
108MP	Less Centralia Situs Depreciation							
		P	S		-	-	-	-
				B17	(168,106,499)	(42,029,817)	(168,106,499)	(42,029,817)
1081390	Accum Depr - Capital Lease							
		PTD	SO	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
1081399	Accum Depr - Capital Lease							
		P	S		-	-	-	-
		P	SE	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
Total General Plant Accum Depreciation				**B17**	**(484,103,708)**	**(135,062,274)**	**(484,103,128)**	**(135,064,034)**
Summary of General Depreciation by Factor								
	S				(163,165,354)	(50,628,900)	(163,165,354)	(50,628,900)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SE				(168,369,396)	(42,095,546)	(168,369,396)	(42,095,546)
	SO				(78,231,519)	(22,105,535)	(78,230,939)	(22,106,984)
	CN				(5,819,925)	(1,802,318)	(5,819,925)	(1,802,318)
	SG				(66,120,630)	(17,771,165)	(66,120,630)	(17,771,165)
	DEU				-	-	-	-
	SSGCT				(33,832)	(8,514)	(33,832)	(8,492)
	SSGCH				(2,363,052)	(650,297)	(2,363,052)	(650,630)
	Remove Capital Leases				-	-	-	-
Total General Depreciation by Factor					(484,103,708)	(135,062,274)	(484,103,128)	(135,064,034)
Total Accum Depreciation - Plant In Service				**B17**	**(6,893,735,360)**	**(2,041,423,829)**	**(6,892,744,441)**	**(2,041,168,235)**
111SP	Accum Prov for Amort-Steam							
		P	SSGCH		-	-	-	-
		P	SSGCT		-	-	-	-
				B18	-	-	-	-
111GP	Accum Prov for Amort-General							
		G-SITUS	S		(19,996,850)	(10,854,756)	(19,996,850)	(10,854,756)
		CUST	CN		(2,557,610)	(792,042)	(2,557,610)	(792,042)
		I-SG	SG		(833,484)	(224,015)	(833,484)	(224,015)
		PTD	SO		(10,896,673)	(3,079,025)	(10,896,673)	(3,079,249)
		P	SE		-	-	-	-
				B18	(34,284,616)	(14,949,837)	(34,284,616)	(14,950,062)

REVISED PROTOCOL
Thirteen Month Average

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2010 Original Filing TOTAL	DECEMBER 2010 Original Filing OREGON	DECEMBER 2010 Reply Results TOTAL	DECEMBER 2010 Reply Results OREGON
2421									
2422	111HP	Accum Prov for Amort-Hydro							
2423			P	SG		(344,575)	(92,611)	(344,575)	(92,611)
2424			P	SG		-	-	-	-
2425			P	SG		(9,857)	(2,649)	(9,857)	(2,649)
2426			P	SG		(407,601)	(109,550)	(407,601)	(109,550)
2427					B18	(762,033)	(204,811)	(762,033)	(204,811)
2428									
2429									
2430	111IP	Accum Prov for Amort-Intangible Plant							
2431			I-SITUS	S		(1,434,385)	(580,763)	(1,434,385)	(580,763)
2432			I-DGP	SG		112,088	30,126	112,088	30,126
2433			I-DGU	SG		(313,621)	(84,292)	(313,621)	(84,292)
2434			P	SE		(1,462,456)	(365,642)	(1,462,456)	(365,642)
2435			I-SG	SG		(42,495,274)	(11,421,406)	(42,495,274)	(11,421,406)
2436			I-SG	SG		(17,094,381)	(4,594,437)	(17,094,381)	(4,594,437)
2437			I-SG	SG		(3,265,906)	(877,774)	(3,265,906)	(877,774)
2438			CUST	CN		(93,562,892)	(28,974,607)	(93,562,892)	(28,974,607)
2439			P	SSGCT		-	-	-	-
2440			P	SSGCH		(26,279)	(7,232)	(26,279)	(7,235)
2441			PTD	SO		(279,823,441)	(79,068,473)	(279,823,441)	(79,074,244)
2442					B18	(439,366,547)	(125,944,499)	(439,366,547)	(125,950,273)
2443	111IP	Less Non-Utility Plant							
2444			NUTIL	OTH		-	-	-	-
2445						(439,366,547)	(125,944,499)	(439,366,547)	(125,950,273)
2446									
2447	111390	Accum Amtr - Capital Lease							
2448			G-SITUS	S		-	-	-	-
2449			P	SG		-	-	-	-
2450			PTD	SO		-	-	-	-
2451						-	-	-	-
2452									
2453		Remove Capital Lease Amtr				-	-	-	-
2454									
2455	**Total Accum Provision for Amortization**				**B18**	**(474,413,197)**	**(141,099,147)**	**(474,413,197)**	**(141,105,146)**
2456									
2457									
2458									
2459									
2460	Summary of Amortization by Factor								
2461		S				(21,431,235)	(11,435,519)	(21,431,235)	(11,435,519)
2462		DGP				-	-	-	-
2463		DGU				-	-	-	-
2464		SE				(1,462,456)	(365,642)	(1,462,456)	(365,642)
2465		SO				(290,720,114)	(82,147,498)	(290,720,114)	(82,153,493)
2466		CN				(96,120,501)	(29,766,649)	(96,120,501)	(29,766,649)
2467		SSGCT				-	-	-	-
2468		SSGCH				(26,279)	(7,232)	(26,279)	(7,235)
2469		SG				(64,652,612)	(17,376,608)	(64,652,612)	(17,376,608)
2470		Less Capital Lease				-	-	-	-
2471	Total Provision For Amortization by Factor					(474,413,197)	(141,099,147)	(474,413,197)	(141,105,146)

PacifiCorp
Oregon General Rate Case December 2010 - Reply
Pro Forma Factors

PacifiCorp
Oregon General Rate Case December 2010 - Reply
Pro Forma Factors
13 MONTH AVERAGE FACTORS **REVISED PROTOCOL**

DESCRIPTION	FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Ref #
Situs	S	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Situs
System Generation	SG	1.79%	26.8769%	7.9563%	41.2071%	5.7042%	16.0910%	0.3778%	0	0	11.4
System Generation (Pac. Power Costs on SG)	SG-P	1.7867%	26.8769%	7.9563%	41.2071%	5.7042%	16.0910%	0.3778%	0	0	11.4
System Generation (R.M.P. Costs on SG)	SG-U	1.7867%	26.8769%	7.9563%	41.2071%	5.7042%	16.0910%	0.3778%	0	0	11.4
Divisional Generation - Pac. Power	DGP	3.6047%	54.2251%	16.0522%	0.0000%	0.0000%	26.1181%	0.0000%	0	0	11.4
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	81.7041%	11.3101%	6.2367%	0.7491%	0	0	11.4
System Capacity	SC	1.8361%	27.5019%	8.1562%	41.2608%	5.4658%	15.4140%	0.3652%	0	0	11.3
System Energy	SE	1.6383%	25.0019%	7.3568%	41.0460%	6.4194%	18.1221%	0.4156%	0	0	11.4
System Energy (Pac. Power Costs on SE)	SE-P	1.6383%	25.0019%	7.3568%	41.0460%	6.4194%	18.1221%	0.4156%	0	0	11.4
System Energy (R.M.P. Costs on SE)	SE-U	1.6383%	25.0019%	7.3568%	41.0460%	6.4194%	18.1221%	0.4156%	0	0	11.4
Divisional Energy - Pac. Power	DEP	3.3781%	51.5526%	15.1693%	0.0000%	0.0000%	29.9001%	0.0000%	0	0	11.4
Divisional Energy - R.M.P.	DEU	0.0000%	0.0000%	0.0000%	79.6977%	12.4642%	7.0312%	0.8069%	0	0	11.4
System Overhead	SO	2.4676%	28.2586%	7.7611%	41.4166%	5.5349%	14.3032%	0.2580%	0	0	11.16
System Overhead (Pac. Power Costs on SO)	SO-P	2.4676%	28.2586%	7.7611%	41.4166%	5.5349%	14.3032%	0.2580%	0	0	11.16
System Overhead (R.M.P. Costs on SO)	SO-U	2.4676%	28.2586%	7.7611%	41.4166%	5.5349%	14.3032%	0.2580%	0	0	11.16
Gross Plant-System	GPS	2.4676%	28.2586%	7.7611%	41.4166%	5.5349%	14.3032%	0.2580%	0	0	11.16
System Net Plant	SNP	2.3119%	27.4388%	7.5354%	42.7774%	5.4522%	14.2222%	0.2621%	0	0	11.16
Seasonal System Capacity Combustion Turbine	SSCCT	1.7063%	25.7072%	7.8281%	45.4296%	4.9205%	13.9596%	0.4487%	0	0	11.7
Seasonal System Energy Combustion Turbine	SSECT	1.6442%	23.2863%	6.9440%	43.2482%	7.7873%	16.5904%	0.4996%	0	0	11.7
Seasonal System Capacity Cholla	SSCCH	1.8628%	28.2418%	8.3604%	40.0318%	5.4624%	15.6952%	0.3456%	0	0	11.8
Seasonal System Energy Cholla	SSECH	1.6268%	25.4083%	7.5680%	40.5717%	6.0886%	18.3375%	0.3990%	0	0	11.8
Seasonal System Generation Cholla	SSGCH	1.8038%	27.5335%	8.1623%	40.1668%	5.6190%	16.3558%	0.3589%	0	0	11.8
Seasonal System Capacity Purchases	SSCP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0	0	11.9
Seasonal System Energy Purchases	SSEP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0	0	11.10
Seasonal System Generation Contracts	SSGC	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0	0	11.9
Seasonal System Generation Combustion Turbine	SSGCT	1.6908%	25.1020%	7.6071%	44.8842%	5.6372%	14.6173%	0.4615%	0	0	11.7
Mid-Columbia	MC	0.9417%	61.7263%	3.9257%	21.7194%	3.0065%	8.4812%	0.1991%	0	0	11.10
Division Net Plant Distribution	SNPD	3.5323%	28.3987%	6.4515%	47.4881%	4.5940%	9.5355%	0.0000%	0	0	11.14
Customer - System	CN	2.5516%	30.9681%	7.0131%	47.9382%	3.9526%	7.5764%	0.0000%	0.00%	0.00%	11.19
Excise Tax - superfund	EXCTAX	3.3436%	29.4303%	6.9751%	38.7516%	3.8248%	9.5889%	-0.7970%	5.9161%	2.9665%	11.20
Interest	INT	2.3119%	27.4388%	7.5354%	42.7774%	5.4522%	14.2222%	0.2621%	0	0.0000%	11.16
CIAC	CIAC	3.5323%	28.3987%	6.4515%	47.4881%	4.5940%	9.5355%	0.0000%	0	0	11.19
Bad Debt Expense	BADDEBT	-0.1529%	40.6511%	14.0034%	36.5710%	3.2177%	5.7097%	0.0000%	0.0000%	0.0000%	11.19
Accumulated Investment Tax Credit 1984	ITC84	3.29%	70.9760%	14.18%	0	0	10.9460%	0	0.00%	0.61%	Fixed
Accumulated Investment Tax Credit 1985	ITC85	5.42%	67.6900%	13.36%	0	0	11.6100%	0	0.00%	1.92%	Fixed
Accumulated Investment Tax Credit 1986	ITC86	4.79%	64.6080%	13.13%	0	0	15.5000%	0	0.00%	1.98%	Fixed
Accumulated Investment Tax Credit 1988	ITC88	4.27%	61.2000%	14.96%	0	0	16.7100%	0	0.00%	2.86%	Fixed
Accumulated Investment Tax Credit 1989	ITC89	4.88%	56.3558%	15.27%	0	0	20.6776%	0	0.00%	2.82%	Fixed
Accumulated Investment Tax Credit 1990	ITC90	1.50%	15.9356%	3.91%	46.94%	13.98%	17.3435%	0	0.00%	0.39%	Fixed
Other Electric	OTHER	0.00%	0.0000%	0.00%	0.00%	0.00%	0.0000%	0.00%	100.00%	0.00%	Situs
Non-Utility	NUTIL	0.00%	0.0000%	0.00%	0.00%	0.00%	0.0000%	0.00%	0.00%	100.00%	Situs
System Net Steam Plant	SNPPS	1.7888%	26.9602%	7.9825%	41.0751%	5.6934%	16.1246%	0.3754%	0	0	11.11
System Net Transmission Plant	SNPT	1.7867%	26.8769%	7.9563%	41.2071%	5.7042%	16.0910%	0.3778%	0	0	11.13
System Net Hydro Plant	SNPPH	1.7867%	26.8769%	7.9563%	41.2071%	5.7042%	16.0910%	0.3778%	0.0000%	0.0000%	11.12
System Net Other Production Plant	SNPPO	1.7845%	26.8364%	7.9484%	41.2910%	5.7026%	16.0574%	0.3797%	0	0	11.12
System Net Intangible Plant	SNPI	2.1072%	27.4569%	7.7097%	41.7018%	6.1493%	14.5808%	0.2943%	0	0	11.15
Trojan Plant Allocator	TROJP	1.7641%	26.5921%	7.8652%	41.1827%	5.8128%	16.3995%	0.3835%	0	0	11.21
Trojan Decommissioning Allocator	TROJD	1.7602%	26.5418%	7.8492%	41.1783%	5.8320%	16.4540%	0.3846%	0	0	11.21
Income Before Taxes	IBT	3.3633%	29.5851%	7.0091%	38.9457%	3.8413%	9.6272%	-0.8030%	5.4434%	2.9878%	11.17
DIT Expense	DITEXP	2.2084%	28.2470%	14.2564%	37.1291%	4.5775%	16.6740%	0.3811%	0.0000%	-3.4735%	11.17
DIT Balance	DITBAL	2.4801%	28.4325%	8.9717%	42.7697%	5.7647%	13.4220%	0.2641%	0.0000%	-2.1049%	11.18
Tax Depreciation	TAXDEPR	1.6994%	26.3160%	14.2466%	39.6013%	5.4568%	15.8259%	0.3583%	0.0000%	-3.5043%	11.22
SCHMAT Depreciation Expense	SCHMDEXP	2.9240%	28.6984%	8.1116%	40.2124%	5.3959%	14.4037%	0.2541%	0.0000%	0.0000%	11.22
SCHMDT Amortization Expense	SCHMAEXP	1.9225%	24.6254%	6.2322%	35.5105%	4.6657%	12.4887%	0.2323%	14.3228%	0.0000%	11.22

PacifiCorp
Oregon General Rate Case December 2010 - Reply
CP ALLOCATION FACTOR

75.00% Demand Percentage
25.00% Energy Percentage

MONTH	CALIFORNIA	OREGON	WASHINGTON	WYOMING	UTAH	IDAHO	WYOMING	FERC	TOTAL
Jan-10	166.6	2,712.7	816.5	1,056.1	3,078.7	462.7	254.8	29.6	8,577.8
Feb-10	157.6	2,587.1	743.5	1,056.2	3,123.2	447.0	272.0	22.9	8,409.6
Mar-10	151.1	2,351.2	651.7	1,014.2	2,860.2	406.7	237.5	28.4	7,701.0
Apr-10	137.4	2,178.1	569.9	1,003.0	2,793.6	419.6	255.3	21.6	7,378.4
May-10	149.2	1,841.4	581.6	958.2	3,590.8	548.6	227.7	32.2	7,929.6
Jun-10	156.7	2,078.1	663.4	1,061.4	3,951.5	490.0	241.7	38.0	8,680.9
Jul-10	157.4	2,371.0	733.3	1,068.5	4,249.3	442.9	237.1	45.7	9,305.2
Aug-10	160.4	2,417.2	722.6	1,053.3	4,201.4	475.7	237.9	37.1	9,305.5
Sep-10	144.3	2,191.4	639.3	1,011.5	3,879.5	476.9	238.9	29.6	8,611.4
Oct-10	139.7	2,230.6	652.2	986.9	2,722.5	397.6	240.4	25.3	7,395.3
Nov-10	153.1	2,239.0	690.8	1,087.1	3,456.4	449.7	272.3	25.5	8,374.0
Dec-10	169.8	2,410.6	722.8	1,118.7	3,513.6	469.6	282.9	30.7	8,718.7
Load Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1,843.3	27,608.4	8,187.8	12,475.2	41,420.7	5,487.0	2,998.4	366.6	100,387.4
Juris % by Division	3.6781%	55.0905%	16.3381%	24.8934%	82.3920%	10.9144%	5.9644%	0.7293%	200.00%
Total Hydro Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Off-System Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Subtotal	1,843.3	27,608.4	8,187.8	12,475.2	41,420.7	5,487.0	2,998.4	366.6	
System Capacity Factor	1.8361%	27.5019%	8.1562%	12.4271%	41.2608%	5.4658%	2.9869%	0.3652%	100.00%

PacifiCorp
Oregon General Rate Case December 2010 - Reply
ENERGY ALLOCATION NOTE

MONTH	CALIFORNIA	OREGON	WASHINGTON	WYOMING	UTAH	IDAHO	WYOMING	FERC	TOTAL
Jan-10	86,497	1,389,779	427,749	741,281	2,089,622	279,191	181,620	20,108	5,215,847
Feb-10	75,058	1,225,348	355,600	681,691	1,878,497	282,460	177,406	16,855	4,692,914
Mar-10	77,461	1,239,088	346,442	694,250	1,929,358	259,217	172,522	17,690	4,736,030
Apr-10	74,760	1,160,511	316,088	693,149	1,789,443	266,816	177,581	17,888	4,496,236
May-10	79,825	1,137,489	319,016	668,022	1,858,908	307,825	169,812	19,469	4,560,365
Jun-10	83,472	1,142,124	314,493	689,088	2,017,578	394,571	171,876	22,198	4,835,400
Jul-10	90,468	1,254,400	372,098	706,273	2,328,547	442,538	173,075	27,535	5,394,933
Aug-10	85,977	1,249,529	374,950	732,983	2,322,070	390,488	174,301	26,073	5,356,371
Sep-10	74,942	1,136,800	343,688	698,171	1,995,411	286,854	170,314	19,990	4,726,170
Oct-10	71,757	1,141,723	351,973	699,095	1,873,409	280,275	175,241	18,216	4,611,688
Nov-10	74,915	1,210,505	368,264	727,495	1,858,423	275,496	184,235	17,395	4,716,728
Dec-10	86,012	1,380,764	425,688	775,854	2,139,527	300,360	196,496	20,400	5,325,099
Load Curtailment	0	0	0	0	0	0	0	0	0
Total	961,144	14,668,059	4,316,049	8,507,349	24,080,793	3,766,091	2,124,479	243,817	58,667,781
Juris % by Division	3.3781%	51.5526%	15.1693%	29.9001%	79.6977%	12.4642%	7.0312%	0.8069%	200.00%
Total Hydro Adjustment	0	0	0	0	0	0	0	0	
Off-System Sales	0	0	0	0	0	0	0	0	
Subtotal	961,144	14,668,059	4,316,049	8,507,349	24,080,793	3,766,091	2,124,479	243,817	
System Energy Factor	1.6383%	25.0019%	7.3568%	14.5009%	41.0460%	6.4194%	3.6212%	0.4156%	100.00%
Divisional Energy - Pacific	3.3781%	51.5526%	15.1693%	29.9001%	0.0000%	0.0000%	0.0000%	0.0000%	100.00%
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	0.0000%	79.6977%	12.4642%	7.0312%	0.8069%	100.00%
System Generation Factor	1.7867%	26.8769%	7.9563%	12.9455%	41.2071%	5.7042%	3.1455%	0.3778%	100.00%
Divisional Generation - Pacific	3.6047%	54.2251%	16.0522%	26.1181%	0.0000%	0.0000%	0.0000%	0.0000%	100.00%
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	0.0000%	81.7041%	11.3101%	6.2367%	0.7491%	100.00%

PacifiCorp
Oregon General Rate Case December 2010 - Reply
Pro Forma Factors
Coincident Peaks:
Forecast:

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1	22	8	166.6	462.7	2,712.7	3,179.9	816.5	1,056.1	254.8	29.6	8,679.0
2010	2	4	8	157.6	447.0	2,587.1	3,123.2	743.5	1,056.2	272.0	22.9	8,409.6
2010	3	30	8	151.1	406.7	2,351.2	2,860.2	651.7	1,014.2	237.5	28.4	7,701.0
2010	4	1	8	137.4	419.6	2,178.1	2,793.6	569.9	1,003.0	255.3	21.6	7,378.4
2010	5	19	15	149.2	548.6	1,841.4	3,590.8	581.6	958.2	227.7	32.2	7,929.6
2010	6	24	15	156.7	660.4	2,078.1	4,141.8	663.4	1,061.4	241.7	38.0	9,041.5
2010	7	19	16	157.4	647.4	2,371.0	4,466.0	733.3	1,068.5	237.1	45.7	9,726.5
2010	8	26	16	160.4	592.0	2,417.2	4,408.9	722.6	1,053.3	237.9	37.1	9,629.4
2010	9	9	16	144.3	480.2	2,191.4	3,996.7	639.3	1,011.5	238.9	29.6	8,731.9
2010	10	29	8	139.7	397.6	2,230.6	2,722.5	652.2	986.9	240.4	25.3	7,395.3
2010	11	24	18	153.1	449.7	2,239.0	3,456.4	690.8	1,087.1	272.3	25.5	8,374.0
2010	12	15	18	169.8	469.6	2,410.6	3,624.1	722.8	1,118.7	282.9	30.7	8,829.3
Total 12 CP				1,843.3	5,981.6	27,608.4	42,364.2	8,187.8	12,475.2	2,998.4	366.6	101,825.5

+ plus

Monsanto Curtailment (ID) - Grossed up for Line Losses (No adjustment - Forecast Loads assumes no curtailment)

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1	22	8									-
2010	2	4	8									-
2010	3	30	8									-
2010	4	1	8									-
2010	5	19	15									-
2010	6	24	15									-
2010	7	19	16									-
2010	8	26	16									-
2010	9	9	16									-
2010	10	4	19									-
2010	11	24	18									-
2010	12	15	18									-
Total 12 CP				-	-	-	-	-	-	-	-	-

- (less)

MagCorp Buy-through (UT) - Grossed up for Line Losses; ID Irrigation Load Control; UT Cool Keeper

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1	22	8				101.2					101.2
2010	2	4	8				-					-
2010	3	30	8				-					-
2010	4	1	8				-					-
2010	5	19	15				-					-
2010	6	24	15		170.4		190.2					360.6
2010	7	19	16		204.6		216.8					421.3
2010	8	26	16		116.3		207.6					323.9
2010	9	9	16		3.3		117.2					120.5
2010	10	4	19				-					-
2010	11	24	18				-					-
2010	12	15	18				110.5					110.5
Total 12 CP				-	494.6	-	943.5	-	-	-	-	1,438.1

= equals

12 CP for Input:

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1	22	8	166.6	462.7	2,712.7	3,078.7	816.5	1,056.1	254.8	29.6	8,577.8
2010	2	4	8	157.6	447.0	2,587.1	3,123.2	743.5	1,056.2	272.0	22.9	8,409.6
2010	3	30	8	151.1	406.7	2,351.2	2,860.2	651.7	1,014.2	237.5	28.4	7,701.0
2010	4	1	8	137.4	419.6	2,178.1	2,793.6	569.9	1,003.0	255.3	21.6	7,378.4
2010	5	19	15	149.2	548.6	1,841.4	3,590.8	581.6	958.2	227.7	32.2	7,929.6
2010	6	24	15	156.7	490.0	2,078.1	3,951.5	663.4	1,061.4	241.7	38.0	8,680.9
2010	7	19	16	157.4	442.9	2,371.0	4,249.3	733.3	1,068.5	237.1	45.7	9,305.2
2010	8	26	16	160.4	475.7	2,417.2	4,201.4	722.6	1,053.3	237.9	37.1	9,305.5
2010	9	9	16	144.3	476.9	2,191.4	3,879.5	639.3	1,011.5	238.9	29.6	8,611.4
2010	10	4	19	139.7	397.6	2,230.6	2,722.5	652.2	986.9	240.4	25.3	7,395.3
2010	11	24	18	153.1	449.7	2,239.0	3,456.4	690.8	1,087.1	272.3	25.5	8,374.0
2010	12	15	18	169.8	469.6	2,410.6	3,513.6	722.8	1,118.7	282.9	30.7	8,718.7
Total 12 CP				1,843.3	5,487.0	27,608.4	41,420.7	8,187.8	12,475.2	2,998.4	366.6	100,387.4
System Capacity Factor				1.8361%	5.4658%	27.5019%	41.2608%	8.1562%	12.4271%	2.9869%	0.3652%	100.0000%

PacifiCorp
Oregon General Rate Case December 2010 - Reply

CY 2010 Forecast
ENERGY
Forecast:

Year	Month	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1	86,497	278,654	1,389,779	2,096,976	427,749	741,281	181,620	20,108	5,222,663
2010	2	75,058	281,620	1,225,348	1,878,119	355,600	681,691	177,406	16,855	4,691,696
2010	3	77,461	258,455	1,239,088	1,929,125	346,442	694,250	172,522	17,690	4,735,034
2010	4	74,760	266,242	1,160,511	1,789,096	316,088	693,149	177,581	17,888	4,495,315
2010	5	79,825	307,398	1,137,489	1,858,577	319,016	668,022	169,812	19,469	4,559,608
2010	6	83,472	393,795	1,142,124	2,021,156	314,493	689,088	171,876	22,198	4,838,202
2010	7	90,468	438,711	1,254,400	2,336,294	372,098	706,273	173,075	27,535	5,398,855
2010	8	85,977	385,079	1,249,529	2,328,234	374,950	732,983	174,301	26,073	5,357,125
2010	9	74,942	285,152	1,136,800	2,000,403	343,688	698,171	170,314	19,990	4,729,459
2010	10	71,757	279,252	1,141,723	1,873,232	351,973	699,095	175,241	18,216	4,610,488
2010	11	74,915	268,077	1,210,505	1,858,383	368,264	727,495	184,235	17,395	4,709,268
2010	12	86,012	294,677	1,380,764	2,146,727	425,688	775,854	196,496	20,400	5,326,617
	Total Energy	961,144	3,737,111	14,668,059	24,116,323	4,316,049	8,507,349	2,124,479	243,817	58,674,331

+ plus

Monsanto Curtailment (ID), Nucor Curtailment (UT) - Grossed up for Line Losses

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1				538		272					809
2010	2				840		378					1,218
2010	3				762		233					995
2010	4				574		347					921
2010	5				426		330					757
2010	6				776		231					1,007
2010	7				3,827		283					4,110
2010	8				5,409		119					5,527
2010	9				1,702		224					1,926
2010	10				1,023		177					1,200
2010	11				7,419		40					7,460
2010	12				5,683		20					5,704
	Total Energy			-	28,980	-	2,654	-	-	-	-	31,634

- (less)

MagCorp Buy-through (UT) - Grossed up for Line Losses

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1						7,625					7,625
2010	2						-					-
2010	3						-					-
2010	4						-					-
2010	5						-					-
2010	6						3,808					3,808
2010	7						8,031					8,031
2010	8						6,282					6,282
2010	9						5,215					5,215
2010	10						-					-
2010	11						-					-
2010	12						7,221					7,221
	Total Energy			-	-	-	38,183	-	-	-	-	38,183

Energy for Input: **= equals**

Year	Month	Day	hour	CA	ID	OR	UT	WA	EWY	WWY	FERC	total
2010	1			86,497	279,191	1,389,779	2,089,622	427,749	741,281	181,620	20,108	5,215,847
2010	2			75,058	282,460	1,225,348	1,878,497	355,600	681,691	177,406	16,855	4,692,914
2010	3			77,461	259,217	1,239,088	1,929,358	346,442	694,250	172,522	17,690	4,736,030
2010	4			74,760	266,816	1,160,511	1,789,443	316,088	693,149	177,581	17,888	4,496,236
2010	5			79,825	307,825	1,137,489	1,858,908	319,016	668,022	169,812	19,469	4,560,365
2010	6			83,472	394,571	1,142,124	2,017,578	314,493	689,088	171,876	22,198	4,835,400
2010	7			90,468	442,538	1,254,400	2,328,547	372,098	706,273	173,075	27,535	5,394,933
2010	8			85,977	390,488	1,249,529	2,322,070	374,950	732,983	174,301	26,073	5,356,371
2010	9			74,942	286,854	1,136,800	1,995,411	343,688	698,171	170,314	19,990	4,726,170
2010	10			71,757	280,275	1,141,723	1,873,409	351,973	699,095	175,241	18,216	4,611,688
2010	11			74,915	275,496	1,210,505	1,858,423	368,264	727,495	184,235	17,395	4,716,728
2010	12			86,012	300,360	1,380,764	2,139,527	425,688	775,854	196,496	20,400	5,325,099
	Total Energy			961,144	3,766,091	14,668,059	24,080,793	4,316,049	8,507,349	2,124,479	243,817	58,667,781
System Energy Factor				1.6383%	6.4194%	25.0019%	41.0460%	7.3568%	14.5009%	3.6212%	0.4156%	100%
System Generation Factor				1.7867%	5.7042%	26.8769%	41.2071%	7.9563%	12.9455%	3.1455%	0.3778%	100%

PacifiCorp
Oregon General Rate Case December 2010 - Reply
Pro Forma Factors
75.00% Demand Percentage
25.00% Energy Percentage

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF THE COMBUSTION TURBINES

MONTH	MWH	Proportion	CALIFORNIA	OREGON	WASHINGTON	MONTANA	WYOMING	UTAH	IDAHO	WYOMING	FERC	
Jan-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Feb-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Mar-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Apr-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
May-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jun-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jul-10	9,666	54.29%	85.5	1287.2	398.1	0.0	580.1	2306.9	240.4	128.7	24.8	
Aug-10	8,138	45.71%	73.3	1104.9	330.3	0.0	481.5	1920.4	217.4	108.7	17.0	
Sep-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oct-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Nov-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Dec-10	-	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	17,804	100.00%	159	2,392	728	-	1,062	4,227	458	237	42	
SSCCT Factor			1.71%	25.71%	7.83%	0.00%	11.41%	45.43%	4.92%	2.55%	0.45%	100.00%
SSGCT Factor			1.69%	25.10%	7.61%	0.00%	11.90%	44.88%	5.64%	2.72%	0.46%	100.00%

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF THE COMBUSTION TURBINES

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	MONTANA	WYOMING	UTAH	IDAHO	WYOMING	FERC	
Jan-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Feb-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Mar-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Apr-10	-	0.00%	-	-	-	-	-	-	-	-	-	
May-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Jun-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Jul-10	9,666	54.29%	49,115	681,019	202,014	-	383,438	1,264,177	240,256	93,963	14,949	
Aug-10	8,138	45.71%	39,300	571,154	171,388	-	335,044	1,061,409	178,490	79,672	11,918	
Sep-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Oct-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Nov-10	-	0.00%	-	-	-	-	-	-	-	-	-	
Dec-10	-	0.00%	-	-	-	-	-	-	-	-	-	
	17,804	100.00%	88,415	1,252,173	373,402	-	718,482	2,325,586	418,746	173,635	26,867	
SSECT Factor			1.64%	23.29%	6.94%	0.00%	13.36%	43.25%	7.79%	3.23%	0.50%	100.00%

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF CHOLLA IV/APS

	MWH													
MONTH	Cholla IV	APS	Total	Proportion	CALIFORNIA	MONTANA	OREGON	WASHINGTON	WYOMING	UTAH	IDAHO	WYOMING	FERC	
Jan-10	256,058	142,575	398,633	13.87%	23.1	0.0	376.2	113.2	146.5	427.0	64.2	35.3	4.1	
Feb-10	229,102	68,850	297,952	10.37%	16.3	0.0	268.2	77.1	109.5	323.7	46.3	28.2	2.4	
Mar-10	131,607	-	131,607	4.58%	6.9	0.0	107.7	29.8	46.4	131.0	18.6	10.9	1.3	
Apr-10	247,929	-	247,929	8.63%	11.9	0.0	187.9	49.2	86.5	241.0	36.2	22.0	1.9	
May-10	249,898	(77,900)	171,998	5.98%	8.9	0.0	110.2	34.8	57.3	214.9	32.8	13.6	1.9	
Jun-10	242,678	(137,970)	104,708	3.64%	5.7	0.0	75.7	24.2	38.7	143.9	17.9	8.8	1.4	
Jul-10	256,363	(142,380)	113,983	3.97%	6.2	0.0	94.0	29.1	42.4	168.5	17.6	9.4	1.8	
Aug-10	257,680	(142,490)	115,190	4.01%	6.4	0.0	96.9	29.0	42.2	168.4	19.1	9.5	1.5	
Sep-10	248,090	(68,780)	179,310	6.24%	9.0	0.0	136.7	39.9	63.1	242.0	29.8	14.9	1.8	
Oct-10	256,659	77,895	334,554	11.64%	16.3	0.0	259.6	75.9	114.9	316.9	46.3	28.0	2.9	
Nov-10	244,387	137,895	382,282	13.30%	20.4	0.0	297.8	91.9	144.6	459.7	59.8	36.2	3.4	
Dec-10	253,472	142,755	396,227	13.78%	23.4	0.0	332.3	99.6	154.2	484.3	64.7	39.0	4.2	
	2,873,922	450	2,874,372	100%	155	-	2,343	694	1,046	3,321	453	256	29	
SSCCH Factor					1.86%	0.00%	28.24%	8.36%	12.61%	40.03%	5.46%	3.08%	0.35%	100.00%
SSGCH Factor					1.80%	0.00%	27.53%	8.16%	13.12%	40.17%	5.62%	3.23%	0.36%	100.00%

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF CHOLLA IV/APS

	MWH													
MONTH	Cholla IV	APS	Total	Proportion	CALIFORNIA	MONTANA	OREGON	WASHINGTON	WYOMING	UTAH	IDAHO	WYOMING	FERC	
Jan-10	256,058	142,575	398,633	13.87%	11,996	-	192,742	59,322	102,805	289,800	38,720	25,188	2,789	
Feb-10	229,102	68,850	297,952	10.37%	7,780	-	127,017	36,861	70,663	194,721	29,279	18,390	1,747	
Mar-10	131,607	-	131,607	4.58%	3,547	-	56,733	15,862	31,787	88,338	11,869	7,899	810	
Apr-10	247,929	-	247,929	8.63%	6,448	-	100,100	27,264	59,788	154,349	23,014	15,317	1,543	
May-10	249,898	(77,900)	171,998	5.98%	4,777	-	68,066	19,089	39,973	111,234	18,420	10,161	1,165	
Jun-10	242,678	(137,970)	104,708	3.64%	3,041	-	41,606	11,456	25,102	73,497	14,374	6,261	809	
Jul-10	256,363	(142,380)	113,983	3.97%	3,587	-	49,743	14,755	28,007	92,338	17,549	6,863	1,092	
Aug-10	257,680	(142,490)	115,190	4.01%	3,446	-	50,075	15,026	29,374	93,057	15,649	6,985	1,045	
Sep-10	248,090	(68,780)	179,310	6.24%	4,675	-	70,916	21,440	43,553	124,478	17,895	10,625	1,247	
Oct-10	256,659	77,895	334,554	11.64%	8,352	-	132,887	40,967	81,369	218,050	32,622	20,397	2,120	
Nov-10	244,387	137,895	382,282	13.30%	9,963	-	160,993	48,978	96,754	247,164	36,640	24,503	2,314	
Dec-10	253,472	142,755	396,227	13.78%	11,857	-	190,336	58,680	106,950	294,930	41,404	27,087	2,812	
	2,873,922	450	2,874,372	100%	79,469	-	1,241,213	369,702	716,126	1,981,955	297,433	179,675	19,492	
SSECH Factor					1.63%	0.00%	25.41%	7.57%	14.66%	40.57%	6.09%	3.68%	0.40%	100.00%

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Pro Forma Factors

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF SEASONAL PURCHASE CONTRACTS

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	MONTANA	WYOMING	UTAH	IDAHO	WYOMING	FERC	TOTAL
Jan-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Feb-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Mar-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Apr-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
May-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jun-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jul-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Aug-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sep-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oct-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Nov-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Dec-10	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	-	0%	-	-	-	-	-	-	-	-	-	
SSCC Factor			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SSGC Factor			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF SEASONAL PURCHASE CONTRACTS

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	MONTANA	WYOMING	UTAH	IDAHO	WYOMING	FERC	TOTAL
Jan-10	-	0%	-	-	-	-	-	-	-	-	-	
Feb-10	-	0%	-	-	-	-	-	-	-	-	-	
Mar-10	-	0%	-	-	-	-	-	-	-	-	-	
Apr-10	-	0%	-	-	-	-	-	-	-	-	-	
May-10	-	0%	-	-	-	-	-	-	-	-	-	
Jun-10	-	0%	-	-	-	-	-	-	-	-	-	
Jul-10	-	0%	-	-	-	-	-	-	-	-	-	
Aug-10	-	0%	-	-	-	-	-	-	-	-	-	
Sep-10	-	0%	-	-	-	-	-	-	-	-	-	
Oct-10	-	0%	-	-	-	-	-	-	-	-	-	
Nov-10	-	0%	-	-	-	-	-	-	-	-	-	
Dec-10	-	0%	-	-	-	-	-	-	-	-	-	
	-	0%	-	-	-	-	-	-	-	-	-	
SSEC Factor			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE MID COLUMBIA CONTRACTS

Contract	CAL	ORE	WASH	MON	WYO	UTAH	IDAHO	WYO	FERC-UP&L	OTHER	TOTAL
Wells	4,512	67,869	20,091	-	32,690	104,056	14,404	7,943	954	-	252,519
Rocky Reach	5,762	86,676	25,659	-	41,749	132,890	18,396	10,144	1,218	-	322,494
Wanapum		(9,873)	(2,923)								(12,795)
Priority		-									-
Displacement		439,837									439,837
Surplus		88,890									88,890
0		-									-
Total	10,274	673,399	42,827	-	74,439	236,946	32,800	18,087	2,172	-	1,090,944
MC Factor	0.9417%	61.7263%	3.9257%	0.0000%	6.8233%	21.7194%	3.0065%	1.6579%	0.1991%	0.0000%	100.0000%

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13 MONTH AVERAGE FACTORS
CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
STEAM :												
STEAM PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0	0	0		
	DGU	0	0	0	0	0	0	0	0	0		
	SG	4,847,374,045	86,606,887	1,302,823,105	385,672,710	627,518,836	1,997,464,007	276,502,854	152,472,069	18,313,577		
	SSGCH	509,530,901	9,190,774	140,291,452	41,589,531	66,865,602	204,662,285	28,630,379	16,472,053	1,828,826		
		5,356,904,946	95,797,661	1,443,114,557	427,262,241	694,384,437	2,202,126,291	305,133,234	168,944,122	20,142,403		
LESS ACCUMULATED DEPRECIATION												
	DGP	(890,379,750)	(15,908,205)	(239,306,334)	(70,841,484)	(115,264,483)	(366,899,993)	(50,788,848)	(28,006,513)	(3,363,891)		
	DGU	(955,852,887)	(17,077,998)	(256,903,473)	(76,050,738)	(123,740,336)	(393,879,597)	(54,523,552)	(30,065,942)	(3,611,251)		
	SG	(625,561,165)	(11,176,754)	(168,131,349)	(49,771,663)	(80,982,282)	(257,775,839)	(35,683,124)	(19,676,758)	(2,363,396)		
	SSGCH	(164,118,231)	(2,960,318)	(45,187,416)	(13,395,851)	(21,537,191)	(65,921,050)	(9,221,751)	(5,305,594)	(589,059)		
		(2,635,912,032)	(47,123,274)	(709,528,572)	(210,059,737)	(341,524,292)	(1,084,476,479)	(150,217,275)	(83,054,807)	(9,927,597)		
TOTAL NET STEAM PLANT		2,720,992,914	48,674,387	733,585,985	217,202,504	352,860,146	1,117,649,812	154,915,959	85,889,315	10,214,806		
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.7888%	26.9602%	7.9825%	12.9681%	41.0751%	5.6934%	3.1565%	0.3754%		

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13 MONTH AVERAGE FACTORS
CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
NUCLEAR PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0	0	0		
	DGU	0	0	0	0	0	0	0	0	0		
	SG	0	0	0	0	0	0	0	0	0		
		0	0	0	0	0	0	0	0	0		
LESS ACCUMULATED DEPRECIATION												
	DGP	0	0	0	0	0	0	0	0	0		
	DGU	0	0	0	0	0	0	0	0	0		
	SG	0	0	0	0	0	0	0	0	0		
		0	0	0	0	0	0	0	0	0		
TOTAL NUCLEAR PLANT		0	0	0	0	0	0	0	0	0		
SNPPN												
SYSTEM NET PLANT PRODUCTION NUCLEAR		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		

HYDRO :		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC
HYDRO PRODUCTION PLANT										
	DGP	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0
	SG	645,856,753	11,539,370	173,586,171	51,386,446	83,609,656	266,139,070	36,840,820	20,315,147	2,440,073
		645,856,753	11,539,370	173,586,171	51,386,446	83,609,656	266,139,070	36,840,820	20,315,147	2,440,073
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)										
	DGP	(150,967,866)	(2,697,307)	(40,575,458)	(12,011,490)	(19,543,608)	(62,209,533)	(8,611,476)	(4,748,629)	(570,363)
	DGU	(29,520,221)	(527,431)	(7,934,116)	(2,348,724)	(3,821,553)	(12,164,438)	(1,683,886)	(928,546)	(111,529)
	SG	(70,488,589)	(1,259,403)	(18,945,136)	(5,608,299)	(9,125,130)	(29,046,329)	(4,020,795)	(2,217,188)	(266,309)
		(250,976,676)	(4,484,141)	(67,454,710)	(19,968,514)	(32,490,291)	(103,420,300)	(14,316,157)	(7,894,364)	(948,200)
TOTAL NET HYDRO PRODUCTION PLANT		394,880,077	7,055,229	106,131,461	31,417,932	51,119,366	162,718,770	22,524,663	12,420,783	1,491,873
SNPPH										
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.7867%	26.8769%	7.9563%	12.9455%	41.2071%	5.7042%	3.1455%	0.3778%

OTHER :		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)										
	DGP	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0
	SG	2,746,243,466	49,066,483	738,104,674	218,499,986	355,516,097	1,131,648,275	156,650,622	86,381,909	10,375,420
	SSGCT	80,562,299	1,362,123	20,222,729	6,128,436	9,583,953	36,159,782	4,541,434	2,192,087	371,755
		2,826,805,765	50,428,607	758,327,403	224,628,422	365,100,051	1,167,808,057	161,192,055	88,573,996	10,747,175
LESS ACCUMULATED DEPRECIATION										
	DGP	0	0	0	0	0	0	0	0	0
	DGU	(1,341,258)	(23,964)	(360,488)	(106,715)	(173,633)	(552,694)	(76,508)	(42,189)	(5,067)
	SG	(232,183,834)	(4,148,374)	(62,403,780)	(18,473,295)	(30,057,455)	(95,676,308)	(13,244,180)	(7,303,243)	(877,200)
	SSGCT	(21,911,899)	(370,480)	(5,500,320)	(1,666,855)	(2,606,711)	(9,834,991)	(1,235,211)	(596,219)	(101,113)
		(255,436,991)	(4,542,818)	(68,264,588)	(20,246,864)	(32,837,799)	(106,063,993)	(14,555,898)	(7,941,651)	(983,380)
TOTAL NET OTHER PRODUCTION PLANT		2,571,368,774	45,885,789	690,062,815	204,381,557	332,262,251	1,061,744,064	146,636,157	80,632,345	9,763,795
SNPPO										
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.7845%	26.8364%	7.9484%	12.9216%	41.2910%	5.7026%	3.1358%	0.3797%

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CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
TOTAL PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0	0	0		
	DGU	0	0	0	0	0	0	0	0	0		
	SG	8,239,474,265	147,212,740	2,214,513,950	655,559,142	1,066,644,590	3,395,251,351	469,994,296	259,169,124	31,129,071		
	SSGCH	509,530,901	9,190,774	140,291,452	41,589,531	66,865,602	204,662,285	28,630,379	16,472,053	1,828,826		
	SSGCT	80,562,299	1,362,123	20,222,729	6,128,436	9,583,953	36,159,782	4,541,434	2,192,087	371,755		
		8,829,567,465	157,765,637	2,375,028,130	703,277,109	1,143,094,144	3,636,073,418	503,166,109	277,833,265	33,329,652		
LESS ACCUMULATED DEPRECIATION												
	DGP	(344,575)	(6,156)	(92,611)	(27,416)	(44,607)	(141,990)	(19,655)	(10,838)	(1,302)		
	DGU	0	0	0	0	0	0	0	0	0		
	SG	(2,955,950,994)	(52,813,278)	(794,467,523)	(235,184,993)	(382,663,873)	(1,218,062,741)	(168,612,713)	(92,978,169)	(11,167,704)		
	SSGCH	(164,118,231)	(2,960,318)	(45,187,416)	(13,395,851)	(21,537,191)	(65,921,050)	(9,221,751)	(5,305,594)	(589,059)		
	SSGCT	(21,911,899)	(370,480)	(5,500,320)	(1,666,855)	(2,606,711)	(9,834,991)	(1,235,211)	(596,219)	(101,113)		
		(3,142,325,700)	(56,150,232)	(845,247,870)	(250,275,115)	(406,852,382)	(1,293,960,772)	(179,089,330)	(98,890,821)	(11,859,177)		
TOTAL NET PRODUCTION PLANT		5,687,241,765	101,615,405	1,529,780,260	453,001,994	736,241,762	2,342,112,646	324,076,779	178,942,444	21,470,475		
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.7867%	26.8985%	7.9652%	12.9455%	41.1819%	5.6983%	3.1464%	0.3775%		

TRANSMISSION :		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC
TRANSMISSION PLANT										
	DGP	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0
	SG	3,238,150,763	57,855,275	870,314,028	257,637,717	419,196,162	1,334,349,183	184,709,890	101,854,642	12,233,866
		3,238,150,763	57,855,275	870,314,028	257,637,717	419,196,162	1,334,349,183	184,709,890	101,854,642	12,233,866
LESS ACCUMULATED DEPRECIATION										
	DGP	(393,223,544)	(7,025,632)	(105,686,236)	(31,286,133)	(50,904,918)	(162,036,160)	(22,430,172)	(12,368,678)	(1,485,615)
	DGU	(394,382,155)	(7,046,333)	(105,997,635)	(31,378,316)	(51,054,907)	(162,513,590)	(22,496,261)	(12,405,121)	(1,489,992)
	SG	(400,388,744)	(7,153,651)	(107,612,019)	(31,856,220)	(51,832,492)	(164,988,733)	(22,838,888)	(12,594,056)	(1,512,685)
		(1,187,994,442)	(21,225,616)	(319,295,890)	(94,520,669)	(153,792,318)	(489,538,483)	(67,765,320)	(37,367,855)	(4,488,292)
TOTAL NET TRANSMISSION PLANT		2,050,156,321	36,629,659	551,018,139	163,117,048	265,403,845	844,810,700	116,944,570	64,486,787	7,745,574
SNPT										
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.7867%	26.8769%	7.9563%	12.9455%	41.2071%	5.7042%	3.1455%	0.3778%

DISTRIBUTION :		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC
DISTRIBUTION PLANT - PACIFIC POWER										
	S	2,769,936,569	219,186,336	1,690,271,132	392,966,425	467,512,676	0	0	0	0
LESS ACCUMULATED DEPRECIATION										
	S	(1,208,680,560)	(101,208,250)	(741,765,252)	(177,488,505)	(188,218,553)	0	0	0	0
		1,561,256,009	117,978,086	948,505,880	215,477,920	279,294,122	0	0	0	0
DNPDP										
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	7.5566%	60.7527%	13.8016%	17.8891%	0.0000%	0.0000%	0.0000%	0.0000%

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DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	2,649,113,440	0	0	0	0	2,305,168,422	267,466,465	76,478,552	0		
LESS ACCUMULATED DEPRECIATION												
	S	(870,402,644)	0	0	0	0	(719,082,700)	(114,028,731)	(37,291,213)	0		
		1,778,710,796	0	0	0	0	1,586,085,722	153,437,734	39,187,340	0		
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	89.1705%	8.6263%	2.2031%	0.0000%		
TOTAL NET DISTRIBUTION PLANT		3,339,966,804	117,978,086	948,505,880	215,477,920	279,294,122	1,586,085,722	153,437,734	39,187,340	0		
DNPD & SNPD												
SYSTEM NET PLANT DISTRIBUTION		100.0000%	3.5323%	28.3987%	6.4515%	8.3622%	47.4881%	4.5940%	1.1733%	0.0000%		
GENERAL :		**TOTAL**	**California**	**Oregon**	**Washington**	**Wyo-PPL**	**Utah**	**Idaho**	**Wyo-UPL**	**FERC**		
GENERAL PLANT												
	S	501,991,764	15,385,769	169,150,222	44,251,434	61,439,392	166,206,171	34,708,130	10,850,646	0		
	DGP	0	0	0	0	0	0	0	0	0		
	DGU	0	0	0	0	0	0	0	0	0		
	SE	781,793	12,808	195,463	57,515	113,367	320,895	50,186	28,310	3,249		
	SG	181,134,195	3,236,282	48,683,228	14,411,621	23,448,803	74,640,214	10,332,217	5,697,498	684,332		
	SO	257,492,301	6,353,865	72,763,772	19,984,343	30,082,554	106,644,429	14,251,916	6,747,134	664,287		
	CN	22,491,824	573,907	6,965,280	1,577,380	1,509,716	10,782,181	889,013	194,347	0		
	DEU	0	0	0	0	0	0	0	0	0		
	SSGCT	116,128	1,963	29,150	8,834	13,815	52,123	6,546	3,160	536		
	SSGCH	4,142,697	74,725	1,140,627	338,140	543,645	1,663,989	232,777	133,925	14,869		
	Remove Capital Lease	(32,584,118)	(540,138)	(12,864,111)	(1,988,896)	(4,501,903)	(10,458,275)	(1,422,125)	(728,492)	(80,178)		
		935,566,585	25,099,181	286,063,632	78,640,371	112,649,389	349,851,727	59,048,661	22,926,528	1,287,095		
LESS ACCUMULATED DEPRECIATION												
	S	(183,162,204)	(5,422,641)	(61,483,655)	(18,327,896)	(24,495,954)	(56,006,681)	(13,304,185)	(4,121,191)	0		
	DGP	(7,296,953)	(130,373)	(1,961,193)	(580,569)	(944,630)	(3,006,865)	(416,231)	(229,523)	(27,568)		
	DGU	(13,863,584)	(247,697)	(3,726,099)	(1,103,031)	(1,794,716)	(5,712,786)	(790,804)	(436,073)	(52,377)		
	SE	(262,896)	(4,307)	(65,729)	(19,341)	(38,122)	(107,909)	(16,876)	(9,520)	(1,093)		
	SG	(45,793,578)	(818,183)	(12,307,887)	(3,643,485)	(5,928,227)	(18,870,222)	(2,612,147)	(1,440,417)	(173,010)		
	SO	(89,127,612)	(2,199,308)	(25,186,234)	(6,917,321)	(10,412,685)	(36,913,583)	(4,933,116)	(2,335,433)	(229,934)		
	CN	(8,377,535)	(213,763)	(2,594,360)	(587,527)	(562,324)	(4,016,041)	(331,131)	(72,388)	0		
	SSGCT	(33,832)	(572)	(8,492)	(2,574)	(4,025)	(15,185)	(1,907)	(921)	(156)		
	SSGCH	(2,363,052)	(42,624)	(650,630)	(192,880)	(310,103)	(949,162)	(132,779)	(76,392)	(8,482)		
		(350,281,245)	(9,079,469)	(107,984,280)	(31,374,624)	(44,490,786)	(125,598,434)	(22,539,176)	(8,721,858)	(492,620)		
TOTAL NET GENERAL PLANT		585,285,340	16,019,712	178,079,352	47,265,748	68,158,604	224,253,293	36,509,485	14,204,670	794,475		
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	2.7371%	30.4261%	8.0757%	11.6454%	38.3152%	6.2379%	2.4270%	0.1357%		

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DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
MINING :												
GENERAL MINING PLANT	SE	469,345,489	7,689,205	117,345,284	34,528,630	68,059,265	192,647,674	30,128,934	16,995,951	1,950,547		
LESS ACCUMULATED DEPRECIATION	SE	(168,106,499)	(2,754,059)	(42,029,817)	(12,367,195)	(24,376,936)	(69,001,039)	(10,791,346)	(6,087,477)	(698,632)		
		301,238,989	4,935,145	75,315,467	22,161,435	43,682,329	123,646,636	19,337,588	10,908,474	1,251,915		
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.6383%	25.0019%	7.3568%	14.5009%	41.0460%	6.4194%	3.6212%	0.4156%		

INTANGIBLE :		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC
INTANGIBLE PLANT										
	S	4,507,682	0	540,701	1,244	246,093	885,391	2,834,252	0	0
	DGP	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0
	SE	3,628,256	59,441	907,133	266,922	526,129	1,489,255	232,911	131,387	15,079
	CN	116,718,484	2,978,216	36,145,444	8,185,616	7,834,479	55,952,768	4,613,421	1,008,539	0
	SG	203,015,418	3,627,229	54,564,219	16,152,561	26,281,446	83,656,839	11,580,361	6,385,763	767,001
	SO	396,534,278	9,784,857	112,055,116	30,775,589	46,326,682	164,230,819	21,947,737	10,390,486	1,022,992
	SSGCT	0	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0	0
		724,404,119	16,449,743	204,212,613	55,381,933	81,214,829	306,215,073	41,208,683	17,916,174	1,805,072
LESS ACCUMULATED AMORTIZATION										
	S	(1,434,385)	0	(580,763)	(365)	(41,965)	(8,778)	(802,515)	0	0
	DGP	112,088	2,003	30,126	8,918	14,510	46,188	6,394	3,526	423
	DGU	(313,621)	(5,603)	(84,292)	(24,953)	(40,600)	(129,234)	(17,890)	(9,865)	(1,185)
	SE	(1,462,456)	(23,959)	(365,642)	(107,589)	(212,069)	(600,280)	(93,880)	(52,958)	(6,078)
	CN	(93,562,892)	(2,387,373)	(28,974,607)	(6,561,685)	(6,280,209)	(44,852,389)	(3,698,172)	(808,456)	0
	SG	(62,855,561)	(1,123,025)	(16,893,616)	(5,000,991)	(8,136,993)	(25,900,977)	(3,585,393)	(1,977,095)	(237,471)
	SO	(279,823,441)	(6,904,907)	(79,074,244)	(21,717,495)	(32,691,478)	(115,893,217)	(15,487,920)	(7,332,283)	(721,898)
	SSGCT	0	0	0	0	0	0	0	0	0
	SSGCH	(26,279)	(474)	(7,235)	(2,145)	(3,449)	(10,555)	(1,477)	(850)	(94)
		(439,366,547)	(10,443,339)	(125,950,273)	(33,406,305)	(47,392,252)	(187,349,241)	(23,680,853)	(10,177,981)	(966,302)
TOTAL NET INTANGIBLE PLANT		285,037,572	6,006,404	78,262,339	21,975,628	33,822,577	118,865,832	17,527,830	7,738,193	838,769
SNPI										
SYSTEM NET INTANGIBLE PLANT		100.0000%	2.1072%	27.4569%	7.7097%	11.8660%	41.7018%	6.1493%	2.7148%	0.2943%

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DESCRIPTION OF FACTOR	TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
GROSS PLANT :											
PRODUCTION PLANT	8,829,567,465	157,765,637	2,375,028,130	703,277,109	1,143,094,144	3,636,073,418	503,166,109	277,833,265	33,329,652		
TRANSMISSION PLANT	3,238,150,763	57,855,275	870,314,028	257,637,717	419,196,162	1,334,349,183	184,709,890	101,854,642	12,233,866		
DISTRIBUTION PLANT	5,419,050,009	219,186,336	1,690,271,132	392,966,425	467,512,676	2,305,168,422	267,466,465	76,478,552	0		
GENERAL PLANT	1,404,912,074	32,788,386	403,408,915	113,169,001	180,708,655	542,499,401	89,177,595	39,922,479	3,237,642		
INTANGIBLE PLANT	724,404,119	16,449,743	204,212,613	55,381,933	81,214,829	306,215,073	41,208,683	17,916,174	1,805,072		
TOTAL GROSS PLANT	19,616,084,429	484,045,377	5,543,234,819	1,522,432,185	2,291,726,466	8,124,305,498	1,085,728,743	514,005,111	50,606,232		
GPS											
GROSS PLANT-SYSTEM FACTOR	100.0000%	2.4676%	28.2586%	7.7611%	11.6829%	41.4166%	5.5349%	2.6203%	0.2580%		
ACCUMULATED DEPRECIATION AND AMORTIZATION											
PRODUCTION PLANT	(3,142,325,700)	(56,150,232)	(845,247,870)	(250,275,115)	(406,852,382)	(1,293,960,772)	(179,089,330)	(98,890,821)	(11,859,177)		
TRANSMISSION PLANT	(1,187,994,442)	(21,225,616)	(319,295,890)	(94,520,669)	(153,792,318)	(489,538,483)	(67,765,320)	(37,367,855)	(4,488,292)		
DISTRIBUTION PLANT	(2,079,083,205)	(101,208,250)	(741,765,252)	(177,488,505)	(188,218,553)	(719,082,700)	(114,028,731)	(37,291,213)	0		
GENERAL PLANT	(518,387,745)	(11,833,528)	(150,014,096)	(43,741,818)	(68,867,722)	(194,599,472)	(33,330,522)	(14,809,335)	(1,191,252)		
INTANGIBLE PLANT	(439,366,547)	(10,443,339)	(125,950,273)	(33,406,305)	(47,392,252)	(187,349,241)	(23,680,853)	(10,177,981)	(966,302)		
	(7,367,157,638)	(200,860,966)	(2,182,273,381)	(599,432,412)	(865,123,227)	(2,884,530,669)	(417,894,756)	(198,537,205)	(18,505,022)		
NET PLANT	12,248,926,791	283,184,411	3,360,961,438	922,999,773	1,426,603,239	5,239,774,829	667,833,986	315,467,907	32,101,209		
SNP											
SYSTEM NET PLANT FACTOR (SNP)	100.0000%	2.3119%	27.4388%	7.5354%	11.6468%	42.7774%	5.4522%	2.5755%	0.2621%		
NON-UTILITY RELATED INTEREST PERCENTAGE	0.0000%										
INT											
INTEREST FACTOR SNP - NON-UTILITY	100.0000%	2.3119%	27.4388%	7.5354%	11.6468%	42.7774%	5.4522%	2.5755%	0.2621%		
TOTAL GROSS PLANT (LESS SO FACTOR)	18,962,057,850	467,906,654	5,358,415,931	1,471,672,252	2,215,317,231	7,853,430,249	1,049,529,089	496,867,491	48,918,952		
SO											
SYSTEM OVERHEAD FACTOR (SO)	100.0000%	2.4676%	28.2586%	7.7611%	11.6829%	41.4166%	5.5349%	2.6203%	0.2580%		

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DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
IBT												
INCOME BEFORE TAXES												
INCOME BEFORE STATE TAXES		380,286,705	12,727,950	111,961,065	26,525,181	70,747,236	147,385,279	14,536,754	(34,314,302)	(3,038,716)	22,453,593	11,302,664
Interest Synchronization		(1,849,196)	0	0	0	0	0	(0)	(0)	0	(1,853,540)	4,344
		378,437,509	12,727,950	111,961,065	26,525,181	70,747,236	147,385,279	14,536,754	(34,314,302)	(3,038,716)	20,600,053	11,307,008
INCOME BEFORE TAXES (FACTOR)		100.0000%	3.3633%	29.585%	7.0091%	18.6946%	38.9457%	3.8413%	-9.0674%	-0.8030%	5.4434%	2.9878%
See Calculation of EXCTAX												
DITEXP:												
Pacific Power												
Production	S	(1,696,428)	(73,668)	(845,648)	(278,891)	(399,936)	(98,285)	0	0	0		0
Transmission	S	(780,928)	(29,108)	(424,537)	(110,704)	(184,633)	(31,946)	0	0	0		0
Distribution	S	(4,656,833)	(287,208)	(3,014,435)	(457,203)	(897,987)	0	0	0	0		0
General	S	54,412	(4)	35,403	(9)	12,678	6,170	0	156	18		0
Mining Plant	S	0	0	0	0	0	0	0	0	0		0
Non-Utility	NUTIL	3,332,055	0	0	0	0	0	0	0	0		3,332,055
Total Pacific Power		(3,747,722)	(389,988)	(4,249,217)	(846,807)	(1,469,878)	(124,061)	0	156	18	0	3,332,055
Rocky Mountain Power												
Production	S	(4,807,347)	0	0	0	0	(3,566,573)	(892,453)	(307,664)	(40,657)		0
Transmission	S	(2,237,946)	0	0	0	0	(1,846,274)	(280,880)	(97,630)	(13,162)		0
Distribution	S	(6,096,603)	15	134	31	30	(4,998,136)	(796,571)	(302,106)	0		0
General	S	(161,009)	(1,346)	(7,264)	(4,418)	(3,017)	(156,771)	6,771	4,942	94		0
Mining Plant	S	0	0	0	0	0	0	0	0	0		0
Non-Utility	NUTIL	0										
Total Rocky Mountain Power		(13,302,905)	(1,331)	(7,130)	(4,387)	(2,987)	(10,567,754)	(1,963,133)	(702,458)	(53,725)	0	0
PC (Post Merger)												
Prod / Other Prod	S	28,253,257	493,894	7,499,779	2,323,892	3,651,901	11,597,530	1,662,597	917,315	106,349	0	0
Cholla Unit 4	S	3,193,349	55,296	886,611	0	422,678	1,269,559	180,851	103,994	11,569		262,791
Gadsby Unit 4, 5 & 6	S	40,105	954	13,308	0	6,556	12,847	657	1,542	227		4,014
Hydro-PPL	S	368,042	4,838	65,610	32,685	52,588	160,455	30,772	18,954	2,140		0
Hydro-UPL	S	265,422	4,411	71,221	20,969	34,786	109,190	15,238	8,583	1,024		0
Transmission	S	19,682,844	315,250	5,909,595	1,425,516	2,765,037	7,654,367	912,822	621,162	79,095		0
Distribution	S	9,580,699	961,429	3,655,281	736,013	931,993	3,001,739	134,862	159,382	0		0
General/ Intangibles	S	(4,920,681)	(128,683)	(1,816,388)	(416,836)	(474,791)	(1,785,447)	(220,153)	(79,014)	3,529		(2,898)
Mining	S	(2,150,931)	(34,826)	(661,848)	(148,746)	(316,907)	(826,503)	(105,247)	(49,770)	(7,084)		0
WCA - CAEE 2007+	S	959,588	17,132	228,379	0	133,431	408,454	67,130	34,076	3,840		67,146
WCA - CAGE 2007+	S	22,283,384	406,378	6,275,007	0	3,012,982	8,734,988	1,188,074	721,664	88,237		1,856,054
WCA - CAGW 2007+	S	70,277,164	1,189,505	18,992,954	15,640,599	9,141,716	28,709,306	4,048,314	2,214,164	266,984		(9,926,378)
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0	0	0		0
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0		0
WCA - General 2007+	S	4,508,669	100,611	1,324,907	402,981	551,281	1,813,898	225,355	126,447	12,624		(49,435)
WCA - JBG 2007+	S	2,523,649	49,436	749,949	486,295	360,928	1,013,301	131,813	87,377	10,543		(365,993)
Non Utility	NUTIL	34,493	0	0	0	0	0	0	0	0		34,493
Total PC (Post Merger)		154,899,053	3,435,625	43,194,365	20,503,368	20,274,179	61,873,684	8,273,085	4,885,876	579,077	0	(8,120,206)
Total Deferred Taxes		137,848,426	3,044,306	38,938,018	19,652,174	18,801,314	51,181,869	6,309,952	4,183,574	525,370	0	(4,788,151)
Percentage of Total (DITEXP)		100.0000%	2.2084%	28.2470%	14.2564%	13.6391%	37.1291%	4.5775%	3.0349%	0.3811%	0.0000%	-3.4735%

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DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
DITBAL :												
Pacific Power												
Production	S	50,913,333	1,807,410	27,825,329	7,015,227	12,142,322	2,123,045	0	0	0		0
Transmission	S	22,470,544	837,230	12,354,765	3,224,211	5,115,760	938,578	0	0	0		0
Distribution	S	40,113,266	3,458,818	23,920,470	5,506,626	7,227,352	0	0	0	0		0
General	S	(565,405)	16	(367,488)	36	(132,486)	(63,692)	(3)	(1,595)	(193)		0
Mining Plant	S	0	0	0	0	0	0	0	0	0		0
Non-Utility Plant	NUTIL	(1,068,812)	0	0	0	0	0	0	0	0		(1,068,812)
Total Pacific Power		111,862,926	6,103,474	63,733,076	15,746,100	24,352,948	2,997,931	(3)	(1,595)	(193)	0	(1,068,812)
Rocky Mountain Power												
Production	S	85,466,215	0	0	0	0	67,169,400	13,195,478	4,509,531	591,806		0
Transmission	S	51,367,211	0	0	0	0	42,995,725	6,035,517	2,057,479	278,490		0
Distribution	S	44,330,856	0	0	0	0	36,097,833	6,016,746	2,216,277	0		0
General	S	(914,548)	(968)	(94,916)	(3,664)	(35,956)	(185,256)	(414,367)	(172,871)	(6,550)		0
Mining Plant	S	0	0	0	0	0	0	0	0	0		0
Non-Utility Plant	NUTIL	0										
Total Rocky Mountain Power		180,249,734	(968)	(94,916)	(3,664)	(35,956)	146,077,702	24,833,374	8,610,416	863,746	0	0
Pacificorp												
Prod / Other Prod	S	407,522,109	7,743,193	121,260,834	32,735,895	52,032,220	161,369,589	22,159,310	8,776,645	1,444,423	0	0
Cholla Unit 4	S	(25,902,812)	(616,887)	(8,626,550)	(2,990,632)	(3,014,425)	(9,408,353)	(1,320,919)	(317,180)	(60,415)		452,549
Gadsby Unit 4, 5 & 6	S	534,003	10,017	138,273	0	68,373	228,233	28,711	16,329	2,359		41,708
Hydro-PPL	S	36,201,206	696,470	11,529,172	2,833,569	4,486,110	14,164,352	1,719,693	665,984	105,856		0
Hydro-UPL	S	9,066,566	207,064	2,890,163	817,357	1,088,761	3,430,471	447,247	161,814	23,689		0
Transmission	S	279,409,323	5,614,119	83,353,451	21,652,812	34,788,533	112,018,132	14,955,119	6,126,976	900,181		0
Distribution	S	430,443,716	19,270,578	129,143,801	25,949,042	31,631,404	197,185,681	21,958,784	5,304,426	0		0
General/ Intangibles	S	123,818,586	2,998,852	39,462,102	10,862,032	14,716,638	46,228,300	6,842,537	2,492,255	203,250		12,620
Mining	S	10,080,759	123,181	3,419,491	561,224	1,675,256	3,611,572	416,367	233,706	39,962		0
WCA - CAEE 2007+	S	9,879,252	135,093	2,700,623	0	1,540,580	3,770,304	528,109	364,710	43,723		796,110
WCA - CAGE 2007+	S	108,053,033	2,022,402	29,580,596	0	14,169,783	44,172,009	5,594,487	3,356,731	412,929		8,744,096
WCA - CAGW 2007+	S	350,143,693	6,259,882	97,510,882	74,022,191	46,722,867	144,384,074	19,381,907	11,082,720	1,367,032		(50,587,862)
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0	0	0		0
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0		0
WCA - General 2007+	S	50,290,524	1,105,143	15,738,686	3,386,074	6,460,236	20,004,181	2,484,220	1,407,673	135,809		(431,498)
WCA - JBG 2007+	S	10,900,799	212,979	3,083,226	2,120,938	1,478,943	4,532,836	572,837	352,584	43,139		(1,496,683)
Non Utility	NUTIL	(497,177)	0	0	0	0	0	0	0	0		(497,177)
Total PC (Post Merger)		1,799,943,580	45,782,086	531,184,750	171,950,502	207,845,279	745,691,381	95,768,409	40,025,373	4,661,937	0	(42,966,137)
Total Deferred Taxes		2,092,056,240	51,884,592	594,822,910	187,692,938	232,162,271	894,767,014	120,601,780	48,634,194	5,525,490	0	(44,034,949)
Percentage of Total (DITBAL)		100.0000%	2.4801%	28.4325%	8.9717%	11.0973%	42.7697%	5.7647%	2.3247%	0.2641%	0.0000%	-2.1049%

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DESCRIPTION OF FACTOR	TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
BADDEBT											
Account 904 Balance	12,407,643	(18,969)	5,043,849	1,737,487	708,409	4,537,593	399,239	34	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100.0000%	-0.1529%	40.6511%	14.0034%	5.7095%	36.5710%	3.2177%	0.0003%	0.0000%	0.0000%	0.0000%
Customer Factors											
Total Electric Customers	1,874,359	47,827	580,452	131,451	125,812	898,534	74,086	16,196	0	0	0
CN											
Customer System factor - CN		2.5516%	30.9681%	7.0131%	6.7123%	47.9382%	3.9526%	0.8641%	0.0000%	0.0000%	0.0000%
Pacific Power Customers	885,542	47,827	580,452	131,451	125,812	0	0	0	0	0	0
CNP											
Customer Service Pacific Power factor - CNP		5.40%	65.55%	14.84%	14.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rocky Mountain Power Customers	988,816	0	0	0	0	898,534	74,086	16,196	0	0	0
CNU											
Customer Service R.M.P. factor - CNU		0.00%	0.00%	0.00%	0.00%	90.87%	7.49%	1.64%	0.00%	0.00%	0.00%
CIAC											
TOTAL NET DISTRIBUTION PLANT	3,339,966,804	117,978,086	948,505,880	215,477,920	279,294,122	1,586,085,722	153,437,734	39,187,340	0	0	0
CIAC FACTOR: Same as (SNPD Factor)	100%	3.53%	28.40%	6.45%	8.36%	47.49%	4.59%	1.17%	0.00%	0.00%	0.00%

PacifiCorp
Oregon General Rate Case December 2010 - Reply
13 MONTH AVERAGE FACTORS
CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
EXCTAX												
Excise Tax (Superfund)												
Total Taxable Income		363,988,011	12,170,379	107,122,937	25,388,431	67,665,994	141,051,114	13,921,785	(32,763,633)	(2,900,804)	21,533,931	10,797,878
Less Other Electric Items:												
419	OTH	0	0	0	0	0	0	0	0	0	0	0
432	OTH	0	0	0	0	0	0	0	0	0	0	0
40910	OTH	0	0	0	0	0	0	0	0	0	0	0
SCHMDT	OTH	0	0	0	0	0	0	0	0	0	0	0
SCHMDT (Steam)	OTH											
Total Taxable Income Excluding Other		363,988,011	12,170,379	107,122,937	25,388,431	67,665,994	141,051,114	13,921,785	(32,763,633)	(2,900,804)	21,533,931	10,797,878
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	3.3436%	29.430%	6.9751%	18.5902%	38.7516%	3.8248%	-9.0013%	-0.7970%	5.9161%	2.9665%
Trojan Allocators												
Premerger												
Dec 1991 Plant		16,918,976										
Dec 1992 Plant		17,094,202										
Average	SG	17,006,589	303,853	4,570,841	1,353,099	2,201,595	7,007,928	970,086	534,935	64,252	0	0
Dec 1991 Reserve		(7,851,432)										
Dec 1992 Reserve		(8,434,030)										
Average	SG	(8,142,731)	(145,484)	(2,188,512)	(647,862)	(1,054,121)	(3,355,386)	(464,476)	(256,126)	(30,764)	0	0
Postmerger												
Dec 1991 Plant		4,284,960										
Dec 1992 Plant		3,485,613										
Average	SG	3,885,287	69,418	1,044,244	309,126	502,971	1,601,015	221,624	122,210	14,679	0	0
Dec 1991 Reserve		(129,394)										
Dec 1992 Reserve		(240,609)										
Average	SG	(185,002)	(3,305)	(49,723)	(14,719)	(23,950)	(76,234)	(10,553)	(5,819)	(699)	0	0
Net Plant		12,564,143	224,481	3,376,850	999,644	1,626,496	5,177,323	716,681	395,200	47,468	0	0
Division Net Plant Nuclear Pacific Power	**DNPPNP**	100.0000%	1.7867%	26.8769%	7.9563%	12.9455%	41.2071%	5.7042%	3.1455%	0.3778%	0.0000%	0.0000%
Division Net Plant Nuclear Rocky Mounta	**DNPPNP**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
System Net Nuclear Plant	**SNNP**	100.0000%	1.7867%	26.8769%	7.9563%	12.9455%	41.2071%	5.7042%	3.1455%	0.3778%	0.0000%	0.0000%

PacifiCorp
Oregon General Rate Case December 2010 - Reply
13 MONTH AVERAGE FACTORS
CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR			TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
Account 182.22													
Pre-merger	(101)	SG	17,094,202	305,418	4,594,389	1,360,070	2,212,937	7,044,031	975,084	537,691	64,583	0	0
	(108)	SG	(8,434,030)	(150,689)	(2,266,804)	(671,039)	(1,091,831)	(3,475,422)	(481,092)	(265,289)	(31,864)	0	0
Post-merger	(101)	SG	3,485,613	62,277	936,824	277,327	451,231	1,436,321	198,826	109,638	13,169	0	0
	(108)	SG	(240,609)	(4,299)	(64,668)	(19,144)	(31,148)	(99,148)	(13,725)	(7,568)	(909)	0	0
	(107)	SG	1,778,549	31,777	478,019	141,507	230,243	732,889	101,452	55,943	6,719	0	0
	(120)	SE	1,975,759	32,369	493,977	145,352	286,503	810,971	126,831	71,546	8,211	0	0
	(228)	SG	7,220,849	129,013	1,940,739	574,514	934,778	2,975,505	411,890	227,129	27,281	27,281	0
	(228)	SG	1,472,376	26,307	395,729	117,147	190,607	606,724	83,987	46,313	5,563	0	0
	(228)	SNNP	3,531,000	63,088	949,023	280,938	457,107	1,455,024	201,415	111,066	13,340	0	0
	(228)	SE	1,743,025	28,556	435,789	128,230	252,754	715,443	111,891	63,118	7,244	0	0
Total Acct 182.22			29,626,734	523,815	7,893,016	2,334,902	3,893,181	12,202,337	1,716,557	949,588	113,336	27,281	0
Revised Study	(228)	SNNP	112,680	2,013	30,285	8,965	14,587	46,432	6,427	3,544	426	0	0
	(228)	SE	941,950	15,432	235,505	69,297	136,591	386,633	60,467	34,110	3,915	0	0
December 1993 Adj.			1,054,630	17,445	265,790	78,262	151,178	433,065	66,895	37,654	4,340	0	0
Adjusted Acct 182.22			30,681,364	541,260	8,158,807	2,413,164	4,044,359	12,635,402	1,783,452	987,242	117,676	27,281	0
TROJP			100%	1.7641%	26.5921%	7.8652%	13.1818%	41.1827%	5.8128%	3.2177%	0.3835%	0.0889%	0.0000%
Trojan Plant Allocator													
Account 228.42													
Plant - Premerger		SG	7,220,849	129,013	1,940,739	574,514	934,778	2,975,505	411,890	227,129	27,281	27,281	0
- Postmerger		SG	1,472,376	26,307	395,729	117,147	190,607	606,724	83,987	46,313	5,563	0	0
Storage Facility		SE	1,743,025	28,556	435,789	128,230	252,754	715,443	111,891	63,118	7,244	0	0
Transition Costs		SNNP	3,531,000	63,088	949,023	280,938	457,107	1,455,024	201,415	111,066	13,340	0	0
Total Acct 228.42			13,967,250	246,963	3,721,280	1,100,829	1,835,246	5,752,696	809,182	447,626	53,427	27,281	0
Transition Costs		SNNP	112,680	2,013	30,285	8,965	14,587	46,432	6,427	3,544	426	0	0
Storage Facility		SE	941,950	15,432	235,505	69,297	136,591	386,633	60,467	34,110	3,915	0	0
December 1993 Adj.			1,054,630	17,445	265,790	78,262	151,178	433,065	66,895	37,654	4,340	0	0
Adjusted Acct 228.42			15,021,880	264,408	3,987,070	1,179,091	1,986,424	6,185,761	876,077	485,280	57,768	27,281	0
TROJD			100.0000%	1.7602%	26.5418%	7.8492%	13.2235%	41.1783%	5.8320%	3.2305%	0.3846%	0.1816%	0.0000%
Trojan Decommissioning Allocator													

PacifiCorp
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13 MONTH AVERAGE FACTORS
CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Wyo-PPL	Utah	Idaho	Wyo-UPL	FERC	Other	Non-Utility
SCHMA												
Amortization Expense :												
Amortization of Limited Term Plant	Acct 404	49,842,458	1,146,963	14,446,605	3,824,757	5,849,019	20,534,904	2,673,100	1,241,373	125,737	0	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	5,479,353	97,898	1,472,679	435,955	709,332	2,257,884	312,552	172,351	20,701	0	0
Amort of Prop. Losses, Unrecovered Plant,	Acct 407	11,586,229	41,476	557,066	(90,878)	308,568	966,569	136,055	75,274	8,982	9,583,118	0
Total Amortization Expense :		66,908,040	1,286,338	16,476,351	4,169,834	6,866,918	23,759,357	3,121,707	1,488,998	155,420	9,583,118	0
Schedule M Amortization Factor		100.0000%	1.9225%	24.6254%	6.2322%	10.2632%	35.5105%	4.6657%	2.2254%	0.2323%	14.3228%	0.0000%
SCHMD												
Depreciation Expense :												
Steam	Acct 403.1	150,926,284	2,698,581	40,641,722	12,032,478	19,559,153	62,069,696	8,599,054	4,757,622	567,979	0	0
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0	0
Hydro	Acct 403.3	17,199,881	307,306	4,622,792	1,368,478	2,226,618	7,087,578	981,112	541,015	64,982	0	0
Other	Acct 403.4	97,152,932	1,733,242	26,064,184	7,720,455	12,548,896	40,132,340	5,539,983	3,044,545	369,286	0	0
Transmission	Acct 403.5	64,865,739	1,158,941	17,433,889	5,160,927	8,397,221	26,729,313	3,700,057	2,040,324	245,065	0	0
Distribution	Acct 403.6	149,160,279	8,299,873	48,396,637	12,282,939	13,176,555	57,800,156	6,867,635	2,336,485	0	0	0
General	Acct 403.7&8	35,864,594	865,710	10,686,011	3,223,167	4,658,940	13,342,782	2,110,080	916,058	61,846	0	0
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0	0
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0	0
Postmerger Hydro Step I Adjustment		0	0	0	0	0	0	0	0	0	0	0
Total Depreciation Expense :		515,169,709	15,063,653	147,845,235	41,788,444	60,567,383	207,161,865	27,797,922	13,636,048	1,309,159	0	0
Schedule M Depreciation Factor		100.0000%	2.9240%	28.6984%	8.1116%	11.7568%	40.2124%	5.3959%	2.6469%	0.2541%	0.0000%	0.0000%
Total Tax depreciation		322,537,005	5,481,373	84,878,899	45,950,638	41,373,710	127,728,826	17,600,149	9,670,494	1,155,722	-	(11,302,806)
Tax Depr factor		100.0000%	1.6995%	26.316%	14.2466%	12.8276%	39.6013%	5.4568%	2.9983%	0.3583%	0.0000%	-3.5043%

PacifiCorp
Normalized Results of Operations
Tab 12 Adjustment Summary
Twelve Months Ending Dec 31, 2010

	Total Adjustments	12.1 Allocation Factors	12.2 Cost of Capital and Capital Structure	12.3 Rate Base	12.4 Insurance Low Claims Bonus	12.5 Workers Compensation Expense	12.6 FAS 112 (Post-Employment Benefits)	12.7 401(k) Expense
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	(15,270,140)	-	-	-	-	-	-	-
5 Other Operating Revenues	55	55	-	-	-	-	-	-
6 Total Operating Revenues	(15,270,085)	55	-	-	-	-	-	-
7								
8 Operating Expenses:								
9 Steam Production	(1,390,787)	5,606	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-	-
12 Other Power Supply	(13,572,680)	(66,469)	8,273	11,298	-	-	-	-
13 Transmission	1,295,810	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	(7,381,167)	3,394	-	-	(122,925)	(366,510)	(226,221)	(1,865,575)
19								
20 Total O&M Expenses	(21,048,823)	(57,469)	8,273	11,298	(122,925)	(366,510)	(226,221)	(1,865,575)
21								
22 Depreciation	(200,868)	252	-	(33,815)	-	-	-	-
23 Amortization	614	614	-	-	-	-	-	-
24 Taxes Other Than Income	2,156	2,156	-	-	-	-	-	-
25 Income Taxes - Federal	2,788,958	46,591	(24,657)	15,691	40,958	122,118	75,375	621,595
26 Income Taxes - State	368,025	(78,355)	(3,487)	2,897	5,934	17,693	10,921	90,059
27 Income Taxes - Def Net	(677,674)	(1,888)	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	4	4	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(18,767,607)	(88,095)	(19,871)	(3,928)	(76,033)	(226,699)	(139,925)	(1,153,920)
32								
33 Operating Rev For Return:	3,497,522	88,150	19,871	3,928	76,033	226,699	139,925	1,153,920
34								
35 Rate Base:								
36 Electric Plant In Service	(7,207,665)	32,919	-	(933,488)	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	(12,688,806)	422	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	569	569	-	-	-	-	-	-
42 Fuel Stock	349	349	-	-	-	-	-	-
43 Material & Supplies	1,365	1,365	-	-	-	-	-	-
44 Working Capital	(282,703)	(746)	(396)	262	(1,071)	(3,192)	(1,970)	(16,250)
45 Weatherization Loans	(0)	(0)	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(20,176,890)	34,878	(396)	(933,226)	(1,071)	(3,192)	(1,970)	(16,250)
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	255,594	(10,742)	-	64,614	-	-	-	-
52 Accum Prov For Amort	(5,999)	(5,999)	-	-	-	-	-	-
53 Accum Def Income Tax	(2,256,282)	(1,692)	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	(630)	(630)	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	(2,007,316)	(19,063)	-	64,614	-	-	-	-
60								
61 Total Rate Base:	(22,184,206)	15,815	(396)	(868,612)	(1,071)	(3,192)	(1,970)	(16,250)
62								
63 Return on Rate Base	0.166%	0.003%	0.001%	0.002%	0.003%	0.008%	0.005%	0.039%
64								
65 Return on Equity	0.347%	0.006%	0.023%	0.004%	0.005%	0.015%	0.009%	0.077%
66								
67 TAX CALCULATION:								
68 Operating Revenue	5,976,831	54,497	(8,273)	22,516	122,925	366,510	226,221	1,865,575
69 Other Deductions								
70 Interest (AFUDC)		-	-	-	-	-	-	-
71 Interest	(578,227)	459	65,663	(25,212)	(31)	(93)	(57)	(472)
72 Schedule "M" Additions	1,705	1,705	-	-	-	-	-	-
73 Schedule "M" Deductions	(1,779,715)	982	-	-	-	-	-	-
74 Income Before Tax	8,336,477	54,761	(73,936)	47,728	122,956	366,603	226,278	1,866,046
75								
76 State Income Taxes	368,025	(78,355)	(3,487)	2,897	5,934	17,693	10,921	90,059
77 Taxable Income	7,968,452	133,116	(70,449)	44,830	117,022	348,910	215,358	1,775,987
78								
79 Federal Income Taxes + Other	2,788,958	46,591	(24,657)	15,691	40,958	122,118	75,375	621,595
APPROXIMATE REVISED PROTOCOL PRICE CHANGE	(9,910,923)	(143,981)	(1,003,683)	(129,404)	(126,276)	(376,502)	(232,389)	(1,916,436)
Approximate Price Change Due to:								
Net Power Costs/TAM	(602,513)	(46,254)						
Embedded Cost Differential	2,203,205	(16,400)	8,273	11,298				
General Rate Case	(11,511,615)	(81,326)	(1,011,956)	(140,702)	(126,276)	(376,502)	(232,389)	(1,916,436)

PacifiCorp
Normalized Results of Operations
Tab 12 Adjustment Summary
Twelve Months Ending Dec 31, 2010

	12.8	12.9	12.10	12.11	12.12	12.13	12.14	12.15
	Challenge Grants	Transition Plan - Oregon Regulatory Asset	MEHC CIC Severance Regulatory Asset	Grid West Regulatory Asset	Wind Interconnection Rate Base	Other Wind Plant Additions	August 2009 - Net Power Cost Update	Embedded Cost Differential
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	(15,270,140)	-
5 Other Operating Revenues	-	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	(15,270,140)	-
7								
8 Operating Expenses:								
9 Steam Production	-	-	-	-	-	-	(1,396,393)	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	24,167	(14,782,211)	1,232,262
13 Transmission	-	-	-	-	-	-	1,295,810	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	(58,280)	(2,274,947)	(2,125,400)	(344,703)	-	-	-	-
19								
20 Total O&M Expenses	(58,280)	(2,274,947)	(2,125,400)	(344,703)	-	24,167	(14,882,793)	1,232,262
21								
22 Depreciation	-	-	-	-	(91,032)	(76,273)	-	-
23 Amortization	-	-	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	19,418	873,288	1,465,648	5,374	71,660	34,519	(154,153)	(424,467)
26 Income Taxes - State	2,813	49,690	212,345	306	10,589	6,339	59,598	(19,318)
27 Income Taxes - Def Net	-	-	(806,610)	130,824	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(36,048)	(1,351,969)	(1,254,017)	(208,199)	(8,783)	(11,247)	(14,977,349)	788,477
32								
33 Operating Rev For Return:	36,048	1,351,969	1,254,017	208,199	8,783	11,247	(292,792)	(788,477)
34								
35 Rate Base:								
36 Electric Plant In Service	-	-	-	-	(4,423,967)	(1,883,129)	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	(8,108,022)	(3,719,449)	(861,756)	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-	-
44 Working Capital	(508)	(19,039)	(6,300)	(4,774)	1,158	575	(224,202)	(6,249)
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(508)	(8,127,061)	(3,725,750)	(866,531)	(4,422,809)	(1,882,554)	(224,202)	(6,249)
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	-	-	-	-	140,341	61,380	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-	-
53 Accum Def Income Tax	-	(1,170,062)	(1,411,568)	327,041	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	-	(1,170,062)	(1,411,568)	327,041	140,341	61,380	-	-
60								
61 Total Rate Base:	(508)	(9,297,123)	(5,137,318)	(539,490)	(4,282,467)	(1,821,173)	(224,202)	(6,249)
62								
63 Return on Rate Base	0.001%	0.066%	0.054%	0.008%	0.010%	0.004%	-0.009%	-0.027%
64								
65 Return on Equity	0.002%	0.129%	0.105%	0.016%	0.019%	0.009%	-0.019%	-0.053%
66								
67 TAX CALCULATION:								
68 Operating Revenue	58,280	2,274,947	2,125,400	344,703	91,032	52,106	(387,347)	(1,232,262)
69 Other Deductions								
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	(15)	(269,851)	(149,112)	(15,659)	(124,299)	(52,860)	(6,508)	(181)
72 Schedule "M" Additions	-	-	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	(2,125,400)	344,703	-	-	-	-
74 Income Before Tax	58,295	2,544,798	4,399,911	15,659	215,332	104,966	(380,839)	(1,232,080)
75								
76 State Income Taxes	2,813	49,690	212,345	306	10,589	6,339	59,598	(19,318)
77 Taxable Income	55,481	2,495,108	4,187,566	15,353	204,743	98,627	(440,437)	(1,212,763)
78								
79 Federal Income Taxes + Other	19,418	873,288	1,465,648	5,374	71,660	34,519	(154,153)	(424,467)
APPROXIMATE REVISED PROTOCOL PRICE CHANGE	(59,869)	(3,557,983)	(2,806,986)	(421,688)	(620,436)	(276,310)	453,967	1,307,051
Approximate Price Change Due to:								
Net Power Costs/TAM							(556,258)	
Embedded Cost Differential						24,167	943,605	1,232,262
General Rate Case	(59,869)	(3,557,983)	(2,806,986)	(421,688)	(620,436)	(300,476)	66,620	74,790

The following is an explanation of the reply adjustments included in the Company's revised revenue requirement addressing issues raised by intervening parties.

12.1 Allocation Factors

The Company has updated allocation factors to reflect two changes. First, allocation factors that rely on the net power cost study modeled in GRID have been updated to reflect changes in net power costs as filed in the Company's August 2009 TAM update. Second, allocation factors calculated based on electric plant in service balances have been updated to reflect plant levels included in the Company's revised revenue requirement. Both of these changes are consistent with the Commission-approved Revised Protocol allocation methodology. Please refer to page 12.0.1 for the actual impact on revenue requirement. Tab 11 shows the updated allocation percentages.

12.2 Cost of Capital and Capital Structure

Cost of capital and capital structure have been updated to the amounts shown on page 2.1. The reply testimony of Company witness Bruce N. Williams addresses the changes in capital structure and cost of debt. The Company has not made any changes to the cost of common equity as addressed in the reply testimony of Company witness Samuel C. Hadaway. Please refer to adjustment summary page 12.0.1 for the actual impact of these updates on revenue requirement.

12.3 Rate Base

This adjustment removes the 2 items identified by OPUC Staff witness Deborah Garcia that are not allowed in rate base. This adjustment also reduces Goodnoe Hills capital included in the test year to reflect the final amount of liquidated damages related to Goodnoe Hills. The Company agreed to update the Goodnoe Hills liquidated damages in OPUC data request 310. The associated impacts to depreciation expense and accumulated depreciation have also been included in this adjustment.

12.4 Insurance Low Claims Bonus

This adjustment includes into results a possible Low Claims Bonus at a 50% probability to be received during the test period as an offset to insurance expense. This adjustment reflects acceptance of the proposed adjustment by OPUC Staff witness Dustin Ball.

12.5 Workers Compensation Expense

This adjustment reduces the level of workers compensation insurance O&M expense as proposed by OPUC Staff witness Dustin Ball.

12.6 FAS 112 (Post Employment Benefits)

This adjustment adopts the reduction to post employment O&M expense as proposed by OPUC Staff witness Dustin Ball.

12.7 401(k) Expense

This adjustment adopts the proposed O&M adjustment related to Stock/401(k) by OPUC Staff witness Dustin Ball.

12.8 Challenge Grants

This adjustment removes expenses related to Challenge Grants as proposed by Staff witness Dustin Ball.

12.9 Transition Plan – Oregon Regulatory Asset

This adjustment removes the Transition Plan-Oregon regulatory asset and related amortization expense and deferred income tax balance impacts from results. The Company accepts OPUC Staff witness Dustin Ball's proposal to establish a separate tariff rider to recover the remaining balance.

12.10 MEHC CIC Severance Regulatory Asset

This adjustment removes the amortization and rate base of the MEHC transition costs from the filing. The Company accepts OPUC Staff witness Dustin Ball's proposal to establish a separate tariff rider to recover these costs.

12.11 Grid West Regulatory Asset

This adjustment removes the Grid West regulatory asset and related amortization expense and deferred income tax balance impacts from results. The Company accepts OPUC Staff witness Dustin Ball's proposal to establish a separate tariff rider to recover the remaining balance.

12.12 Wind Interconnection Rate Base

This adjustment adopts the proposed adjustment by OPUC Staff witness Ed Durrenburger to remove the Glenrock Wind and Eurus Seven Mile interconnection projects from results. The associated impacts to depreciation expense and accumulated depreciation have also been included in this adjustment.

12.13 Other Wind Plant Additions

This adjustment removes the contingency amounts for High Plains, Glenrock III, and Seven Mile Hill II identified by Staff witness Ed Durrenberger. The associated impacts to depreciation expense and accumulated depreciation have also been included in this adjustment.

12.14 August 2009 Net Power Cost Update

The net power cost 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, and normal hydro and weather conditions for the twelve-months ending December 31, 2010. The GRID study for this reply adjustment is based on the August 2009 TAM Update as shown on page 12.14.2.

As described in the testimony of R. Bryce Dalley, this adjustment is included in the calculation of overall revenue requirement for computational purposes only. The Company is not requesting recovery of net power costs as part of the general rate case.

12.15 Embedded Cost Differential (ECD)

This adjustment reflects updated NPC as reported in the Company's August 2009 TAM update. As discussed previously in PPL/700, the Company is seeking to recover its NPC through the TAM (Docket UE-207) and not in this proceeding. However, an update of NPC is required to properly calculate the ECD, which is included as part of the non-NPC revenue requirement. This adjustment is calculated within the model. Please refer to adjustment summary page 12.0.2 for the actual impact of this update.

ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#

Description of Adjustment:

The Company has updated allocation factors to reflect two changes. First, allocation factors that rely on the net power cost study modeled in GRID have been updated to reflect changes in net power costs as filed in the Company's August 2009 TAM update. Second, allocation factors calculated based on electric plant in service balances have been updated to reflect plant levels included in the Company's revised revenue requirement. Both of these changes are consistent with the Commission-approved Revised Protocol allocation methodology. Please refer to page 12.0.1 for the actual impact on revenue requirement. Tab 11 shows the updated allocation percentages.

ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#

Description of Adjustment:

Cost of capital and capital structure have been updated to the amounts shown on page 2.1. The reply testimony of Company witness Bruce N. Williams addresses the changes in capital structure and cost of debt. The Company has not made any changes to the cost of common equity as addressed in the reply testimony of Company witness Samuel C. Hadaway. Please refer to adjustment summary page 12.0.1 for the actual impact of these updates on revenue requirement.

Pacificorp
Oregon General Rate Case, December 2010
Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(1,468,653)	SG	26.877%	(394,728)	
General Plant	397	3	(4,325)	SO	28.259%	(1,222)	
Other Plant	343	3	(2,000,000)	SG	26.877%	(537,538)	
			(3,472,979)			(933,488)	12.3.1
Adjustment to Depreciation Expense:							
Steam Depreciation Expense	403SP	3	(44,495)	SG	26.877%	(11,959)	
General Depreciation Expense	403GP	3	(296)	SO	28.259%	(84)	
Other Depreciation Expense	403OP	3	(81,007)	SG	26.877%	(21,772)	
			(125,798)			(33,815)	12.3.1
Adjustment to Depreciation Reserve:							
Steam Depreciation Reserve	108SP	3	81,161	SG	26.877%	21,814	
General Depreciation Reserve	108GP	3	580	SO	28.259%	164	
Other Depreciation Reserve	108OP	3	158,638	SG	26.877%	42,637	
			240,380			64,615	12.3.1

Description of Adjustment:

This adjustment removes the 2 items identified by OPUC Staff witness Deborah Garcia that are not allowed in rate base. This adjustment also reduces Goodnoe Hills capital included in the test year to reflect the final amount of liquidated damages related to Goodnoe Hills. The Company agreed to update the Goodnoe Hills liquidated damages in OPUC data request 310. The associated impacts to depreciation expense and accumulated depreciation have also been included in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2010
Rate Base

Capital Addition

Project Description	FERC Acct	Factor	Inservice Date	July 08 to Dec 10 Plant Adds	Test Period 13 Month Avg. Plant Adds	
CWIP Inservice Not assigned to Specific Projects	312	SG	various	1,468,653	**1,468,653**	Ref. 12.3
Purchase Treadmill for NTO Employees	397	SO	Jul-08	4,325	**4,325**	Ref. 12.3
Goodnoe Hills Wind Project*	343	SG	May-08	2,000,000	**2,000,000**	Ref. 12.3

*As per the Company's Data Response OPUC 310, the Company is removing $2m from the Goodnoe Hills capital amount included in the test year, to reflect the final amount of liquidated damages at Goodnoe Hills

Depreciation Expense

Project Description	Rate	Depreciation Expense Year Ending Dec.2010	
CWIP Inservice Not assigned to Specific Projects	3.030%	**44,495**	Ref. 12.3
Purchase Treadmill for NTO Employees	6.853%	**296**	Ref. 12.3
Goodnoe Hills Wind Project	4.050%	**81,007**	Ref. 12.3

Depreciation Reserve

	Rate	Depreciation Reserve 13 Month Avg.	
CWIP Inservice Not assigned to Specific Projects	3.030%	**(81,161)**	Ref. 12.3
Purchase Treadmill for NTO Employees	6.853%	**(580)**	Ref. 12.3
Goodnoe Hills Wind Project	4.050%	**(158,638)**	Ref. 12.3

Pacificorp
Oregon General Rate Case, December 2010
Insurance Low Claims Bonus

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Insurance Expense	924	3	(435,000)	SO	28.259%	(122,925)	12.4.1

Description of Adjustment:

This adjustment includes into results a possible Low Claims Bonus at a 50% probability to be received during the test period as an offset to insurance expense. This adjustment reflects acceptance of the proposed adjustment by OPUC Staff witness Dustin Ball.

Insurance Low Claims Bonus

Adjustment Detail:

Low Claims Bonus received in Prior Periods:	
Policy Year 10-1-06 to 10-1-07; Received March 2008	$ 869,677
Policy Year 10-1-07 to 10-1-08; Received December 2008	$ 869,962
Probability ($870,000 x 50%)	x 50%
Insurance Expense Amount to Remove from filing	$ 435,000 **Ref. 12.4**

Pacificorp
Oregon General Rate Case, December 2010
Workers Compensation Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Workers Compensation Expense	930	3	(1,296,986)	SO	28.259%	(366,510)	12.5.1

Description of Adjustment:

This adjustment reduces the level of workers compensation insurance O&M expense as proposed by OPUC Staff witness Dustin Ball.

Adjustment Detail:

CY 2008 Actual Workers Compensation Expense	1,606,948	
Escalation Rate to 2009	1.05	
2009 Forecast Workers Comp Expense	1,687,295	
Escalation Rate to 2010	1.05	
2010 Forecast Workers Comp Expense	1,771,660	
Workers Compensation included in the Company's Filing	3,586,891	
	(1,815,230)	
O&M percentage	71.45%	
Adjustment to Workers Compensation O&M Expense	(1,296,986)	**Ref. 12.5**

Pacificorp
Oregon General Rate Case, December 2010
FAS 112 (Post Employment Benefits)

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Post Employment expense	930	3	(800,539)	SO	28.259%	(226,221)	12.6.1

Description of Adjustment:

This adjustment adopts the reduction to post employment O&M expense as proposed by OPUC Staff witness Dustin Ball.

Adjustment Detail:

CY 2008 Actual	5,073,226	
Escalation Rate to 2009	1.03	
2009 Forecast Postemployment Expense	5,225,423	
Escalation Rate to 2010	1.03	
2010 Forecast Postemployment Expense	5,382,185	
Postemployment included in the Company's Filing	6,502,600	
	(1,120,415)	
O&M percentage	71.45%	
Adjustment to Post Employment Expense	(800,539)	**Ref .12.6**

Pacificorp
Oregon General Rate Case, December 2010
401(k) Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
401(k) expense	930	3	(6,601,790)	SO	28.259%	(1,865,575)	12.7.1

Description of Adjustment:

This adjustment adopts the proposed O&M adjustment related to Stock/401(k) by OPUC Staff witness Dustin Ball.

PacifiCorp
Oregon General Rate Case - December 2010
401(k) Expense

Adjustment Detail:

January - March 2009 Actual	8,028,109	
Annualize	4	
2009 Forecast	32,112,436	
Escalation to 2010	1.025	
2010 Forecast	32,915,247	
Transition credit reduction	(700,000)	
2010 Forecast	32,215,247	
401(k) in filing	41,454,956	
	$ (9,239,709)	
O&M percentage	71.45%	
401(k) Expense to Remove from filing	(6,601,790)	**Ref. 12.7**

Pacificorp
Oregon General Rate Case, December 2010
Challenge Grants

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Challenge Grants	930	1	(206,237)	SO	28.259%	(58,280)	12.8.1

Description of Adjustment:

This adjustment removes expenses related to Challenge Grants as proposed by Staff witness Dustin Ball.

PacifiCorp
Oregon General Rate Case - December 2010
Challenge Grants

		Challenge Grant	
Jul-07	$	3,600	
Aug-07	$	12,000	
Sep-07	$	100	
Oct-07	$	9,833	
Nov-07	$	57,499	
Dec-07	$	61,603	
Jan-08	$	-	
Feb-08	$	17,300	
Mar-08	$	12,500	
Apr-08	$	11,250	
May-08	$	1,380	
Jun-08	$	5,500	
Total	$	192,565	
Disallowance		100%	
Staff Adjustment	$	192,565	
Total Adjustments	$	192,565	
Escalation to 2010		1.071	
Total Adjustment	**$**	**206,237**	**Ref.12.8**

Pacificorp
Oregon General Rate Case, December 2010
Transition Plan - Oregon Regulatory Asset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Amortization Expense	930	1	(2,274,947)	OR	100.000%	(2,274,947)	12.9.1
Adjustment to Rate Base:							
Transition Plan Asset at June 2008	182M	1	(8,108,022)	OR	100.000%	(8,108,022)	12.9.1
Adjustment to Tax:							
Accumulated Deferred Tax Balance	283	1	1,170,062	OR	100.000%	1,170,062	12.9.1

Description of Adjustment:

This adjustment removes the Transition Plan-Oregon regulatory asset and related amortization expense and deferred income tax balance impacts from results. The Company accepts OPUC Staff witness Dustin Ball's proposal to establish a separate tariff rider to recover the remaining balance.

PacifiCorp
Oregon General Rate Case - December 2010
OR Transition Plan Asset

FERC	Description	Unadjusted 12 Months Ended Jun-08	Escalation To Dec-10	Adjusted 12 Months Ending Dec-10	Budget Amount 12 Months Ending Dec-10	Amount In Filing	
930	Transition Plan OR - Amortization Expense	3,892,299	7.1%	4,168,813	2,274,947	**2,274,947**	Ref. 12.9
182M	Transition Plan OR Asset	8,108,022	-	8,108,022	-	**8,108,022**	Ref. 12.9
283	Transition Plan OR - Accumulated Deferred Tax Avg. Balance	(1,170,062)	-	(1,170,062)	-	**(1,170,062)**	Ref. 12.9

Pacificorp
Oregon General Rate Case, December 2010
MEHC CIC Severance Regulatory Asset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Amortizaton of deferred CIC severance	930	3	(7,521,243)	SO	28.259%	(2,125,400)	12.10.1
Adjustment to Rate Base:							
Unamort. Change-in-Control Severance	182M	3	(13,162,176)	SO	28.259%	(3,719,449)	12.10.1
Adjustment to Tax:							
Sch M Adjustment*	SCHMDT	3	(7,521,243)	SO	28.259%	(2,125,400)	12.10.1
Deferred Tax Expense	41110	3	(2,854,387)	SO	28.259%	(806,610)	12.10.1
Deferred Tax Balance	190	3	(4,995,177)	SO	28.259%	(1,411,568)	12.10.1

Description of Adjustment:

This adjustment removes the amortization and rate base of the MEHC transition costs from the filing. The Company accepts OPUC Staff witness Dustin Ball's proposal to establish a separate tariff rider to recover these costs.

PacifiCorp
Oregon General Rate Case - December 2010
Recap of Costs

				Ref
Severance Accrual to Amortize				
	Mar-06	9,091,098		
	Apr-06	2,442,461		
	May-06	1,654,407		
	Jun-06	3,787,684		
	Jul-06	752,698		
	Aug-06	5,429,173		
	Sep-06	8,353,838		
	Oct-06	2,932,641		
	Nov-06	3,434,349		
	Dec-06	515,787		
	Jan-07	309,965		
	Feb-07	2,174,847		
	Mar-07	2,074,000		
		42,952,949		
Less Backfills Included Above		(5,346,732)		
Amount to Amortize		**37,606,217**		**12.10.2**
Amortization of deferral - 5 year period				
Amortization 12 months ended December 2010			**7,521,243**	**12.10**
Unamortized Balance in Rate Base				
12/31/2009			16,922,798	**12.10.2**
12/31/2010			9,401,554	**12.10.2**
Average Balance			**13,162,176**	**12.10**
Total Incremental Deferred Tax Expense			**(2,854,387)**	**12.10**
Total Incremental Deferred Tax Balance			**(4,995,177)**	**12.10**

PacifiCorp
Oregon General Rate Case - December 2010
MEHC CIC Severance Regulatory Asset
MEHC Change-in-Control Severance Amortization Schedule

	Month	Monthly Amortization	Balance	Expense	Sch M	DIT Expense	DIT BAL
			37,606,217	**Ref. 12.10.1**			(14,271,935)
Apr-07	1	626,770	36,979,447				
May-07	2	626,770	36,352,676				
Jun-07	3	626,770	35,725,906		1,880,311	(713,597)	(13,558,339)
Jul-07	4	626,770	35,099,136				
Aug-07	5	626,770	34,472,366				
Sep-07	6	626,770	33,845,595				
Oct-07	7	626,770	33,218,825				
Nov-07	8	626,770	32,592,055				
Dec-07	9	626,770	31,965,284		3,760,622	(1,427,194)	(12,131,145)
Jan-08	10	626,770	31,338,514				
Feb-08	11	626,770	30,711,744				
Mar-08	12	626,770	30,084,974				
Apr-08	13	626,770	29,458,203				
May-08	14	626,770	28,831,433				
Jun-08	15	626,770	28,204,663		3,760,622	(1,427,194)	(10,703,952)
Jul-08	16	626,770	27,577,892				
Aug-08	17	626,770	26,951,122				
Sep-08	18	626,770	26,324,352				
Oct-08	19	626,770	25,697,582				
Nov-08	20	626,770	25,070,811				
Dec-08	21	626,770	24,444,041		3,760,622	(1,427,194)	(9,276,758)
Jan-09	22	626,770	23,817,271				
Feb-09	23	626,770	23,190,500				
Mar-09	24	626,770	22,563,730				
Apr-09	25	626,770	21,936,960				
May-09	26	626,770	21,310,190				
Jun-09	27	626,770	20,683,419		3,760,622	(1,427,194)	(7,849,564)
Jul-09	28	626,770	20,056,649				
Aug-09	29	626,770	19,429,879				
Sep-09	30	626,770	18,803,108				
Oct-09	31	626,770	18,176,338				
Nov-09	32	626,770	17,549,568				
Dec-09	33	626,770	**16,922,798**	**Ref. 12.10.1**	3,760,622	(1,427,194)	(6,422,371)
					7,521,243		
Jan-10	34	**626,770**	16,296,027				
Feb-10	35	**626,770**	15,669,257				
Mar-10	36	**626,770**	15,042,487				
Apr-10	37	**626,770**	14,415,717				
May-10	38	**626,770**	13,788,946				
Jun-10	39	**626,770**	13,162,176		3,760,622	(1,427,194)	(4,995,177)
Jul-10	40	**626,770**	12,535,406				
Aug-10	41	**626,770**	11,908,635				
Sep-10	42	**626,770**	11,281,865				
Oct-10	43	**626,770**	10,655,095				
Nov-10	44	**626,770**	10,028,325				
Dec-10	45	**626,770**	**9,401,554**	**Ref. 12.10.1**	3,760,622	(1,427,194)	(3,567,984)
					7,521,243	**Ref. 12.10.1**	
Jan-11	46	626,770	8,774,784				
Feb-11	47	626,770	8,148,014				
Mar-11	48	626,770	7,521,243				
Apr-11	49	626,770	6,894,473				
May-11	50	626,770	6,267,703				
Jun-11	51	626,770	5,640,933		3,760,622	(1,427,194)	(2,140,790)
Jul-11	52	626,770	5,014,162				
Aug-11	53	626,770	4,387,392				
Sep-11	54	626,770	3,760,622				
Oct-11	55	626,770	3,133,851				
Nov-11	56	626,770	2,507,081				
Dec-11	57	626,770	1,880,311		3,760,622	(1,427,194)	(713,597)
Jan-12	58	626,770	1,253,541				
Feb-12	59	626,770	626,770				
Mar-12	60	626,770	(0)		1,880,311	(713,597)	-

Pacificorp
Oregon General Rate Case, December 2010
Grid West Regulatory Asset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Amortization Expense	930	3	(344,703)	OR	100.000%	(344,703)	12.11.2
Adjustment to Rate Base:							
Misc. Regulatory Assets-Grid West Loan	182M	1	(861,756)	OR	100.000%	(861,756)	12.11.2
Adjustment to Tax:							
Sch M Adjustment	SCHMDT	3	344,703	OR	100.000%	344,703	12.11.2
Deferred Tax Expense	41110	1	130,824	OR	100.000%	130,824	12.11.2
Deferred Tax Balance	283	1	327,041	OR	100.000%	327,041	12.11.2

Description of Adjustment:

This adjustment removes the Grid West regulatory asset and related amortization expense and deferred income tax balance impacts from results. The Company accepts OPUC Staff witness Dustin Ball's proposal to establish a separate tariff rider to recover the remaining balance.

PacifiCorp
Oregon General Rate Case - December 2010
Grid West
OR RTO Grid West Loan
Account #187081

Authorized Cost of Capital = 8.057%
Authorized Cost of Capital = 8.16% effective January 1, 2007 in UE - 179

Month	Begin Balance	Adjustments/ Amortization	Interest Accrual	Balance	Sch M	Ditexp	A/C 283 Ditbal	Point in Time	Sch M	Ditexp
Mar-06				768,451			(291,635)			
Apr-06	768,451		5,160	773,611	(5,160)	1,958	(293,593)			
May-06	773,611		5,194	778,805	(5,194)	1,971	(295,564)			
Jun-06	778,805		5,229	784,034	(5,229)	1,984	(297,548)			
Jul-06	784,034		5,264	789,298	(5,264)	1,998	(299,546)			
Aug-06	789,298		5,299	794,598	(5,299)	2,011	(301,557)			
Sep-06	794,598		5,335	799,933	(5,335)	2,025	(303,582)			
Oct-06	799,933		5,371	805,303	(5,371)	2,038	(305,620)			
Nov-06	805,303		5,407	810,710	(5,407)	2,052	(307,672)			
Nov-06	810,710	5,841		804,869	5,841	(2,217)	(305,455)			
Dec-06	804,869		(39)	804,830	39	(15)	(305,440)			
Dec-06	804,830		5,404	810,234	(5,404)	2,051	(307,491)			
Jan-07	810,234		5,510	815,743	(5,510)	2,091	(309,582)			
Feb-07	815,743		5,547	821,290	(5,547)	2,105	(311,687)			
Mar-07	821,290		5,585	826,875	(5,585)	2,119	(313,806)			
Apr-07	826,875		5,623	832,498	(5,623)	2,134	(315,940)			
May-07	832,498		5,661	838,159	(5,661)	2,148	(318,088)			
Jun-07	838,159		5,699	843,858	(5,699)	2,163	(320,251)			
Jul-07	843,858		5,738	849,597	(5,738)	2,178	(322,429)			
Aug-07	849,597		5,777	855,374	(5,777)	2,193	(324,622)			
Sep-07	855,374		5,817	861,190	(5,817)	2,207	(326,829)			
Oct-07	861,190		5,856	867,047	(5,856)	2,222	(329,051)			
Nov-07	867,047		5,896	872,942	(5,896)	2,238	(331,289)			
Dec-07	872,942		5,936	878,878	(5,936)	2,253	(333,542)			
Jan-08	878,878		5,976	884,855	(5,976)	2,268	(335,810)			
Feb-08	884,855		6,017	890,872	(6,017)	2,284	(338,094)			
Mar-08	890,872		6,058	896,930	(6,058)	2,299	(340,393)			
Apr-08	896,930		6,099	903,029	(6,099)	2,315	(342,708)			
May-08	903,029		6,141	909,169	(6,141)	2,330	(345,038)			
Jun-08	909,169		6,182	915,352	(6,182)	2,346	(347,384)			
Jul-08	915,352		6,224	921,576	(6,224)	2,362	(349,746)			
Aug-08	921,576		6,267	927,843	(6,267)	2,378	(352,124)			
Sep-08	927,843		6,309	934,152	(6,309)	2,394	(354,518)			
Oct-08	934,152		6,352	940,505	(6,352)	2,411	(356,929)			
Nov-08	940,505		6,395	946,900	(6,395)	2,427	(359,356)			
Dec-08	946,900		6,439	953,339	(6,439)	2,444	(361,800)			
Jan-09	953,339		6,483	959,822	(6,483)	2,460	(364,260)			
Feb-09	959,822		6,527	966,348	(6,527)	2,477	(366,737)			
Mar-09	966,348		6,571	972,920	(6,571)	2,494	(369,231)			
Apr-09	972,920		6,616	979,535	(6,616)	2,511	(371,742)			
May-09	979,535		6,661	986,196	(6,661)	2,528	(374,270)			
Jun-09	986,196		6,706	992,902	(6,706)	2,545	(376,815)			
Jul-09	992,902		6,752	999,654	(6,752)	2,562	(379,377)			
Aug-09	999,654		6,798	1,006,452	(6,798)	2,580	(381,957)			
Sep-09	1,006,452		6,844	1,013,296	(6,844)	2,597	(384,554)			
Oct-09	1,013,296		6,890	1,020,186	(6,890)	2,615	(387,169)			

PacifiCorp
Oregon General Rate Case - December 2010
Grid West
OR RTO Grid West Loan
Account #187081

Authorized Cost of Capital = 8.057%
Authorized Cost of Capital = 8.16% effective January 1, 2007 in UE - 179

Month	Begin Balance	Adjustments/ Amortization	Interest Accrual	Balance		Sch M	Ditexp	A/C 283 Ditbal	Point in Time	Sch M	Ditexp
Nov-09	1,020,186		6,937	1,027,123		(6,937)	2,633	(389,802)			
Dec-09	1,027,123		6,984	**1,034,108**	**Ref. 12.11**	(6,984)	2,651	**(392,453)**			
Jan-10	1,034,108	**28,725**		1,005,383		**28,725**	**(10,902)**	(381,551)			
Feb-10	1,005,383	**28,725**		976,657		**28,725**	**(10,902)**	(370,649)			
Mar-10	976,657	**28,725**		947,932		**28,725**	**(10,902)**	(359,747)			
Apr-10	947,932	**28,725**		919,207		**28,725**	**(10,902)**	(348,845)			
May-10	919,207	**28,725**		890,482	B/E Avg	**28,725**	**(10,902)**	(337,943)	B/E Avg		
Jun-10	890,482	**28,725**		861,756	**861,756**	**28,725**	**(10,902)**	(327,041)	**(327,041)**		
Jul-10	861,756	**28,725**		833,031	**Ref. 12.11**	**28,725**	**(10,902)**	(316,139)	**Ref. 12.11**		
Aug-10	833,031	**28,725**		804,306		**28,725**	**(10,902)**	(305,237)			
Sep-10	804,306	**28,725**		775,581		**28,725**	**(10,902)**	(294,335)			
Oct-10	775,581	**28,725**		746,856		**28,725**	**(10,902)**	(283,433)			
Nov-10	746,856	**28,725**		718,130		**28,725**	**(10,902)**	(272,531)			
Dec-10	718,130	**28,725**		**689,405**	**Ref. 12.11**	**28,725**	**(10,902)**	**(261,629)**	**12 ME Dec 2010**	$\boxed{\textbf{344,703}}$	$\boxed{\textbf{(130,824)}}$
										Ref. 12.11	**Ref. 12.11**
Jan-11	689,405	28,725		660,680		28,725	(10,902)	(250,727)			
Feb-11	660,680	28,725		631,955		28,725	(10,902)	(239,825)			
Mar-11	631,955	28,725		603,230		28,725	(10,902)	(228,923)			
Apr-11	603,230	28,725		574,504		28,725	(10,902)	(218,021)			
May-11	574,504	28,725		545,779		28,725	(10,902)	(207,119)			
Jun-11	545,779	28,725		517,054		28,725	(10,902)	(196,217)			
Jul-11	517,054	28,725		488,329		28,725	(10,902)	(185,315)			
Aug-11	488,329	28,725		459,603		28,725	(10,902)	(174,413)			
Sep-11	459,603	28,725		430,878		28,725	(10,902)	(163,511)			
Oct-11	430,878	28,725		402,153		28,725	(10,902)	(152,609)			
Nov-11	402,153	28,725		373,428		28,725	(10,902)	(141,707)			
Dec-11	373,428	28,725		344,703		28,725	(10,902)	(130,805)			
Jan-12	344,703	28,725		315,977		28,725	(10,902)	(119,903)			
Feb-12	315,977	28,725		287,252		28,725	(10,902)	(109,001)			
Mar-12	287,252	28,725		258,527		28,725	(10,902)	(98,099)			
Apr-12	258,527	28,725		229,802		28,725	(10,902)	(87,197)			
May-12	229,802	28,725		201,077		28,725	(10,902)	(76,295)			
Jun-12	201,077	28,725		172,351		28,725	(10,902)	(65,393)			
Jul-12	172,351	28,725		143,626		28,725	(10,902)	(54,491)			
Aug-12	143,626	28,725		114,901		28,725	(10,902)	(43,589)			
Sep-12	114,901	28,725		86,176		28,725	(10,902)	(32,687)			
Oct-12	86,176	28,725		57,450		28,725	(10,902)	(21,785)			
Nov-12	57,450	28,725		28,725		28,725	(10,902)	(10,883)			
Dec-12	28,725	28,725		(0)		28,725	(10,883)	0			

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove Glenrock Wind Interconnection	355	3	(10,997,680)	SG	26.877%	(2,955,834)	
Remove Eurus 7 Mile Hill Interconnection	355	3	(5,462,439)	SG	26.877%	(1,468,133)	
			(16,460,119)			(4,423,967)	12.12.1
Adjustment to Depreciation Expense:							
Remove Glenrock Wind Interconnection	403TP	3	(226,300)	SG	26.877%	(60,822)	
Remove Eurus 7 Mile Hill Interconnection	403TP	3	(112,401)	SG	26.877%	(30,210)	
			(338,701)			(91,032)	12.12.1
Adjustment to Depreciation Reserve:							
Remove Glenrock Wind Interconnection	108TP	3	348,879	SG	26.877%	93,768	
Remove Eurus 7 Mile Hill Interconnection	108TP	3	173,285	SG	26.877%	46,574	
			522,164			140,341	12.12.1

Description of Adjustment:

This adjustment adopts the proposed adjustment by OPUC Staff witness Ed Durrenburger to remove the Glenrock Wind and Eurus Seven Mile interconnection projects from results. The associated impacts to depreciation expense and accumulated depreciation have also been included in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2010
Wind Interconnection Rate Base

Capital Addition

Project Description	FERC Acct	Factor	Inservice Date	July 08 to Dec 10 Plant Adds	Test Period 13 Month Avg. Plant Adds	
Glenrock Wind Interconnection	355	SG	Dec-08	10,997,680	**10,997,680**	Ref.12.12
Eurus 7 Mile Hills Interconnection	355	SG	Dec-08	5,462,439	**5,462,439**	Ref.12.12

Depreciation Expense

Project Description	Rate	Depreciation Expense Year Ending Dec.2010	
Glenrock Wind Interconnection	2.058%	**226,300**	Ref. 12.12
Eurus 7 Mile Hills Interconnection	2.058%	**112,401**	Ref. 12.12

Depreciation Reserve

	Rate	Depreciation Reserve 13 Month Avg.	
Glenrock Wind Interconnection	2.058%	**(348,879)**	Ref. 12.12
Eurus 7 Mile Hills Interconnection	2.058%	**(173,285)**	Ref. 12.12

Pacificorp
Oregon General Rate Case, December 2010
Other Wind Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
High Plains	343	3	(5,544,000)	SG	26.877%	(1,490,054)	
Glenrock III	343	3	(975,000)	SG	26.877%	(262,050)	
Seven Mile Hill II	343	3	(487,500)	SG	26.877%	(131,025)	
			(7,006,500)			(1,883,129)	12.13.1
Adjustment to Depreciation Expense:							
High Plains	403OP	3	(224,550)	SG	26.877%	(60,352)	
Glenrock III	403OP	3	(39,491)	SG	26.877%	(10,614)	
Seven Mile Hill II	403OP	3	(19,745)	SG	26.877%	(5,307)	
			(283,786)			(76,273)	12.13.1
Adjustment to Depreciation Reserve:							
High Plains	108OP	3	140,344	SG	26.877%	37,720	
Glenrock III	108OP	3	57,591	SG	26.877%	15,479	
Seven Mile Hill II	108OP	3	30,441	SG	26.877%	8,182	
			228,375			61,380	12.13.1

Description of Adjustment:

This adjustment removes the contingency amounts for High Plains, Glenrock III, and Seven Mile Hill II identified by Staff witness Ed Durrenberger. The associated impacts to depreciation expense and accumulated depreciation have also been included in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2010
Other Wind Plant Additions

Capital Addition

Project Description	FERC Acct	Factor	Inservice Date	Contingency Amounts	
High Plains	343	SG	Nov.09	**5,544,000**	Ref. 12.13
Glenrock III	343	SG	Jan.09	**975,000**	Ref. 12.13
Seven Mile Hill II	343	SG	Dec.08	**487,500**	Ref. 12.13

Depreciation Expense

Project Description	Rate	Depreciation Expense Year Ending Dec.2010	
High Plains	4.050%	**224,550**	Ref. 12.13
Glenrock III	4.050%	**39,491**	Ref. 12.13
Seven Mile Hill II	4.050%	**19,745**	Ref. 12.13

Depreciation Reserve

	Rate	Depreciation Reserve 13 Month Avg.	
High Plains	4.050%	**(140,344)**	Ref. 12.13
Glenrock III	4.050%	**(57,591)**	Ref. 12.13
Seven Mile Hill II	4.050%	**(30,441)**	Ref. 12.13

Pacificorp
Oregon General Rate Case, December 2010
August 2009 - Net Power Cost Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447	3	318,152	SG	26.877%	85,509	
Existing Firm UPL	447	3	-	SG	26.877%	-	
Post-Merger Firm	447	3	(57,133,295)	SG	26.877%	(15,355,650)	
Non-Firm	447	3	-	SE	25.002%	-	
Total Sales for Resale			(56,815,143)			(15,270,140)	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555	3	1,461,502	SG	26.877%	392,806	
Existing Firm Demand UPL	555	3	(611,370)	SG	26.877%	(164,317)	
Existing Firm Energy	555	3	3,333,941	SE	25.002%	833,548	
Post-merger Firm	555	3	(24,865,730)	SG	26.877%	(6,683,133)	
Secondary Purchases	555	3	-	SE	25.002%	-	
Seasonal Contracts	555	3	-	SSGC	0.000%	-	
Other Generation	555	3	(3,339,924)	SG	26.877%	(897,667)	
Post-merger Firm Type 1	555	1	-	SG	26.877%	-	
Total Purchased Power Adjustments:			(24,021,582)			(6,518,764)	
Wheeling Expense (Account 565)							
Existing Firm PPL	565	3	-	SG	26.877%	-	
Existing Firm UPL	565	3	(0)	SG	26.877%	(0)	
Post-merger Firm	565	3	4,828,564	SG	26.877%	1,297,768	
Non-Firm	565	3	(7,828)	SE	25.002%	(1,957)	
Total Wheeling Expense Adjustments:			4,820,736			1,295,811	
Fuel Expense (Accounts 501, 503, 547)							
Fuel Consumed - Coal	501	3	6,500,209	SE	25.002%	1,625,176	
Cholla / APS Exchange	501	3	242,534	SSECH	25.40833%	61,624	
Fuel Consumed - Gas	501	3	(12,334,934)	SE	25.002%	(3,083,968)	
Natural Gas Consumed	547	3	(32,140,943)	SE	25.002%	(8,035,846)	
Simple Cycle Combustion Turbines	547	3	(5,029,605)	SSECT	23.286%	(1,171,207)	
Steam from Other Sources	503	3	3,101	SE	25.002%	775	
Total Fuel Expense Adjustments:			(42,759,638)			(10,603,446)	
Total Power Cost Adjustment			(5,145,341)			(556,259)	

Description of Adjustment:

The net power cost 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, and normal hydro and weather conditions for the twelve-months ending December 31, 2010. The GRID study for this reply adjustment is based on the August 2009 TAM Update shown on page 12.14.2.

As described in the testimony of R. Bryce Dalley, this adjustment is included in the calculation of overall revenue requirement for computational purposes only. The Company is not requesting recovery of net power costs as part of the general rate case.

Note: Oregon-allocated net power costs have a variance of $32,351 from the figures reported in the Company's August 2009 TAM update. This is driven by changes in the SSECH and SSECT allocation factors. Factor updates were not included in the August 2009 TAM exhibits.

PacifiCorp

Allocated NPC to Oregon for TAM

	ACCOUNT	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010		FINAL UE-199 CY 2009	FILED CY2010	GRC Reply Factors CY2010	FINAL UE-199 CY 2009	Original Filing CY2010	August Update With GRC Reply Factors CY2010	TC Variance From Original Filing	Oregon-Allocated Variance from Original Filing
Sales for Resale													
Existing Firm PPL	447	24,281,555	24,656,916	24,975,068	SG	26.411%	26.877%	26.877%	6,413,106	6,627,011	6,712,520	318,152	85,509
Existing Firm UPL	447	25,490,590	25,490,589	25,490,589	SG	26.411%	26.877%	26.877%	6,732,429	6,851,076	6,851,076	-	-
Post-Merger Firm	447	882,169,664	696,790,188	639,656,892	SG	26.411%	26.877%	26.877%	232,993,623	187,275,491	171,919,842	(57,133,295)	(15,355,650)
Non-Firm	447	-	-	-	SE	25.525%	25.002%	25.002%	-	-	-	-	-
Total Sales for Resale		931,941,809	746,937,693	690,122,550					246,139,158	200,753,578	185,483,438	(56,815,143)	(15,270,140)
Purchased Power													
Existing Firm Demand PPL	555	62,711,383	57,671,363	59,132,864	SG	26.411%	26.877%	26.877%	16,562,973	15,500,265	15,893,071	1,461,502	392,806
Existing Firm Demand UPL	555	46,726,726	47,195,846	46,584,477	SG	26.411%	26.877%	26.877%	12,341,196	12,684,773	12,520,456	(611,370)	(164,317)
Existing Firm Energy	555	66,847,124	55,596,693	58,930,634	SE	25.525%	25.002%	25.002%	17,062,586	13,900,229	14,733,777	3,333,941	833,548
Post-merger Firm	555	707,106,149	376,422,870	351,557,140	SG	26.411%	26.877%	26.877%	186,756,845	101,170,739	94,487,605	(24,865,730)	(6,683,133)
Secondary Purchases	555	-	-		SE	25.525%	25.002%	25.002%	-	-	-	-	-
Seasonal Contracts	555	7,688,490	-	-	SSGC	24.488%	0.000%	0.000%	1,882,756	-	-	-	-
Other Generation Expense	555	5,247,531	11,022,399	7,682,475	SG	26.411%	26.877%	26.877%	1,385,948	2,962,477	2,064,810	(3,339,924)	(897,667)
Total Purchased Power		896,327,403	547,909,171	523,887,589					235,992,304	146,218,483	139,699,720	(24,021,582)	(6,518,764)
Wheeling Expense													
Existing Firm PPL	565	31,031,711	43,189,893	43,189,893	SG	26.411%	26.877%	26.877%	8,195,919	11,608,098	11,608,098	-	-
Existing Firm UPL	565	172,448	168,268	168,268	SG	26.411%	26.877%	26.877%	45,546	45,225	45,225	(0)	(0)
Post-merger Firm	565	83,334,742	96,107,739	100,936,303	SG	26.411%	26.877%	26.877%	22,009,897	25,830,766	27,128,533	4,828,564	1,297,768
Non-Firm	565	184,789	282,748	274,921	SE	25.525%	25.002%	25.002%	47,167	70,692	68,735	(7,828)	(1,957)
Total Wheeling Expense		114,723,691	139,748,649	144,569,385					30,298,529	37,554,781	38,850,591	4,820,736	1,295,811
Fuel Expense													
Fuel Consumed - Coal	501	568,676,213	604,154,098	610,654,307	SE	25.525%	25.002%	25.002%	145,153,389	151,049,995	152,675,171	6,500,209	1,625,176
Cholla / APS Exchange	501	57,517,646	54,964,906	55,207,439	SSECH	25.897%	25.405%	25.40833%	14,895,507	13,963,575	14,027,286	242,534	63,711
Fuel Consumed - Gas	501	27,408,356	21,128,538	8,793,603	SE	25.525%	25.002%	25.002%	6,995,924	5,282,536	2,198,568	(12,334,934)	(3,083,968)
Natural Gas Consumed	547	374,811,293	458,583,217	426,442,274	SE	25.525%	25.002%	25.002%	95,669,782	114,654,511	106,618,665	(32,140,943)	(8,035,846)
Simple Cycle Combustion Turbines	547	23,655,228	17,499,425	12,469,820	SSECT	24.286%	23.563%	23.28625%	5,744,981	4,123,302	2,903,754	(5,029,605)	(1,219,548)
Steam from Other Sources	503	3,541,671	3,494,899	3,498,000	SE	25.525%	25.002%	25.002%	904,004	873,791	874,566	3,101	775
Total Fuel Expense		1,055,610,407	1,159,825,082	1,117,065,444					269,363,588	289,947,711	279,298,011	(42,759,638)	(10,649,700)
							242,534						
Net Power Cost		1,134,719,692	1,100,545,210	1,095,399,869					289,515,263	272,967,396	272,364,884	(5,145,341)	(602,513)
Net Power Costs in Rates from UE-199		**1,043,323,002**							**266,835,529**				
			57,222,208	(5,145,341)						**6,131,867**	**5,529,355**	Increase Absent Load Change	

Oregon-allocated NPC Baseline in Rates from UE 199	$	266,835,529
2009 MWH (excluding Schedule 33)		14,026,969
$/MWH in Rates		19.02
2010 MWH (excluding Schedule 33)		13,267,901
2010 Recovery of NPC in Rates	$	**252,395,751**

20,571,645 **19,969,133** Increase With Load Change

(602,513) Variance from Original Filing

PacifiCorp
August 2009 Update
Period Ending
12 months ended December 2010

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 01/10-12/10	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	24,975,068	24,975,068			
Post Merger	639,656,892				639,656,892
Utah Pre Merger	25,490,589	25,490,589			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	690,122,550	50,465,657	-	-	639,656,892
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	47,058,000	47,058,000			
Pacific Capacity	1,411,140	600,000	811,140		
Mid Columbia	10,467,011	3,140,103	7,326,908		
Misc/Pacific	7,223,139	1,497,810	5,725,329		
Q.F. Contracts/PPL	66,761,501	6,836,951	33,310,620		26,613,931
Pacific Sub Total	132,920,792	59,132,864	47,173,996	-	26,613,931
Gemstate	2,716,400		2,716,400		
GSLM	-		-		
QF Contracts/UPL	92,440,272	21,093,887	9,040,237		62,306,148
IPP Layoff	25,490,589	25,490,589	-		
UP&L to PP&L	-	-	-		
Utah Sub Total	120,647,262	46,584,477	11,756,637	-	62,306,148
APS Supplemental	9,756,544				9,756,544
Avoided Cost Resource	-				-
Blanding Purchase	19,725				19,725
Chehalis Tolling	-				-
Combine Hills	3,911,516				3,911,516
Constellation p257677	-				-
Constellation p257678	-				-
Constellation p268849	-				-
Deseret Purchase	32,249,754				32,249,754
Georgia-Pacific Camas	7,280,700				7,280,700
Hermiston Purchase	92,817,337				92,817,337
Hurricane Purchase	328,501				328,501
Idaho Power P278538	777,066				777,066
Kennecott Generation Incentive	8,211,540				8,211,540
LADWP 491303-4	1,161,570				1,161,570
MagCorp	-				-
MagCorp Reserves	1,755,360				1,755,360
Morgan Stanley p189046	10,683,600				10,683,600
Morgan Stanley p244840	-				-
Morgan Stanley p244841	-				-
Morgan Stanley p272153-6-8	1,485,000				1,485,000
Morgan Stanley p272154-7	1,572,000				1,572,000
Nebo Heat Rate Option	-				-
NuCor	4,610,400				4,610,400
P4 Production	16,193,520				16,193,520
Rock River	5,041,688				5,041,688
Roseburg Forest Products	8,767,111				8,767,111
Three Buttes Wind	10,935,525				10,935,525
Tri-State Purchase	11,267,375				11,267,375
UBS p268848	-				-
UBS p268850	-				-
Weyerhaeuser Reserve	-				-
Wolverine Creek	9,748,726				9,748,726
Place Holder	-				-
BPA So. Idaho Exchange	-				-
DSM (Irrigation)	-				-
PSCO Exchange	3,600,000				3,600,000
TransAlta p371343/s371344	(1,644,000)				(1,644,000)

Short Term Firm Purchases	22,106,505				22,106,505
New Firm Sub Total	262,637,061	-	-	-	262,637,061
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	516,205,115	105,717,341	58,930,634	-	351,557,140
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	43,189,893	43,189,893			
Utah Firm Wheeling and Use of Facilities	168,268	168,268			
Post Merger	100,936,303				100,936,303
Nonfirm Wheeling	274,921			274,921	
TOTAL WHEELING & U. OF F. EXPENSE	144,569,385	43,358,161	-	274,921	100,936,303
THERMAL FUEL BURN EXPENSE					
Carbon	20,059,572			20,059,572	
Cholla	55,207,439			55,207,439	
Colstrip	12,944,264			12,944,264	
Craig	20,838,403			20,838,403	
Chehalis	96,392,799			96,392,799	
Currant Creek	114,429,808			114,429,808	
Dave Johnston	52,577,538			52,577,538	
Gadsby	8,793,603			8,793,603	
Gadsby CT	12,469,820			12,469,820	
Hayden	11,288,166			11,288,166	
Hermiston	56,036,843			56,036,843	
Hunter	112,775,720			112,775,720	
Huntington	96,648,088			96,648,088	
Jim Bridger	181,504,009			181,504,009	
Lake Side	149,158,260			149,158,260	
Little Mountain	10,424,564			10,424,564	
Naughton	81,873,772			81,873,772	
West Valley	-			-	
Wyodak	20,144,777			20,144,777	
TOTAL FUEL BURN EXPENSE	1,113,567,444	-	-	1,113,567,444	-
OTHER GENERATION EXPENSE					
Blundell	3,498,000			3,498,000	
Wind Integration Charge	7,682,475			7,682,475	
TOTAL OTHER GEN. EXPENSE	11,180,475	-	-	11,180,475	-
NET POWER COST	1,095,399,869	98,609,845	58,930,634	1,125,022,840	(187,163,450)

PacifiCorp
Original TAM filing
Period Ending
12 months ended December 2010

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 01/10-12/10	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	24,656,916	24,656,916			
Post Merger	696,790,188				696,790,188
Utah Pre Merger	25,490,589	25,490,589			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	746,937,693	50,147,505	-	-	696,790,188
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	47,058,000	47,058,000			
Pacific Capacity	1,411,140	600,000	811,140		
Mid Columbia	5,839,267	1,751,780	4,087,487		
Misc/Pacific	7,223,139	1,497,810	5,725,329		
Q.F. Contracts/PPL	62,755,881	6,763,772	32,954,084		23,038,024
Pacific Sub Total	124,287,426	57,671,363	43,578,040	-	23,038,024
Gemstate	2,716,400		2,716,400		
GSLM	-		-		
QF Contracts/UPL	97,112,137	21,705,257	9,302,253		66,104,627
IPP Layoff	25,490,589	25,490,589	-		
UP&L to PP&L	-	-	-		
Utah Sub Total	125,319,126	47,195,846	12,018,653	-	66,104,627
APS Supplemental	10,927,901				10,927,901
Avoided Cost Resource	-				-
Blanding Purchase	19,725				19,725
Chehalis Tolling	-				-
Combine Hills	3,911,516				3,911,516
Constellation p257677	-				-
Constellation p257678	-				-
Constellation p268849	-				-
Deseret Purchase	32,249,754				32,249,754
Georgia-Pacific Camas	7,280,700				7,280,700
Hermiston Purchase	98,888,667				98,888,667
Hurricane Purchase	328,501				328,501
Idaho Power RTSA Purchase	2,372,618				2,372,618
Kennecott Generation Incentive	8,211,540				8,211,540
MagCorp	-				-
MagCorp Reserves	1,755,360				1,755,360
Morgan Stanley p189046	10,683,600				10,683,600
Morgan Stanley p244840	-				-
Morgan Stanley p244841	-				-
Morgan Stanley p272153-6-8	1,485,000				1,485,000
Morgan Stanley p272154-7	3,369,600				3,369,600
Nebo Heat Rate Option	-				-
NuCor	4,610,400				4,610,400
P4 Production	16,193,520				16,193,520
Rock River	5,041,688				5,041,688
Roseburg Forest Products	8,767,111				8,767,111
Three Buttes Wind	10,935,525				10,935,525
Tri-State Purchase	10,971,155				10,971,155
UBS p268848	-				-
UBS p268850	-				-
Weyerhaeuser Reserve	-				-
Wolverine Creek	9,748,726				9,748,726
Place Holder	-				-
BPA So. Idaho Exchange	-				-
DSM (Irrigation)	-				-
PSCO Exchange	3,600,000				3,600,000
TransAlta p371343/s371344	(1,644,000)				(1,644,000)

Short Term Firm Purchases	37,571,611				37,571,611
New Firm Sub Total	287,280,219	-	-	-	287,280,219
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	536,886,772	104,867,209	55,596,693	-	376,422,870
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	43,189,893	43,189,893			
Utah Firm Wheeling and Use of Facilities	168,268	168,268			
Post Merger	96,107,739				96,107,739
Nonfirm Wheeling	282,748			282,748	
TOTAL WHEELING & U. OF F. EXPENSE	139,748,649	43,358,161	-	282,748	96,107,739
THERMAL FUEL BURN EXPENSE					
Carbon	19,446,056			19,446,056	
Cholla	54,964,906			54,964,906	
Colstrip	12,395,660			12,395,660	
Craig	20,691,191			20,691,191	
Chehalis	97,520,795			97,520,795	
Currant Creek	123,816,195			123,816,195	
Dave Johnston	52,590,391			52,590,391	
Gadsby	21,128,538			21,128,538	
Gadsby CT	17,499,425			17,499,425	
Hayden	11,369,342			11,369,342	
Hermiston	62,004,977			62,004,977	
Hunter	111,340,062			111,340,062	
Huntington	96,354,411			96,354,411	
Jim Bridger	180,236,369			180,236,369	
Lake Side	164,937,833			164,937,833	
Little Mountain	10,303,418			10,303,418	
Naughton	80,290,581			80,290,581	
West Valley	-			-	
Wyodak	19,440,034			19,440,034	
TOTAL FUEL BURN EXPENSE	1,156,330,183	-	-	1,156,330,183	-
OTHER GENERATION EXPENSE					
Blundell	3,494,899			3,494,899	
Wind Integration Charge	11,022,399			11,022,399	
TOTAL OTHER GEN. EXPENSE	14,517,298	-	-	14,517,298	-
NET POWER COST	1,100,545,210	98,077,865	55,596,693	1,171,130,230	(224,259,579)

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							

Description of Adjustment:

This adjustment reflects updated NPC as reported in the Company's August 2009 TAM update. As discussed previously in PPL/700, the Company is seeking to recover its NPC through the TAM (Docket UE-207) and not in this proceeding. However, an update of NPC is required to properly calculate the ECD, which is included as part of the non-NPC revenue requirement. This adjustment is calculated within the model. Please refer to adjustment summary page 12.0.2 for the actual impact of this update.

R. Bryce Dalley
Exhibit PPL/709

Docket No. UE-210
Exhibit PPL/709
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

OPUC Staff Data Request Responses

August 2009

August 10, 2009

TO: Katherine McDowell
Counsel for PacifiCorp

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 210
PacifiCorp's Third Set of Data Requests to OPUC
Dated July 30, 2009 – Due August 10, 2009
Data Requests 3.7 - 3.8

Request:

3.7 See Staff/700, Rossow/2, lines 3-5. Please provide docket numbers or other specific reference where application of a 3-year historical average calculation for uncollectible accounts has been adopted by the Commission.

Response:

3.7 Many of the dockets in which Staff had adjustments to uncollectible accounts involving a 3-year average were all settled before going to hearing. In docket UG 132, a 3-year average was used. See Order 99-697, Stipulation and Agreement, Appendix D, page 4 of 8.

Request:

3.8 See Staff/700. Please explain how Mr. Rossow's analysis behind the adjustment to uncollectible expense has taken into account the current economic conditions faced by Oregon customers?

a. Please provide any analysis, documentation, and workpapers that show how a three-year average of write-offs is relevant for forecasting a 2010 uncollectible expense amount.

b. Has any consideration been given to the upward trending of the write-off levels from 2006 to the present?

Response:

3.8 The adjustment using a 3-year average to uncollectible expense takes into account the 2006, 2007, and 2008 economic conditions relating to uncollectible expense, which may spike from year to year.

a. PacifiCorp is already in possession of staff's workpaper involving the uncollectible expense adjustment.

b. No consideration was given to the upward trending of the write-off levels from 2006 to the present. Instead, Staff relied on PacifiCorp's Global Insight Customer Account escalated factor.

August 10, 2009

TO: Katherine McDowell
Counsel for PacifiCorp

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 210
PacifiCorp's Third Set of Data Requests to OPUC
Dated July 30, 2009 – Due August 10, 2009
Data Requests 3.12 - 3.19

Request:

3.16 See Staff/100, Garcia/8, lines 10. Please provide citations to past Commission cases where the referenced "policy" has been articulated and/or implemented.

Response:

3.16 Staff is not aware of any general rate case proceeding, where the filing was based on a future test year, in which Commission Staff has advocated an adjustment to a reasonable level of proforma distribution plant addition to rate base.

August 10, 2009

TO: Katherine McDowell
Counsel for PacifiCorp

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 210
PacifiCorp's 3rd Set of Data Requests to OPUC
Dated July 30, 2009 – Due August 10, 2009
Data Request 3.20-3.23 - Peng

Request:

3.21 In reference to the workpapers associated with Adjustment S-7 (Peng – depreciation and amortization), please explain why the following projects are shown to use a different depreciation rate than the applicable rate for its function and factor. Please provide all supporting analyses and documentation to support the difference.

a. Fleet Trans Fire Protection Upgrade project (Function Steam, Factor SG) is using a depreciation rate of 3.225% instead of 3.030%

b. Garden Valley – Capacity Solution project (feeder upgrades) (Function Distribution, Factor OR) is using a depreciation rate 2.058% instead of 2.863%

c. U1-Plant Vehicle Replacement project (Function General, Factor SG) is using a depreciation rate 3.029% instead of 3.225%

Response:

3.21 The Staff depreciation rates for these projects are typographical errors.. The correct depreciation rates should be 3.225%, 2.058%, and 3.029%, respectively. The corrections noted above will be reflected in Staff's next round of testimony.

Docket No. UE-210
Exhibit PPL/710
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Company Responses to ICNU Data Requests 9.8 and 9.33

August 2009

ICNU Data Request 9.8

Provide the following information for Pacific Power Oregon for each of the calendar years 2008, 2007, 2006, 2005, and 2004:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

Response to ICNU Data Request 9.8

Please refer to Attachment ICNU 9.8 for the total-Company and Oregon-allocated share of the requested wage and salary information. For 2007 and 2008, PacifiCorp began using FERC 707 for a labor clearing account. The total salary and wages are booked to FERC 707 and allocated out to the various other FERC accounts using labor allocations from time entry. The response provided shows only the total wages and salaries booked and excludes all labor allocation activity since this is considered secondary labor. FERC 707 has a zero balance on a consolidated basis.

Please refer to non-confidential Attachment ICNU 9.8 on the enclosed CD.

ICNU Data Request 9.8

Provide the following information for Pacific Power Oregon for each of the calendar years 2008, 2007, 2006, 2005, and 2004:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

1st Supplemental Response to ICNU Data Request 9.8

Please see below for follow-up questions from ICNU and the Company's responses regarding the Company's original response to ICNU Data Request 9.8, dated July 2, 2009.

Confirm that the information provided in response to ICNU Data Requests 9.8 and 9.9 is payroll only. There are no benefits or payroll taxes included.

The Company confirms that there are no benefits or payroll taxes included in the Company's original response to ICNU Data Requests 9.8 and 9.9.

Confirm that the total payroll provided in response to ICNU Data Request 9.8 on the tabs labeled 2004, 2005, 2006, 2007, and 2008 is total payroll. Is payroll expense the amount from the individual year tab less the capitalized labor from the CapLabor 2004-2008 tab?

Yes. The total payroll amount provided in Attachment ICNU 9.8, on the tabs labeled 2004, 2005, 2006, and 2008, is the gross expense which excludes any capitalization. The net payroll expense would be the gross expense amount for each of those years less the capitalized portion shown on the CapLabor 2004 – 2008 tab.

Confirm that the information provided in response to ICNU Data Request 9.8 on the tabs labeled 2004, 2005, 2006, 2007, 2008 includes non-utility payroll (accounts 416 through 426.5) that should be excluded if it is to be compared to total Labor and Incentives on page 4.2.2 of Exhibit PPL/702.

Yes. The amounts provided were total company gross expense and the corresponding capitalized portion of those expenses.

ICNU Data Request 9.8

Provide the following information for Pacific Power Oregon for each of the calendar years 2008, 2007, 2006, 2005, and 2004:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

2nd Supplemental Response to ICNU Data Request 9.8

In the Company's original response to ICNU 9.8, the Company provided the responsive data it had available and indicated that it was incomplete because: (1) it did not reflect the allocation of FERC 707 expenses; and (2) it did not reflect the final allocation of other accounts.

FERC 707 is by far the largest account for labor costs. The numbers provided in the original response reflected FERC 707 costs as allocated to "other" instead of system. The effect of this was to reflect the FERC 707 costs in total expense (i.e. include it in the denominator), but incorrectly assign none of the expense to Oregon (i.e. exclude it from the numerator). The result produced allocation ratios of 19.90% and 18.86% in 2007 and 2008, respectively. The allocation percentages in 2004-2006, before the Company used FERC account 707, ranged from 28.41% to 28.96%.

The Company began using FERC account 707 in 2007 as a temporary labor clearing account. Each month the labor expenses associated with the Company's power delivery employees (distribution and transmission functions) are temporarily charged to this account. Through the Company's labor allocation activity process (secondary labor settlements), the amounts charged to FERC account 707 are credited with the offsetting debit booked to the appropriate FERC accounts with correct revised protocol factors based on the type of work identified. As shown on the "2008" tab, lines 953 and 954 of the original Attachment ICNU 9.8, FERC account 707 includes significant balances which are not allocated to any state. These balances represent the labor expenses associated with the Company's power delivery employees and will remain in FERC account 707 until the labor allocation activity is processed within the Company's accounting system (SAP). Once the labor allocation activity is processed, FERC account 707 is left with zero balance.

A high-level approximation of the total Oregon allocation share of FERC 707 costs can be determined by allocating the balances included in that account by the System Net Plant Distribution (SNPD) factor. Attachment ICNU 9.8 – 2nd

Supplemental provides this data. The table below shows the approximate Oregon allocation when FERC 707 is allocated in this manner. Please note that accurate state allocation percentages can only be determined after the labor allocation activity is processed for each of the years shown in the attachment. This processing ensures that labor expenses are booked to the appropriate FERC accounts with correct revised protocol allocation factors.

Year	*Approximate Oregon Allocation %
2004	29.0%
2005	28.5%
2006	28.4%
2007	28.4%
2008	28.2%

**These percentages are approximations only based on data extracted from SAP before labor allocation activity processing. The labor allocation activity must be processed to determine the final FERC account and allocator. The labor allocation activity settlement process includes wages, salaries, benefits, etc. and cannot be run for wages and salaries only.*

The Company's CY 2010 projection of Oregon-allocated labor and benefit expenses as filed in Exhibit PPL/702 is based on actual data for the 12-month period ending June 2008, including all labor allocation activity processing. These percentages are shown in the table below.

Year	*Actual Oregon Allocation %'s After Labor Allocation Activity is Processed	
12 ME June 2008	29.5%	Actual
CY 2010 Forecast (PPL/702)	29.5%	Projected based on June 08 Actuals

** These percentages are determined after all labor allocation activity is processed for all components of labor (wages, benefits, pensions, etc.)*

Please refer to non-confidential Attachment ICNU 9.8 – 2nd Supplemental on the enclosed CD.

ICNU Data Request 9.33

Provide the following information for Pacific Power Oregon by month for January through May 2009:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

Response to ICNU Data Request 9.33

Please refer to Attachment ICNU 9.33. PacifiCorp uses FERC 707 as a labor clearing account. The total salary and wages are booked to FERC 707 and allocated out to the various other FERC accounts using labor allocations from time entry. The response provided shows only the total wages and salaries booked and excludes all labor allocation activity since this is considered secondary labor. FERC 707 has a zero balance on a consolidated basis.

Please refer to non-confidential Attachment ICNU 9.33 on the enclosed CD.

ICNU Data Request 9.33

Provide the following information for Pacific Power Oregon by month for January through May 2009:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

1st Supplemental Response to ICNU Data Request 9.33

Please refer to the Company's 2nd Supplemental response to ICNU Data Request 9.8. In connection with that response, the Company is also providing attachment ICNU 9.33 1st Supplemental which allocates FERC account 707 on an SNPD factor for a high-level approximation of the total Oregon allocation share of the costs. This attachment is consistent with the Attachment ICNU 9.8 2nd Supplemental.

Please note that accurate state allocation percentages can only be determined after the labor allocation activity is processed. This processing ensures that labor expenses are booked to the appropriate FERC accounts with correct revised protocol allocation factors.

Please refer to non-confidential Attachment ICNU 9.33 – 1st Supplemental on the enclosed CD.

Richard A. Vail
Exhibit PPL/1100

Docket No. UE-210
Exhibit PPL/1100
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Richard A. Vail

August 2009

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

A. My name is Richard A. Vail. My business address is PacifiCorp, 825 NE Multnomah, Suite 1500, Portland, Oregon 97232. My position is Director of Asset Management for PacifiCorp.

Q. Have you previously filed testimony in this case?

A. No.

Q. Please describe your education and business experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from Portland State University. In addition to formal education, I have attended numerous educational, professional, electric industry and asset management seminars. I have held a number of positions with the Company including Substation Engineer; Manager, Maintenance Planning; Manager, Capital Planning and Director; Investment Planning. During my 15 years of employment, I have gained extensive experience working across the Company' s service territory prior to assuming my current position of Director, Asset Management.

Purpose and Summary

Q. What is the purpose of your testimony?

A. Along with Company witness Mr. R. Bryce Dalley, I respond to Staff witness Ms. Deborah Garcia' s adjustment to rate base. The purpose of my testimony on this adjustment is to explain the Company' s budgeting process for distribution plant additions and demonstrate why Ms. Garcia' s removal of $52 million of distribution plant additions from the test year is contradicted by her own testimony. Specifically, I demonstrate that distribution plant additions are attributable to several drivers, not just load growth, and that the inclusion in rate base of items that are placed into service on an ongoing or monthly basis is reasonable. In addition, my testimony demonstrates that: (1) the Oregon distribution plant-in-service additions in this case are forecast at levels that are lower than actual plant-in-service additions for several years; and (2) Staff's filed position for Oregon distribution plant-in-service additions is lower than actual additions since at least 2003. Similarly, Mr. Dalley's testimony demonstrates that Staff's significant reduction to plant-in-service produces a net plant-in-service for the calendar year 2010 test period that is <u>less</u> than the actual net plant-in-service through June 2009.

Q. Please summarize Ms. Garcia's proposed rate base adjustment as it applies to distribution rate base.

A. Staff proposes to disallow over $52 million of Company investment in the Oregon distribution system. This is composed of two categories of adjustments: (1) removal of 50 percent of the rate base additions between the June 2008 base period and the end of the 2010 test period that have "monthly" or "various" in-service dates, and (2) removal of 100 percent of all other rate base additions after the rate effective date of February 2, 2010, notwithstanding the fact that the test period in this proceeding is calendar year 2010. Of the $52 million investment disallowance, $50.7 million is associated with items in the former category. This adjustment is shown on Staff/103, Garcia/1.

Q. On what rationale does Ms. Garcia rely in support of this significant disallowance of investment in the Company' s Oregon distribution system?

A. Ms. Garcia' s testimony in support of this disallowance is not clear. On the one hand, Ms. Garcia states:

> " Historically, the Commission has allowed a reasonable percentage increase in distribution plant rate base for a future test year, relative to the expected growth in a utility' s customer base. The other point to this accommodation is that, aside from installing new distribution plant, the utility has ongoing obligations related to safety and reliability to repair, replace, or reinforce this plant. Staff/100, Garcia/8, lines 16-21."

> " Some examples of these costs are for the poles, wires, meters and other plant necessary to distribute electricity to customers. These costs are ongoing in nature and can be reasonably assumed to be made on a regular basis. Staff/100, Garcia/8 lines 13-16."

> " A review of the items in the Distribution category confirms that they are necessary for the direct provision of service to customers, such as wires, poles, meters, etc. Staff/100, Garcia/9, lines 12-14."

Even while expressly acknowledging the necessary and recurring nature of this investment, Ms. Garcia recommends removing 50 percent of the items with in-service dates that occur on an on-going or monthly basis. Her recommendation is supported, she claims, by a " finding that PacifiCorp has proposed a level of Distribution Plant that is more than three times higher than projected customer growth." Staff/100, Garcia/12, lines 2-3.

Q. Does the Company agree with Staff' s proposed disallowance?

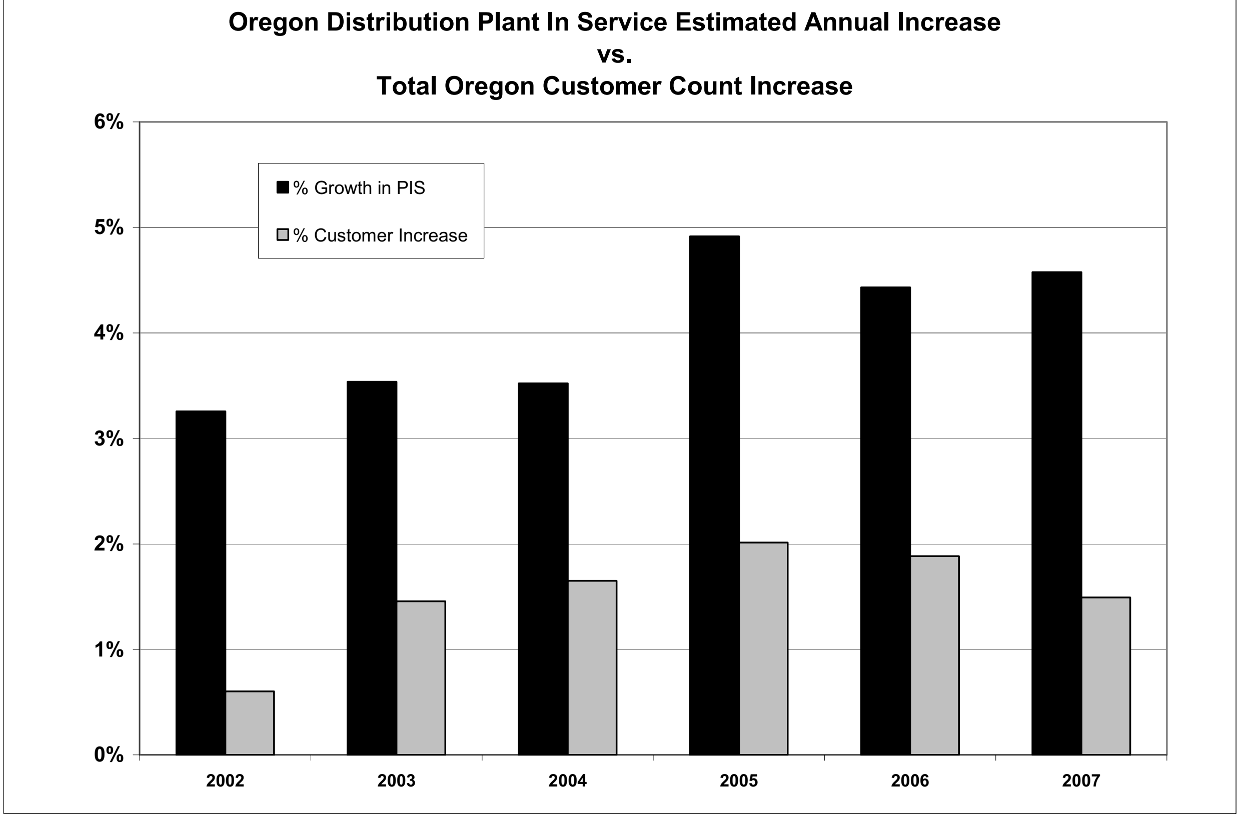
A. No. The significant and unprecedented disallowance of investment in the Oregon distribution system is contradicted by Ms. Garcia' s own testimony that these distribution investments " are necessary for direct provision of service to customers." As I show below, Staff is correct that the Company' s distribution investments included in this filing are necessary for the safety and reliability of the system. The level of distribution plant investment cannot simply be tied to customer growth, and the nature of distribution plant makes it difficult to forecast specific in-service dates, thus leading to items with ongoing and monthly in-service dates.

Distribution Plant Investment

Q. How does the Company's plant-in-service growth compare to customer growth?

A. Table 1 below shows PacifiCorp's Oregon distribution plant-in-service increases compared to the changes in customer growth since 2002. As this table shows, customer growth does not consistently track with increases in plant-in-service. In light of the age of PacifiCorp's asset base, and increasing regulatory and other demands, it is incorrect to assume that increases in distribution plant are driven solely by customer growth. Safety, reliability and obsolescence are also factors that must be considered.

Table 1



Q. Does Ms. Garcia' s testimony recognize that distribution investment is not solely related to customer growth?

A. Yes. As noted above, she acknowledges, " aside from installing new distribution plant, the utility has ongoing obligations related to safety and reliability to repair, replace, or reinforce this plant." Staff/100, Garcia/8, lines 19-21.

Q. What types of costs are generally included in the budget for distribution plant?

A. Distribution plant expenditures include replacement of aging or failed assets, costs to address increased demand by existing customers, costs to install assets required to maintain compliance with right-of-way agreements, state and federal regulatory requirements, and funding to improve reliability and otherwise upgrade the performance of the asset base.

Q. How does the Company develop its capital budget for distribution expenditures?

A. PacifiCorp's capital budget for distribution is broken down into the following major categories:

- New Connects
- Mandated/Compliance
- System Reinforcement
- Asset Replacement/Renewal
- Performance Upgrades/Reliability

In developing the budget, PacifiCorp's first priority is to identify non-discretionary expenditures required to operate its business. A second level of investment is then identified, which have some discretionary aspects, but are critical to the operation of the asset base. Finally, a third level of investment is identified that includes investments that may be termed "discretionary," but which deliver a significant benefit to customers. The spending in these categories is aggregated to form the capital budget which is then managed through the year.

Q. What type of expenditures are typically identified by the Company as non-discretionary?

A. Non-discretionary expenditures generally include costs associated with mandates/compliance, costs to connect new customers per tariff requirements and costs to replace assets.

Mandates and compliance issues include such items as highway or roadway relocations, overhead to underground conversions, and investments required to maintain compliance with environmental regulations. The budget levels for these items are determined by a combination of known factors such as avian mitigation commitments to the Fish and Wildlife Service and estimates and reviews of historical run rates for things such as roadway relocations.

Costs to connect new customers per tariff requirements are estimated based on forecasts of new connect volume and historical cost per unit data. New connect volume forecasts are developed through review of economic trends and forecasts and historical data.

Assets are replaced that fail in service due to age, deterioration and storm and casualty damage. A large component of this category in Oregon is the distribution pole replacement program. The main driver for this program is the requirements associated with service quality performance measures adopted in Order No. 98-191 and Oregon Administrative Rules 860-024-010 through 860-024-012. These require PacifiCorp to replace or reinforce deteriorated poles that are discovered through inspection and testing programs within specified timeframes. PacifiCorp maintains detailed records on the actual quantity of deteriorated poles outstanding and uses this data together with reasonable projections based on over 10 years of inspection results to forecast this work in the future.

Q. Please explain what types of expenditures are in the second level of investment - costs that have some discretionary aspects but are critical to the operation of the asset base.

A. These expenditures include costs to add capacity to the distribution system to accommodate load growth and funding for targeted reliability improvement efforts.

The costs to add capacity for load growth are typically to construct additional substation capacity or to add distribution feeder capacity. The projects are all proposed to alleviate situations where the actual loading of the equipment has exceeded nameplate or thermal ratings. While these projects may be deferred for a short period, the risks of continued load growth with subsequent customer impacts if equipment were to fail are not acceptable.

The Company' s reliability improvement spending is intended to continue to deliver reliability performance consistent with the levels agreed upon with Commission Staff in the Company' s service quality measures, adopted in UE 94.

Q. Please explain what types of expenditures are in the third level of investment - costs that may be considered discretionary.

A. Examples of discretionary investments include replacement of aging or deteriorated equipment prior to failure which will avoid customer outages and reduce fault response costs. It also includes increasing spare equipment and emergency response equipment inventories to mitigate impacts of storms or equipment failures. While these costs may be considered discretionary, they provide significant benefits to customers for reliability.

Q. Once these costs have been identified, how do they stack up to one another in the distribution plant budget?

A. Table 2 below shows the breakdown of costs included in the budget for 2009, which is part of this filing. As the table shows, over 95 percent of the Company's proposed plant-in-service additions are limited or non-discretionary items, essential for maintaining regulatory compliance and reliable service.

Table 2
2009 Oregon Distribution Plant In Service Additions by Major Category

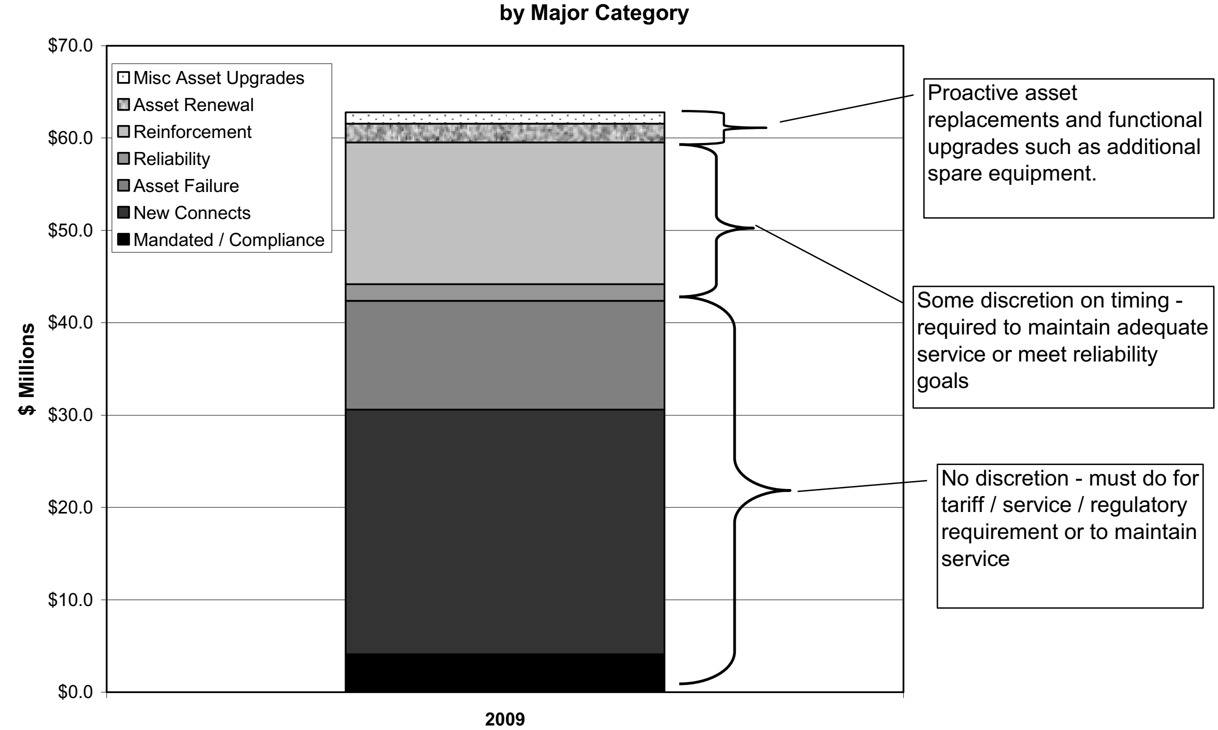


Table 1 and Table 2 together demonstrate that Staff's adjustment on the basis that distribution plant investment is higher than load growth is not valid since the drivers for investment are not limited to customer growth, and in fact, costs associated with customer growth are only a fraction of the total.

" Various" or " Monthly" In-Service Dates

Q. Please explain why PacifiCorp identifies certain distribution items as having " monthly" or " various" in-service dates

A. PacifiCorp budgets projects greater than $1 million individually. Typical examples would include substation construction projects where additional distribution voltage capacity is being added (e.g., 12 kV to 25 kV). Within PacifiCorp' s capital budget plan for Oregon, there are individual projects with a distribution component greater than $1 million. However, the vast majority of distribution projects are small work efforts, such as installing distribution facilities for a new residential customer or replacing a transformer. Each of these items is represented by a separate element in the Company' s accounting system, with an individual in-service date. For instance, in 2008 the Oregon distribution plant in-service consisted of approximately 5,600 individual elements, with an average cost of $10,800.

Due to the high volume of these small projects, it would be time consuming to develop a forecast with exact in-service dates and budgetary figures for each element. PacifiCorp does, however, have processes in place to generate reasonable forecasts of these costs that are used in developing the budget. The term " various" is used to capture costs of this nature that are on-going and placed in service in more than one month. For instance, the Company knows that transformers will fail, but the Company cannot predict the specific date to budget a replacement. Instead, the Company assumes certain on-going levels of expenditures for these small distribution projects.

Q. Even with the budgetary and forecasting methods, due to the nature of the required investment in the distribution system, won' t there be variations in spending from planned amounts?

A. Yes, although history shows that the variations are small. PacifiCorp establishes annual capital budgets to which it closely adheres. Increases in spending in a particular program due to unforeseen circumstances are offset by targeted reductions in other programs. Table 3 below illustrates the planned versus actual capital spending for the Pacific Power transmission and distribution system. As shown, while there may be some small variations in total planned versus actual spending on a year to year basis, the Company typically delivers the planned capital spending which translates into the delivery of planned plant-in-service additions.

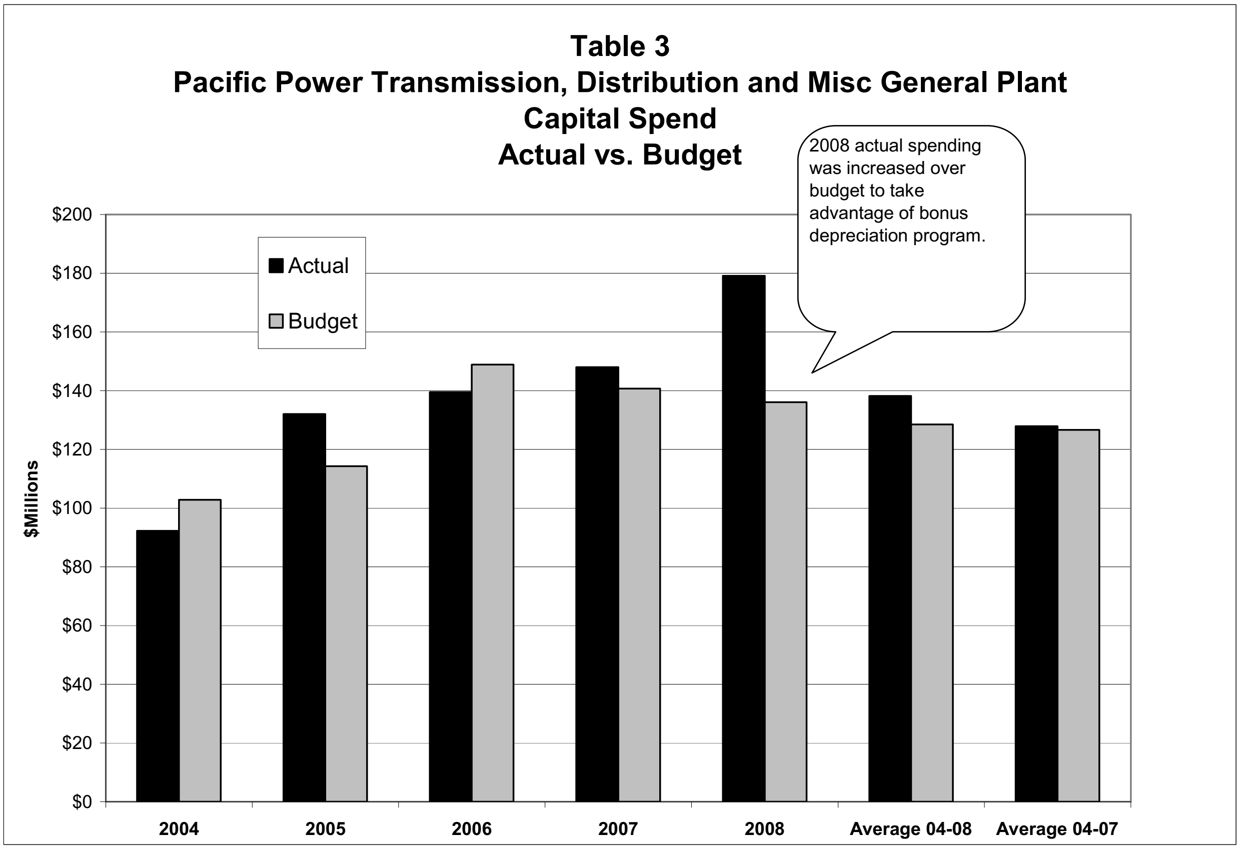
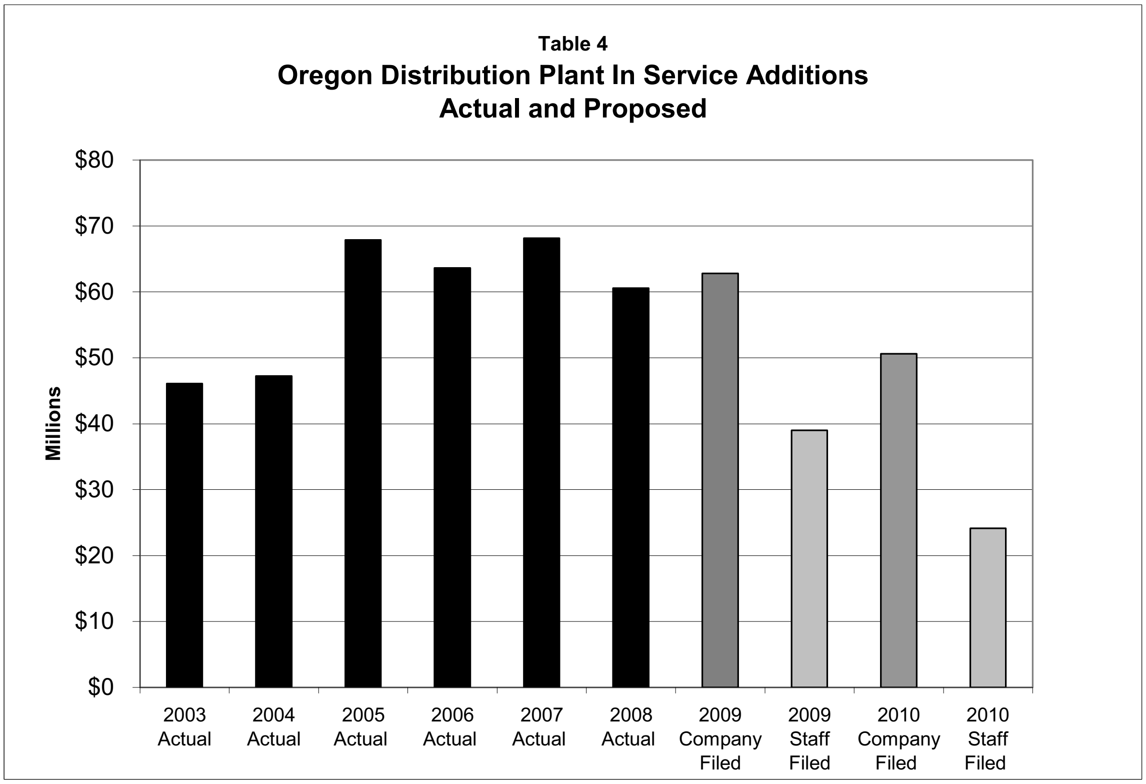


Table 3
Pacific Power Transmission, Distribution and Misc General Plant Capital Spend
Actual vs. Budget

Q. How do the distribution plant additions in the filing compare to previous years?

A. As shown in Table 4 below, the proposed Oregon distribution plant additions for 2009 and 2010 are consistent with the amounts delivered in recent years. Note that the budgeted level for 2010 included in the filing is less than 2008 actual expenditures or 2009 proposed expenditures. This is because the Company has already taken into consideration a slower customer growth rate due to the current economic conditions and because 2008 and 2009 included certain large distribution substation capacity projects being placed in service in Oregon. The table also shows that Staff's proposed cuts to distribution rate base would result in investment levels that are significantly below prior year expenditures since 2003, which could compromise the safety and reliability of the system. This table further demonstrates that the Oregon distribution costs included in the filing are reasonable.



Q. Does this conclude your testimony?

A. Yes.

Kenneth T. Houston
Exhibit PPL/1200

Docket No. UE-210
Exhibit PPL/1200
Witness: Kenneth T. Houston

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Kenneth T. Houston

August 2009

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

A. My name is Kenneth T. Houston; my business address is PacifiCorp, 825 NE Multnomah, Suite 1600, Portland, Oregon, 97232. My position is Director, Transmission for PacifiCorp.

Q. Have you previously filed testimony in this case?

A. No.

Q. What are your responsibilities?

A. In my current role, I am responsible for Open Access Transmission Tariff (" OATT") Administration, which includes responding to customer requests for interconnection to PacifiCorp' s transmission system and responding to transmission service requests. I am also responsible for managing the interconnection and contract requirements for open access customers and for interconnections with neighboring utilities.

Q. Please summarize your educational and professional background.

A. I hold a Bachelor' s Degree in electrical engineering and a Master' s Degree in management. I am registered as a professional engineer in Oregon, New Mexico, and Texas. I have held engineering design, operations, and management positions in distribution and transmission roles for three electric utilities over the past 27 years. My major responsibilities have included managing the OATT for the New Mexico assets of Texas New Mexico Power Company during the late 1990' s; developing the requirements, contracts, infrastructure, and staff training related to establishing a new control area in the Electric Reliability Council of Texas

(" ERCOT") during 1996 and 1997; and, beginning in 2000, regular interactions with several technical and market work groups established by ERCOT to develop the market protocols that were later utilized to implement retail competition and market deregulation in Texas.

Between 2001 and 2003, my employer was a newly established affiliate of Texas New Mexico Power Company, First Choice Power. My role was to purchase energy, fuel, and transmission rights as required to serve the competitively acquired retail customer base in the deregulated Texas market. In 2003, I accepted a position with PacifiCorp and have served in variations of my current role since that time.

Purpose and Summary

Q. What is the purpose of your testimony?

A. I respond to the testimony of Staff witness Mr. Ed Durrenberger, who proposes to disallow approximately $47 million from the Company' s rate base related to investment in the Company' s transmission system. Specifically, Mr. Durrenberger proposes adjustments to three transmission plant additions: the Three Mile Knoll substation, the Chappel Creek/Cimarex line extension, and the McClelland-Emigration tap upgrade.

Q. Please summarize your testimony.

A. My testimony demonstrates that these three investments are prudent capital additions to PacifiCorp' s network transmission system with costs appropriately allocated to Oregon under the Revised Protocol inter-jurisdictional cost allocation methodology. I demonstrate that the basis for Mr. Durrenberger' s adjustments are flawed and that the Commission should reject these proposed adjustments. Specifically, my testimony establishes that:

- The total cost for the Three Mile Knoll substation is prudent and reasonable when actually compared against a similarly situated substation;
- The costs of the Chappel Creek/Cimarex line extension were appropriately shared between Cimarex and PacifiCorp's other customers; and
- Both the Chappel Creek/Cimarex line extension and the McClelland-Emigration tap upgrade are transmission-level voltage projects that provide stability to PacifiCorp's network system and should be allocated consistently with the Revised Protocol.

Three Mile Knoll Substation

Q. Please summarize Mr. Durrenberger's proposed adjustment to the cost of the Three Mile Knoll substation.

A. Staff proposes to disallow $24 million of the Company's investment in the Three Mile Knoll substation by reducing rate base from $56 million to $32 million on a total-company basis. Staff asserts that the cost of the Three Mile Knoll substation is too high based on an informal e-mail exchange between Staff and the Bonneville Power Administration ("BPA") related to cost estimates of "similarly situated" substations. Mr. Durrenberger also raises concerns that PacifiCorp has inappropriately included costs for a potential expansion of the Three Mile Knoll substation in its rate base request.

Q. Do you have concerns with Mr. Durrenberger' s analysis of the substation?

A. Yes, I have several concerns. First, Mr. Durrenberger' s testimony and e-mail exchange with BPA incorrectly describe the characteristics of the substation, which then forms the basis for his cost comparison of " similarly situated" substations. The Three Mile Knoll substation has many unique characteristics and was constructed based on the results of a competitive procurement process to ensure that the costs are prudent and reasonable. Second, Mr. Durrenberger raises concerns regarding recovery of costs to accommodate future possible expansion. Designing a substation to accommodate future expansion is an appropriate undertaking that will benefit customers over time. I discuss each of these points in turn.

Q. In his testimony, Mr. Durrenberger describes the Three Mile Knoll substation as " a transmission level substation with a single 230-138 kV transformer and other switching gear." Is this description correct?

A. No. The Company provided a description of the Three Mile Knoll substation project in Exhibit PPL/702 at page 8.6.24. The description states: " The substation will consist of one 345-138 kilovolt, 700 megavolt-ampere transformer, three 345 kilovolt breakers, breaker-and-a-half protection scheme, and a 138 kilovolt switchyard."

Q. Do the plans or description provided by the Company in response to Staff data request 273 indicate a 230-138 kV substation?

A. No. All information provided by the Company describes a new 345-138 kV substation.

Q. Mr. Durrenberger notes that BPA indicated that its budgetary numbers used for similarly situated substations range from $17 to $25 million. Do you agree with this assessment?

A. No, based on the information requested and received by Staff from BPA, they neither asked for nor received budgetary numbers from BPA for a similarly situated substation; the range of costs received from BPA should therefore be disregarded. Exhibit PPL/1201 includes the Staff response to Company data request 3.1 and contains a copy of the informal e-mail exchange between Staff and BPA. It shows that Staff asked for " a high-level cost estimate" for a transmission substation that was different from Three Mile Knoll and received " ball park rough" numbers for substations that were different from Three Mile Knoll. Specifically, Staff requested cost ranges for transmission substations of 500 kV-345 kV or 345 kV-230 kV; BPA responds with numbers for 500 kV-230 kV. Therefore, Staff' s cost estimate is not relevant for the Three Mile Knoll substation. Furthermore, BPA' s e-mail notes, " Price will go up from here depending on the number of breakers and bays on both the low side (230kv) and number breakers and bays on the high side (500kv), and if capacitor banks are also needed, etc." This demonstrates that in order to have a reliable cost estimate, it is necessary to have a detailed scope of the functions, layout and design of the specific project.

Q. Are there unique characteristics of the Three Mile Knoll substation that need to be considered when making cost comparisons to other substations?

A. Yes, the substation has several unique features, including series compensation, a line reactor, and a substantial 138 kV yard including six line terminations. The 138 kV yard was constructed to replace an outdated 138 kV substation previously known as the Caribou station. The reconfigured 138 kV substation increases reliability for the 138 kV network by providing additional line breaker positions and a more reliable bus configuration.

Q. Has the Company recently constructed a 345-138 kV substation similar to the Three Mile Knoll substation?

A. Yes. The Company recently completed a 345-138 kV substation in the Salt Lake valley, known as the Oquirrh substation.

Q. How does the cost of the Oquirrh substation compare to the cost of the Three Mile Knoll substation?

A. Although the Three Mile Knoll and Oquirrh substations are not exactly alike, the cost of the Oquirrh substation was approximately $50 million. In other words, the cost to construct the Oquirrh substation is similar to the cost to construct the Three Mile Knoll substation.

Q. Did the Company conduct a competitive procurement process for the construction of the Three Mile Knoll substation?

A. Yes. PacifiCorp issued a request for proposals on November 14, 2006 to construct the Three Mile Knoll substation. After reviewing and evaluating the bids on a least-cost, risk-adjusted basis, the Company ultimately selected the successful bidder.

Q. Mr. Durrenberger indicates that the costs for the project include costs for possible future expansion. Do the plans provided by the Company in response to Staff data request 273 (Staff/402, Durrenberger/1-2) indicate a possible future expansion of the Three Mile Knoll substation?

A. Yes. As indicated in Attachment 273d to that data request, the Three Mile Knoll substation was designed to accommodate an expansion in the future, specifically a second 345-138 kV transformer. The second transformer would be added in the future to support reliability and load growth needs.

Q. Were any of the costs associated with designing the facility for potential future expansion of the Three Mile Knoll substation included in the Company' s request for inclusion in rate base?

A. Yes. The substation was designed, graded, grounded and fenced to accommodate future expansion. These are the only future expansion costs included in rate base in this proceeding.

Q. Why is it reasonable to include the costs associated with the accommodation for future expansion with the project costs in this proceeding?

A. It is prudent utility practice to recognize future expansion requirements during the initial design phase in order to achieve efficiencies that will, in the longer term, decrease costs to customers for the same level of service. When a new substation is constructed, the ultimate design is evaluated with this in mind. Property is purchased, grading is completed, and fencing and grounding are installed during initial construction to minimize the total installed cost of the ultimate design. This is accomplished by permitting the ultimate substation layout once, and incorporating a substation design that will not require substantial rework during future expansions.

Chappel Creek/Cimarex Line Extension

Q. Please summarize Mr. Durrenberger's proposed adjustment for the Chappel Creek/Cimarex line extension project ("Chappel Creek Project").

A. Staff proposes to disallow $15.6 million of the total-Company investment in the Chappel Creek Project. The adjustment is based on the following erroneous assumptions: (1) the project was completed for the sole benefit of a single customer that should be responsible for all costs above the line extension allowance; and (2) the line extension was a general distribution improvement in Wyoming and therefore should be paid for by Wyoming customers.

Q. Do you agree with Staff's claim that the Chappel Creek Project was completed for the sole benefit of a single customer, Cimarex Energy?

A. No. The Chappel Creek Project was identified as the least-cost alternative to address overloaded 69-kV transmission lines and deteriorating transmission voltage levels in the Pinedale area of Wyoming. For the most part, the Chappel Creek Project would have been completed irrespective of Cimarex Energy's load request.

Sublette County, Wyoming is an area of significant load growth in which there are large industrial customers who have requested load service, such as Cimarex and Air Products. In addition, many small commercial and industrial customers in the Big Piney and Pinedale area are also requesting additional service due to load growth. Because the 69 kV transmission line between

Labarge and Big Piney had reached voltage and thermal limits, all customers in Sublette County will benefit from these transmission upgrades.

The master plan for the area includes additional transmission infrastructure to be installed from Chimney Butte to Paradise and from Paradise to Jonah Field and onto a future substation on the Atlantic City-Rock Springs line. This will create a network transmission path that is an integral part of the PacifiCorp transmission network. Completion of this ultimate layout also adds to the reliability of the main grid transmission system.

Q. Were any elements of the Chappel Creek Project constructed for the sole benefit of Cimarex Energy?

A. Yes. Certain elements of the project were constructed solely to accommodate a 50 MW service request by Cimarex Energy. For example, the 230 kV transmission line between the Chimney Butte substation and the Cimarex facility is being constructed for the sole purpose of serving Cimarex Energy' s 50 MW load request.

Q. Were the costs for any elements of the project shared between PacifiCorp and Cimarex Energy?

A. Yes. Certain elements of the project were a necessary transmission system improvement, accelerated by Cimarex Energy' s load request. The costs for those elements were allocated on a *pro rata* basis between Cimarex Energy and the Company, based upon the percentage of capacity required to accommodate the load request. For example, it was necessary for PacifiCorp to address the existing 33 MW load in the area. One solution considered by the Company was to construct a 230 kV line to Chimney Butte and install a 230-69 kV transformer. Per PacifiCorp's standards, the smallest conductor used on 230 kV is 795 ACSR (aluminum conductor steel reinforced).

Also during this time, Cimarex requested a 230 kV connection to serve its 50 MW of load in the same area. This also would have required a 230 kV line to be built from the Chappel Creek substation to Cimarex. As previously discussed, PacifiCorp also identified the need for a future 230 kV transmission loop through the Upper Green Basin to a future substation to be located on the Atlantic City – Rock Springs 230 kV line. The total cost of these three projects is far greater than a project that would solely benefit Cimarex. The 50 MW Cimarex request and the 33 MW general Company need totaled 83 MW. Thus the cost sharing arrangement was established so that Cimarex was responsible for 50/83, or approximately 60 percent.

The Company further decided to install a high capacity conductor 1272 ACSR as part of an overall plan to upgrade the transmission network in southwest Wyoming and to provide enhanced long-term reliability. The costs of the conductor and the 40 percent share of the base cost of the total project are the basis of the Company rate base request in this proceeding. The proposed solution solves Cimarex's load request, solves PacifiCorp's immediate need to serve existing load in the area, and builds the first leg of a future 230 kV transmission path through a congestion portion of the Wyoming network – all in a cost-effective manner.

Q. Was Cimarex provided a line extension allowance for their portion of the Chappel Creek Project?

A. Yes, in part. As part of the 2005 Wyoming general rate case, PacifiCorp' s line extension tariff in Wyoming (Rule 12) was amended to eliminate the extension allowance for transmission voltage line extensions. As part of the transition, customers who had reached a certain point in line extension negotiations were grandfathered under the existing line extension tariff. Cimarex Energy originally requested 25 MW of load service under the pre-2005 line extension tariff. Subsequent to the elimination of the line extension allowance, Cimarex Energy requested an additional 25 MW of load service. Although Cimarex Energy total requested load service was 50 MW, it was only provided an allowance for 25 MW.

Q. Mr. Durrenberger suggests that this project is a distribution improvement, not transmission. Is this correct?

A. No. This project is clearly transmission related. Both the Federal Energy Regulatory Commission (" FERC") and PacifiCorp classify lines at 46 kV and above as transmission.

Q. How are costs for transmission investments allocated under the Revised Protocol for inter-jurisdictional cost allocations?

A. Under the Revised Protocol adopted by the Commission in Order No. 05-021, costs associated with transmission assets are classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated among the states based upon the

System Generation (" SG") factor. The costs for this project were properly allocated in the Company' s filing based on the Revised Protocol.

McClelland-Emigration Tap Upgrade

Q. Please provide a brief description of the McClelland-Emigration tap upgrade project (" McClelland Project").

A. The foothill area of Salt Lake City is served by two 46 kV transmission line feeds from the McClelland substation, which are operated on a looped system. The area includes several hospitals, a university, and approximately 15,000 residential customers. Due to increased demand for electricity in recent years, system upgrades were required to support reliable load service in the area, especially during summer peak conditions. During any contingency in the area, lines became overloaded, shifting load and overloading adjacent lines, resulting in cascading outages throughout the system. To remedy the problem, the Company upgraded the transmission system to 138 kV by installing larger conductor and poles.

Q. Please summarize Staff' s adjustment to the costs for the McClelland-Emigration tap upgrade.

A. Mr. Durrenberger proposes that the costs of the McClelland Project be assigned solely to Utah customers because, he argues, it only serves a narrow subset of Utah customers and does not benefit Oregon customers. Mr. Durrenberger states that he views these costs as " more akin to distribution costs and not transmission costs given the need and use of the line." Staff/400, Durrenberger/4. His adjustment removes approximately $7.4 million from total Company rate base, or $2 million on an Oregon-allocated basis.

Q. Do you agree with Staff' s characterization of the McClelland Project as being " more akin to distribution costs" ?

A. No. As discussed above, both the FERC and PacifiCorp classify lines at 46 kV and above as transmission. The McClelland Project was required to upgrade an existing 46 kV transmission system to 138 kV. In other words, the cost of this transmission asset is clearly a part of the PacifiCorp transmission network and should be allocated among the states in accordance with the Revised Protocol.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/1201
Witness: Kenneth T. Houston

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Kenneth T. Houston

OPUC Response to PacifiCorp' s Data Request

August 2009

August 10, 2009

TO: Katherine McDowell
Counsel for PacifiCorp

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 210
PacifiCorp's Third Set of Data Requests to OPUC
Dated July 30, 2009 – Due August 10, 2009
Data Requests 3.1-3.6

Request:

3.1 See Staff/400, Durrenberger/3, lines 3-6. "I asked the Bonneville Power Administration (BPA) for a cost range for similar transmission voltage substations. The BPA indicated that budgetary numbers used for similarly situated substations would range from $17 to $25 million."

a. Please provide the names and positions of all personnel at the Bonneville Power Administration who were contacted regarding the Threemile Knoll substation.

b. Please provide any and all documentation, including contingency capacity required for reliability purposes provided by the BPA to support a range of $17 to $25 million for a similarly situated substation.

c. Please provide analysis that indicates the level of communications infrastructure included in the BPA pricing, particularly any provisions made for remedial action schemes required for generator tripping.

d. Please detail what considerations were used to define a "similarly situated" substation.

Response:

3.1

a. The individual consulted at BPA was Mr. Leon Kempner. He was contacted by JR Gonzalez, the Program Manager of the Utility Safety and Reliability Group at the PUC. Mr. Kempner indicated that the information he provided came from the BPA Substation Design Group.

b. The only document I have supporting the BPA estimate is a copy of the Email message Mr. Kempner sent to JR Gonzalez and forwarded on to me.

c. I do not have any communications infrastructure analysis supporting this adjustment.

d. The information supplied to Mr. Kempner was limited to the description of the substation contained in PacifiCorp Exhibit 702, item 8.6.24 which is the information provided by PacifiCorp in the Rate Case Filing.

Exhibit PPL/1201
Houston/2

From: GONZALEZ JR
Sent: Monday, June 22, 2009 7:27 AM
To: DURRENBERGER Ed
Subject: FW: Transmission Substation Cost Range

Ed,

Below is the response on reasonable cost range for a substation from my contact at BPA. It is what we were talking about... When you get some time, let's talk about it...

Thanks,

J. R. Gonzalez, P.E., Administrator
Safety, Reliability & Security Division
Oregon Public Utility Commission
550 Capitol St. NE, Suite 215
Salem, OR 97308-2148
503-373-1531
503-373-7752 (Fax)

From: Kempner,Leon Jr - TEL-TPP-3 [mailto:lkempnerjr@bpa.gov]
Sent: Wednesday, June 17, 2009 4:59 PM
To: GONZALEZ JR
Subject: RE: Transmission Substation Cost Range

JR,

The information below is what I was able to obtain from our Substation Design Group. I hope it helps.

Leon

Based on some recent projects at 500/230kv here are some "ball park rough" numbers:

17Million for a three bay 230 yard (with four breakers for three circuits) with little 500kv yard (no breakers, one circuit) and a 500/230kv 1300 mva transformer

25Million for a three bay 230 yard (with four breakers for three circuits) and minimum 500kv yard (three breakers, two circuits) and a 500/230kv 1300 mva transformer

Price will go up from here depending on the number of breakers and bays on both the low side (230kv) and number breakers and bays on the high side (500kv), and if capacitor banks are also needed, etc.

From: GONZALEZ JR [jose.gonzalez@state.or.us]
Sent: Tuesday, June 16, 2009 4:41 PM
To: Kempner,Leon Jr - TEL-TPP-3
Subject: Transmission Substation Cost Range

Leon,

Hello!

I am trying to get a cost range for building a transmission sub (500 KV-345KV or 345KV-230KV), single transformer bank. I am looking for a high-level cost estimate, so I can make an educated decision on a study we are performing. For example, would a cost range of $15 million to $30 Million be a reasonable cost range for the above?

I hope you can help me.

Thanks,

J. R. Gonzalez, P.E., Administrator
Safety, Reliability & Security Division
Oregon Public Utility Commission
550 Capitol St. NE, Suite 215
Salem, OR 97308-2148
503-373-1531
503-373-7752 (Fax)

Erich D. Wilson
Exhibit PPL/804

Docket No. UE-210
Exhibit PPL/804
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Erich D. Wilson

August 2009

Q. Are you the same Erich D. Wilson who previously provided testimony in this docket?

A. Yes, I am.

Purpose and Summary

Q. What is the purpose of your reply testimony?

A. The purpose of my testimony is to respond to certain labor and benefit cost adjustments proposed by the Staff of the Oregon Public Utility Commission ("Staff") witnesses Ms. Lisa Gorsuch and Mr. Dustin Ball, and the joint witness for the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon ("ICNU-CUB"), Ms. Ellen Blumenthal. Specifically, I respond to proposed adjustments related to the Company's Annual Incentive Plan, medical benefits, 401(K) plan, pension administration expense, and worker's compensation insurance.

Q. Please summarize your testimony.

A. My testimony explains that:

- As a result of the emphasis on cost control, the Company's total wages and benefits remain almost constant, with only a one percent increase over the last four years. Moreover, the labor costs and benefits requested in this case are actually lower on a per megawatt-hour basis than those incurred in 2006.
- The Company's Annual Incentive Plan is an integral part of the Company's compensation strategy, and implements a "pay-at-risk" approach that provides proper incentives to both executive and non-executive employees for the achievement of important Company goals. Because target pay under the plan

is set at market levels, reducing incentive pay as recommended by Staff and ICNU-CUB would result in below-market salaries for the Company' s workforce, limiting the ability to attract a competitive workforce and thus jeopardizing the Company' s safety, reliability, efficiency, and customer service goals.

- The Company' s health care expenses are based on careful research into medical care costs conducted specifically for the Company based on industry and Company-specific data. The Company' s health care expenses thus reflect the best forecast of costs for the test period. In contrast, the reductions proposed by Staff are based on more general and less accurate data.
- The Company accepts Staff' s proposed adjustment related to 401(K) expense. The ICNU-CUB proposed adjustment to 401(K) is absorbed within Staff' s adjustment, therefore no further adjustment is necessary.
- The Company' s pension administration expense included in the case is reasonable and properly reflects the expected costs in the test period.
- The Company accepts Staff' s proposed worker' s compensation insurance adjustment because it reflects an updated cost based on information that has become available since the initial filing.

Q. Are there labor-related adjustments proposed in this case that you will not be addressing?

A. Yes. Mr. R. Bryce Dalley will be addressing Ms. Blumenthal' s proposed adjustment to the Company' s forecast FTE/employee count, and her adjustment to the Company' s Oregon allocation factor for labor. Also, Mr. Bruce N. Williams will be responding to Mr. Ball's proposed adjustment to FAS 87 pension expense and FAS 106 post retirement benefits.

Background

Q. Please place in perspective the labor costs the Company is seeking to recover in this case?

A. Overall the Company is seeking approximately $539 million in labor expenses, including base pay, incentive compensation, pension and benefits costs. As discussed in my direct testimony, this amount is less than one percent higher than the approximately $534 million in labor expenses that were included in the Company's last rate case filing - UE 179 - which had a test period of 2007. Moreover, when compared with the Company's actual labor costs incurred in 2006 of $533 million, the request in this case represents an increase of less than 1 percent over four years. On a dollar-per-megawatt hour basis, the request in this case represents a 3 percent decrease since 2007. Thus, even in the face of increasing loads, rising medical costs and negotiated wage increases, the Company is holding the line on labor costs.

Q. How has the Company managed to contain labor costs in the current environment?

A. The Company's success is due primarily to the emphasis on cost control brought by MidAmerican Energy Holdings Company ("MEHC"). Consistent with this new emphasis, the Company has implemented a workforce restructuring program that has allowed a reduction in staffing in key areas without compromising the critical goals of safety, reliability and customer service. In addition, the Company has continued to re-design health, welfare, and retirement plans to shift more responsibility from the Company to employees. Thus, despite the fact that Staff and ICNU-CUB recommend numerous specific adjustments to the filing, the Commission should not lose sight of the fact that the Company's labor costs reflect substantial cost reductions.

Q. Has the Company implemented other changes due to MEHC ownership that are relevant to your testimony?

A. Yes. In addition to efficiency, MEHC places a heavy emphasis on safety, system reliability and customer service. For this reason, the incentive and merit pay programs are more focused than ever on the successful attainment of these goals.

Q. Can you provide examples showing the Company's commitment to attaining goals in these areas?

A. Yes. The following achievements are evidence of the Company's commitment to safety, system reliability and customer service:

- Pacific Power is continuing to improve in virtually all customer service and customer satisfaction metrics, as demonstrated by the J.D. Power and TQS Research customer service surveys. Most recently, Pacific Power was ranked number one in overall customer satisfaction among large industrial customers in a TQS Research survey. The Company is also on target to meet goals for improvement in customer guarantee failures, billing accuracy, and Commission complaints.
- Pacific Power is on target to meet its goals for improving safety performance by meeting improvement goals in the majority of its key safety metrics,

including recordable incident and accident rates, lost time incidents, and restricted duty incidents.

- Pacific Power has seen improvements in service quality measures, including Average Interruption Duration and Average Interruption Frequency.

Q. What conclusions do you draw from these improvements relevant to your testimony?

A. I conclude that the Company' s compensation and benefits policies are working. In particular, the compensation and benefit packages are competitive enough to attract and retain the workforce needed to support customers. Further, the Company' s incentive pay programs motivate employees to perform at an excellent level to meet the Company' s goals of safety, reliability and customer service, all to the benefit of customers and the Company.

Proposed Adjustments To Annual Incentive Plan Expense

Q. Please describe the Company' s Annual Incentive Plan as it is currently structured.

A. In order to attract, motivate, develop and retain a highly qualified workforce, the Company' s philosophy is to provide total remuneration which, when employees' performance is at desired levels, is equal to the average remuneration provided by the Company' s competitors for labor. In other words, the Company' s goal is to set target wages and benefits at the market average.

The intent of the Company' s Annual Incentive Program is to put some of the competitive total remuneration " at risk." The portion of pay " at risk" is the guideline (or target) incentive percentage assigned to a particular job. In exceptional performance years, the incentive payment for a specific employee may be more than target and in low performance years may be below target, but on average, the incentive is generally at the guideline level. If the individual fails to earn the full guideline incentive, that individual will be paid less than the competitive total cash compensation in the marketplace for that year.

Q. On the whole, when considered over all eligible employees, does the Company ever pay out an amount in incentive pay that exceeds target?

A. No. While some employees will earn above target, others will earn below, and on the whole, the Company pays out no more than target compensation.

Staff Adjustment

Q. Please describe Staff witness Ms. Gorsuch's proposed adjustments to PacifiCorp's Annual Incentive Plan expense.

A. Ms. Gorsuch proposes that the Commission disallow 100 percent of officer bonuses and 50 percent of what she refers to as "merit-based bonuses." These proposals result in Staff's proposed reductions to test period incentive expense of $3.5 million to operations and maintenance ("O&M") and $1.4 million to rate base, on an Oregon-allocated basis.

Q. What reasons does Ms. Gorsuch offer for her recommendation?

A. Ms. Gorsuch states that her proposals are based on Commission policies which she suggests are to automatically disallow: (1) 100 percent of officers' bonuses and incentives because they are "typically based solely on increased earnings"; (2) 75 percent of performance based incentives because they are "generally focused on increased earnings" ; and (3) 50 percent of merit-based bonuses because they " equally benefit shareholders and ratepayers."

Q. Do you agree with Ms. Gorsuch's proposed adjustment to incentive pay expense?

A. No. First, from an overall standpoint, reducing incentive expense will result in employees being underpaid. As I explained in my direct testimony, incentive pay is not " extra pay." Rather, incentive pay is an integral portion of a competitive level of pay. As such, it constitutes a reasonable expense that is necessary to the successful operations of the Company. Any reduction below the competitive target incentive level would place the Company in a position of not being able to offer competitive pay levels and placing operational and customer objectives at risk. Second, I believe it would be inappropriate for the Commission to disallow a portion of a competitive level of pay simply because it is in the form of an incentive payment. PacifiCorp has adopted an incentive program with a " pay at risk" component based on the Company's belief that such a policy is the best approach for encouraging higher employee performance. If the Commission routinely and automatically disallows a portion of market compensation simply because it is incentive pay, it will effectively be encouraging the Company to drop its " pay at risk" policy in favor of a system of flat salaries that are paid to employees regardless of performance. If this were to occur, customers would lose what I believe are substantial benefits from the Company's current program.

Q. Do you agree that the Commission should disallow incentive payments that benefit shareholders?

A. No. In fact, a singular focus on whether a payment benefits shareholders misses the mark. Instead, the focus should be on whether an incentive program is designed to benefit customers.

Q. Please explain.

A. At the outset, I do not agree that it is the Commission' s policy to automatically disallow incentive payments that benefit both shareholders and customers. Instead, I believe that what the Commission has traditionally attempted to do is to disallow incentive payments - or portions of incentive payments - to the extent that they reward goals that are designed to benefit *only* shareholders.

Moreover, the framework proposed by Ms. Gorsuch is predicated on a mistaken belief that shareholder and customer benefits are always in conflict. In fact, the Company' s employee policies are based on the belief that the opposite is true. That is, PacifiCorp is most successfully operated when customer and shareholder goals are in alignment, and goals that contribute to the successful operations of the Company benefit shareholders and customers alike. There is no reason to disallow incentive payments that reward such goals.

Q. Do you agree that rewards tied to all financial goals are unrecoverable?

A. No. While goals tied to profits benefit shareholders, goals that encourage efficiency and cost-containment benefit customers as well. For this reason a payment tied to cost-containment goals should not be disallowed.

Q. Has the Company structured the Annual Incentive Plan with these principles in mind?

A. Yes. The Company has taken care to ensure that all goals selected for incentive payments relate to the delivery of safe, reliable and efficient electric service to customers.

Q. Can you provide more detail on employee goals?

A. As I explained in my direct testimony, all employees have individual and group goals. The group goals describe characteristics that the Company believes are important to the success of all employees, such as customer focus, job knowledge, planning and decision making. The individual goals are tailored for each employee to describe how that employee can further the Company's priorities in six key areas: Safety and Employee Commitment, Operational Excellence, Customer Service, Financial Strength, Regulatory Integrity and Environmental Respect.

Q. Do the financial goals relate to corporate profits?

A. No. The financial goals are tied to cost containment measures such as reducing overtime, and developing and meeting budgets.

Q. Have you provided samples of individual goal sheets for several employees?

A. Yes. Attached is Exhibit PPL/805, which contains copies of 2009 individual objectives for three actual employees classified from analyst to manager level. The group includes a Dispatch Supervisor, Distribution Manager, and a Business Analyst. (The names have been redacted to protect employee privacy.) As you can see, each employee has between one and five key objectives that serve as goals for the year. Each objective is described in detail. Next, each objective is assigned a set of concrete goals by which they will be measured and a weighting for that particular objective. All of the employees' goals focus on objective outcomes that are closely tied to safety, efficiency, reliability and customer service. None of them are tied to the Company's financial performance. Moreover, each goal sheet reflects the significant attention and effort that goes into tailoring these for each employee.

Q. Ms. Gorsuch states that incentive payments to Company officers should be disallowed because they are generally connected to financial goals. What is your response?

A. It is true that corporate officers are responsible for the financial health of the utility. For that reason their performance goals may, unlike the goals for other employees, include ensuring adequate revenues in addition to cost containment. However, both of these types of goals benefit customers by ensuring that the Company is financially healthy to allow it to make the investments necessary to serve customers. There is therefore no reason to automatically disallow Annual Incentive Plan payments to officers.

Q. Does the Company offer any incentive pay programs that are tied solely to corporate earnings?

A. Yes. The Company offers a long-term incentive program to select senior management employees. This plan is based on MEHC net income improvement and is vested over a five-year cycle. The Company is not requesting recovery of any costs associated with this program.

Q. Has the Company made changes to the Annual Incentive Plan in response to Commission feedback?

A. Yes. In 2006, the Company adjusted its Annual Incentive Plan in response to feedback from the Commission. Prior to that time, the Company sought recovery of all awards made to employees under the plan, whether or not those awards resulted in total employee compensation that was above a target (competitive market) level. In response to the Commission's previous decisions on recovery of employee compensation, including incentives, the Company now seeks to recover only that portion of incentive payments that result in compensation at the target level.

<u>ICNU-CUB Adjustment</u>

Q. Please describe the ICNU-CUB witness Ms. Blumenthal's proposed adjustment to the Annual Incentive Plan.

A. Ms. Blumenthal proposes reducing the incentive level in the filing by approximately $12.3 million on a total-company basis and $3.6 million on an Oregon-allocated basis.

Q. What reasons does Ms. Blumenthal give for her adjustment?

A. Ms. Blumenthal reasons as follows: The employees work for the Company, which has two stakeholders - customers and shareholders. When the Company operates efficiently both groups benefit. Therefore both groups should share the costs of the incentive plan.

Q. Do you agree?

A. No, as I stated above, if the incentive pay is a component of market compensation, and if the goals of the plan are designed to benefit customers, then the Company should be allowed to recover the cost of the plan. Whether or not shareholders also benefit should not be the issue.

Q. Does Ms. Blumenthal offer any criticism of the Annual Incentive Plan?

A. Yes. Ms. Blumenthal argues that the Company has offered no evidence that the Annual Incentive Plan is effective at producing higher than average performance. Moreover, Ms. Blumenthal even suggests that the plan might be counterproductive, arguing that studies show that "many employees actually perform worse when there is a promise of a large bonus if certain goals are reached . . . ." ICNU-CUB/400, Blumenthal/9.

Q. What do you make of Ms. Blumenthal's concern?

A. I do not share Ms. Blumenthal's concern, in particular as it relates to PacifiCorp's Annual Incentive Plan. I am aware that there are differences of opinion as to what type of incentive plans are most effective in encouraging employee performance. For instance, the study cited by Ms. Blumenthal suggests that too large of an incentive might distract an employee from performance. However, human resource experts are overwhelmingly of the opinion that a well-crafted incentive plan with a pay-at-risk element will produce superior performance. In my opinion, the Annual Incentive Plan is just such a program.

Staff's Proposed Adjustment To Medical Health Care Benefits

Q. Please describe Staff witness Mr. Ball's proposed adjustment to PacifiCorp's health care expense.

A. Mr. Ball proposes two changes to the Company's health care expense, resulting in a single adjustment. First, Mr. Ball proposes adjusting the health care benefits expense to reflect a 6.5 percent increase over 2009 budget as opposed to the 8.0 percent proposed by the Company. Second, Mr. Ball proposes his own method to reflect employee/employer sharing of costs premium costs. Taken together, these proposals result in Mr. Ball's recommendation for a reduction to operating expenses of $3.6 million on a total-system basis, and $1.0 on an Oregon-allocated basis.

Q. What reasons does Mr. Ball give for his proposal to use a 6.5 percent escalation factor instead of an 8 percent escalation factor?

A. Mr. Ball bases this proposal on a news release issued by Hewitt Associates ("Hewitt") dated September 22, 2008, in which Hewitt projects a 6.4 percent increase in health care costs for employers in 2009.

Q. Do you agree that it is reasonable to apply this Hewitt projection to PacifiCorp's health costs for 2010?

A. No, for two reasons. First, the September 2008 Hewitt projection relied on by Staff appears to be based on a generic overview of medical costs for all industries in all geographic areas. It should be noted that the release specifically notes that there is significant regional variation in health care costs. On the other hand, the escalation factor used by the Company was developed by Hewitt specifically for

PacifiCorp, based on information that is specifically tailored for and drawn from the Company's experience and plan design. In particular, during each year, the Company provides Hewitt with demographic information about the Company's employees, claims experience and market conditions. Hewitt takes all of this information and, in combination with its own data, forecasts the Company's expected expense. This process results in a significantly more accurate forecast.

Second, the projection cited by Mr. Ball is nearly a year old at this point and was intended to predict costs for 2009, not 2010, the test period in this case.

Q. How does Mr. Ball's calculation of the employer/employee sharing percentages differ from the Company's?

A. The sharing percentages included in the Company's calculations are based on advice from Hewitt, considering all of the known information as the actual percentages applicable to each category of employee. The aggregate sharing proportion calculated by Hewitt is approximately 82/18. Mr. Ball attempted to perform a calculation similar to Hewitt, but using incomplete, and in one case, erroneous information. Specifically, Mr. Ball relied on the projected sharing information for each employee grouping contained in the Company's response to Staff's data request 86. That response states that the goal sharing for non-union employees is 80/20. However, after factoring in variances from that goal for the various types of programs available to those employees (such as high vs. low deductibles) Hewitt projects an effective sharing proportion of 82/18. Moreover, in performing his calculations, as shown on Staff/202, Ball/3, Mr. Ball has used the wrong percentage for the employer portion of health care costs for the UWUA

127 and 197 employee groups. Specifically, Mr. Ball shows a sharing percentage for those groups as 80/20 instead of the correct proportion, 87/13, which is correctly shown in data request 86.

Staff' s Proposed Adjustment To 401(K) Expense

Q. Please describe Mr. Ball' s proposed adjustment to the Company' s 401(K) expense.

A. At the time PacifiCorp prepared this case it did not have data for its 2009 401(K) expense. For that reason, the Company estimated this expense for 2010 by taking the 2008 budgeted expense and then applying an annual escalation factor of 4.7 percent to reach a 2010 forecast. Mr. Ball requested and received actual data for the Company' s 401(K) expense for the first quarter of 2009 and used this information as his starting point. Mr. Ball annualized this data and escalated the result to 2010 using a 2.5 factor. Mr. Ball' s method results in his recommendation that 401(K) expense be reduced by $9.2 million on a total-system basis, and $2.6 million on an Oregon-allocated basis.

Q. Do you agree with Mr. Ball' s proposed adjustment?

A. Yes, although the Company does not necessarily agree with the method Mr. Ball used, the overall result is reasonable.

ICNU-CUB' s Proposed Adjustment To 401(K) Expense

Q. Please describe Ms. Blumenthall' s proposed adjustment to 401(K) expense?

A. Ms. Blumenthall adopts a correction identified in discovery to the Company' s enhanced 401(K) costs.

Q. Do you agree with this proposed adjustment?

A. Yes; however, Mr. Ball also incorporates this correction in his adjustment to 401(K). Since the Company has adopted Mr. Ball's proposed adjustment, no further adjustment is necessary to reflect this correction.

Staff's Proposed Pension Administration Expense Adjustment

Q. What does Mr. Ball propose with respect to the Company's pension administration expense?

A. Mr. Ball proposes a reduction in pension administration expense of $211,698 on a total-Company basis, or $59,820 on an Oregon-allocated basis. Mr. Ball states that the Company's actual pension administration expense for 2007 was $926,312 and for 2008 was $339,567. Mr. Ball states that due to the varying nature of the expense, Staff proposes to include the pension expense amount included in the base period, adjusted for inflation - $666,759. He claims that Staff's adjustment is close to the simple average of the actual 2007 and 2008 expense of $632,440.

Q. Do you agree with Staff's proposed adjustment?

A. No. The Company incurred an unusually low level of pension administration expense in 2008 that is not representative of what the Company can expect to incur in the future. In 2008, the Company did not incur costs related to certain union negotiations because the parties settled early or deferred negotiations. The events in 2008 were unusual and cannot be expected to occur in the test period. Therefore, it is unreasonable to use 2008 as half of the calculation of pension administration expense as Staff has.

Q. What is your position on the methodology Staff has proposed for calculating the adjustment to the pension administration expense?

A. The Commission should reject Staff's proposed methodology. It is not clear why Staff has chosen to use the base period expense for this adjustment, while using actual annualized 2009 results to calculate the adjustment to the 401(K) expense. If Staff applied that same methodology to pension expense, the expense would actually *increase* by $132,495 on an Oregon basis. There is no reason for Staff to annualize actual 2009 results for one expense while using a different methodology to adjust a similar expense.

Q. How do you propose the Commission resolve this issue?

A. I propose that the Commission reject Staff's proposed adjustment on the basis that consistent methodologies should be utilized for similar adjustments.

Staff's Worker's Compensation Insurance Adjustment

Q. Please describe Mr. Ball's proposed adjustment to worker's compensation insurance costs.

A. Mr. Ball proposed that the Company's proposal for worker's compensation insurance costs be reduced by $1.8 million on a total-system basis, and $0.5 million on an Oregon-allocated basis.

Q. What reason does Mr. Ball give for this adjustment?

A. Mr. Ball's proposal is based on the Company's 2008 worker's compensation insurance budget, escalated for 2010. Mr. Ball used the Company's 2008 actual expense, and escalated this number instead.

Q. Do you agree with Mr. Ball' s adjustment?

A. Yes. Since the time the Company filed the case, the Company not only has the actual 2008 expense numbers as a point of reference, but has been able to renegotiate the rates based on those numbers. The resulting worker' s compensation expense budget for 2009 shows Mr. Ball' s adjustments to be reasonable.

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE PUBLIC UTILITY COMMISSION

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PACIFICORP

Exhibit Accompanying Reply Testimony of Erich D. Wilson

Examples of Employee Goals

August 2009

#1

2009 Performance Management

Review Period: 01/01/2009 to 12/31/2009

General Information

Employee Information

Last Name	First Name	Middle
Supervisor, Dispatch	**00001027**	
Title	..	..

Manager Information

Name	Title

Section I - Objectives

Weighting of Objectives: 70%

Keeping in mind that your goals should be a component of your department or business unit's goals, list in order of importance the main duties, tasks, projects or goals for the appraisal period. As in the past, each employee is required to have a safety goal.

Section I - Objectives: 1 of 5

Objective Name — Weight 10%

Safety and Employee Commitment Goals

Description

To ensure that Pacific Power T&D Operations' employees understand that safety is our number one priority, our goal is to increase safety awareness and compliance at all levels within Transmission and Distribution (T&D) Operations. This requires T&D Operations to develop a true "Safety Culture", implement an accident free work environment philosophy, and actively support and deliver the MidAmerican/Pacific Power Health and Safety

Improvement Plan for T&D Operations.

Measurement

The deliverables for T&D Dispatch to achieve this are as follows:

- Meet or exceed Pacific Power lost time accident rate target
- Meet or exceed Pacific Power recordable incident rate
- Meet or exceed Pacific Power preventable vehicle accident rate
- Maintain 85% of department first aid and CPR trained
- Deliver MidAmerican Energy Holding Company Safety Improvement Plan
- Deliver safety training to all T&D Dispatch employees as outlined by the Health & Safety Department

Section I - Objectives: 2 of 5

Objective Name — Weight 20%

Operational Excellence

Description

T&D Operations' goal is to ensure that high standards are met for our operations and system performance.

T&D has implemented initiatives to ensure that our operations operate as centers of excellence. To demonstrate this, T&D commits to improving service quality by achieving targeted metrics in states we serve.

Measurement

The deliverables for T&D Dispatch to achieve this are as follows:

- Deliver Grid Operations and Dispatch transmission switching orders with no more than 3 switching errors. (Dispatch & Grid control errors in total)
- Deliver Dispatch distribution switching orders with no more than 6 switching errors. (PCC & SCC control errors in total)
- Training delivered to dispatchers per schedule
- Achieve the system annual average interruption frequency index (SAIFI) per customer in Rocky Mountain Power
- Achieve the system annual average interruption

duration index (SAIDI) per customer in Rocky Mountain Power

- Achieve the annual customer average interruption duration index (CAIDI) per occurrence in Rocky Mountain Power
- Achieve a system annual average interruption frequency index (SAIFI) per customer of 1.32 in Pacific Power
- Achieve a system annual average interruption duration index (SAIDI) per customer of 149 minutes in Pacific Power
- Achieve an annual customer average interruption duration index (CAIDI) per occurrence of 111 minutes in Pacific Power

Section I - Objectives: 3 of 5

Objective Name — Weight 20%

Customer Service

Description

T&D Operations' goal for customer service is to continue focusing on delivering reliability, dependability, and exceptional services to our customers. This has required T&D Operations to develop and execute plans to improve stakeholder satisfaction, customer service levels and customer perceptions.

Measurement

The deliverables for T&D Dispatch to achieve this are as follows:

- No more than 230 commission complaints in Pacific Power
- No more than 266 commission complaints in Rocky Mountain Power
- No more than 188 customer guarantee failures in Pacific Power
- No more than 217 customer guarantee failures in Rocky Mountain Power
- Restore 85% of customers off supply within 3 hours in Pacific Power
- Restore 85% of customers off supply within 3 hours in Rocky Mountain Power
- Maintain Call to Assign time of 40 minutes for PacifiCorp
- Improve Pacific Power residential customer satisfaction to first quartile ranking in Western Region as measured by J.D. Power survey

- Improve Pacific Power small and medium size business satisfaction to second quartile ranking in Western Region as measured by J.D. Power survey
- Improve Pacific Power large industrial customer satisfaction to number 1 as measured by TQS Research Inc survey
- Maintain Rocky Mountain Power residential customer third quartile satisfaction ranking in Western Region as measured by J.D. Power survey
- Maintain Rocky Mountain Power small and medium size business third quartile satisfaction ranking in Western Region as measured by J.D. Power survey

Section I - Objectives: 4 of 5

Objective Name | Weight 5%

Financial

Description

Pacific Power T&D Operations' financial goal is to retain the financial integrity of MidAmerican by achieving its financial targets.
Efficiency initiatives have been put in place to ensure that T&D Operations is maximizing the MidAmerican investment.

Measurement

The deliverables for T&D Dispatch to achieve this are as follows:
- Achieve Pacific Power OMAG budget

The deliverables for T&D Dispatch to achieve this are as follows:
- Reduce dispatch 2009 overtime hours 5% from the dispatch overtime hours for 2008

Section I - Objectives: 5 of 5

Objective Name | Weight 15%

Regulatory Integrity/Compliance

Description

Pacific Power T&D Operations' regulatory goal is to ensure that we maintain our regulatory integrity. This requires T&D Operations to implement MEHC commitments and meet state mandates.

Measurement

The deliverables for T&D dispatch to achieve this are as follows:

- Compliant with WECC/NERC reliability standards
- Conduct an annual evacuation drill of PCC and apply our business continuity plan for short term denial of access
- Conduct an annual evacuation drill of SCC and apply our business continuity plan for short term denial of access
- Provide annual refresher training to sub transmission dispatchers on the manual load shed plan (Review the plan, identify overlap of all load shed programs)
- Provide annual refresher training to sub transmission dispatchers on Load Shed/Restore (LSR) functionality in Ranger to manually shed load
- Annually review the manual load shed plan data and make any required additions/edits (Add new circuits, review critical circuits, etc)
- Provide annual refresher training for state commission outage notifications with outage coordinators

#2

2009 Performance Management

Review Period: 01/01/2009 to 12/31/2009

General Information

Employee Information

Last Name	First Name	Middle

Mgr, Distribution **00001027**

Title .. ..

Manager Information

Name Title

Section I - Objectives

Weighting of Objectives: 70%

Keeping in mind that your goals should be a component of your department or business unit's goals, list in order of importance the main duties, tasks, projects or goals for the appraisal period. As in the past, each employee is required to have a safety goal.

Section I - Objectives: 1 of 6

Objective Name Weight 20%

Safety and Employee Commitment

Description

Target Zero - Goal of Zero safety-related incidents is to ensure all employees go home in the same or better condition that when they came to work. Safety performance will be measured on continuous improvement over the previous year:

Measurement

- Meet or exceed the PP overall recordable incident rate of < 2.00 broken down into "At-Fault" recordable incident rate of < 0.90 and "Wear and Tear" recordable incident rate of < 1.10.
- Reduce preventable vehicle accidents to < 30 at the T&D Operations level.
- Implement the Pacific Power Safety Improvement Plan in all districts.
- Deliver safety training to all T&D Operations district employees as outlined by the Health & Safety Department.
- Develop the 2008 compliance calendar and perform the scheduled actions.

Section I - Objectives: 2 of 6

Objective Name | Weight 10%

Environmental Respect:

Description

Ensure that PacifiCorp is meeting environmental regulations and RESPECT policy commitments/obligations to our customers, regulators, and other key stakeholders. This requires implementation of the Pacific Power environmental plan and required actions to reduce risk associated with non-compliance and to manage and/or eliminate any environmental damage.

Measurement

- Deliver bird power line programs, completing >95% of corrective actions within the identified time frames.
- Report all eagle mortalities to environmental services within 48 hours, and remediate poles within 30 days.
- Correct all facilities within 90 days where protected birds have been killed.
- Correct all potential non-compliance items identified in the quarterly facility compliance checklists, completing them within 90 days of identification.
- Correct all deficiencies found by environmental audits within 30 days.
- Reduce preventable incidents and commensurate quantity (gallons) of oil spilled to 17 spills and 192 gallons
- Ensure 100% of required training is completed on an annual basis
- Implement the SF6 reduction plan as outlined in the MEHC transaction commitments, achieving the annual 5% reduction goal.
- Leaking/weeping transformers are considered A priority conditions and will be removed from service and replaced within 30 days of identification.
- If during the course of maintenance or construction we discover a distribution pole or pad-mounted transformer that is not manufacture-certified as non-PCB by nameplate information or a certified lab test, the unit will be removed from service within 30 days and replaced with a non-PCB unit. If during the course of an inspection activity we discover a distribution pole or pad-mounted transformer that is not manufacture-certified as non-PCB by nameplate information or a certified lab test, the unit will be noted in FPI as a D condition and

will be replaced during a future maintenance or construction activity.

Section I - Objectives: 3 of 6

Objective Name Weight 15%

Operational Excellence

Description

Ensure that high standards are met for our operations and system maintenance. Improve Pacific Power service quality by achieving targeted metrics in the states we serve (Oregon, Washington and California). Achieve the network investment plans set forth by Asset Management for capital, maintenance and vegetation management, and deliver within agreed budget.

Measurement

• Reduce annual system error-caused outages as follows:
• Contact caused by Pacific Power employees: <7
• Switching errors in the field: <1
• Testing/startup/faulty installation/incorrect record: <60
• Improper protecting relay settings coordination: <8
• Support work planning initiatives:
• For districts that have had the new work planning processes rolled-out in their area.
♣ All estimators are scheduling their week in Optic
♣ All customer appointments are in Optic
♣ All crew scheduling is in Optic
♣ All servicemen scheduling is in Optic
♣ Planning meetings are held weekly
• For districts that have not had the new work planning processes rolled-out in their area.
♣ RUT is reviewed and updated at least once a month
♣ Maintenance end-of-year forecast to work plan is updated monthly
♣ Planning meetings are held weekly with minutes posted to server.
• Deliver >97% of the maintenance plan.
• Correct all "A" conditions within 30 days for Pacific Power areas.
• Deliver >90% of project-managed projects by year-end.
• Deliver reliability projects on schedule and

within budget by the end of the year. Complete all feeder hardening projects in Oregon, Washington and California as established by Asset Management (Fuse It or Lose It, Saving SAIDI, and feeder capital improvements) for those projects delivered by Asset by the end of quarter one 2008.

Section I - Objectives: 4 of 6

Objective Name — Weight 10%

Customer Service

Description

Focus on delivering reliable, dependable, and exceptional service to our customers.

Measurement

- Receive less than 51 commission complaints:
- Receive less than 77 customer guarantee failures.
- Restore 85% of customers off supply within 3.0 hours.
- Send out targeted customer communications explaining vegetation management, Saving SAIDI, and Fuse-It-or-Lose-It projects

Section I - Objectives: 5 of 6

Objective Name — Weight 10%

Financial

Description

Retain the financial integrity of MidAmerican by achieving financial targets and implementing efficiency initiatives.

Measurement

- Achieve OMAG budget of $117 million
- Deliver maintenance plan with 1% (or greater)

efficiencies.
•   Maintain planned overtime hours to <10% of straight time hours.

Section I - Objectives: 6 of 6

Objective Name | Weight 5%

Regulatory Integrity

Description

Maintain PP's regulatory integrity by implementing MEHC commitments and meeting state mandates.

Measurement

•   Comply with GO165 and Oregon AFOR
•   Comply with all NERC/FERC/WECC reliability standards, timeframes, and company programs.
•   Complete all annual compliance-related training as outlined in NERC/FERC/WECC standards.

#3

2009 Performance Management

Review Period: 01/01/2009 to 12/31/2009

General Information

Employee Information

Last Name	First Name	Middle
Analyst, Business - Car	**00001027**	
Title	..	..

Manager Information

Name | Title

Section I - Objectives

Weighting of Objectives: 70%

Keeping in mind that your goals should be a component of your department or business unit's goals, list in order of importance the main duties, tasks, projects or goals for the appraisal period. As in the past, each employee is required to have a safety goal.

Section I - Objectives: 1 of 4

Objective Name | Weight 5%

Health and Safety

Description

a. Integrate health and safety as a value in how all work is conducted by constantly striving to create a workplace that is healthy and safe for ourselves and those around us.

b. Ensure that healthy & safe work practices are never compromised, even in crisis situations.

c. Set a personal example by consistently demonstrating healthy & safe personal behaviors.

d. Identify, report, and evaluate health and safety risks and ensure that controls are implemented to eliminate or minimize health and safety risks.

e. Actively contribute to a healthy and safe work environment by involvement in the team efforts in these areas and encourage others to get involved.

f. Create and sustain a healthy and safe work environment by integrating health and safety in how all work is performed.

Measurement

Measurement:
1. Attend 4 safety meetings, including required meetings.

2. Identify and report any health and safety risks observed in the workplace.

3. Integrate health and safety behaviors in all work performed.

Section I - Objectives: 2 of 4

Objective Name Weight 30%

Performance Reporting and Variance Analysis for Transmission and EAM

Description

a. Provide accurate & timely performance reports and variance commentary for Transmission and EAM to management.

b. Distribute monthly OMAG and Transmission revenue reports to management via email in the required timeframe, including variance analysis and comments.

c. Periodically assess Transmission and EAM reporting needs. As needed or required, develop and provide additional performance reports.

d. Provide OMAG forecast updates as needed.

e. Increase knowledge of capital reporting and forecasting.

f. Provide bi-weekly NERC Compliance reports as required.

Measurement

1. Provide accurate & timely performance reports and variance commentary to KD Adair for the Pacific Power monthly close meeting. Attend meeting as backup when needed.

2. Provide reporting package via email within one day after closing for workforce and OMAG to Transmission and EAM management. Include revenue reporting for Transmission and analysis and commentary for material variances.

3. Provide ad-hoc information requests and reports in the required timeframe.

4. Develop and provide additional performance reports as needed or required.

5. Assist with development of Transmission profitability reporting.

6. Provide OMAG forecast updates in the required timeframe.

7. Learn basic components of capital reporting and forecasting, especially for the Transmission development plan.

Section I - Objectives: 3 of 4

Objective Name

Weight 25%

Annual OMAG and Workforce Budgets for Transmission and EAM

Description

a. Work with Finance groups, and Transmission and EAM management to prepare annual OMAG and workforce budgets.

b. Calculate, analyze and update activity rates.

c. Determine labor allocations by order for EAM and applicable Transmission Development cost centers.

d. Assist with development of the 10 year OMAG and workforce plan, as needed.

Measurement

1. Prepare Transmission and EAM annual OMAG and workforce budgets with clear assumptions that achieve targets. Document budget assumptions, including support and management review.

2. Monitor and update workforce changes in SAP as needed throughout the year to provide accurate headcount, salaries and activity rates for each cost center. Updates include salary increases and position transfers.

3. Budget OMAG line items by order, by cost center, for EAM and applicable Transmission Development cost centers.

4. Calculate activity rates for the annual budget, including support and analysis. Finalize rates in December to include applicable workforce updates. Submit updated rates to Pacific Power Finance as actual rates

for the upcoming year.

5. Determine labor allocations by order for EAM and applicable Transmission Development cost centers, including billable hours and hours budgeted to capital surcharge and capital projects.

Section I - Objectives: 4 of 4

Objective Name

Weight 10%

Transmission Revenue

Description

a. Work with Pacific Power Finance, Transmission management, Ernie Knudsen and KD Adair to assist with preparation of annual and 10-year revenue budgets.

b. Provide monthly revenue forecast updates to management as needed.

c. Finalize annual budgeted revenue in SAP.

d. Develop greater understanding of Transmission Revenue.

Measurement

1. Timely completion of annual and 10-year revenue budgets, on target.

2. Develop new monthly revenue forecast format to provide detail that will assist with tracking and forecasting variances.

3. Input annual budget in SAP, accurately and on-time.

Docket No. UE-210
Exhibit PPL/1300
Witness: Norman K. Ross

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Norman K. Ross

August 2009

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

A. My name is Norman K. Ross. My business address is PacifiCorp, 825 NE Multnomah, Suite 1900, Portland, Oregon 97232. I am a Director within the Company’ s corporate tax department. Prior to assuming my present duties in 1998, I served from 1987 through 1998 within the corporate tax department of Pacific Telecom, Inc., a former PacifiCorp subsidiary.

Q. Have you previously filed testimony in this case?

A. No.

Q. Please briefly describe your education and business experience.

A. I received a Bachelor of Business Administration with a concentration in accounting from Seattle Pacific University in June 1980. I also received the Certified Public Accountant designation in 1984. I have been employed by PacifiCorp or its affiliates for the past 22 years. My business experience includes all areas of the corporate tax function.

Q. Please describe your present duties.

A. I am currently responsible for all activities related to the Company’ s property, sales, use, excise, gross receipt and miscellaneous tax obligations.

Purpose and Summary

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to respond to Staff’ s proposed adjustments to the Company’ s property tax expense. Specifically, I demonstrate that the method used by Staff witness Mr. Dustin Ball to estimate property tax expense in the test year is overly simplistic and fails to take into consideration a number of factors that affect property tax expense. I also provide a detailed overview of the method used by the Company to estimate property taxes, which takes into account important multi-state assumptions.

Q. Please describe Staff's proposed adjustment.

A. Staff witnesses Mr. Ball and Ms. Deborah Garcia have both submitted testimony with respect to the Company's 2010 property tax expense. Both witnesses recommend that the Company be allowed to recover $87.5 million in property tax expense for calendar year 2010. The recommended $87.5 million amount is $8.3 million or 8.6 percent lower than the Company's $95.8 million estimate of 2010 property tax expense.

Q. Do you agree with Staff's estimate?

A. No. Staff's proposed adjustment is based upon a methodology that is far too simplistic and fails to recognize the factors that drive the Company's property tax expense. The method employed by the Company, on the other hand, produces a far more accurate and realistic estimate given year over year increases in the level of property subject to assessment and operating earnings.

Q. Please explain.

A. The Company's property tax estimation methodology, which the Company previously provided in the form of a detailed narrative description and calculation in Confidential Exhibit PPL/704 in this proceeding, gives specific consideration to all relevant and material factors that impact property tax expense. These factors include the following: state-by-state assessed values, the amount of tax to be capitalized for projects under construction as of the January 1, 2010 lien date, the amount of property tax chargeable to fuel expense for mining related assets, state specific exemptions for intangible property, pollution control equipment, and other exempt assets, state specific assessment ratios, and state specific tax rates.

Q. Please describe Staff's proposed method for estimating property tax expense.

A. Staff's method relies upon the assumption that changes to property tax expense result only from changes in rate base. This inaccurate assumption leads Staff to estimate 2010 property tax expense in a manner that oversimplifies the process. Although it is true that changes to the level of rate base may influence the values assigned to the Company's taxable property, the influence is indirect at best.

Q. Does Staff testify that rate base is the only element that drives changes in property tax expense?

A. No. Mr. Ball states that rate base is the "main driver" of the regulatory property tax expense. However, his method of calculating the Company's property tax expense ignores these other drivers. Mr. Ball does not explain what those other drivers are, attempt to quantify them, or provide any evidence to support his claim that property tax expense is a function primarily of rate base.

Q. Is calculating estimated property taxes using only rate base reliable?

A. No. Rate base represents an incomplete and unreliable basis on which to estimate property tax expense. Rate base is not a valuation methodology in and of itself and thus its use as the sole basis for estimating the period to period change in the Company's property tax expense is fatally flawed. The Company's state-by-state methodology, which utilizes the specific factors used by states in assessing property taxes, produces a more reliable estimate of 2010 property tax expense. It gives proper consideration to changes in the level of operating property, operating income, exemptions and other factors.

Q. Staff's method suggests that year-to-year taxes are a linear function of rate base. Is this true?

A. No. The specific method reflected on the worksheets contained within Staff/102 and Staff/202 implicitly assumes that there is a linear or ratable relationship between rate base and property tax expense. No such relationship exists and Mr. Ball provides no evidence of such a relationship. Changes to property tax expense result from numerous factors other than changes in rate base.

Q. What factors other than changes in rate base does Staff fail to consider?

A. Staff fails to consider the following factors:

1. <u>Staff's Method Ignores the Effect of Operating Income on Assessed Values</u>. Because Staff's proposed method relies solely on rate base, which contains the Company's net investment in operating property, the method ignores the effect that changes in operating income have on assessed values and therefore property tax expense. The level of operating earnings significantly affects the assessed values assigned to the Company's operating property. Staff's method gives no consideration to this important factor.

2. <u>Staff's Method Ignores CWIP</u>. The method fails to take into account changes in construction work in progress ("CWIP") which, while not included within rate base, is nonetheless subject to property tax assessment.

3. <u>Staff's Method Ignores the Issue of Exempt Property</u>. Because rate base

contains both intangible and tangible property and certain intangible personal property is exempt from taxation in certain states, the method fails to consider whether changes in rate base result from changes to taxable (tangible) or exempt (intangible) property.

4. Staff' s Method Ignores Timing Issues. The method fails to take into account the fact that property tax expense is a function of the assessed values assigned to property owed by the Company on January 1st of each calendar year. Rate base is, by contrast, a reflection of a simple beginning to end of year average or a 13-month average of plant balances.

5. Staff' s Method Ignores Capitalization Activity. The method fails to take into account differences in the level of property taxes capitalized during the two-year period from which the 0.8157 percent rate is derived and the level of capitalization of property tax expected to occur during calendar year 2010.

Q. Does the Company' s method for estimating property tax expense take into consideration these additional factors?

A. Yes. Each of the factors discussed above are specifically taken into account within the methodology employed by the Company when estimating property tax expense. For this reason, Staff' s $87.5 million estimate of property tax expense substantially understates the amount of property tax expense the Company will incur during 2010. On a normalized basis, the Company currently expects to incur approximately $86.3 million in 2009 property tax expense. Hence, the proposed rate base dependent method would provide only a $1.2 million year-over-year increase in property tax expense despite another year' s (from January 1, 2009 to January 1, 2010) substantial increase in taxable operating property.

Q. Mr. Ball indicates that his estimation method was "approved by the Commission in Order No. 09-020." Do you agree that this means the Commission should apply this method here?

A. No. Order No. 09-020 in UE 197 was based upon a record unique to that proceeding and should not establish definitive Commission policy regarding property tax estimate methods. In UE 197, Portland General Electric ("PGE") originally argued that the property tax is a function of the rate base. Then, after Staff pointed out an error in PGE's calculations, PGE argued that property taxes are a function of assets and tax rates and should be calculated accordingly. Staff initially argued that taxes should be determined by escalating the 2007 taxes by the Consumer Price Index. Then Staff argued that property taxes are a function of plant-in-service, net of depreciation, and not a function of the overall rate base.

Finally, Staff accepted PGE's original method—even though it had been repudiated by PGE—and acknowledged "that there is likely a more reasonable common ground, [but] for purposes of this case, Staff will concede to using PGE's method of basing the ratio on the actual average rate base rather than the gross plant net of depreciation." Staff's Reply Brief at 4-5. In adopting its final position on this issue, Staff recognized (1) there is likely a more reasonable method and (2) the method adopted was unique to that case.

Although the Commission ultimately adopted Staff's approach, the Commission's endorsement of Staff's method amounted to recognizing it was better supported relative to PGE's revised method. Order No. 09-020 at 24.

Although the Commission adopted Staff' s method in that docket, the more comprehensive method used by PacifiCorp was not presented to the Commission in the PGE case.

Q. Is the practice employed when estimating PGE' s property tax expense reliable when estimating PacifiCorp' s property tax expense?

A. No. While the methodology used by the Commission in UE 197 may have produced a reasonable estimate of property tax expense for PGE, it will not do so here. PacifiCorp is a substantially more complex public utility from both a regulatory and property taxation point of view. Instead of being subject to a single state' s regulatory oversight, PacifiCorp is subject to regulatory oversight by six states. Instead of having property in two western states, PacifiCorp currently has taxable operating property in ten. PacifiCorp is, therefore, subject to variability in appraisal methodologies that affect the values assigned by the ten western states that annually value PacifiCorp' s operating property. Moreover, because PacifiCorp is in the midst of a sizeable capital investment plan, the use of a simplistic method that relies exclusively upon the relationship between rate base (which has no direct correlation to assessed value) and tax expense will not produce a reliable estimate of PacifiCorp' s property tax expense.

Q. Staff suggests that PacifiCorp has overstated its forecast property tax expenses in 2007 and 2008. Has the Company recently improved the methods it employs when estimating property tax expense?

A. Yes. Beginning with the estimate for 2008, the Company adopted a substantially more robust and granular estimation methodology that produces state specific estimates of property tax expense based upon each state's unique mixture of valuation approaches, financial assumptions, exemptions, assessment ratios, and tax rates. The improved methodology was adopted so as to give more specific consideration to the principal factors impacting property tax expense (the level of assessable property and the level of operating income) and the unique state specific tax policies and practices affecting the Company's tax expense. Estimation methodologies used prior to 2008 relied primarily upon broad changes in Company-wide assessable property and net operating income. The change to a more granular state-by-state approach was prompted by the recognition that substantial increases in assessable property were affecting individual state tax burdens in unequal ways.

These changes to the Company's forecasting methodology resulted in a significantly more accurate forecast for calendar year 2008. While no estimation technique will be 100 percent accurate, the Company's detailed estimation methodology is substantially more reliable since it specifically considers the various factors actually relied upon by state assessment staff when determining the assessed values of the Company's taxable operating property. Staff's method, on the other hand, bears no relationship to how property taxes are actually assessed and has no track record of accurately predicting property tax expense.

Q. Please provide a brief overview of the improved method used by the Company when estimating 2010 assessed values.

A. The method begins with state specific valuation models created by the Company's tax department. Each model consists of a series of appraisal worksheets that are functionally identical to the specific cost, income and sales comparison methods routinely employed by each individual state. Beginning with a version of each state' s model that reflects the particular valuation methods each state employed when determining the assessed values for the most recent year, the Company is then able to increase or decrease key property and income amounts within those models and thereby produce an estimate of assessed value for the next tax year.

Once adjustments for anticipated changes in key property and income data are made, the Company makes adjustments for known or anticipated changes in the level of exempt property, assessment ratios or other factors expected to impact the next year' s valuation. The objective is to produce an estimate of assessed value based upon anticipated changes to all material valuation data.

The resulting state specific estimate of 2010 assessed values is then input into column " b" of the master property tax estimation worksheet. The anticipated year over year percentage change in assessed value, calculated by dividing estimated 2010 assessed value by the final 2008 assessed value, is then used to project tax expense for 2010.

Q. Do you have any other concerns with Staff' s calculation of the proposed adjustment?

A. Yes. In Staff/202, Ball/13, Staff makes an adjustment to prior year property tax expense in recognition of the fact that additional tax will be owed during future years when the enterprise zone related property tax exemption for the Leaning Juniper wind resource expires. However, it is unclear why only $600,000 is added back in the Commission' s 2007 actual column when $1,200,000 is added back in the 2008 column. To the extent that Staff intended to recognize the amount of additional tax that will be paid once the existing enterprise zone exemption expires, it would be necessary to add approximately $1,200,000 to both the 2007 and 2008 columns instead of adding in $600,000 for 2007 and $1,200,000 for 2008. Lastly, I will note that PacifiCorp' s internally developed estimate of 2010 property tax expense already accounted for the expiration of the enterprise zone related exemption.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/912
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of C. Craig Paice

August 2009

Q. Are you the same C. Craig Paice that previously provided testimony in this docket?

A. Yes.

Purpose and Summary

Q. What is the purpose of your reply testimony?

A. My reply testimony includes revised exhibits to reflect changes in the Oregon Results of Operations contained in the reply testimony of Company witness Mr. R. Bryce Dalley and to address several issues in the filed cost of service study. Additionally, I respond to the testimony of Staff of the Oregon Public Utility Commission (" Staff") witness Dr. George Compton, the Industrial Customers of Northwest Utilities (" ICNU") witness Mr. Donald Schoenbeck, the Citizens' Utility Board (" CUB") witness Mr. Bob Jenks and the Klamath Water Users Association (" KWUA") witness Mr. Gary Saleba.

Q. Please summarize your testimony.

A. My testimony:

- Explains the Company' s proposed change to the methodology used to develop customer class loads and demonstrates that this methodology results in a better match between customer class loads and system loads. This addresses concerns raised by Staff and ICNU on this issue.
- Explains the revisions proposed by the Company to the inputs for street lighting customers.
- Explains revisions to the distribution feeder model to better match billing determinants to the underlying data in the cost study.

- Presents an updated line loss study that better reflects underlying megawatt-hour sales.
- Responds to several proposed changes to the cost study recommended by Staff, ICNU, CUB and KWUA.

Updated Exhibits

Q. Have you prepared any updates to the exhibits filed with your reply testimony?

A. Yes. Exhibits PPL/913 through 919 are updates to Exhibits PPL/901 through 907. The revised exhibits reflect changes in the Oregon Results of Operations as presented in Company witness Mr. Dalley's reply testimony. The application of PacifiCorp's proposed rate increase, shown on page 2 of Exhibit PPL/913, is consistent with Mr. Dalley's Exhibit PPL/707. The revised exhibits also reflect the following changes to the filed cost of service study:

- Customer class loads were used in lieu of customer load factors as inputs to develop customer demand values.
- Inputs to the cost of service study related to street lighting customers were revised.
- Several inputs related to the hypothetical distribution feeder model were modified.
- Adjusted demand and energy line loss values based on the revised Oregon line loss study.

Q. What are the implications of the updated cost of service results?

A. The overall revenue requirement decrease coupled with updates to the marginal cost of service study produces cost reductions for all customer classes. Significant cost reductions occur for Irrigation Schedule 41 (approximately 8 percent) and Street Lighting, Schedules 51, 53, and 54 (approximately 47 percent). Cost reductions for large general service customers, Schedules 30 and 48, range from 1.4 percent to 2.7 percent. Cost reductions for small general service customers, Schedules 23 and 28, range from 0.8 percent to 1.9 percent. Cost reductions for residential customers, Schedule 4, are 0.08 percent.

Customer Class Loads

Q. Please explain why you are proposing to change the methodology used to develop customer class loads?

A. Customer class loads used in the cost of service study that accompanied my direct testimony (see Exhibit/PPL 907, Tab 2.3, lines 5-7) were derived using class load factors. This method required megawatt hours at the generation level to be divided by 8,760 hours and then divided by the appropriate load factor to estimate system, feeder and transformer loads used in the cost study. The class load factor method is a legacy method used for a number of years before information necessary to develop specific class loads was available. This method can be imprecise because loads are calculated from forecasted energy, grossed up for energy-related loss factors, instead of directly using demand-related loss factors. In the Company's direct case, this method resulted in a megawatt discrepancy when comparing class loads to jurisdictional loads.

In response to concerns expressed by Dr. Compton and Mr. Schoenbeck regarding these "missing MW," and as a result of additional analysis, the

Company determined that customer class loads can and should be calculated from actual Load Research sample data. As a result, customer class loads now more closely match total system loads.

Using the updated methodology, the revised customer loads result in only a two percent difference between customer class loads and total system loads. As such, the Company proposes to incorporate the revised customer class loads (adjusted by demand-related losses) into the cost of service study to: 1) replace load data based on the previous load factor method, and 2) mitigate the megawatt differences between class and jurisdictional loads.

Q. How were the proposed customer class loads developed?

A. Customer class peaks were calculated using actual average Load Research sample data expanded by customer populations and adjusted to the forecasted energy usage for the test period. Exhibit PPL/919, Tab 1.3, lines 7-9 shows three different load values (Peak MW @ Generator) developed for each customer class.

- Line 7 represents the average of 12 monthly peaks at the time of the PacifiCorp system peak or Coincident Peak ("CP") loads, also referred to as system loads.
- Line 8 represents the average of 12 monthly peaks at the time of the Company's Oregon distribution system peak or Distribution Coincident Peaks ("DCP"), also referred to as feeder loads.
- Line 9 represents the annual maximum non-coincidental peaks ("NCP"), also referred to as transformer loads. Various rate schedule NCP values

are adjusted by a coincidence factor to recognize diversity existing among classes whose customers share a transformer.

Street Lighting Revisions

Q. Please explain revisions made to the street lighting customer inputs.

A. In response to Staff data request 317, three street lighting inputs were identified for revision:

- On Tab 3.2 of Exhibit PPL/907, the number of 400 watt lamps on Schedule 51 was mistakenly entered as 13,228. This represented the total number of Schedule 51 monthly bills for the historic test period. The actual number of 400 watt lamps on this schedule is 1,102 (13,228 divided by the 12 billing months in the test period). As such, the number of lamps for the Street Lighting class was overstated in the cost of service study.
- An earlier draft version of the forecast of customers and energy was used for the street lighting class instead of the final version that was used for other classes as shown on Tab 3.2 of Exhibit PPL/907.
- Lamp line watt values used on Tab 3.4 of Exhibit PPL/907 were not updated in the initial filing.

Updates have been made to the marginal cost of service study to reflect each of these changes.

Hypothetical Distribution Feeder Model

Q. Please explain revisions to the distribution feeder model.

A. The Company updated the feeder model residential and irrigation customer counts, slightly modifying the customers-per-mile number from 30.69 to 29.70.

Also, the large customer results (greater than 4 megawatts) from the feeder model are now included in the cost of service study. This results in a better match between the billing determinants used to develop prices and the underlying data in the cost study. These changes have also been incorporated into the updated cost of service study.

Adjusted Demand and Energy Line Losses

Q. Please explain the adjustments to the line loss factors.

A. The Company's Oregon 2007 Analysis of System Losses was adjusted in response to data requests from Mr. Schoenbeck. The underlying megawatt-hour sales used in the original 2007 line loss study were inadvertently misstated. Subsequently, line losses were recalculated by the Company and provided to Mr. Schoenbeck. These adjusted numbers were utilized to develop the Company's revised cost of service study and rate design exhibits sponsored by Company witness Mr. William R. Griffith. Revised line loss factors are provided in Exhibit PPL/920.

Reply to Opening Testimony of Dr. George Compton

Q. Do you agree with the long-run marginal generation energy cost adjustment that Dr. Compton presents in his opening testimony?

A. I agree with Dr. Compton that there is a need to incorporate more current natural gas prices into the marginal cost of service study; however, I do not accept his proposed method of determining those prices. He proposes to reduce the Company's natural gas price in each year of the 20-year stream by an arbitrary value equal to 5/8 of the value shown in the marginal cost study (a reduction of

3/8). This results in an amount equal to $5/MMBTu beginning in 2010. Dr. Compton claims this value is more in line with the recent pricing of natural gas than the $8 per MMBTu value (beginning in 2010) used in the Company's initial filing. Dr. Compton's response to the Company's data request 2.15, included as Exhibit PPL/921, identifies the basis for his gas price assumptions:

> " As a subscriber to the *Wall Street Journal* I'm regularly exposed to articles referring to the natural gas industry ... However, the following citation from the Googled reference, " Natural Gas" by Tom Whipple in the journal of the *Association for the Study of Peak Oil and Gas,* June 22, 2009, should be sufficient for the limited purpose of my testimony …"

PacifiCorp does not believe Dr. Compton's response sufficiently justifies the appropriate gas prices the Company might expect to incur during the next 20 years. Dr. Compton's proposed methodology results in an amount equal to $5/MMBtu in 2010, escalating to $5.38/MMBtu in 2029, an increase of only eight percent in 20 years. The 20-year stream of natural gas prices included in the Company's marginal cost of service study was taken from the Company's last approved avoided cost filing in 2007 - specifically, Table 9 in Advice No. 07-014. The Company's methodology uses avoided costs to approximate generation-related marginal costs and was approved by the Commission in Docket UM 827, Order No. 98-374 at 14 where it states:

> We conclude that using avoided cost for marginal generation costs is appropriate in an increasingly competitive generation market.

The Company recently filed an avoided cost study with the Commission on July 9, 2009 showing more current natural gas prices ($5.78/MMBTu in 2010) and is willing to update the marginal cost of service study following approval of new avoided costs by the Commission.

Q. Do you agree with Dr. Compton that marginal generation demand-related costs should be developed from a single coincident peak (1 CP)?

A. No. I do not agree with this recommendation for several reasons. First, the Company has historically allocated costs using the 12 CP methodology to recognize that the entire six-state system is planned and dispatched on an integrated basis. To model actual system operations, PacifiCorp has utilized the 12 CP methodology to allocate system generation demand costs since its merger with Utah Power in 1989. PacifiCorp also utilizes the 12 CP methodology because it recognizes that the Company serves customers for all twelve months of the year, and that each of the monthly peaks is important.

Second, the 12 CP methodology assures consistency in allocation methods between the Jurisdictional Allocation Model ("JAM") and class cost of service ("COS") model. Finally, the opening testimony of CUB witness Mr. Bob Jenks at CUB/100, Jenks/20, provides further support for using 12 monthly coincident peaks. He shows that the Gadsby natural gas fired generation plant, a simple cycle combustion turbine that the Company uses to meet its peak requirements, has operated for 10 consecutive months, from June 2008 through March 2009.

Q. Do you agree with Dr. Compton's proposal to increase system coincident loads by a 12 percent reserve margin?

A. Not at the present time. As previously mentioned, marginal generation costs are based on the Company's approved avoided cost study which does not include a reserve margin. The Commission decision approving use of avoided costs for estimating marginal generation costs makes no mention of a reserve margin, nor do the state loads included in the JAM (to which the COS class loads are compared) include a reserve margin. Also, Dr. Compton provides no analysis or substantive support for the inclusion of a reserve margin. He only expresses his concern at the absence of a reserve margin. The inclusion of a reserve margin in the marginal cost study should be determined by either a consensus agreement among all parties or Commission order.

Q. Dr. Compton raises issues with the Company's method of allocating trunk-related costs in the distribution feeder model. How are trunk-related costs allocated?

A. All trunk costs (branches 6 and 7) are allocated on the basis of demand.

Q. Do you agree with Dr. Compton's proposal to revise the allocation of trunk costs in the feeder model by allocating a portion of trunk costs to commitment?

A. No. Customer load is the criterion used by Company engineers to determine the type of conductor and associated poles used for the feeder trunk. At each point on the feeder, the conductor must be sized to carry the entire downstream load. Branches 6 and 7 are composed of larger conductor and poles that are needed to serve the larger load closer to the substation. More than 85 percent of the feeder load is located on branches 6 and 7 and all demand on the feeder flows from the substation through branch 7. Outer branches 1 through 5 of the feeder are significantly different from the feeder trunk. Loads on branches 1 through 5 are smaller. These branches are also farther away from the substation and do not feed into other branches. As such, classifying trunk-related costs as demand is appropriate.

Q. Is Dr. Compton's other recommendation to assign commitment costs to demand appropriate?

A. No. Feeder model commitment costs are not determined by the level of customer demand, rather they are a direct function of constructing a branch with the smallest single-phase conductor and the smallest pole. This would provide customers access to the distribution system even though those customers required no load. Assigning costs related to a minimum-sized system (one that does not vary with load) based on demand does not comport with standard cost allocation practices.

Q. Why should distribution feeder model commitment costs be allocated on the basis of customers?

A. Commitment costs, which are only assigned to the outer branches in the feeder model are defined by the minimum size conductor and poles used by the Company. As previously discussed, the basis for these types of costs is not demand, but the number of customers connected to the system. This method of calculating marginal distribution costs was recognized as reasonable by the Commission in its decision in Order No. 98-374 at 11 when discussing the systems used by Portland General Electric (" PGE") (facilities) and PacifiCorp (minimum system):

> We conclude that the facilities design and minimum system

> approaches are reasonable methods for calculating marginal distribution costs. The minimum system and facilities design approaches categorize the costs of the distribution system that are dedicated to the specific groups of customers at the time of installation. These costs are not affected by actual usage and do not benefit from the diversity of system-wide or feeder-wide load. The minimum system approach identifies these costs as a function of the number of customers on the system.

Q. Do you agree with Dr. Compton's proposal that distribution peak demand should be based on a single distribution peak (" 1 DCP") instead of a twelve distribution coincident peaks (" 12 DCP") method?

A. No. The Company has determined that distribution system demand-related costs should be based on the cost-causal link between customer service characteristics and utility costs. This link is established when costs are allocated using service characteristics that are the same or similar to those employed by utility engineers when making investment decisions. The Company' s position comports with the following statement by the Commission in Order No. 98-374 at 11:

> PGE makes a compelling argument that distribution marginal costs should be based on the decisions of system planners who design the distribution system. This is a reasonable way to allo-cate costs based on cost causation.

System engineers have determined that using a 12 DCP method to allocate demand-related pole and conductor costs is appropriate because these costs are incurred by the Company from diverse customer loads occurring throughout all twelve months. Load diversity is recognized in the planning process. The Company prepared an additional analysis showing that: 1) different distribution substations reached their annual peaks in all months throughout the year; and 2) a majority of substations did not reach their annual peak in a single month. This data is provided in Exhibit PPL/922.

Q. Does the Company use a 12 DCP method to allocate distribution-related costs in other jurisdictions?

A. Yes. The Company has also used the 12 DCP method in California, Idaho, Wyoming and Utah.

Q. Dr. Compton references that most utilities, including PGE, classify pole and conductor costs as demand related. Do you believe this is a valid reason for the Company to change its methodology?

A. No. The Company's Oregon distribution system was designed to meet the unique needs of its primarily rural service territory. PGE's system, on the other hand, serves a much denser urban population. A utility should be allowed to choose the approach that best fits the particular circumstances of its system and the characteristics of its customers.

Reply to Opening Testimony of Mr. Donald Schoenbeck

Q. Mr. Schoenbeck points out that demand loss factors were not used in the Company's filed marginal cost of service study. Have any changes been made to incorporate specific loss factors for demand?

A. Yes. The Company agrees with Mr. Schoenbeck that both demand and energy loss factors should be used in the preparation of marginal costs. In the revised marginal cost of service study included with my reply testimony, demand loss factors were applied to Oregon customer class load data as recommended by Mr. Schoenbeck. Earlier in my testimony, I addressed this proposed change to use customer class load data based on load research sample load data to derive marginal demand-related costs.

Q. Mr. Schoenbeck applies facility-specific loss factors to different customer categories, rather than the average secondary, primary and transmission voltage levels for all customer categories. Do you agree with this approach?

A. No. The Company does not support Mr. Schoenbeck's approach since it fails to reflect the integrated nature of system losses and it could, if carried to its logical conclusion, result in individual loss factors being applied to each customer. Such a result would be inconsistent with the "postage stamp" nature of the Company's retail rates.

Mr. Schoenbeck's approach recalculates loss factors for Schedule 48 customers only, while failing to readjust losses for all other customer classes. In order to accurately capture total line losses, calculation of loss factors for one class of customers requires that loss factors must be recalculated for all other customer classes at the same time. Failure to do so will not account for total line losses on the system. As a result, this calculation produces an inappropriate cost reduction for Schedule 48 customers, with no corresponding change for any other rate schedule classes.

Q. Are there additional concerns with Mr. Schoenbeck's method of recalculating loss factors?

A. Yes. When estimating peak demand and energy loss factors for Schedule 48 primary and secondary customers, Mr. Schoenbeck assumes that any customer with a demand greater than 2,000 kW was served from a dedicated customer substation. Mr. Schoenbeck acknowledges that no basis exists for this assumption other than his judgment. *See* Exhibit PPL/923 (ICNU response to PacifiCorp data request 1.2).

Contrary to his assumption, the Company's distribution engineers indicate that dedicated substations are typically located immediately adjacent to the customer being served, but no more than one-half mile away. Using one-half mile as the maximum distance between a substation and a dedicated customer, the Company prepared Exhibit PPL/924, which shows substation distances and load size data for Schedule 48 customers extracted from the Company's Computer Aided Distribution Operations System ("CADOPS") and Customer Service System ("CSS"). The exhibit shows 72 customers with loads in excess of 2,000 kW. Seventy-five percent of these customers are served at a distance of one-half mile or greater from the substation. The average distance from the substation for customers over 2,000 kW is 1.50 miles. This exhibit clearly demonstrates that Mr. Schoenbeck's assumption that all customers over 2,000 kW are served from a "dedicated substation" is incorrect.

Q. Mr. Schoenbeck advocates using only January, July, August and December system peaks for allocating generation capacity costs and January and February system peaks for allocating transmission costs. Do you agree with his position?

A. No. For reasons previously cited, the Company continues to use the 12 monthly coincident peaks to allocate generation and transmission costs. In addition, the Company considers the transmission system to be an extension of the generation system since investments in high-voltage bulk transmission lines are being made to move both demand and energy. It is usually not possible to site a generating plant close to the customers the plant is intended to serve. Therefore, transmission lines are constructed to transmit energy being generated, along with the accompanying capacity. This position also comports with the following statement from the 1992 *Electric Utility Cost Allocation Manual* published by National Association of Regulatory Utility Commissioners (" NARUC") at 75:

> …the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.

Q. Mr. Schoenbeck argues that substations and demand-related feeder costs be allocated based upon a single non-coincident peak (" 1 NCP"). Do you agree with his assessment?

A. No. The Company allocates demand-related distribution using 12 DCP. By using this method, costs are allocated using service characteristics that are the same or similar to those used by utility engineers to make investment decisions; resulting in a cost-causal link between customer service characteristics and utility costs.

Distribution engineers primarily design distribution substations, poles and conductors to meet the <u>simultaneous</u> peak load of connected customers. This peak load recognizes the concept of customer diversity (i.e., characteristic whereby individual customer peak demands usually occur at different times). Substations, poles and conductors are used by many customers, and they do not need to be large enough to meet the maximum peak demand or NCP. These facilities need to be just large enough to meet customers' simultaneous (coincident) distribution peak demand. Use of the 12 DCP method accomplishes this goal and is employed in cost of service studies prepared and filed by the Company in Oregon, California, Idaho, Utah, and Wyoming.

Q. Mr. Schoenbeck recommends using a 1 NCP to develop line transformer costs. Do you agree with his position?

A. I agree that a single NCP should be used to develop line transformer costs, but I am opposed to using only a winter peak as recommended by Mr. Schoenbeck. To be more consistent with cost causation, I recommend that transformer demand-related costs be calculated using the annual maximum NCP for each customer rate schedule. Where multiple customers on the same rate schedule are connected to one transformer, the annual maximum NCP should be adjusted by a coincidence factor to recognize load diversity. The key cost driver of line transformer investment is customer peak demand which can occur in any of the twelve months of the year. Based on my recommendation, the annual maximum NCP by rate schedule was used in the revised marginal cost of service study for allocating line transformers.

Q. Do you agree with Mr. Schoenbeck that a portion of the trunk should be allocated to commitment in the feeder model?

A. No. Since his position is similar to Dr. Compton's, please refer to my earlier discussion of this subject.

Reply to Testimony of CUB witness Mr. Bob Jenks

Q. Mr. Jenks presents a discussion regarding “sunk costs.” Which of the Company’s total costs are sunk and which are not?

A. Bonbright’s *Principles of Public Utility Rates* (Second Edition, 1988, page 30), states the “essential characteristics of a sunk investment is that the productive capital facilities are so specialized as to location or purpose that they cannot easily be converted to alternative productive uses.” According to this definition, almost all of the Company’s costs could be considered “sunk investments,” i.e., generating plants, transmission lines, substations and computer systems, etc. Actually, there would be very few capital investments made by the Company that could <u>not</u> be considered a “sunk investment.”

Q. Should these “sunk costs” be included in the Company’s marginal cost of service study?

A. Yes. The Company’s marginal cost of service study takes a long-run approach to assigning costs to the various customer classes. A very important component of these long-run costs is capital investment that could be considered “sunk costs.” If costs associated with Company’s investments (i.e., generating plants, transmission lines, and substations) were not allocated to customer classes, significant cost drivers currently presented in the cost of service study would be ignored.

Q. Mr. Jenks states that meters and service drops are not truly marginal costs except when new customers sign up for service and this new customer growth should determine meter and service drop costs. Do you agree?

A. No. Meters and service drops could also be considered a “ sunk cost,” one that does not go away when a customer relocates. However, allocating meters and service drops based on only new customers ignores the costs the Company must incur to maintain, upgrade, and replace equipment for existing customers. In Order No. 98-374 at 11, the Commission rejected these same arguments. The Order states:

> We also reject CUB’ s argument that metering and billing costs are sunk and, therefore, should not be included in a marginal cost study. PGE and PacifiCorp demonstrated that the costs of these components should be considered in a marginal costs study. There are repairs, maintenance, upgrades, and opportunity costs that require expenditures at the margin by the utility. These costs are appropriately included in the marginal cost study.

Q. Does allocating meters and service drops using only new customer numbers produce reasonable results?

A. No. Under this methodology, customer classes decreasing in size would receive a negative allocation of meters and service drop costs. These customer classes would be rewarded for abandoning the investment the Company made to serve them. This approach could also introduce unnecessary volatility into the Company’ s cost of service study since some classes could receive cost reductions (if customer numbers declined) in one rate case, yet be allocated cost increases in a subsequent case (if customer numbers increased). This scenario would occur simply because costs were being allocated based on a count of new customers.

Q. Is the Company' s approach of assigning the cost of new meters and service drops to customers flawed since many of these meters and services were previously purchased at lower prices?

A. No. The Company' s cost of service study is a marginal cost of service study, one which measures the incremental cost of different aspects of services. These costs are used to allocate the embedded revenue requirement. Moreover, existing customers require maintenance, repairs, and upgrades on their existing meter and service drop and will eventually require new equipment. A customer whose meter was purchased years ago at a lower price is the customer most likely to require a replacement at current prices. Allocating meter and service drop costs based on the most recent price is a reasonable practice.

Q. Mr. Jenks references several characteristics of customers on branch 5 of the Company' s feeder model. He points out that residential customers make up 79 percent of customers on branch 5 and 62 percent of peak demand on branch 5, but are allocated 75 percent of cost. Is this a reasonable comparison?

A. No. Branches 1 through 5 of the Company' s feeder model represent the segments of the feeder that are farther away from the substation and contain fewer customers per mile than the trunk. As such, little investment in larger poles and wire has been made beyond the minimum size system to accommodate a greater level of demand on these branches. The principal cost driver on these branches is the investment in poles and conductors required over long distances to serve rural and isolated pockets of customers. It should be expected that more remote segments, which are not sized much beyond the minimum required size, would have a much higher portion of commitment or customer related costs.

Q. Mr. Jenks states: " Poles and conductors serve a single purpose: they are designed to transmit electricity from the substation to the customer. They carry energy. They have to be sized to meet the peak demand that is expected on them." Is this statement correct?

A. It is partially correct. However, poles and conductors do more than provide customers with electricity. They also provide customers with <u>access</u> to electricity. This access is invaluable to customers even if they use only a small amount of electricity. For example, a remote vacation cabin that is occupied sparingly during a year compared to a residence occupied year-round will have very little electric usage. It is unlikely this location will require larger size poles and conductors to meet electric load. Nonetheless, access to electricity is important to the owner, even though usage is on a limited basis during the year. To receive electric service, the owner will continue to pay for access to the system in addition to the actual electricity used. This is an important principle in pole and conductor classification.

Q. Mr. Jenks recommends that the generation energy price used in the marginal cost of service study include 37 percent wind, because of the Renewable Energy Standard that was established with the passage of SB 838. Should his proposal be incorporated in the Company' s marginal cost of service study?

A. Perhaps at some point in the future. The Company' s avoided costs do not currently include a wind generation component. However, as discussed earlier in my testimony, the Commission concluded in UM 827 that using avoided costs to develop marginal generation costs was appropriate. The cost of service study should comport with the established practice until such time that the Commission revises its position on this subject.

Q. **Regarding a carbon regulatory cost, Mr. Jenks notes that "PacifiCorp's workpapers do not identify such a cost being included in the forecast of marginal energy costs." Do the marginal generation energy costs included in the cost of service study include an environmental adder?**

A. Yes. Environmental-adders of $2.31 per megawatt-hour for combined cycle combustion turbines and $3.79 per megawatt-hour for simple cycle combustion turbines were embedded within the avoided cost study used in the Company's marginal cost of service study.

Q. **Do you agree with Mr. Jenks' position concerning the allocation of marginal generation demand costs?**

A. Yes. For reasons previously mentioned, the Company continues to use and support the 12 CP method for the allocation of these costs in the cost of service study.

Rebuttal of KWUA witness Mr. Gary Saleba

Q. Mr. Saleba makes the statement that " PacifiCorp does not provide sufficient evidence in its filing to support the conclusion that its marginal energy costs are the same across the year." Why didn' t the Company differentiate energy costs by time period in its marginal cost of service study?

A. As stated earlier in my testimony, the Commission ordered that it was appropriate to develop marginal generation costs based upon avoided costs in UM 827. The approved avoided cost study does not distinguish time-differentiated energy prices.

Q. Regarding time-differentiation of energy costs, Mr. Saleba states that " Absent such a showing PacifiCorp must differentiate their energy cost allocation within the COSA by season." Do you agree with this statement?

A. No. The precedent in Oregon is to use the approved avoided cost study. If a party chooses to propose a method that departs from the Commission-approved methodology, it is the party' s burden to provide analysis and support. Mr. Saleba provided no analyses or related data supporting his assertion.

Q. Mr. Saleba claims that there are significant unresolved questions about how the feeder model takes into account individual irrigation customers and their location. Does he identify these unresolved questions?

A. No.

Q. Mr. Saleba also asserts that the Company did not provide sufficient information for support, including irrigation customers in the hypothetical feeder model due to the absence of specific documentation regarding size, location and customer density. Is he correct?

A. No. The hypothetical feeder model, which estimates customer distribution pole and conductor costs, is fully documented. A description of the feeder model development was provided in Exhibit PPL/907 (pages 5-13). This description specifically references use in the feeder model of CADOPS data to determine customer distances. The Company received no data requests on this issue from Mr. Saleba. Ultimately, the Company provides the same level of detail for all rate schedule classes in the cost of service study and in the feeder model.

Q. Does this conclude your reply testimony?

A. Yes.

C. Craig Paice
Exhibit PPL/913

Docket No. UE-210
Exhibit PPL/913
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Functionalized Revenue Requirement

August 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2010 Forecast

Function		Revenue Requirement
Production		$ 628,341,142
Transmission		$ 82,092,130
Distribution		$ 277,575,414
Ancillary		$ 11,174,486
Customer Billing		$ 11,527,729
Customer Metering		$ 28,212,303
Customer Other		$ 13,136,076
Retail Service	a	$ -
Public Purposes	b	$ -
Total State of Oregon		$ 1,052,059,281

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2010 Forecast

		ROR	ROE	Total	Production	Trans-mission	Distribution	Ancillary	Consumer: Billing	Consumer: Metering	Consumer: Other	Retail Service [a]	Public Purposes [b]	Distribution Components: Poles & Wires	Distribution Components: DSM	Distribution Components: Franchise Tax
2	Functionalized Situs Revenues @ Earned	6.42%	6.86%	949,341,303	575,596,122	65,110,984	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025	-	-	223,883,177	0	22,233,321
3	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
4	Total Oregon General Business Revenue			949,341,303	575,596,122	65,110,984	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025	-	-	223,883,177	0	22,233,321
5																
6	Target Increase in Return	8.53%	11.00%	61,922,602	32,533,232	10,474,005	17,969,873	0	174,326	643,457	127,710			17,969,873	-	-
7																
8	Add															
9	Uncollectible Expense			545,609	280,167	90,199	167,101	0	1,501	5,541	1,100	-	-	154,751	-	12,350
10	Franchise Tax			2,311,154			2,311,154									2,311,154
11	Other Revenue Based Taxes			64,920	33,336	10,732	19,883	0	179	659	131	-	-	18,413	-	1,469
12	Inc Taxes - State			4,530,752	2,380,391	766,362	1,314,819	0	12,755	47,080	9,344	-	-	1,314,819	-	-
13	Inc Taxes - Federal			33,342,940	17,517,894	5,639,849	9,676,085	0	93,868	346,477	68,767	-	-	9,676,085	-	-
14	Total Increase Needed			102,717,977	52,745,020	16,981,147	31,458,916	0	282,629	1,043,214	207,051	-	-	29,133,942	-	2,324,974
15																
16	Total Oregon General Business Revenue @	8.53%	11.00%	1,052,059,280	628,341,142	82,092,130	277,575,414	11,174,486	11,527,729	28,212,303	13,136,076	-	-	253,017,119	0	24,558,294
17	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
18	Total Unbundled Revenue Requirement			1,052,059,280	628,341,142	82,092,130	277,575,414	11,174,486	11,527,729	28,212,303	13,136,076	-	-	253,017,119	0	24,558,294
19																
20	Rate Base			2,936,122,521	1,542,595,958	496,635,482	852,059,617	1	8,265,839	30,510,148	6,055,475			852,059,617	-	-
					52.539%	16.915%	29.020%	0.000%	0.282%	1.039%	0.206%	0.000%	0.000%	29.020%	0.000%	0.000%

Source:
Total Column : Exhibit PPL 902
Row 1: Exhibit PPL 902
Row 8: Uncollectible 0.53117%
Row 9: Franchise Tax @ 2.2500%
Row 10: Other Revenue Based Taxes 0.0000%
Row 11: Inc Taxes - State 4.5400%
Row 12: Inc Taxes - Federal 35.0000%
Row 19: Exhibit PPL 1002

Notes:
a - Retail Services are conducted as unregulated activities.
b -DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

C. Craig Paice
Exhibit PPL/914

Docket No. UE-210
Exhibit PPL/914
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Unbundled Results of Operations

August 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2010 Forecast

	Description of Account Summary:	Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Other
	Operating Revenues								
1	General Business Revenues	949,341,303	575,596,122	65,110,984	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	186,446,628	148,294,143	38,152,485	-	-	-	-	-
5	Other Operating Revenues	42,876,160	24,677,064	20,913,916	3,829,688	(11,174,486)	4,615,089	11,832	3,057
6	Total Operating Revenues	1,178,664,091	748,567,329	124,177,385	249,946,185	0	15,860,190	27,180,920	12,932,082
7									
8	Operating Expenses:								
9	Steam Production	250,559,290	250,559,290	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	9,911,805	9,911,805	-	-	-	-	-	-
12	Other Power Supply	261,435,192	261,435,192	-	-	-	-	-	-
13	Transmission	52,555,833	227,849	52,327,985	-	-	-	-	-
14	Distribution	70,710,593	-	-	65,959,265	-	-	4,751,328	-
15	Customer Accounts	31,710,902	3,203,339	531,391	1,069,593	0	10,454,727	10,493,813	5,958,039
16	Customer Service	3,695,469	-	-	1,198,841	-	-	-	2,496,628
17	Sales	-	-	-	-	-	-	-	-
18	Administrative & General	49,670,470	18,650,096	4,739,965	19,576,953	-	1,857,343	3,178,446	1,667,667
19									
20	Total O & M Expenses	730,249,555	543,987,570	57,599,341	87,804,653	0	12,312,070	18,423,587	10,122,334
21									
22	Depreciation	147,845,235	74,721,230	19,263,620	50,682,215	-	240,694	2,686,782	250,695
23	Amortization Expense	16,476,351	8,613,341	999,828	3,245,748	-	1,511,417	1,158,825	947,191
24	Taxes Other Than Income	51,966,873	14,760,151	4,645,773	31,733,906	0	202,475	486,446	138,122
25	Income Taxes - Federal	23,758,403	(373,894)	5,939,691	14,240,198	0	912,729	2,067,334	972,345
26	Income Taxes - State	4,838,128	1,616,129	793,032	1,901,266	0	121,862	276,018	129,822
27	Income Taxes - Def Net	17,114,105	8,669,451	3,138,265	5,172,757	-	28,296	122,508	(17,174)
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29	Misc Revenue & Expense	(2,076,505)	(2,457,569)	(84,959)	465,280	-	-	742	-
30									
31	Total Operating Expenses	990,172,144	649,536,409	92,294,591	195,246,024	0	15,329,543	25,222,242	12,543,335
32									
33	Operating Revenue for Return	188,491,947	99,030,920	31,882,794	54,700,162	0	530,647	1,958,677	388,747
34									
35	Rate Base:								
36	Electric Plant in Service	5,543,234,819	2,662,161,725	897,899,724	1,837,922,900	-	34,630,374	87,906,695	22,713,401
37	Plant Held for Future Use	(0)	2,398,305	(2,398,306)	-	-	-	-	-
38	Misc Deferred Debits	20,133,708	8,370,921	11,029,863	336,614	-	96,053	186,184	114,072
39	Elec Plant Acq Adj	18,568,147	18,568,147	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-	-
41	Prepayments	12,201,019	5,616,099	737,339	3,635,698	-	579,668	1,043,103	589,111
42	Fuel Stock	41,007,740	41,007,740	-	-	-	-	-	-
43	Material & Supplies	49,319,573	39,619,002	3,331,669	6,152,974	-	-	215,928	-
44	Working Capital	12,584,036	6,967,567	1,167,055	3,103,098	0	373,525	627,912	344,880
45	Weatherization Loans	(696)	-	-	(696)	-	-	-	-
46	Miscellaneous Rate Base	1,206,251	1,206,251	-	-	-	-	-	-
47									
48	Total Electric Plant	5,698,254,596	2,785,915,758	911,767,344	1,851,150,587	0	35,679,620	89,979,822	23,761,465
49									
50	Rate Base Deductions:								
51	Accum Prov For Depr	(2,041,168,235)	(917,607,943)	(317,172,989)	(767,605,245)	-	(2,546,282)	(34,554,054)	(1,681,723)
52	Accum Prov For Amort	(141,105,146)	(43,526,226)	(5,100,942)	(42,868,870)	-	(21,822,835)	(14,784,447)	(13,001,826)
53	Accum Def Income Taxes	(551,004,650)	(265,043,883)	(90,328,433)	(182,196,552)	-	(2,339,965)	(8,789,682)	(2,306,135)
54	Unamortized ITC	(4,172,305)	(1,686,630)	(200,801)	(1,418,610)	-	(227,033)	(408,458)	(230,773)
55	Customer Adv for Const	(3,499,244)	-	(1,906,223)	(1,536,895)	-	-	(56,126)	-
56	Customer Service Deposits	-	-	-	-	-	-	-	-
57	Misc. Rate Base Deductions	(21,182,496)	(15,455,118)	(422,474)	(3,464,798)	-	(477,665)	(876,907)	(485,534)
58									
59	Total Rate Base Deductions	(2,762,132,076)	(1,243,319,800)	(415,131,862)	(999,090,970)	-	(27,413,780)	(59,469,674)	(17,705,990)
60									
61	Total Rate Base	2,936,122,520	1,542,595,958	496,635,482	852,059,617	1	8,265,839	30,510,148	6,055,475
62									
63	Return on Rate Base	6.4198%	6.4198%	6.4198%	6.4198%	6.4212%	6.4198%	6.4198%	6.4198%
64									
65	Return on Equity	6.8647%	6.8647%	6.8647%	6.8647%	6.8675%	6.8647%	6.8647%	6.8647%

Docket No. UE-210
Exhibit PPL/915
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Ancillary Service Revenues

August 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
CY 2010 Ancillary Services Revenue
12 Months Ended December 31, 2010 Forecast

Line	Item	Notes	Thermal Resource	Hydro Resource	Other Resource	Firm Purchases	Total Resources
1	System Resources CY 2010 (MWH)	(Note 1)	54,812,550	3,932,604	2,708,907	10,123,248	71,577,309
2	Plant allocated to Oregon based on JAM dollars	(Note 2)	26.94%	26.88%	26.83%	26.55%	
3	Oregon share of Resource Providing Service by type (MWH)	(Line 1 x Line 2)	14,766,136	1,056,961	726,700	2,688,108	19,237,905
4	Resource type % of total		76.76%	5.49%	3.78%	13.97%	100.00%
5	Oregon Retail Load, Including Losses, by resource type	(Line 4 x Line 5 Total)	11,258,531	805,887	554,077	2,049,564	14,668,059
7	FERC Tariff Ancillary Service Charges						
	Regulation and Frequency Response Service						
8	Billing Determinant (Load Energy MWH)		NA	NA	NA	NA	14,668,059
9	Charge ($/MWH)		NA	NA	NA	NA	0.1600
10	Total Cost	(Line 8 x Line 9)	NA	NA	NA	NA	$2,346,889
	Operating Reservice - Spinning Reserve Service						
11	Billing Determinant (Generated Energy in MWH)		11,258,531	805,887	554,077	2,049,564	14,668,059
12	Charge ($/MWH)		0.3730	0.2660	NA	NA	
13	Total Cost	(Line 11 x Line 12)	$4,199,432	$214,366			$4,413,798
	Operating Reservice - Supplemental Reserve Service						
14	Billing Determinant (Generated Energy in MWH)		11,258,531	805,887	554,077	2,049,564	14,668,059
15	Charge ($/MWH)		0.3730	0.2660	NA	NA	
16	Total Cost	(Line 14 x Line 15)	$4,199,432	$214,366			$4,413,798
17	Oregon Annual Ancillary Service Revenue ($ x thousands)	Line 10 + Line 13 + Line 16)					$11,174,486

Note 1 - Source :Net Power Cost Analysis

Note 2 - CY 2010 JAM Model

Total Electric Plant in Service by Plant Type ($ x Millions)	Thermal	Hydro	Other	Total
Oregon	1,443.1	173.6	758.3	2,375.0
System	5,356.9	645.9	2,826.8	8,829.6
Percent of System	26.94%	26.88%	26.83%	26.90%

2008 JAM Model - Acount 555 Purchased Power SG	Dollars
Oregon - Unadjusted	212,980,461
System	802,071,244
Percent of System	26.55%

2010 JAM Model - Production Plant	TOTAL	OTHER	OREGON
Total Steam Production Plant	5,356,904,946	3,913,790,389	1,443,114,557
Total Hydraulic Plant	645,856,753	472,270,582	173,586,171
Total Other Production Plant	2,826,805,765	2,068,478,363	758,327,403
TOTAL PRODUCTION PLANT	8,829,567,465	6,454,539,334	2,375,028,130

C. Craig Paice
Exhibit PPL/916

Docket No. UE-210
Exhibit PPL/916
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Oregon Marginal Cost of Service Summary

August 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2010 Forecast
(Dollars in 000's)

Line	Description	(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) Primary (pri)	(F) General Power - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) General Power - Schedule 30 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) 1 - 4 M (pri)	(O) > 4 MW (sec)	(P) > 4 M (pri)	(Q) Trans (trn)	(R) Irrg Sch 41 (sec)	(S) Irrg KWUA (sec)	(S) Sch 51,53,54 Streetlighting (sec)
	Demand Related Marginal Cost																				
1	Generation	$161,795	$73,417	$6,521	$5,949	$15	$5,886	$9,641	$12,021	$238	$2,603	$13,514	$1,145	$7,499	$4,840	$571	$12,603	$3,615	$1,717	$1,481	
2	Transmission	$163,662	$74,265	$6,597	$6,017	$15	$5,954	$9,752	$12,160	$240	$2,633	$13,670	$1,158	$7,586	$4,896	$578	$12,748	$3,657	$1,736	$1,498	
3	Distribution																				
4	Poles	$43,918	$27,466	$2,083	$1,832	$4	$1,177	$1,929	$2,521	$49	$584	$3,042	$257	$1,143	$726	$8	$143	$0	$953	$973	
5	Conductor	$73,160	$44,797	$3,361	$2,957	$8	$2,072	$3,393	$4,436	$86	$1,015	$5,291	$448	$2,193	$1,391	$19	$306	$0	$1,387	$1,410	
6	Substations	$53,934	$28,171	$1,979	$1,741	$4	$1,738	$2,846	$3,720	$72	$810	$4,221	$357	$2,323	$1,474	$168	$3,884	$0	$426	$368	
7	Subtotal: Pole, Cond, Subs	$171,013	$100,434	$7,422	$6,529	$17	$4,987	$8,168	$10,677	$207	$2,410	$12,554	$1,062	$5,659	$3,590	$195	$4,333	$0	$2,766	$2,751	
8	Transformers	$6,968	$4,040	$592	$238	$0	$237	$344	$437	$0	$90	$423	$0	$313	$0	$39	$0	$0	$214	$184	
9	Distribution subtotal	$177,981	$104,474	$8,014	$6,768	$17	$5,224	$8,513	$11,114	$207	$2,500	$12,977	$1,062	$5,972	$3,590	$235	$4,333	$0	$2,980	$2,935	
10																					
11	Total Demand Related	$503,438	$252,156	$21,132	$18,734	$47	$17,064	$27,906	$35,295	$685	$7,736	$40,161	$3,365	$21,057	$13,326	$1,384	$29,684	$7,272	$6,433	$5,914	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$766,783	$330,631	$35,432	$26,170	$68	$26,275	$40,900	$56,104	$1,075	$12,544	$65,598	$5,535	$36,175	$24,439	$3,305	$69,247	$23,370	$8,320	$7,180	$1,595
16	Transmission Energy Related	$52,473	$22,626	$2,425	$1,791	$5	$1,798	$2,799	$3,839	$74	$858	$4,489	$379	$2,476	$1,672	$226	$4,739	$1,599	$569	$491	$109
17	Total Energy	$819,256	$353,257	$37,857	$27,961	$73	$28,074	$43,699	$59,943	$1,149	$13,402	$70,087	$5,914	$38,650	$26,111	$3,532	$73,986	$24,969	$8,890	$7,671	$1,704
18																					
19	Customer Related Marginal Cost																				
20	Poles	$61,601	$47,136	$7,297	$1,058	$4	$216	$170	$98	$3	$14	$33	$3	$1	$1	$0	$0	$0	$1,853	$789	$3,714
21	Conductor	$23,235	$18,881	$2,922	$423	$1	$87	$68	$39	$1	$5	$14	$1	$1	$0	$0	$0	$0	$742	$317	$47
22	Transformers	$68,657	$35,458	$14,284	$4,648	$0	$3,090	$2,830	$1,794	$0	$246	$613	$0	$129	$0	$3	$0	$0	$5,454	$2,153	$107
23	Service Drops	$45,223	$33,849	$5,887	$2,042	$0	$1,018	$834	$1,060	$0	$120	$298	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,510	$7,428	$1,187	$356	$41	$165	$164	$422	$60	$48	$120	$62	$32	$67	$1	$41	$86	$228	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,442	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$31
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,134	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$248,830	$175,881	$35,632	$9,115	$48	$4,979	$4,382	$3,596	$68	$509	$1,265	$84	$476	$161	$8	$97	$89	$8,523	$3,416	$3,915
30																					
31	Total Revenue @ Full MC																				
32	Generation	$928,578	$404,048	$41,953	$32,119	$83	$32,161	$50,541	$68,125	$1,313	$15,147	$79,112	$6,680	$43,674	$29,279	$3,876	$81,850	$26,985	$10,037	$8,661	$1,595
33	Transmission	$216,135	$96,891	$9,022	$7,808	$20	$7,752	$12,551	$15,999	$314	$3,491	$18,159	$1,537	$10,062	$6,568	$804	$17,487	$5,256	$2,305	$1,989	$109
34	Distribution	$376,699	$239,798	$38,406	$14,939	$22	$9,635	$12,415	$14,106	$211	$2,885	$13,934	$1,067	$6,217	$3,592	$239	$4,333	$0	$11,029	$6,195	$3,871
35	Customer - Billing	$18,233	$15,442	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$31
36	Customer - Metering	$18,829	$14,127	$2,309	$519	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,134	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,565,784	$776,439	$94,445	$55,784	$167	$50,003	$75,898	$98,783	$1,901	$21,606	$111,410	$9,353	$60,049	$39,536	$4,921	$103,729	$32,328	$23,811	$16,994	$5,619
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,571,524	$781,295	$94,621	$55,810	$167	$50,116	$75,987	$98,835	$1,903	$21,647	$111,513	$9,363	$60,184	$39,598	$4,923	$103,767	$32,330	$23,846	$17,001	$5,619

C. Craig Paice
Exhibit PPL/917

Docket No. UE-210
Exhibit PPL/917
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Unbundled Revenue Requirement Allocation by Rate Schedule

August 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedul

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C)	(D) General Service Sch 28	(E)	(F) General Service Sch 30	(G)	(H) Large Power Service Sch 48T	(I)	(J)	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$928,578	$404,048	$74,072	$83	$150,827	$1,313	$94,259	$6,680	$47,550	$111,129	$26,985	$10,037	$1,595
6	Transmission	$216,135	$96,891	$16,830	$20	$36,302	$314	$21,650	$1,537	$10,866	$24,055	$5,256	$2,305	$109
7	Distribution	$376,699	$239,798	$53,345	$22	$36,157	$211	$16,819	$1,067	$6,456	$7,925	$0	$11,029	$3,871
8	Customer - Billing	$18,233	$15,442	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$31
9	Customer - Metering	$18,829	$14,127	$2,829	$41	$920	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,134	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,565,784	$776,439	$150,229	$167	$224,685	$1,901	$133,016	$9,353	$64,970	$143,265	$32,328	$23,811	$5,619
12														
13	**Functional Revenue Requirement Allocation Factor**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.51%	7.98%	0.01%	16.24%	0.14%	10.15%	0.72%	5.12%	11.97%	2.91%	1.08%	0.17%
16	Transmission	100.00%	44.83%	7.79%	0.01%	16.80%	0.15%	10.02%	0.71%	5.03%	11.13%	2.43%	1.07%	0.05%
17	Distribution	100.00%	63.66%	14.16%	0.01%	9.60%	0.06%	4.46%	0.28%	1.71%	2.10%	0.00%	2.93%	1.03%
18	Ancillary Service	100.00%	43.51%	7.98%	0.01%	16.24%	0.14%	10.15%	0.72%	5.12%	11.97%	2.91%	1.08%	0.17%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.17%
20	Customer - Metering	100.00%	75.03%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.16%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$605,406	$263,428	$48,293	$54	$98,335	$856	$61,454	$4,355	$31,002	$72,453	$17,593	$6,544	$1,040
28	Transmission	$79,096	$35,458	$6,159	$7	$13,285	$115	$7,923	$562	$3,976	$8,803	$1,924	$844	$40
29	Distribution	$243,782	$155,186	$34,522	$14	$23,399	$137	$10,884	$690	$4,178	$5,128	$0	$7,137	$2,505
30	Ancillary Services	$10,767	$4,685	$859	$1	$1,749	$15	$1,093	$77	$551	$1,288	$313	$116	$18
31	Customer - Billing	$11,107	$9,407	$1,375	$1	$200	$1	$16	$1	$18	$13	$0	$57	$19
32	Customer - Metering	$27,183	$20,394	$4,083	$60	$1,328	$88	$330	$96	$67	$171	$124	$439	$3
33	Customer - Other	$12,657	$10,619	$1,552	$1	$261	$1	$57	$4	$39	$29	$1	$72	$21
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,662	$12,193	$2,347	$3	$3,216	$29	$1,897	$138	$929	$2,001	$450	$370	$90
36	Total	$1,013,658	$511,369	$99,191	$140	$141,773	$1,242	$83,654	$5,923	$40,760	$89,886	$20,404	$15,580	$3,735
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	90.29%	92.22%	91.53%	70.80%	87.72%	90.45%	87.71%	89.79%	88.14%	86.08%	85.28%	91.93%	93.40%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$98,477	$39,775	$8,401	$41	$17,403	$119	$10,284	$605	$4,833	$12,510	$3,003	$1,257	$247
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	10.76%	8.43%	9.25%	41.25%	13.99%	10.55%	14.02%	11.37%	13.45%	16.17%	17.26%	8.77%	7.07%
46	(Line 41 / Line 1)													

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2010 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	H	I	J
Line No.	**Description**	**Generation**	**Transmission**	**Distribution**	**Ancillary**	**C Billing**	**C Metering**	**C Other**	**DSM**	**Franchise Fees**	**Total**
1	Earned Functional Revenue Requirement	$575,596	$65,111	$223,883	$11,174	$11,245	$27,169	$12,929	$0	22,233	$949,341
2											
3	Percent of Total	60.63%	6.86%	23.58%	1.18%	1.18%	2.86%	1.36%	0.00%	2.34%	100.00%
4											
5	Revenue From Classes Included in MC Study	$554,885	$62,768	$215,827	$10,772	$10,840	$26,191	$12,464	$0	$21,433	$915,181
6											
7	Other Revenues										
8	Partial Requirements - Sch. 47 pri										$18,498
9	Partial Requirements - Sch. 47 trn										$7,223
10	USBR Billed Revenue										$3,839
11	AGA										$2,380
12	Lighting										$2,617
13	Employee Discount										($396)
14	Total Oregon Situs Revenue										$949,341

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2010 Functionalized Revenue - Target
($ 000)

		A	B	C	D	E	F	G	H	I	J	
Line No.	**Description**	**Generation**	**Transmission**	**Distribution**	**Ancillary**	**C Billing**	**C Metering**	**C Other**	**DSM**	**Franchise Fees**	**Total**	
1	Target Functional Revenue Requirement	628,341	82,092	253,017	11,174	11,528	28,212	13,136	0	24,558	$1,052,059	
2												
3	Percent of Total	59.72%	7.80%	24.05%	1.06%	1.10%	2.68%	1.25%	0.00%	2.33%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$605,406	$79,096	$243,782	$10,767	$11,107	$27,183	$12,657	$0	$23,662	$ 1,013,658	98,477
6												
7	Other Revenues											102,718
8	Partial Requirements - Sch. 47 pri										$21,510	$3,012
9	Partial Requirements - Sch. 47 trn										$8,426	$1,203
10	USBR Billed Revenue										$3,665	-$173
11	AGA										$2,380	$0
12	Lighting										$2,850	$233
13	Employee Discount										($430)	($33)
14	Total Oregon Situs Revenue										$1,052,059	98,477

Docket No. UE-210
Exhibit PPL/918
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Functional JAM

August 2009

Exhibit PPL/918

REVISED PROTOCOL
Year End
RESULTS OF OPERATIONS SUMMARY

REVISED PROTOCOL Description of Account Summary:	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
General Business Revenues	949,341,303	575,596,122	65,110,984	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025
General Business Revenues	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-
Special Sales	186,446,628	148,294,143	38,152,485	-	-	-	-	-
Other Operating Revenues	42,876,160	24,677,064	20,913,916	3,829,688	(11,174,486)	4,615,089	11,832	3,057
Total Operating Revenues	1,178,664,091	748,567,329	124,177,385	249,946,185	0	15,860,190	27,180,920	12,932,082
Operating Expenses:								
Steam Production	250,559,290	250,559,290	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-
Hydro Production	9,911,805	9,911,805	-	-	-	-	-	-
Other Power Supply	261,435,192	261,435,192	-	-	-	-	-	-
Transmission	52,555,833	227,849	52,327,985	-	-	-	-	-
Distribution	70,710,593	-	-	65,959,265	-	-	4,751,328	-
Customer Accounts	31,710,902	3,203,339	531,391	1,069,593	0	10,454,727	10,493,813	5,958,039
Customer Service	3,695,469	-	-	1,198,841	-	-	-	2,496,628
Sales	-	-	-	-	-	-	-	-
Administrative & General	49,670,470	18,650,096	4,739,965	19,576,953	-	1,857,343	3,178,446	1,667,667
Total O & M Expenses	730,249,555	543,987,570	57,599,341	87,804,653	0	12,312,070	18,423,587	10,122,334
Depreciation	147,845,235	74,721,230	19,263,620	50,682,215	-	240,694	2,686,782	250,695
Amortization Expense	16,476,351	8,613,341	999,828	3,245,748	-	1,511,417	1,158,825	947,191
Taxes Other Than Income	51,966,873	14,760,151	4,645,773	31,733,906	0	202,475	486,446	138,122
Income Taxes - Federal	23,758,403	(373,894)	5,939,691	14,240,198	0	912,729	2,067,334	972,345
Income Taxes - State	4,838,128	1,616,129	793,032	1,901,266	0	121,862	276,018	129,822
Income Taxes - Def Net	17,114,105	8,669,451	3,138,265	5,172,757	-	28,296	122,508	(17,174)
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
Misc Revenue & Expense	(2,076,505)	(2,457,569)	(84,959)	465,280	-	-	742	-
Total Operating Expenses	990,172,144	649,536,409	92,294,591	195,246,024	0	15,329,543	25,222,242	12,543,335
Operating Revenue for Return	188,491,947	99,030,920	31,882,794	54,700,162	0	530,647	1,958,677	388,747
Rate Base:								
Electric Plant In Service	5,543,234,819	2,662,161,725	897,899,724	1,837,922,900	-	34,630,374	87,906,695	22,713,401
Plant Held for Future Use	(0)	2,398,305	(2,398,306)	-	-	-	-	-
Misc Deferred Debits	20,133,708	8,370,921	11,029,863	336,614	-	96,053	186,184	114,072
Elec Plant Acq Adj	18,568,147	18,568,147	-	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-	-	-	-
Prepayments	12,201,019	5,616,099	737,339	3,635,698	-	579,668	1,043,103	589,111
Fuel Stock	41,007,740	41,007,740	-	-	-	-	-	-
Material & Supplies	49,319,573	39,619,002	3,331,669	6,152,974	-	-	215,928	-
Working Capital	12,584,036	6,967,567	1,167,055	3,103,098	0	373,525	627,912	344,880
Weatherization Loans	(696)	-	-	(696)	-	-	-	-
Miscellaneous Rate Base	1,206,251	1,206,251	-	-	-	-	-	-
Total Electric Plant	5,698,254,596	2,785,915,758	911,767,344	1,851,150,587	0	35,679,620	89,979,822	23,761,465
Rate Base Deductions:								
Accum Prov For Depr	(2,041,168,235)	(917,607,943)	(317,172,989)	(767,605,245)	-	(2,546,282)	(34,554,054)	(1,681,723)
Accum Prov For Amort	(141,105,146)	(43,526,226)	(5,100,942)	(42,868,870)	-	(21,822,835)	(14,784,447)	(13,001,826)
Accum Def Income Taxes	(551,004,650)	(265,043,883)	(90,328,433)	(182,196,552)	-	(2,339,965)	(8,789,682)	(2,306,135)
Unamortized ITC	(4,172,305)	(1,686,630)	(200,801)	(1,418,610)	-	(227,033)	(408,458)	(230,773)
Customer Adv for Const	(3,499,244)	-	(1,906,223)	(1,536,895)	-	-	(56,126)	-
Customer Service Deposits	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(21,182,496)	(15,455,118)	(422,474)	(3,464,798)	-	(477,665)	(876,907)	(485,534)
Total Rate Base Deductions	(2,762,132,076)	(1,243,319,800)	(415,131,862)	(999,090,970)	-	(27,413,780)	(59,469,674)	(17,705,990)
Total Rate Base	2,936,122,520	1,542,595,958	496,635,482	852,059,617	1	8,265,839	30,510,148	6,055,475
Return on Rate Base	6.420%	6.420%	6.420%	6.420%	6.418%	6.420%	6.420%	6.420%
Return on Equity	6.865%	6.865%	6.865%	6.865%	6.862%	6.865%	6.865%	6.865%
100 Basis Points in Equity:	14,974,225	7,867,239	2,532,841	4,345,504	0	42,156	155,602	30,883
Revenue Requirement Impact	24,132,903	12,679,075	4,082,001	7,003,343	0	67,940	250,772	49,772
Rate Base Decrease	(216,085,841)	(113,528,350)	(36,550,210)	(62,707,880)	(0)	(608,330)	(2,245,414)	(445,657)

RESULTS OF OPERATIONS SUMMARY

REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
Sales to Ultimate Customers											
440	Residential Sales				0	0	0	0	0	0	0
			S	471,582,657	575,596,122	65,110,984	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025
				471,582,657							
442	Commercial & Industrial Sales										
			S	473,034,023							
		P	SE	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-
				473,034,023	-	-	-	-	-	-	-
444	Public Street & Highway Lighting										
			S	4,724,623							
			SO	-							
				4,724,623	-	-	-	-	-	-	-
445	Other Sales to Public Authority										
			S	-							
				-	-	-	-	-	-	-	-
448	Interdepartmental										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				949,341,303	575,596,122	65,110,984	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025
447	Sales for Resale-Non NPC										
		WSF	S	963,190	766,093	197,097	-	-	-	-	-
				963,190	766,093	197,097	-	-	-	-	-
447NPC	Sales for Resale-NPC										
		WSF	SG	185,483,438	147,528,050	37,955,388	-	-	-	-	-
		WSF	SE	0	0	0	-	-	-	-	-
		WSF	SG	-	-	-	-	-	-	-	-
				185,483,438	147,528,050	37,955,388	-	-	-	-	-
	Total Sales for Resale			186,446,628	148,294,143	38,152,485	-	-	-	-	-
449	Provision for Rate Refund										
		WSF	S	-	-	-	-	-	-	-	-
		WSF	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Sales from Electricity				1,135,787,931	723,890,265	103,263,469	246,116,498	11,174,486	11,245,101	27,169,088	12,929,025
450	Forfeited Discounts & Interest										
		CUST	S	2,699,352	-	-	-	-	2,699,352	-	-
		CUST	SO	-	-	-	-	-	-	-	-
				2,699,352	-	-	-	-	2,699,352	-	-
451	Misc Electric Revenue										
		CUST	S	1,911,077	-	-	-	-	1,911,077	-	-
		GP	SG	-	-	-	-	-	-	-	-
		DSM	SO	3,821	-	-	3,821	-	-	-	-
				1,914,898	-	-	3,821	-	1,911,077	-	-
453	Water Sales										
		P	SG	22,169	22,169	-	-	-	-	-	-
				22,169	22,169	-	-	-	-	-	-
454	Rent of Electric Property										
		D	S	5,808,234	-	-	5,808,234	-	-	-	-
		T	SG	1,461,653	-	1,461,653	-	-	-	-	-
		GP	SO	746,078	358,307	120,851	247,370.58	-	4,661	11,831.58	3,057
				8,015,965	358,307	1,582,504	6,055,605	-	4,661	11,832	3,057
	Oregon Ancillary Services				11,174,486			(11,174,486)			
456	Other Electric Revenue										
		D	S	(2,230,667)	-	-	(2,230,667)	-	-	-	-
		CUST	CN	-	-	-	-	-	-	-	-
		OTHSE	SE	4,088,267	706	4,087,561	-	-	-	-	-
		OTHSO	SO	929	0	0	929	-	-	-	-
		OTHSGR	SG	28,365,247	13,121,397	15,243,851	-	-	-	-	-
				30,223,776	13,122,103	19,331,412	(2,229,738)	-	-	-	-
	Total Other Electric Revenues			42,876,160	24,677,064	20,913,916	3,829,688	(11,174,486)	4,616,089	11,832	3,057
Total Electric Operating Revenues				1,178,664,091	748,567,329	124,177,385	249,946,185	0	15,860,190	27,180,920	12,932,082

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Summary of Revenues by Factor											
	S			958,492,488	576,362,215	65,308,081	249,694,065	11,174,486	15,855,529	27,169,088	12,929,025
	CN			-	-	-	-	-	-	-	-
	SE			4,088,267	706	4,087,561	-	-	-	-	-
	SO			750,828	358,307	120,851	252,121	-	4,661	11,832	3,057
	SG			215,332,508	160,649,446	54,660,892	-	-	-	-	-
	DGP			-	-	-	-	-	-	-	-
Total Electric Operating Revenues				1,178,664,091	737,370,674	124,177,385	249,946,185	11,174,486	15,860,190	27,180,920	12,932,082
Miscellaneous Revenues											
41160	Gain on Sale of Utility Plant - CR										
		D	S	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
41170	Loss on Sale of Utility Plant										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances										
		P	S	-	-	-	-	-	-	-	-
		P	SE	(2,080,448)	(2,080,448)	-	-	-	-	-	-
				(2,080,448)	(2,080,448)	-	-	-	-	-	-
41181	Gain from Disposition of NOX Credits										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4194	Impact Housing Interest Income										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant										
		D	S	444,952	-	-	444,952	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		T	SG	(95,809)	-	(95,809)	-	-	-	-	-
		P	CN	207	207.1329307	-	-	-	-	-	-
		PTD	SO	61,528	29,607	10,849	20,328.70	-	-	742.38	-
		P	SG	(406,936)	(406,936)	-	-	-	-	-	-
				3,942	(377,121)	(84,959)	465,280	-	-	742	-
Total Miscellaneous Revenues				(2,076,505)	(2,457,569)	(84,959)	465,280	-	-	742	-
Miscellaneous Expenses											
4311	Interest on Customer Deposits										
		CUST	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				-	-	-	-	-	-	-	-
Net Misc Revenue and Expense				(2,076,505)	(2,457,569)	(84,959)	465,280	-	-	742	-
500	Operation Supervision & Engineering										
		P	SG	5,739,991	5,739,991	-	-	-	-	-	-
		P	SSGCH	380,069	380,069	-	-	-	-	-	-
				6,120,059	6,120,059	-	-	-	-	-	-
501	Fuel Related-Non NPC										
		P	SE	3,561,573	3,561,573	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSECT	-	-	-	-	-	-	-	-
		P	SSECH	446,551	446,551	-	-	-	-	-	-
				4,008,124	4,008,124	-	-	-	-	-	-
501NPC	Fuel Related-NPC										
		P	SE	154,873,739	154,873,739	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSECT	-	-	-	-	-	-	-	-
		P	SSECH	14,027,286	14,027,286	-	-	-	-	-	-
				168,901,025	168,901,025	-	-	-	-	-	-
	Total Fuel Related			172,909,149	172,909,149	-	-	-	-	-	-
502	Steam Expenses										
		P	SG	9,104,859	9,104,859	-	-	-	-	-	-
		P	SSGCH	822,522	822,522	-	-	-	-	-	-
				9,927,382	9,927,382	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC										
		P	SE	326	326	-	-	-	-	-	-
				326	326	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC										
		P	SE	874,566	874,566	-	-	-	-	-	-
				874,566	874,566	-	-	-	-	-	-
505	Electric Expenses										
		P	SG	778,003	778,003	-	-	-	-	-	-
		P	SSGCH	412,404	412,404	-	-	-	-	-	-
				1,190,407	1,190,407	-	-	-	-	-	-
506	Misc. Steam Expense										
		P	SG	11,702,141	11,702,141	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSGCH	531,004	531,004	-	-	-	-	-	-
				12,233,145	12,233,145	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
506	Misc. Steam Expense										
		P	SG	11,702,141	11,702,141	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSGCH	531,004	531,004	-	-	-	-	-	-
				12,233,145	12,233,145	-	-	-	-	-	-
507	Rents										
		P	SG	184,337	184,337	-	-	-	-	-	-
		P	SSGCH	1,674	1,674	-	-	-	-	-	-
				186,011	186,011	-	-	-	-	-	-
510	Maint Supervision & Engineering										
		P	SG	4,990,858	4,990,858	-	-	-	-	-	-
		P	SSGCH	514,747	514,747	-	-	-	-	-	-
				5,505,605	5,505,605	-	-	-	-	-	-
511	Maintenance of Structures										
		P	SG	6,543,416	6,543,416	-	-	-	-	-	-
		P	SSGCH	303,016	303,016	-	-	-	-	-	-
				6,846,432	6,846,432	-	-	-	-	-	-
512	Maintenance of Boiler Plant										
		P	SG	21,503,712	21,503,712	-	-	-	-	-	-
		P	SSGCH	1,603,631	1,603,631	-	-	-	-	-	-
				23,107,342	23,107,342	-	-	-	-	-	-
513	Maintenance of Electric Plant										
		P	SG	6,861,205	6,861,205	-	-	-	-	-	-
		P	SSGCH	1,027,582	1,027,582	-	-	-	-	-	-
				7,888,787	7,888,787	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant										
		P	SG	2,622,105	2,622,105	-	-	-	-	-	-
		P	SSGCH	1,147,972	1,147,972	-	-	-	-	-	-
				3,770,078	3,770,078	-	-	-	-	-	-
Total Steam Power Generation				**250,559,290**	**250,559,290**	-	-	-	-	-	-
517	Operation Super & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
518	Nuclear Fuel Expense										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
519	Coolants and Water										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
520	Steam Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
523	Electric Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
529	Maintenance of Structures										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
530	Maintenance of Reactor Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
531	Maintenance of Electric Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
532	Maintenance of Misc Nuclear										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Nuclear Power Generation				-	-	-	-	-			
535	Operation Super & Engineering										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	2,139,741	2,139,741	-	-	-	-	-	-
		P	SG	219,168	219,168	-	-	-	-	-	-
				2,358,909	2,358,909	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
536	Water For Power										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	66,075	66,075	-	-	-	-	-	-
		P	SG	2,420	2,420	-	-	-	-	-	-
				68,495	68,495	-	-	-	-	-	-
537	Hydraulic Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	962,358	962,358	-	-	-	-	-	-
		P	SG	106,880	106,880	-	-	-	-	-	-
				1,069,238	1,069,238	-	-	-	-	-	-
538	Electric Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	3,026,737	3,026,737	-	-	-	-	-	-
		P	SG	1,520,651	1,520,651	-	-	-	-	-	-
				4,547,388	4,547,388	-	-	-	-	-	-
540	Rents (Hydro Generation)										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	41,730	41,730	-	-	-	-	-	-
		P	SG	2,542	2,542	-	-	-	-	-	-
				44,272	44,272	-	-	-	-	-	-
541	Maint Supervision & Engineering										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
542	Maintenance of Structures										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	241,247	241,247	-	-	-	-	-	-
		P	SG	18,208	18,208	-	-	-	-	-	-
				259,455	259,455	-	-	-	-	-	-
543	Maintenance of Dams & Waterways										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	235,830	235,830	-	-	-	-	-	-
		P	SG	113,094	113,094	-	-	-	-	-	-
				348,924	348,924	-	-	-	-	-	-
544	Maintenance of Electric Plant										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	331,398	331,398	-	-	-	-	-	-
		P	SG	242,405	242,405	-	-	-	-	-	-
				573,803	573,803	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	431,794	431,794	-	-	-	-	-	-
		P	SG	209,526	209,526	-	-	-	-	-	-
				641,321	641,321	-	-	-	-	-	-
				-							
Total Hydraulic Power Generation				9,911,805	9,911,805	-	-	-	-	-	-
ACCT	DESCRIPTION	FUNCTION	FACTOR	Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
546	Operation Super & Engineering										
		P	SG	129,162	129,162	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
				129,162	129,162	-	-	-	-	-	-
547	Fuel-Non-NPC										
		P	SE	-	-	-	-	-	-	-	-
		P	SSECT	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
547NPC	Fuel-NPC										
		P	SE	106,618,665	106,618,665	-	-	-	-	-	-
		P	SSECT	2,903,754	2,903,754	-	-	-	-	-	-
				109,522,419	109,522,419	-	-	-	-	-	-

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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
548	Generation Expense										
		P	SG	3,719,306	3,719,306	-	-	-	-	-	-
		P	SSGCT	385,797	385,797	-	-	-	-	-	-
				4,105,102	4,105,102	-	-	-	-	-	-
549	Miscellaneous Other										
		P	SG	7,897,757	7,897,757	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
				7,897,757	7,897,757	-	-	-	-	-	-
550	Maint Supervision & Engineering										
		P	SG	497,741	497,741	-	-	-	-	-	-
		P	SSGCT	0	0	-	-	-	-	-	-
				497,741	497,741	-	-	-	-	-	-
551	Maint Supervision & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
552	Maintenance of Structures										
		P	SG	129,842	129,842	-	-	-	-	-	-
		P	SSGCT	38,532	38,532	-	-	-	-	-	-
				168,374	168,374	-	-	-	-	-	-
553	Maint of Generation & Electric Plant										
		P	SG	2,433,974	2,433,974	-	-	-	-	-	-
		P	SSGCT	199,057	199,057	-	-	-	-	-	-
				2,633,031	2,633,031	-	-	-	-	-	-
554	Maintenance of Misc. Other										
		P	SG	36,518	36,518	-	-	-	-	-	-
		P	SSGCT	40,189	40,189	-	-	-	-	-	-
				76,708	76,708	-	-	-	-	-	-
Total Other Power Generation				125,030,295	125,030,295	-	-	-	-	-	-
555	Purchased Power-Non NPC										
		DSM	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC										
		P	SG	124,965,942	124,965,942	-	-	-	-	-	-
		P	SE	14,733,777	14,733,777	-	-	-	-	-	-
		P	SSGC	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-
				139,699,720	139,699,720	-	-	-	-	-	-
	Total Purchased Power			139,699,720	139,699,720	-	-	-	-	-	-
556	System Control & Load Dispatch										
		P	SG	619,531	619,531	-	-	-	-	-	-
				619,531	619,531	-	-	-	-	-	-
557	Other Expenses										
		P	S	(57,199)	(57,199)	-	-	-	-	-	-
		P	SG	9,344,271	9,344,271	-	-	-	-	-	-
		P	SGCT	321,868	321,868	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSGCT	109	109	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-
				9,609,049	9,609,049	-	-	-	-	-	-
	Embedded Cost Differentials										
	Company Owned Hydro	P	DGP	(34,051,523)	(34,051,523)	-	-	-	-	-	-
	Company Owned Hydro	P	SG	16,877,782	16,877,782	-	-	-	-	-	-
	Mid-C Contract	P	MC	(23,154,241)	(23,154,241)	-	-	-	-	-	-
	Mid-C Contract	P	SG	10,081,826	10,081,826	-	-	-	-	-	-
	Existing QF Contracts	P	S	27,876,994	27,876,994	-	-	-	-	-	-
	Existing QF Contracts	P	SG	(11,154,241)	(11,154,241)	-	-	-	-	-	-
				(13,523,403)	(13,523,403)	-	-	-	-	-	-
Total Other Power Supply				136,404,897	136,404,897	-	-	-	-	-	-
TOTAL PRODUCTION EXPENSE				521,906,287	521,906,287	-	-	-	-	-	-

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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Summary of Production Expense by Factor											
	S			27,819,795	27,819,795	-	-	-	-	-	-
	SG			245,521,844	245,521,844	-	-	-	-	-	-
	SE			280,662,647	280,662,647	-	-	-	-	-	-
	SNPPH			-	-	-	-	-	-	-	-
	TROJP			-	-	-	-	-	-	-	-
	SGCT			321,868	321,868	-	-	-	-	-	-
	DGP			(34,051,523)	(34,051,523)	-	-	-	-	-	-
	DEU			-	-	-	-	-	-	-	-
	DEP			-	-	-	-	-	-	-	-
	SNPPS			-	-	-	-	-	-	-	-
	SNPPO			-	-	-	-	-	-	-	-
	DGU			-	-	-	-	-	-	-	-
	MC			(23,154,241)	(23,154,241)	-	-	-	-	-	-
	SSGCT			663,685	663,685	-	-	-	-	-	-
	SSECT			2,903,754	2,903,754	-	-	-	-	-	-
	SSGC			-	-	-	-	-	-	-	-
	SSGCH			6,744,621	6,744,621	-	-	-	-	-	-
	SSECH			14,473,837	14,473,837	-	-	-	-	-	-
Total Production Expense by Factor				521,906,287	521,906,287	-	-	-	-	-	-
560	Operation Supervision & Engineering										
		T	SG	2,553,838	-	2,553,838	-	-	-	-	-
				2,553,838	-	2,553,838	-	-	-	-	-
561	Load Dispatching										
		T	SG	2,371,924	-	2,371,924	-	-	-	-	-
				2,371,924	-	2,371,924	-	-	-	-	-
562	Station Expense										
		T	SG	519,273	-	519,273	-	-	-	-	-
				519,273	-	519,273	-	-	-	-	-
563	Overhead Line Expense										
		T	SG	(280,315)	-	(280,315)	-	-	-	-	-
				(280,315)	-	(280,315)	-	-	-	-	-
564	Underground Line Expense										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
565	Transmission of Electricity by Others-Non NPC										
		T	SG	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
565NPC	Transmission of Electricity by Others-NPC										
		T	SG	38,781,856	-	38,781,856	-	-	-	-	-
		T	SE	68,735	-	68,735	-	-	-	-	-
				38,850,591	-	38,850,591	-	-	-	-	-
	Total Transmission of Electricity by Others			38,850,591	-	38,850,591	-	-	-	-	-
566	Misc. Transmission Expense										
		T	SG	111,392	-	111,392	-	-	-	-	-
				111,392	-	111,392	-	-	-	-	-
567	Rents - Transmission										
		T	SG	394,170	-	394,170	-	-	-	-	-
				394,170	-	394,170	-	-	-	-	-
568	Maint Supervision & Engineering										
		T	SG	12,274	-	12,274	-	-	-	-	-
				12,274	-	12,274	-	-	-	-	-
569	Maintenance of Structures										
		T	SG	1,034,011	-	1,034,011	-	-	-	-	-
				1,034,011	-	1,034,011	-	-	-	-	-
570	Maintenance of Station Equipment										
		STEP_UP	SG	2,684,028	227,849	2,456,180	-	-	-	-	-
				2,684,028	227,849	2,456,180	-	-	-	-	-
571	Maintenance of Overhead Lines										
		T	SG	4,154,028	-	4,154,028	-	-	-	-	-
				4,154,028	-	4,154,028	-	-	-	-	-
572	Maintenance of Underground Lines										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant										
		T	SG	150,619	-	150,619	-	-	-	-	-
				150,619	-	150,619	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				52,555,833	227,849	52,327,985	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Summary of Transmission Expense by Factor											
	SE			68,735	-	-	-	-	-	-	-
	SG			52,487,098	-	-	-	-	-	-	-
	SNPT			-	227,849	13,477,393	-	-	-	-	-
Total Transmission Expense by Factor				52,555,833	227,849	13,477,393	-	-	-	-	-
580	Operation Supervision & Engineering										
		D_SPLIT	S	(21)	-	-	(20.08)	-	-	(0.73)	-
		D_SPLIT	SNPD	5,666,616	-	-	5,466,968.63	-	-	199,647.67	-
				5,666,595	-	-	5,466,949	-	-	199,647	-
581	Load Dispatching										
		D	S	-	-	-	-	-	-	-	-
		D	SNPD	3,813,426	-	-	3,813,426	-	-	-	-
				3,813,426	-	-	3,813,426	-	-	-	-
582	Station Expense										
		D	S	1,215,958	-	-	1,215,958	-	-	-	-
		D	SNPD	(11,247)	-	-	(11,247)	-	-	-	-
				1,204,711	-	-	1,204,711	-	-	-	-
583	Overhead Line Expenses										
		D	S	588,926	-	-	588,926	-	-	-	-
		D	SNPD	66,587	-	-	66,587	-	-	-	-
				655,514	-	-	655,514	-	-	-	-
584	Underground Line Expense										
		D	S	(216,863)	-	-	(216,863)	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-
				(216,863)	-	-	(216,863)	-	-	-	-
585	Street Lighting & Signal Systems										
		D	S	-	-	-	-	-	-	-	-
		D	SNPD	68,252	-	-	68,252	-	-	-	-
				68,252	-	-	68,252	-	-	-	-
586	Meter Expenses										
		C_Meter	S	2,376,254	-	-	-	-	-	2,376,253.85	-
		C_Meter	SNPD	371,068	-	-	-	-	-	371,068.35	-
				2,747,322	-	-	-	-	-	2,747,322	-
587	Customer Installation Expenses										
		D	S	5,807,463	-	-	5,807,463	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-
				5,807,463	-	-	5,807,463	-	-	-	-
588	Misc. Distribution Expenses										
		D	S	1,649,755	-	-	1,649,755	-	-	-	-
		D	SNPD	(557,433)	-	-	(557,433)	-	-	-	-
				1,092,322	-	-	1,092,322	-	-	-	-
908	Rents										
		D	S	1,868,519	-	-	1,868,519	-	-	-	-
		D	SNPD	75,683	-	-	75,683	-	-	-	-
				1,944,202	-	-	1,944,202	-	-	-	-
590	Maint Supervision & Engineering										
		D_SPLIT	S	277,517	-	-	267,739.36	-	-	9,777.55	-
		D_SPLIT	SNPD	1,736,817	-	-	1,675,625.27	-	-	61,191.99	-
				2,014,334	-	-	1,943,365	-	-	70,970	-
591	Maintenance of Structures										
		D	S	473,352	-	-	473,352	-	-	-	-
		D	SNPD	52,634	-	-	52,634	-	-	-	-
				525,987	-	-	525,987	-	-	-	-
592	Maintenance of Station Equipment										
		D	S	3,313,499	-	-	3,313,499	-	-	-	-
		D	SNPD	557,480	-	-	557,480	-	-	-	-
				3,870,979	-	-	3,870,979	-	-	-	-
593	Maintenance of Overhead Lines										
		D	S	30,842,053	-	-	30,842,053	-	-	-	-
		D	SNPD	407,343	-	-	407,343	-	-	-	-
				31,249,397	-	-	31,249,397	-	-	-	-
594	Maintenance of Underground Lines										
		D	S	6,193,419	-	-	6,193,419	-	-	-	-
		D	SNPD	1,916	-	-	1,916	-	-	-	-
				6,195,335	-	-	6,195,335	-	-	-	-
595	Maintenance of Line Transformers										
		D	S	54,401	-	-	54,401	-	-	-	-
		D	SNPD	313,292	-	-	313,292	-	-	-	-
				367,693	-	-	367,693	-	-	-	-
596	Maint of Street Lighting & Signal Sys.										
		D	S	858,984	-	-	858,984	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-
				858,984	-	-	858,984	-	-	-	-
597	Maintenance of Meters										
		C_Meter	S	1,235,413	-	-	-	-	-	1,235,412.50	-
		C_Meter	SNPD	497,977	-	-	-	-	-	497,976.62	-
				1,733,389	-	-	-	-	-	1,733,389	-

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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
599	Maint of Misc. Distribution Plant										
		D	S	1,118,212	-	-	1,118,212	-	-	-	-
		D	SNPD	(6,661)	-	-	(6,661)	-	-	-	-
				1,111,551	-	-	1,111,551	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				70,710,593	-	-	65,959,265	-	-	4,751,328	-
Summary of Distribution Expense by Factor											
	S			57,656,840	-	-	54,035,397	-	-	3,621,443	-
	SNPD			13,053,753	-	-	11,923,869	-	-	1,129,885	-
Total Distribution Expense by Factor				70,710,593	-	-	65,959,265	-	-	4,751,328	-
901	Supervision										
		CUST901	S	(1,022,122)	-	-	-	-	(648,613)	71,439	(444,947)
		CUST901	CN	763,639	-	-	-	-	484,587	(53,373)	332,425
				(258,482)	-	-	-	-	(164,026)	18,066	(112,522)
902	Meter Reading Expense										
		C_Meter	S	10,232,031	-	-	-	-	-	10,232,031.11	-
		C_Meter	CN	239,983	-	-	-	-	-	239,982.89	-
				10,472,014	-	-	-	-	-	10,472,014	-
903	Customer Receipts & Collections										
		CUST903	S	2,139,103	-	-	-	-	1,275,208	-	863,895
		CUST903	CN	15,777,196	-	-	-	-	9,405,444	-	6,371,752
				17,916,299	-	-	-	-	10,680,652	-	7,235,647
904	Uncollectible Accounts										
		REVREQ	S	5,042,637	3,202,569	531,264	1,069,336	0	67,854	116,287.17	55,327
		P	SG	-	-	-	-	-	-	-	-
		REVREQ	CN	1,212	769	128	257	0	16	27.94	13
				5,043,849	3,203,339	531,391	1,069,593	0	67,870	116,315	55,340
905	Misc. Customer Accounts Expense										
		CUST905	S	5,686	-	-	-	-	504	438	4,744
		CUST905	CN	(1,468,463)	-	-	-	-	(130,274)	(113,019)	(1,225,170)
				(1,462,777)	-	-	-	-	(129,769)	(112,582)	(1,220,426)
TOTAL CUSTOMER ACCOUNTS EXPENSE				31,710,902	3,203,339	531,391	1,069,593	0	10,454,727	10,493,813	5,958,039
Summary of Customer Accts Exp by Factor											
	S			16,397,335	3,202,569	531,264	1,069,336	0	694,954	10,420,194	479,018
	CN			15,313,567	769	128	257	0	9,759,773	73,619	5,479,021
	SG			-	3,203,339	531,391	-	0	-	-	-
Total Customer Accounts Expense by Factor				31,710,902	6,406,678	1,062,783	1,069,593	0	10,454,727	10,493,813	5,958,039
907	Supervision										
		C_Service	S	-	-	-	-	-	-	-	-
		C_Service	CN	93,092	-	-	-	-	-	-	93,092
				93,092	-	-	-	-	-	-	93,092
908	Customer Assistance										
		DSM	S	1,198,841	-	-	1,198,841	-	-	-	-
		C_Service	CN	1,364,661	-	-	-	-	-	-	1,364,661
				2,563,502	-	-	1,198,841	-	-	-	1,364,661
909	Informational & Instructional Adv										
		C_Service	S	38,033	-	-	-	-	-	-	38,033
		C_Service	CN	980,259	-	-	-	-	-	-	980,259
				1,018,292	-	-	-	-	-	-	1,018,292
910	Misc. Customer Service										
		C_Service	S	-	-	-	-	-	-	-	-
		C_Service	CN	20,583	-	-	-	-	-	-	20,583
				20,583	-	-	-	-	-	-	20,583
TOTAL CUSTOMER SERVICE EXPENSE				3,695,469	-	-	1,198,841	-	-	-	2,496,628
Summary of Customer Service Exp by Factor											
	S			1,236,874	-	-	1,198,841	-	-	-	38,033
	CN			2,458,595	-	-	-	-	-	-	2,458,595
Total Customer Service Expense by Factor				3,695,469	-	-	1,198,841	-	-	-	2,496,628
911	Supervision										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
912	Demonstration & Selling Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
913	Advertising Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
916	Misc. Sales Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL SALES EXPENSE				-	-	-	-	-	-	-	-
Total Sales Expense by Factor											
	S			-	-	-	-	-	-	-	-
	CN			-	-	-	-	-	-	-	-
Total Sales Expense by Factor				-	-	-	-	-	-	-	-
Total Customer Service Exp Including Sales				3,695,469	-	-	1,198,841	-	-	-	2,496,628
920	Administrative & General Salaries										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-
		LABOR	SO	22,586,740	9,130,560	1,087,032	7,679,636	-	1,229,041	2,211,184	1,249,287
				22,586,740	9,130,560	1,087,032	7,679,636	-	1,229,041	2,211,184	1,249,287
921	Office Supplies & expenses										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-
		LABOR	SO	3,715,460	1,501,953	178,814	1,263,280	-	202,174	363,734	205,504
				3,715,460	1,501,953	178,814	1,263,280	-	202,174	363,734	205,504
922	Office Supplies & expenses										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-
		LABOR	SO	(6,450,090)	(2,607,412)	(310,424)	(2,193,072)	-	(350,977)	(631,447)	(356,759)
				(6,450,090)	(2,607,412)	(310,424)	(2,193,072)	-	(350,977)	(631,447)	(356,759)
923	Outside Services										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-
		LABOR	SO	3,097,489	1,252,142	149,073	1,053,166	-	168,548	303,236	171,324
				3,097,489	1,252,142	149,073	1,053,166	-	168,548	303,236	171,324
924	Property Insurance										
		GP	SO	9,908,085	4,758,399	1,604,923	3,285,138.74	-	61,899	157,126.12	40,598
				9,908,085	4,758,399	1,604,923	3,285,139	-	61,899	157,126	40,598
925	Injuries & Damages										
		LABOR	SO	2,519,432	1,018,466	121,253	856,623	-	137,093	246,646	139,351
				2,519,432	1,018,466	121,253	856,623	-	137,093	246,646	139,351
926	Employee Pensions & Benefits										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
928	Franchise Requirements										
		DSM	S	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
928	Regulatory Commission Expense										
		D	S	2,814,219	-	-	2,814,219	-	-	-	-
		D	CN	-	-	-	-	-	-	-	-
		D	SO	-	-	-	-	-	-	-	-
		FERC	SG	252,743	130,091	122,652	-	-	-	-	-
				3,066,961	130,091	122,652	2,814,219	-	-	-	-
929	Duplicate Charges										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	SO	(1,424,427)	(575,817)	(68,553)	(484,314)	-	(77,509)	(139,448)	(78,786)
				(1,424,427)	(575,817)	(68,553)	(484,314)	-	(77,509)	(139,448)	(78,786)
930	Misc General Expenses										
		LABOR	S	3,863,494	1,561,795	185,938	1,313,613	-	210,229	378,226	213,692
		LABOR	CN	1,676	678	81	570	-	91	164	93
		LABOR	SO	(1,090,282)	(440,740)	(52,472)	(370,703)	-	(59,327)	(106,736)	(60,304)
				2,774,889	1,121,733	133,547	943,480	-	150,994	271,654	153,481
931	Rents										
		LABOR	S	966,793	390,820	46,529	328,716	-	52,607	94,647	53,474
		LABOR	SO	1,630,637	659,175	78,478	554,427	-	88,730	159,635	90,192
				2,597,430	1,049,996	125,007	883,143	-	141,337	254,282	143,665
935	Maintenance of General Plant										
		G	S	33,985	8,731	7,455	16,229	-	909	661	-
		CUST	CN	-	-	-	-	-	-	-	-
		G	SO	7,244,518	1,861,253	1,589,186	3,459,427	-	193,834	140,818	-
				7,278,503	1,869,985	1,596,641	3,475,655	-	194,743	141,478	-
TOTAL ADMINISTRATIVE & GEN EXPENSE				49,670,470	18,650,096	4,739,965	19,576,953	-	1,857,343	3,178,446	1,667,667

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Summary of A&G Expense by Factor											
	S			7,678,491	1,961,347	239,922	4,472,776	-	263,746	473,533	267,166
	SO			41,737,560	19,165,392	4,687,734	17,296,680	-	1,944,483	3,336,196	1,757,166
	SG			252,743	130,091	122,652	-	-	-	-	-
	CN			1,676	678	81	570	-	91	164	93
Total A&G Expense by Factor				49,670,470	21,257,508	5,050,388	21,770,025	-	2,208,320	3,809,893	2,024,425
TOTAL O&M EXPENSE				730,249,555	543,987,570	57,599,341	87,804,653	0	12,312,070	18,423,587	10,122,334
403SP	Steam Depreciation										
		P	SG	9,090,981	9,090,981	-	-	-	-	-	-
		P	SG	8,946,743	8,946,743	-	-	-	-	-	-
		P	SG	19,356,531	19,356,531	-	-	-	-	-	-
		P	SSGCH	3,247,467	3,247,467	-	-	-	-	-	-
				40,641,722	40,641,722	-	-	-	-	-	-
403NP	Nuclear Depreciation										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
403HP	Hydro Depreciation										
	Pre-Merger Pacific	P	SG	1,046,894	1,046,894	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	270,633	270,633	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	2,298,504	2,298,504	-	-	-	-	-	-
	Post-Merger Utah	P	SG	1,006,761	1,006,761	-	-	-	-	-	-
				4,622,792	4,622,792	-	-	-	-	-	-
403OP	Other Production Depreciation										
		P	SG	32,414	32,414	-	-	-	-	-	-
		P	SG	25,360,042	25,360,042	-	-	-	-	-	-
		P	SSGCT	671,728	671,728	-	-	-	-	-	-
		P	SSGCH	-	-	-	-	-	-	-	-
				26,064,184	26,064,184	-	-	-	-	-	-
403TP	Transmission Depreciation										
		T_Split	SG	3,016,575	83,969.53	2,932,605.54	-	-	-	-	-
		T_Split	SG	3,370,163	93,812.03	3,276,351.36	-	-	-	-	-
		T_Split	SG	11,047,151	307,509.03	10,739,641.97	-	-	-	-	-
				17,433,889	485,291	16,948,599	-	-	-	-	-
403	Distribution Depreciation										
360	Land & Land Rights	D	S	59,166	-	-	59,166	-	-	-	-
361	Structures	D	S	233,902	-	-	233,902	-	-	-	-
362	Station Equipment	D	S	3,761,906	-	-	3,761,906	-	-	-	-
363	Storage Battery Equipme	D	S	-	-	-	-	-	-	-	-
364	Poles & Towers	D	S	15,783,591	-	-	15,783,591	-	-	-	-
365	OH Conductors	D	S	6,521,785	-	-	6,521,785	-	-	-	-
366	UG Conduit	D	S	2,096,675	-	-	2,096,675	-	-	-	-
367	UG Conductor	D	S	3,285,318	-	-	3,285,318	-	-	-	-
368	Line Trans	D	S	9,967,097	-	-	9,967,097	-	-	-	-
369	Services	D	S	3,821,583	-	-	3,821,583	-	-	-	-
370	Meters	C_Meter	S	2,153,361	-	-	-	-	-	2,153,360.84	-
371	Inst Cust Prem	D	S	106,738	-	-	106,738	-	-	-	-
372	Leased Property	D	S	-	-	-	-	-	-	-	-
373	Street Lighting	D	S	605,513	-	-	605,513	-	-	-	-
				48,396,637	-	-	46,243,276	-	-	2,153,361	-
403GP	General Depreciation										
		TD	S	4,302,300	-	1,462,303	2,739,937.25	-	-	100,059.49	-
		G-DGP	SG	94,463	64,764	29,699	-	-	-	-	-
		G-DGU	SG	173,413	118,892	54,521	-	-	-	-	-
		P	SE	5,210	5,210	-	-	-	-	-	-
		COM_EQ	CN	432,212	68,909	170,225	187,041	-	-	-	6,036
		G-SG	SG	1,221,134	838,070	374,974	7,773	-	-	316	-
		LABOR	SO	4,423,364	1,788,120	212,883	1,503,972	-	240,694	433,036	244,659
		G-SG	SSGCT	840	576	258	5	-	-	0	-
		G-SG	SSGCH	33,074	22,699	10,156	211	-	-	9	-
				10,686,011	2,907,240	2,315,021	4,438,939	-	240,694	533,421	250,695
403GV0	General Vehicles										
		G-SG	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
403MP	Mining Depreciation										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
403EP	Experimental Plant Depreciation										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-

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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
984	4031	ARO Depreciation										
985			P	S	-	-	-	-	-	-	-	-
986					-	-	-	-	-	-	-	-
987												
988												
989		TOTAL DEPRECIATION EXPENSE			147,845,235	74,721,230	19,263,620	50,682,215	-	240,694	2,686,782	250,695
990												
991	Summary	S			52,698,937	-	1,462,303	48,983,213	-	-	2,253,420	-
992		DGP			-	10,286,608	2,962,305	-	-	-	-	-
993		DGU			-	9,462,494	3,330,873	-	-	-	-	-
994		SG			86,332,403	45,862,153	11,114,616	7,773	-	-	316	-
995		SO			4,423,364	1,788,120	212,883	1,503,972	-	240,694	433,036	244,659
996		CN			432,212	68,909	170,225	187,041	-	-	-	6,036
997		SE			5,210	5,210	-	-	-	-	-	-
998		SSGCH			3,280,541	68,909	170,225	187,041	-	-	-	6,036
999		SSGCT			672,568	838,070	374,974	7,773	-	-	316	-
1000		Total Depreciation Expense By Factor			147,845,235	68,380,474	19,798,406	50,876,814	-	240,694	2,687,089	256,731
1001												
1002	404GP	Amort of LT Plant - Capital Lease Gen										
1003			TD	S	688,163	-	233,899	438,259.14	-	-	16,004.74	-
1004			I-SG	SG	-	-	-	-	-	-	-	-
1005			LABOR	SO	457,875	185,093	22,036	155,680	-	24,915	44,825	25,325
1006			I-DGU	SG	-	-	-	-	-	-	-	-
1007			CUST	CN	71,936	-	-	-	-	71,936	-	-
1008			I-DGP	SG	-	-	-	-	-	-	-	-
1009					1,217,973	185,093	255,935	593,939	-	96,851	60,829	25,325
1010												
1011	404SP	Amort of LT Plant - Cap Lease Steam										
1012			P	SG	-	-	-	-	-	-	-	-
1013			P	SG	-	-	-	-	-	-	-	-
1014					-	-	-	-	-	-	-	-
1015												
1016	404IP	Amort of LT Plant - Intangible Plant										
1017			TD	S	19,205	-	6,527	12,230.66	-	-	446.65	-
1018			P	SE	60,359	60,359	-	-	-	-	-	-
1019			I-SG	SG	1,242,521	1,112,363	129,756	387	-	-	16	-
1020			LABOR	SO	7,953,029	3,214,966	382,756	2,704,081	-	432,758	778,581	439,887
1021			CSS_SYS	CN	1,785,105	-	-	-	-	981,808	321,319	481,978
1022			I-SG	SG	2,069,936	1,853,103	216,162	644	-	-	26	-
1023			I-SG	SG	83,234	74,515	8,692	26	-	-	1	-
1024			I-DGP	SG	-	-	-	-	-	-	-	-
1025			I-SG	SSGCT	-	-	-	-	-	-	-	-
1026			I-SG	SSGCH	-	-	-	-	-	-	-	-
1027			I-DGU	SG	4,285	4,285	-	-	-	-	-	-
1028					13,217,674	6,319,591	743,894	2,717,368	-	1,414,566	1,100,390	921,865
1029												
1030	404MP	Amort of LT Plant - Mining Plant										
1031			P	SE	-	-	-	-	-	-	-	-
1032					-	-	-	-	-	-	-	-
1033												
1034	404OP	Amort of LT Plant - Other Plant										
1035			P	SSGCT	-	-	-	-	-	-	-	-
1036					-	-	-	-	-	-	-	-
1037												
1038												
1039	404HP	Amortization of Other Electric Plant										
1040		Pre-Merger Pacific	P	SG	613	613	-	-	-	-	-	-
1041		Pre-Merger Utah	P	SG	10,346	10,346	-	-	-	-	-	-
1042		Post-Merger Plant	P	SG	-	-	-	-	-	-	-	-
1043					10,958	10,958	-	-	-	-	-	-
1044												
1045		Total Amortization of Limited Term Plant			14,446,605	6,515,643	999,828	3,311,307	-	1,511,417	1,161,219	947,191
1046												
1047												
1048	405	Amortization of Other Electric Plant										
1049			GP	S	-	-	-	-	-	-	-	-
1050												
1051					-	-	-	-	-	-	-	-
1052												
1053	406	Amortization of Plant Acquisition Adj										
1054			P	S	-	-	-	-	-	-	-	-
1055			P	SG	-	-	-	-	-	-	-	-
1056			P	SG	-	-	-	-	-	-	-	-
1057			P	SG	1,472,679	1,472,679	-	-	-	-	-	-
1058			P	SO	-	-	-	-	-	-	-	-
1059					1,472,679	1,472,679	-	-	-	-	-	-
1060	407	Amort of Prop Losses, Unrec Plant, etc										
1061			D_SPLIT	S	(67,953)	-	-	(65,558.98)	-	-	(2,394.14)	-
1062			GP	SO	-	-	-	-	-	-	-	-
1063			P	SG-P	0	0	-	-	-	-	-	-
1064			P	SE	-	-	-	-	-	-	-	-
1065			P	SG	89,528	89,528	-	-	-	-	-	-
1066			P	TROJP	535,491	535,491	-	-	-	-	-	-
1067					557,066	625,019	-	(65,559)	-	-	(2,394)	-
1068												
1069		TOTAL AMORTIZATION EXPENSE			16,476,351	8,613,341	999,828	3,245,748	-	1,511,417	1,158,825	947,191

RESULTS OF OPERATIONS SUMMARY
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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
Summary of Amortization Expense by Factor											
	S			639,414	-	240,426	384,931	-	-	14,057	-
	SE			60,359	60,359	-	-	-	-	-	-
	TROJP			535,491	535,491	-	-	-	-	-	-
	DGP			-	613	-	-	-	-	-	-
	DGU			-	14,630	-	-	-	-	-	-
	SO			8,410,904	3,400,059	404,792	2,859,761	-	457,673	823,406	465,212
	SSGCT			-	1,472,679	-	-	-	981,808	321,319	481,978
	SSGCH			-	-	-	-	-	-	-	-
	CN			1,857,041	-	-	-	-	1,053,744	321,319	481,978
	SG			4,973,142	2,674,570	129,756	387	-	-	16	-
Total Amortization Expense by Factor				16,476,351	8,158,402	774,974	3,245,078	-	2,493,225	1,480,117	1,429,169
408	Taxes Other Than Income										
		D	S	22,233,321	-	-	22,233,321	-	-	-	-
		GP	GPS	27,067,802	12,999,425	4,384,475	8,974,639	-	169,101	429,251.35	110,910
		REVREQ	SO	2,480,187	1,575,162	261,299	525,946	0	33,374	57,195.07	27,212
		P	SE	185,563	185,563	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-
				51,966,873	14,760,151	4,645,773	31,733,906	0	202,475	486,446	138,122
41140	Deferred Investment Tax Credit - Fed										
		PTD	DGU	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
41141	Deferred Investment Tax Credit - Idaho										
		PTD	DGU	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt										
		NP	S	85,221,543	43,131,763	14,595,740	26,052,299	-	260,187	977,946.66	203,607
		NP	SNP	-	-	-	-	-	-	-	-
				85,221,543	43,131,763	14,595,740	26,052,299	-	260,187	977,947	203,607
428	Amortization of Debt Disc & Exp										
		NP	SNP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
429	Amortization of Premium on Debt										
		NP	SNP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
431	Other Interest Expense										
		NUTIL	OTH	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-
		NP	SNP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
432	AFUDC - Borrowed										
		NP	SNP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Total Electric Interest Deductions for Tax			85,221,543	43,131,763	14,595,740	26,052,299	-	260,187	977,947	203,607
	Non-Utility Portion of Interest										
		427 NUTIL	NUTIL	-	-	-	-	-	-	-	-
		428 NUTIL	NUTIL	-	-	-	-	-	-	-	-
		429 NUTIL	NUTIL	-	-	-	-	-	-	-	-
		431 NUTIL	NUTIL	-	-	-	-	-	-	-	-
	Total Non-utility Interest			-	-	-	-	-	-	-	-
	Total Interest Deductions for Tax			85,221,543	43,131,763	14,595,740	26,052,299	-	260,187	977,947	203,607
419	Interest & Dividends										
		GP	S	-	-	-	-	-	-	-	-
		GP	SNP	-	-	-	-	-	-	-	-
	Total Operating Deductions for Tax			-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
1154												
1155	41010	Deferred Income Tax - Federal-DR										
1156			GP	S	148,994,697	71,555,327	24,134,337	49,400,896	-	930,818	2,362,813.73	610,506
1157			P	TROJD	-	-	-	-	-	-	-	-
1158			PT	DGP	-	-	-	-	-	-	-	-
1159			LABOR	SO	2,117,172	855,855	101,893	719,852	-	115,204	207,266	117,102
1160			NP	SNP	6,706,346	3,394,171	1,148,584	2,050,136	-	20,475	76,957.63	16,022
1161			P	SE	3,167,857	3,167,857	-	-	-	-	-	-
1162			PT	SG	2,070,538	1,515,275	555,263	-	-	-	-	-
1163			GP	GPS	-	-	-	-	-	-	-	-
1164			DITEXP	DITEXP	-	-	-	-	-	-	-	-
1165			CUST	BADDEBT	-	-	-	-	-	-	-	-
1166			CSS_SYS	CN	-	-	-	-	-	-	-	-
1167			P	IBT	-	-	-	-	-	-	-	-
1168			D	SNPD	-	-	-	-	-	-	-	-
1169					163,056,610	80,488,485	25,940,077	52,170,883	-	1,066,497	2,647,037	743,630
1170												
1171												
1172												
1173	41110	Deferred Income Tax - Federal-CR										
1174			GP	S	(127,018,858)	(61,001,338)	(20,574,665)	(42,114,555)	-	(793,528)	(2,014,312.65)	(520,460)
1175			P	SE	(3,069,465)	(3,069,465)	-	-	-	-	-	-
1176			PT	DGP	-	-	-	-	-	-	-	-
1177			NP	SNP	(11,704,320)	(5,923,713)	(2,004,578)	(3,578,020)	-	(35,734)	(134,311.11)	(27,963)
1178			PT	SG	(140,850)	(103,078)	(37,772)	-	-	-	-	-
1179			GP	GPS	-	-	-	-	-	-	-	-
1180			LABOR	SO	(3,839,782)	(1,552,210)	(184,797)	(1,305,550)	-	(208,939)	(375,905)	(212,381)
1181			PT	SNPD	-	-	-	-	-	-	-	-
1182			CUST	CN	-	-	-	-	-	-	-	-
1183			P	SGCT	(96,104)	(96,104)	-	-	-	-	-	-
1184			DITEXP	DITEXP	-	-	-	-	-	-	-	-
1185			P	TROJD	(168,217)	(168,217)	-	-	-	-	-	-
1186			P	IBT	95,091	95,091	-	-	-	-	-	-
1187												
1188												
1189					(145,942,505)	(71,819,034)	(22,801,812)	(46,998,126)	-	(1,038,201)	(2,524,529)	(760,804)
1190												
1191	TOTAL DEFERRED INCOME TAXES				17,114,105	8,669,451	3,138,265	5,172,757	-	28,296	122,508	(17,174)
1192	SCHMAF	Additions - Flow Through										
1193			SCHMAF	S	-	-	-	-	-	-	-	-
1194			SCHMAF	SNP	-	-	-	-	-	-	-	-
1195			SCHMAF	SO	-	-	-	-	-	-	-	-
1196			SCHMAF	SE	-	-	-	-	-	-	-	-
1197			P	TROJP	-	-	-	-	-	-	-	-
1198			SCHMAF	SG	-	-	-	-	-	-	-	-
1199					-	-	-	-	-	-	-	-
1200												
1201	SCHMAP	Additions - Permanent										
1202			P	S	-	-	-	-	-	-	-	-
1203			P	SE	11,251	11,251	-	-	-	-	-	-
1204			PTD	SNP	-	-	-	-	-	-	-	-
1205			SCHMAP-SO	SO	2,751,824	1,117,051	146,087	934,595	-	144,907	261,891	147,294
1206			SCHMAP	SG	-	-	-	-	-	-	-	-
1207			D	BADDEBT	-	0	-	-	-	-	-	-
1208					2,763,075	1,128,302	146,087	934,595	-	144,907	261,891	147,294
1209												
1210	SCHMAT	Additions - Temporary										
1211			SCHMAT-SITUS	S	40,918,848	20,686,020	2,235,679	12,109,123	-	1,516,548	2,829,949	1,541,529
1212			SCHMAT	SG	-	-	-	-	-	-	-	-
1213			D_SPLIT	CIAC	-	-	-	-	-	-	-	-
1214			SCHMAT-SNP	SNP	30,840,609	14,079,240	6,214,948	10,117,523	-	9,990	414,350	4,558
1215			P	TROJD	443,249	443,249	-	-	-	-	-	-
1216			SCHMAT-SNP	SG	-	-	-	-	-	-	-	-
1217			SCHMAT-SE	SE	8,087,969	7,960,590	10,290	72,697	-	11,634	20,931	11,826
1218			PT	SG	0	0	0	-	-	-	-	-
1219			SCHMAT-GPS	GPS	-	-	-	-	-	-	-	-
1220			SCHMAT-SO	SO	288,238	120,684	44,434	103,032	-	3,256	8,390	8,443
1221			SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-
1222			P	SGCT	253,232	253,232	-	-	-	-	-	-
1223			TAXDEPR	TAXDEPR	168,924,866	90,897,432	27,022,458	49,941,342	-	265,796	598,041	199,798
1224			BOOKDEPR	SCHMDEXP	-	-	-	-	-	-	-	-
1225					249,757,011	134,440,448	35,527,809	72,343,716	-	1,807,224	3,871,660	1,766,154
1226												
1227	TOTAL SCHEDULE - M ADDITIONS				252,520,086	135,568,749	35,673,896	73,278,310	-	1,952,131	4,133,551	1,913,449
1228												
1229	SCHMDF	Deductions - Flow Through										
1230			SCHMDF	S	-	-	-	-	-	-	-	-
1231			SCHMDF	DGP	-	-	-	-	-	-	-	-
1232			SCHMDF	DGU	-	-	-	-	-	-	-	-
1233					-	-	-	-	-	-	-	-
1234	SCHMDP	Deductions - Permanent										
1235			SCHMDP	S	-	-	-	-	-	-	-	-
1236			P	SE	68,520	68,520	-	-	-	-	-	-
1237			SCHMDP	SNP	104,559	52,179	4,416	29,915	-	4,726	8,518	4,804
1238			SCHMDP	IBT	-	-	-	-	-	-	-	-
1239			P	SG	5,046,505	5,046,505	-	-	-	-	-	-
1240			SCHMDP-SO	SO	3,871,572	1,565,061	186,327	1,316,359	-	210,669	379,017	214,139
1241					9,091,157	6,732,265	190,743	1,346,274	-	215,395	387,536	218,943
1242												

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
SCHMDT	Deductions - Temporary										
		SCHMDT-SITUS	S	-	-	-	-	-	-	-	-
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	17,671,064	8,067,223	3,567,089	5,800,635	-	-	236,118	-
		SCHMDT	CN	-	-	-	-	-	-	-	-
		SCHMDT	TROJD	-	-	-	-	-	-	-	-
		SCHMDT	DGP	-	-	-	-	-	-	-	-
		P	SE	8,347,246	8,347,246	-	-	-	-	-	-
		PT	SG	4,877,687	3,569,622	1,308,065	-	-	-	-	-
		SCHMDT-GPS	GPS	-	-	-	-	-	-	-	-
		SCHMDT-SO	SO	(4,250,799)	(1,696,625)	(597,835)	(1,529,181)	-	(58,925)	(124,732)	(243,502)
		TAXDEPR	TAXDEPR	253,803,705	136,570,213	40,600,298	75,035,120	-	399,349	898,535	300,189
		SCHMDT-SNP	SNPD	-	-	-	-	-	-	-	-
				280,448,903	154,857,679	44,877,617	79,306,574	-	340,424	1,009,921	56,688
TOTAL SCHEDULE - M DEDUCTIONS				289,540,060	161,589,944	45,068,360	80,652,848	-	555,819	1,397,457	275,631
TOTAL SCHEDULE - M ADJUSTMENTS				(37,019,974)	(26,021,195)	(9,394,465)	(7,374,538)	-	1,396,312	2,736,094	1,637,818
NOTE:	Positive Schedule M amounts increase taxable income and therefore reduce tax expense.										
	Negative Schedule M amounts decrease taxable income and therefore increase tax expense.										
40911	State Income Taxes										
		IBT	IBT	4,998,356	1,776,357	793,032	1,901,266	0	121,862	276,017.92	129,822
		IBT	IBT	-	-	-	-	-	-	-	-
	Renewable Energy Credits	P	SG	(160,228)	(160,228)	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				4,838,128	1,616,129	793,032	1,901,266	0	121,862	276,018	129,822
Calculation of Taxable Income:											
	Operating Revenues			1,178,664,091	748,567,329	124,177,385	249,946,185	0	15,860,190	27,180,920	12,932,082
	Operating Deductions:										
	O & M Expenses			730,249,555	543,987,570	57,599,341	87,804,653	0	12,312,070	18,423,587	10,122,334
	Depreciation Expense			147,845,235	74,721,230	19,263,620	50,682,215	-	240,694	2,686,782	250,695
	Amortization Expense			16,476,351	8,613,341	999,828	3,245,748	-	1,511,417	1,158,825	947,191
	Taxes Other Than Income			51,966,873	14,760,151	4,645,773	31,733,906	0	202,475	486,446	138,122
	Interest & Dividends (AFUDC-Equity)			-	-	-	-	-	-	-	-
	Misc Revenue & Expense			(2,076,505)	(2,457,569)	(84,959)	465,280	-	-	742	-
	Total Operating Deductions			944,461,509	639,624,723	82,423,603	173,931,802	0	14,266,656	22,756,382	11,458,342
	Other Deductions:										
	Interest Deductions			85,221,543	43,131,763	14,595,740	26,052,299	-	260,187	977,947	203,607
	Interest on PCRBS			-	-	-	-	-	-	-	-
	Schedule M Adjustments			(37,019,974)	(26,021,195)	(9,394,465)	(7,374,538)	-	1,396,312	2,736,094	1,637,818
	Income Before State Taxes			111,961,065	39,789,648	17,763,577	42,587,546	0	2,729,658	6,182,685	2,907,950
	State Income Taxes			4,838,128	1,616,129	793,032	1,901,266	0	121,862	276,018	129,822
Total Taxable Income				107,122,937	38,173,519	16,970,546	40,686,281	0	2,607,796	5,906,667	2,778,129
Tax Rate				35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
Federal Income Tax - Calculated				37,493,028	13,360,732	5,939,691	14,240,198	0	912,729	2,067,334	972,345
Adjustments to Calculated Tax:											
40910	PMI	P	SE	-	-	-	-	-	-	-	-
40910	Renewable Energy Credits	P	SG	(13,734,625)	(13,734,625)	-	-	-	-	-	-
40910		P	SO	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-
Federal Income Tax				23,758,403	(373,894)	5,939,691	14,240,198	0	912,729	2,067,334	972,345
TOTAL OPERATING EXPENSES				990,172,144	649,536,409	92,294,591	195,246,024	0	27,641,613	43,645,830	22,665,669
310	Land and Land Rights										
		P	SG	626,102	626,102	-	-	-	-	-	-
		P	SG	9,352,738	9,352,738	-	-	-	-	-	-
		P	SG	15,136,182	15,136,182	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-
		P	SSGCH	343,167	343,167	-	-	-	-	-	-
				25,458,188	25,458,188	-	-	-	-	-	-
311	Structures and Improvements										
		P	SG	63,129,897	63,129,897	-	-	-	-	-	-
		P	SG	87,990,766	87,990,766	-	-	-	-	-	-
		P	SG	50,407,163	50,407,163	-	-	-	-	-	-
		P	SSGCH	15,095,178	15,095,178	-	-	-	-	-	-
				216,623,004	216,623,004	-	-	-	-	-	-
312	Boiler Plant Equipment										
		P	SG	188,907,860	188,907,860	-	-	-	-	-	-
		P	SG	171,356,803	171,356,803	-	-	-	-	-	-
		P	SG	436,916,890	436,916,890	-	-	-	-	-	-
		P	SSGCH	87,834,914	87,834,914	-	-	-	-	-	-
				885,016,466	885,016,466	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1327	314	Turbogenerator Units										
1328			P	SG	39,376,935	39,376,935	-	-	-	-	-	-
1329			P	SG	38,943,144	38,943,144	-	-	-	-	-	-
1330			P	SG	115,351,585	115,351,585	-	-	-	-	-	-
1331			P	SSGCH	18,360,092	18,360,092	-	-	-	-	-	-
1332					212,031,756	212,031,756	-	-	-	-	-	-
1333												
1334	315	Accessory Electric Equipment										
1335			P	SG	23,668,778	23,668,778	-	-	-	-	-	-
1336			P	SG	37,414,442	37,414,442	-	-	-	-	-	-
1337			P	SG	18,128,895	18,128,895	-	-	-	-	-	-
1338			P	SSGCH	17,787,235	17,787,235	-	-	-	-	-	-
1339					96,999,350	96,999,350	-	-	-	-	-	-
1340												
1341												
1342												
1343	316	Misc Power Plant Equipment										
1344			P	SG	1,321,215	1,321,215	-	-	-	-	-	-
1345			P	SG	1,423,373	1,423,373	-	-	-	-	-	-
1346			P	SG	3,367,144	3,367,144	-	-	-	-	-	-
1347			P	SSGCH	870,866	870,866	-	-	-	-	-	-
1348					6,982,599	6,982,599	-	-	-	-	-	-
1349												
1350	317	Steam Plant ARO										
1351			P	S	-	-	-	-	-	-	-	-
1352					-	-	-	-	-	-	-	-
1353												
1354	SP	Unclassified Steam Plant - Account 300										
1355			P	SG	3,193	3,193	-	-	-	-	-	-
1356					3,193	3,193	-	-	-	-	-	-
1357												
1358												
1359	**Total Steam Production Plant**				**1,443,114,557**	**1,443,114,557**	-	-	-	-	-	-
1360												
1361												
1362	Summary of Steam Production Plant by Factor											
1363		S			-	-	-	-	-	-	-	-
1364		DGP			-	317,030,787	-	-	-	-	-	-
1365		DGU			-	346,481,266	-	-	-	-	-	-
1366		SG			1,302,823,105	639,311,052	-	-	-	-	-	-
1367		SSGCH			140,291,452	139,951,478	-	-	-	-	-	-
1368	Total Steam Production Plant by Factor				1,443,114,557	1,442,774,583	-	-	-	-	-	-
1369	320	Land and Land Rights										
1370			P	SG	-	-	-	-	-	-	-	-
1371			P	SG	-	-	-	-	-	-	-	-
1372					-	-	-	-	-	-	-	-
1373												
1374	321	Structures and Improvements										
1375			P	SG	-	-	-	-	-	-	-	-
1376			P	SG	-	-	-	-	-	-	-	-
1377					-	-	-	-	-	-	-	-
1378												
1379	322	Reactor Plant Equipment										
1380			P	SG	-	-	-	-	-	-	-	-
1381			P	SG	-	-	-	-	-	-	-	-
1382					-	-	-	-	-	-	-	-
1383												
1384	323	Turbogenerator Units										
1385			P	SG	-	-	-	-	-	-	-	-
1386			P	SG	-	-	-	-	-	-	-	-
1387					-	-	-	-	-	-	-	-
1388												
1389	324	Land and Land Rights										
1390			P	SG	-	-	-	-	-	-	-	-
1391			P	SG	-	-	-	-	-	-	-	-
1392					-	-	-	-	-	-	-	-
1393												
1394	325	Misc. Power Plant Equipment										
1395			P	SG	-	-	-	-	-	-	-	-
1396			P	SG	-	-	-	-	-	-	-	-
1397					-	-	-	-	-	-	-	-
1398												
1399												
1400	NP	Unclassified Nuclear Plant - Acct 300										
1401			P	SG	-	-	-	-	-	-	-	-
1402					-	-	-	-	-	-	-	-
1403												
1404												
1405	**Total Nuclear Production Plant**				-	-	-	-	-	-	-	-

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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
Summary of Nuclear Production Plant by Factor											
	DGP			-	-	-	-	-	-	-	-
	DGU			-	-	-	-	-	-	-	-
	SG			-	-	-	-	-	-	-	-
Total Nuclear Plant by Factor				-	-	-	-	-	-	-	-
330	Land and Land Rights										
	Pre-Merger Pacific	P	SG	2,856,173	2,856,173	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	1,426,507	1,426,507	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	839,284	839,284	-	-	-	-	-	-
	Post-Merger Utah	P	SG	170,856	170,856	-	-	-	-	-	-
				5,292,821	5,292,821	-	-	-	-	-	-
331	Structures and Improvements										
	Pre-Merger Pacific	P	SG	5,766,366	5,766,366	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	1,430,960	1,430,960	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	13,558,847	13,558,847	-	-	-	-	-	-
	Post-Merger Utah	P	SG	1,908,432	1,908,432	-	-	-	-	-	-
				22,664,605	22,664,605	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways										
	Pre-Merger Pacific	P	SG	40,361,402	40,361,402	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	5,394,836	5,394,836	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	40,940,533	40,940,533	-	-	-	-	-	-
	Post-Merger Utah	P	SG	15,399,938	15,399,938	-	-	-	-	-	-
				102,096,709	102,096,709	-	-	-	-	-	-
333	Water Wheel, Turbines, & Generators										
	Pre-Merger Pacific	P	SG	8,814,330	8,814,330	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	2,489,505	2,489,505	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	9,564,550	9,564,550	-	-	-	-	-	-
	Post-Merger Utah	P	SG	4,695,173	4,695,173	-	-	-	-	-	-
				25,563,558	25,563,558	-	-	-	-	-	-
334	Accessory Electric Equipment										
	Pre-Merger Pacific	P	SG	1,261,923	1,261,923	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	1,052,769	1,052,769	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	9,953,668	9,953,668	-	-	-	-	-	-
	Post-Merger Utah	P	SG	1,248,855	1,248,855	-	-	-	-	-	-
				13,517,215	13,517,215	-	-	-	-	-	-
335	Misc. Power Plant Equipment										
	Pre-Merger Pacific	P	SG	346,744	346,744	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	52,248	52,248	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	264,004	264,004	-	-	-	-	-	-
	Post-Merger Utah	P	SG	3,484	3,484	-	-	-	-	-	-
				666,480	666,480	-	-	-	-	-	-
336	Roads, Railroads & Bridges										
	Pre-Merger Pacific	P	SG	1,246,626	1,246,626	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	222,803	222,803	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	2,156,202	2,156,202	-	-	-	-	-	-
	Post-Merger Utah	P	SG	159,154	159,154	-	-	-	-	-	-
				3,784,784	3,784,784	-	-	-	-	-	-
337	Hydro Plant ARO										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300										
	Pre-Merger Pacific	P	S	-	-	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Hydraulic Plant				173,586,171	173,586,171	-	-	-	-	-	-
Summary of Hydraulic Plant by Factor											
	S			-	23,585,892	-	-	-	-	-	-
	SG			173,586,171	75,280,040	-	-	-	-	-	-
	DGP			-	60,653,564	-	-	-	-	-	-
	DGU			-	12,069,627	-	-	-	-	-	-
Total Hydraulic Plant by Factor				173,586,171	171,589,123	-	-	-	-	-	-
340	Land and Land Rights										
		P	SG	5,790,065	5,790,065	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
				5,790,065	5,790,065	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
341	Structures and Improvements										
		P	SG	25,267,861	25,267,861	-	-	-	-	-	-
		P	SG	44,642	44,642	-	-	-	-	-	-
		P	SSGCT	1,034,614	1,034,614	-	-	-	-	-	-
				26,347,117	26,347,117	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories										
		P	SG	1,824,618	1,824,618	-	-	-	-	-	-
		P	SG	32,612	32,612	-	-	-	-	-	-
		P	SSGCT	573,361	573,361	-	-	-	-	-	-
				2,430,590	2,430,590	-	-	-	-	-	-
343	Prime Movers										
		P	S	-	-	-	-	-	-	-	-
		P	SG	193,872	193,872	-	-	-	-	-	-
		P	SG	614,471,913	614,471,913	-	-	-	-	-	-
		P	SSGCT	13,835,327	13,835,327	-	-	-	-	-	-
				628,501,111	628,501,111	-	-	-	-	-	-
344	Generators										
		P	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	56,966,647	56,966,647	-	-	-	-	-	-
		P	SSGCT	3,984,598	3,984,598	-	-	-	-	-	-
				60,951,245	60,951,245	-	-	-	-	-	-
345	Accessory Electric Plant										
		P	SG	31,632,181	31,632,181	-	-	-	-	-	-
		P	SG	42,085	42,085	-	-	-	-	-	-
		P	SSGCT	794,829	794,829	-	-	-	-	-	-
				32,469,096	32,469,096	-	-	-	-	-	-
346	Misc. Power Plant Equipment										
		P	SG	1,835,003	1,835,003	-	-	-	-	-	-
		P	SG	3,175	3,175	-	-	-	-	-	-
				1,838,178	1,838,178	-	-	-	-	-	-
347	Other Production ARO										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300										
		P	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Other Production Plant				758,327,403	758,327,403	-	-	-	-	-	-
Summary of Other Production Plant by Factor											
	S			-	-	-	-	-	-	-	-
	DGU			-	316,387	-	-	-	-	-	-
	SG			738,104,674	737,788,287	-	-	-	-	-	-
	SSGCT			20,222,729	17,942,439	-	-	-	-	-	-
Total of Other Production Plant by Factor				758,327,403	756,047,113	-	-	-	-	-	-
Experimental Plant											
103	Experimental Plant										
		P	SG	-	-	-	-	-	-	-	-
Total Experimental Plant				-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT				2,375,028,130	2,375,028,130	-	-	-	-	-	-
350	Land and Land Rights										
		T	SG	5,694,177	-	5,694,177	-	-	-	-	-
		T	SG	13,043,058	-	13,043,058	-	-	-	-	-
		T	SG	4,975,853	-	4,975,853	-	-	-	-	-
				23,713,088	-	23,713,088	-	-	-	-	-
352	Structures and Improvements										
		T	S	-	-	-	-	-	-	-	-
		T	SG	2,067,906	-	2,067,906	-	-	-	-	-
		T	SG	4,925,338	-	4,925,338	-	-	-	-	-
		T	SG	10,991,643	-	10,991,643	-	-	-	-	-
				17,984,887	-	17,984,887	-	-	-	-	-
353	Station Equipment										
		STEP_UP	SG	35,860,653	3,044,231	32,816,423	-	-	-	-	-
		STEP_UP	SG	52,408,043	4,448,948	47,959,095	-	-	-	-	-
		STEP_UP	SG	197,111,745	16,732,925	180,378,820	-	-	-	-	-
				285,380,440	24,226,103	261,154,337	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
354	Towers and Fixtures										
		T	SG	42,014,691	-	42,014,691	-	-	-	-	-
		T	SG	33,979,760	-	33,979,760	-	-	-	-	-
		T	SG	38,902,038	-	38,902,038	-	-	-	-	-
				114,896,488	-	114,896,488	-	-	-	-	-
355	Poles and Fixtures										
		T	SG	16,584,826	-	16,584,826	-	-	-	-	-
		T	SG	30,259,397	-	30,259,397	-	-	-	-	-
		T	SG	182,488,432	-	182,488,432	-	-	-	-	-
				229,332,655	-	229,332,655	-	-	-	-	-
356	Clearing and Grading										
		T	SG	53,176,296	-	53,176,296	-	-	-	-	-
		T	SG	42,451,924	-	42,451,924	-	-	-	-	-
		T	SG	93,673,989	-	93,673,989	-	-	-	-	-
				189,302,209	-	189,302,209	-	-	-	-	-
357	Underground Conduit										
		T	SG	1,712	-	1,712	-	-	-	-	-
		T	SG	24,633	-	24,633	-	-	-	-	-
		T	SG	836,291	-	836,291	-	-	-	-	-
				862,636	-	862,636	-	-	-	-	-
358	Underground Conductors										
		T	SG	-	-	-	-	-	-	-	-
		T	SG	292,300	-	292,300	-	-	-	-	-
		T	SG	1,720,826	-	1,720,826	-	-	-	-	-
				2,013,126	-	2,013,126	-	-	-	-	-
359	Roads and Trails										
		T	SG	500,725	-	500,725	-	-	-	-	-
		T	SG	118,396	-	118,396	-	-	-	-	-
		T	SG	2,442,528	-	2,442,528	-	-	-	-	-
				3,061,649	-	3,061,649	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300										
		T	SG	3,766,851	-	3,766,851	-	-	-	-	-
				3,766,851	-	3,766,851	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				870,314,028	24,226,103	846,087,925	-	-	-	-	-
Summary of Transmission Plant by Factor											
	DGP			-	3,044,231	152,856,754	-	-	-	-	-
	DGU			-	4,448,948	173,053,900	-	-	-	-	-
	SG			870,314,028	16,732,925	520,177,270	-	-	-	-	-
Total Transmission Plant by Factor				870,314,028	24,226,103	846,087,925	-	-	-	-	-
360	Land and Land Rights										
		D	S	8,935,528	-	-	8,935,528	-	-	-	-
				8,935,528	-	-	8,935,528	-	-	-	-
361	Structures and Improvements										
		D	S	14,747,335	-	-	14,747,335	-	-	-	-
				14,747,335	-	-	14,747,335	-	-	-	-
362	Station Equipment										
		D	S	175,817,518	-	-	175,817,518	-	-	-	-
				175,817,518	-	-	175,817,518	-	-	-	-
363	Storage Battery Equipment										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures										
		D	S	406,460,463	-	-	406,460,463	-	-	-	-
				406,460,463	-	-	406,460,463	-	-	-	-
365	Overhead Conductors										
		D	S	216,663,023	-	-	216,663,023	-	-	-	-
				216,663,023	-	-	216,663,023	-	-	-	-
366	Underground Conduit										
		D	S	78,912,761	-	-	78,912,761	-	-	-	-
				78,912,761	-	-	78,912,761	-	-	-	-
367	Underground Conductors										
		D	S	141,854,929	-	-	141,854,929	-	-	-	-
				141,854,929	-	-	141,854,929	-	-	-	-
368	Line Transformers										
		D	S	357,264,059	-	-	357,264,059	-	-	-	-
				357,264,059	-	-	357,264,059	-	-	-	-
369	Services										
		D	S	201,106,275	-	-	201,106,275	-	-	-	-
				201,106,275	-	-	201,106,275	-	-	-	-
370	Meters										
		C_Meter	S	59,552,063	-	-	-	-	-	59,552,062.78	-
				59,552,063	-	-	-	-	-	59,552,063	-

RESULTS OF OPERATIONS SUMMARY

REVISED PROTOCOL

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1672	371	Installations on Customers' Premises										
1673			D	S	2,436,751	-	-	2,436,751	-	-	-	-
1674					2,436,751	-	-	2,436,751	-	-	-	-
1675												
1676	372	Leased Property										
1677			D	S	-	-	-	-	-	-	-	-
1678					-	-	-	-	-	-	-	-
1679												
1680	373	Street Lights										
1681			D	S	21,113,867	-	-	21,113,867	-	-	-	-
1682					21,113,867	-	-	21,113,867	-	-	-	-
1683												
1684	DP	Unclassified Dist Plant - Acct 300										
1685			D	S	5,406,560	-	-	5,406,560	-	-	-	-
1686					5,406,560	-	-	5,406,560	-	-	-	-
1687												
1688	DS0	Unclassified Dist Sub Plant - Acct 300										
1689			D	S	-	-	-	-	-	-	-	-
1690					-	-	-	-	-	-	-	-
1691												
1692												
1693	TOTAL DISTRIBUTION PLANT				1,690,271,132	-	-	1,630,719,069	-	-	59,552,063	-
1694												
1695	Summary of Distribution Plant by Factor											
1696		S			1,690,271,132	-	-	1,630,719,069	-	-	59,552,063	-
1697												
1698	Total Distribution Plant by Factor				1,690,271,132	-	-	1,630,719,069	-	-	59,552,063	-
1699	389	Land and Land Rights										
1700			D_SPLIT	S	2,236,138	-	-	2,157,353.40	-	-	78,784.17	-
1701			B_Center	CN	349,476	-	-	-	-	260,479.91	-	88,996.38
1702			G-DGU	SG	89	61	28	-	-	-	-	-
1703			G-SG	SG	330	226	101	2	-	-	0	-
1704			LABOR	SO	1,581,933	639,487	76,134	537,867	-	86,080	154,867	87,498
1705					4,167,966	639,775	76,263	2,695,223	-	346,560	233,651	176,494
1706												
1707	390	Structures and Improvements										
1708			D_SPLIT	S	31,776,208	-	-	30,656,660.98	-	-	1,119,547.46	-
1709			G-DGP	SG	96,254	65,991	30,262	-	-	-	-	-
1710			G-DGU	SG	422,927	289,958	132,969	-	-	-	-	-
1711			B_Center	CN	3,746,120	-	-	-	-	2,792,146.15	-	953,973.36
1712			G-SG	SG	1,100,500	755,279	337,931	7,005	-	-	285	-
1713			LABOR	SO	28,764,883	11,628,039	1,384,368	9,780,243	-	1,565,221	2,816,008	1,591,004
1714					65,906,891	12,739,267	1,885,530	40,443,909	-	4,357,367	3,935,841	2,544,977
1715												
1716	391	Office Furniture & Equipment										
1717			D_SPLIT	S	5,541,584	-	-	5,346,341.15	-	-	195,242.49	-
1718			G-DGP	SG	73,494	50,387	23,107	-	-	-	-	-
1719			G-DGU	SG	75,529	51,782	23,746	-	-	-	-	-
1720			B_Center	CN	2,278,997	-	-	-	-	1,698,635.74	-	580,361.19
1721			G-SG	SG	1,226,204	841,550	376,531	7,805	-	-	318	-
1722			P	SE	29,788	29,788	-	-	-	-	-	-
1723			LABOR	SO	18,443,155	7,455,539	887,614	6,270,790	-	1,003,571	1,805,538	1,020,102
1724			G-SG	SSGCH	20,471	14,050	6,286	130	-	-	5	-
1725			G-SG	SSGCT	-	-	-	-	-	-	-	-
1726					27,689,221	8,443,097	1,317,284	11,625,067	-	2,702,207	2,001,103	1,600,464
1727												
1728	392	Transportation Equipment										
1729			D_SPLIT	S	19,740,286	-	-	19,044,790.98	-	-	695,494.77	-
1730			LABOR	SO	2,321,992	938,652	111,751	789,492	-	126,350	227,317	128,431
1731			G-SG	SG	4,134,948	2,837,835	1,269,721	26,320	-	-	1,071	-
1732			B_Center	CN	-	-	-	-	-	-	-	-
1733			G-DGU	SG	275,283	188,734	86,549	-	-	-	-	-
1734			P	SE	189,512	189,512	-	-	-	-	-	-
1735			G-DGP	SG	41,922	28,742	13,180	-	-	-	-	-
1736			G-SG	SSGCH	107,654	73,884	33,057	685	-	-	28	-
1737			G-SG	SSGCT	11,209	7,693	3,442	71	-	-	3	-
1738					26,822,807	4,265,052	1,517,701	19,861,360	-	126,350	923,914	128,431
1739												
1740	393	Stores Equipment										
1741			D_SPLIT	S	2,536,913	-	-	2,447,532.20	-	-	89,381.18	-
1742			G-DGP	SG	90,180	61,828	28,353	-	-	-	-	-
1743			G-DGU	SG	180,989	124,086	56,903	-	-	-	-	-
1744			LABOR	SO	139,750	56,493	6,726	47,516	-	7,604	13,681	7,730
1745			G-SG	SG	854,643	586,545	262,436	5,440	-	-	221	-
1746			G-SG	SSGCT	13,548	9,298	4,160	86	-	-	4	-
1747					3,816,022	838,249	358,577	2,500,574	-	7,604	103,287	7,730
1748												

RESULTS OF OPERATIONS SUMMARY
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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1749	394	Tools, Shop & Garage Equipment										
1750			D_SPLIT	S	9,951,080	-	-	9,600,481.10	-	-	350,598.99	-
1751			G-DGP	SG	755,084	517,685	237,400	-	-	-	-	-
1752			G-SG	SG	5,103,965	3,502,876	1,567,278	32,488	-	-	1,322	-
1753			LABOR	SO	1,175,219	475,076	56,560	399,582	-	63,949	115,051	65,002
1754			P	SE	1,777	1,777	-	-	-	-	-	-
1755			G-SG	SG	1,194,891	820,060	366,916	7,606	-	-	310	-
1756			G-SG	SSGCH	501,287	344,035	153,930	3,191	-	-	130	-
1757			G-SG	SSGCT	951	653	292	6	-	-	0	-
1758					18,684,254	5,662,161	2,382,375	10,043,354	-	63,949	467,412	65,002
1759												
1760	395	Laboratory Equipment										
1761			D_SPLIT	S	10,965,818	-	-	10,579,467.81	-	-	386,350.50	-
1762			G-DGP	SG	16,175	11,089	5,085	-	-	-	-	-
1763			G-DGU	SG	209,419	143,577	65,842	-	-	-	-	-
1764			LABOR	SO	1,565,910	633,010	75,363	532,419	-	85,208	153,299	86,611
1765			P	SE	10,610	10,610	-	-	-	-	-	-
1766			G-SG	SG	1,603,737	1,100,653	492,461	10,208	-	-	416	-
1767			G-SG	SSGCH	69,660	47,808	21,390	443	-	-	18	-
1768			G-SG	SSGCT	3,520	2,416	1,081	22	-	-	1	-
1769					14,444,849	1,949,164	661,221	11,122,561	-	85,208	540,084	86,611
1770												
1771	396	Power Operated Equipment										
1772			D_SPLIT	S	27,920,155	-	-	26,936,465.26	-	-	983,690.02	-
1773			G-DGP	SG	263,850	180,895	82,955	-	-	-	-	-
1774			G-SG	SG	7,340,110	5,037,554	2,253,932	46,722	-	-	1,902	-
1775			LABOR	SO	485,436	196,235	23,363	165,051	-	26,415	47,523	26,850
1776			G-DGU	SG	560,218	384,084	176,133	-	-	-	-	-
1777			P	SE	18,457	18,457	-	-	-	-	-	-
1778			P	SSGCT	-	-	-	-	-	-	-	-
1779			G-SG	SSGCH	270,577	185,698	83,086	1,722	-	-	70	-
1780					36,858,803	6,002,924	2,619,469	27,149,961	-	26,415	1,033,185	26,850
1781	397	Communication Equipment										
1782			COM_EQ	S	52,135,234	8,312,129	20,533,306	22,561,731	-	-	-	728,069
1783			COM_EQ	SG	1,156,436	184,375	455,459	500,452	-	-	-	16,150
1784			COM_EQ	SG	2,060,876	328,574	811,670	891,852	-	-	-	28,780
1785			COM_EQ	SO	13,670,229	2,179,499	5,383,979	5,915,846	-	-	-	190,905
1786			COM_EQ	CN	529,600	84,436	208,581	229,187	-	-	-	7,396
1787			COM_EQ	SG	16,096,145	2,566,273	6,339,418	6,965,671	-	-	-	224,783
1788			COM_EQ	SE	(55,098)	(8,785)	(21,700)	(23,844)	-	-	-	(769)
1789			COM_EQ	SSGCH	170,978	27,260	67,339	73,992	-	-	-	2,388
1790			COM_EQ	SSGCT	(77)	(12)	(30)	(33)	-	-	-	(1)
1791					85,764,323	13,673,749	33,778,021	37,114,854	-	-	-	1,197,699
1792												
1793	398	Misc. Equipment										
1794			D_SPLIT	S	464,639	-	-	448,268.65	-	-	16,370.28	-
1795			G-DGP	SG	5,023	3,444	1,579	-	-	-	-	-
1796			G-DGU	SG	5,170	3,544	1,625	-	-	-	-	-
1797			B_Center	CN	61,088	-	-	-	-	45,531.35	-	15,556.38
1798			LABOR	SO	926,556	374,555	44,592	315,035	-	50,418	90,707	51,248
1799			P	SE	417	417	-	-	-	-	-	-
1800			G-SG	SG	402,947	276,545	123,733	2,565	-	-	104	-
1801			G-SG	SSGCT	-	-	-	-	-	-	-	-
1802					1,865,839	658,504	171,530	765,868	-	95,949	107,182	66,805
1803												
1804	399	Coal Mine										
1805			P	SE	117,345,284	117,345,284	-	-	-	-	-	-
1806	MP	Unclassified Mine Plant	P	SE	-	-	-	-	-	-	-	-
1807					117,345,284	117,345,284	-	-	-	-	-	-
1808												
1809	399L	WIDCO Capital Lease										
1810			P	SE	-	-	-	-	-	-	-	-
1811												
1812												
1813		Remove Capital Leases			-	-	-	-	-	-	-	-
1814					-	-	-	-	-	-	-	-
1815												
1816	1011390	General Capital Leases										
1817			D_SPLIT	S	5,882,166	-	-	5,674,924.43	-	-	207,241.98	-
1818			P	SG	3,335,890	3,335,890	-	-	-	-	-	-
1819			LABOR	SO	3,646,055	1,473,897	175,474	1,239,682	-	198,397	356,939	201,666
1820					12,864,111	4,809,787	175,474	6,914,606	-	198,397	564,181	201,666
1821												
1822		Remove Capital Leases			(12,864,111)	(4,809,787)	(175,474)	(6,914,606)	-	(198,397)	(564,181)	(201,666)
1823					-	-	-	-	-	-	-	-
1824												
1825	1011346	General Gas Line Capital Leases										
1826			P	SG	-	-	-	-	-	-	-	-
1827					-	-	-	-	-	-	-	-
1828												
1829		Remove Capital Leases			-	-	-	-	-	-	-	-
1830					-	-	-	-	-	-	-	-
1831												
1832	GP	Unclassified Gen Plant - Acct 300										
1833			D_SPLIT	S	-	-	-	-	-	-	-	-
1834			LABOR	SO	42,655	17,243	2,053	14,503	-	2,321	4,176	2,359
1835			CUST	CN	-	-	-	-	-	-	-	-
1836			G-SG	SG	-	-	-	-	-	-	-	-
1837			G-DGP	SG	-	-	-	-	-	-	-	-
1838			G-DGU	SG	-	-	-	-	-	-	-	-
1839					42,655	17,243	2,053	14,503	-	2,321	4,176	2,359
1840												

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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
1841	399G	Unclassified Gen Plant - Acct 300										
1842			D_SPLIT	S	-	-	-	-	-	-	-	-
1843			LABOR	SO	-	-	-	-	-	-	-	-
1844			G-SG	SG	-	-	-	-	-	-	-	-
1845			G-DGP	SG	-	-	-	-	-	-	-	-
1846			G-DGU	SG	-	-	-	-	-	-	-	-
1847					-	-	-	-	-	-	-	-
1848												
1849		TOTAL GENERAL PLANT			403,408,915	172,234,469	44,770,026	163,337,235	-	7,813,929	9,349,836	5,903,421
1850												
1851		Summary of General Plant by Factor										
1852		S			169,150,222	8,312,129	20,533,306	135,454,017	-	-	4,122,702	728,069
1853		DGP			-	1,248,634	1,233,591	891,852	-	-	-	28,780
1854		DGU			-	2,334,461	1,722,382	899,458	-	-	310	28,780
1855		SG			48,683,228	17,505,337	13,023,542	7,104,227	-	-	5,640	224,783
1856		SO			72,763,772	26,255,574	8,380,745	25,842,976	-	3,189,119	5,737,584	3,432,556
1857		SE			117,540,747	117,587,061	(21,700)	(23,844)	-	-	-	(769)
1858		CN			6,965,280	84,436	208,581	229,187	-	4,796,793	-	1,646,283
1859		DGP			-	4,726,451	7,185,051	7,295,516	-	50,418	91,310	276,031
1860		SSGCT			29,150	11,839,198	1,362,769	9,756,402	-	1,565,221	2,816,009	1,590,234
1861		SG			1,140,627	8,427,573	1,168,001	6,885,214	-	1,089,651	1,960,509	1,109,988
1862		Less Capital Leases			(12,864,111)	(4,809,787)	(175,474)	(6,914,606)	-	(198,397)	(564,181)	(201,666)
1863		Total General Plant by Factor			403,408,915	193,511,067	54,620,793	187,420,399	-	10,492,804	14,169,882	8,863,068
1864	301	Organization										
1865			D_SPLIT	S	-	-	-	-	-	-	-	-
1866			LABOR	SO	-	-	-	-	-	-	-	-
1867			I-SG	SG	-	-	-	-	-	-	-	-
1868					-	-	-	-	-	-	-	-
1869	302	Franchise & Consent										
1870			D_SPLIT	S	-	-	-	-	-	-	-	-
1871			I-SG	SG	8,683,286	7,773,683	906,792	2,702	-	-	110	-
1872			I-DGP	SG	27,760,743	27,760,743	-	-	-	-	-	-
1873			I-DGU	SG	2,483,623	2,483,623	-	-	-	-	-	-
1874			I-DGP	SG	-	-	-	-	-	-	-	-
1875			I-DGU	SG	154,401	154,401	-	-	-	-	-	-
1876					39,082,054	38,172,450	906,792	2,702	-	-	110	-
1877												
1878	303	Miscellaneous Intangible Plant										
1879			D_SPLIT	S	540,701	-	-	521,650.98	-	-	19,050.12	-
1880			LABOR	SG	15,419,680	6,233,317	742,103	5,242,789	-	839,051	1,509,547	852,872
1881			LABOR	SO	112,055,116	45,297,637	5,392,878	38,099,454	-	6,097,400	10,969,909	6,197,838
1882			P	SE	907,133	907,133	-	-	-	-	-	-
1883			CSS_SYS	CN	36,145,444	-	-	-	-	19,879,994	6,506,180	9,759,270
1884			I-DGP	SG	62,485	62,485	-	-	-	-	-	-
1885			I-DGP	SSGCT	-	-	-	-	-	-	-	-
1886					165,130,559	52,500,572	6,134,982	43,863,894	-	26,816,445	19,004,687	16,809,980
1887	303	Less Non-Utility Plant										
1888			I-SITUS	S	-	-	-	-	-	-	-	-
1889					165,130,559	52,500,572	6,134,982	43,863,894	-	26,816,445	19,004,687	16,809,980
1890	IP	Unclassified Intangible Plant - Acct 300										
1891			D_SPLIT	S	-	-	-	-	-	-	-	-
1892			I-SG	SG	-	-	-	-	-	-	-	-
1893			I-DGU	SG	-	-	-	-	-	-	-	-
1894			LABOR	SO	-	-	-	-	-	-	-	-
1895					-	-	-	-	-	-	-	-
1896												
1897		TOTAL INTANGIBLE PLANT			204,212,613	90,673,022	7,041,773	43,866,596	-	26,816,445	19,004,796	16,809,980
1898												
1899		Summary of Intangible Plant by Factor										
1900		S			540,701	-	-	521,651	-	-	19,050	-
1901		DGP			-	27,823,228	-	-	-	-	-	-
1902		DGU			-	2,483,623	-	-	-	-	-	-
1903		SG			54,564,219	14,007,000	1,648,895	5,245,491	-	839,051	1,509,657	852,872
1904		SO			112,055,116	45,297,637	5,392,878	38,099,454	-	6,097,400	10,969,909	6,197,838
1905		CN			36,145,444	-	-	-	-	19,879,994	6,506,180	9,759,270
1906		SSGCT			-	62,485	-	-	-	-	-	-
1907		SSGCH			-	-	-	-	-	-	-	-
1908		SE			907,133	907,133	-	-	-	-	-	-
1909		Total Intangible Plant by Factor			204,212,613	90,581,106	7,041,773	43,866,596	-	26,816,445	19,004,796	16,809,980
1910		Summary of Unclassified Plant (Account 106)										
1911		DP			5,406,560	-	-	5,406,560	-	-	-	-
1912		DS0			-	-	-	-	-	-	-	-
1913		GP			42,655	17,243	2,053	14,503	-	2,321	4,176	2,359
1914		HP			-	-	-	-	-	-	-	-
1915		NP			-	-	-	-	-	-	-	-
1916		OP			-	-	-	-	-	-	-	-
1917		TP			3,766,851	-	3,766,851	-	-	-	-	-
1918		TS0			-	-	-	-	-	-	-	-
1919		IP			-	-	-	-	-	-	-	-
1920		MP			-	-	-	-	-	-	-	-
1921		SP			3,193	3,193	-	-	-	-	-	-
1922		Total Unclassified Plant by Factor			9,219,258	20,436	3,768,904	5,421,062	-	2,321	4,176	2,359
1923												
1924		TOTAL ELECTRIC PLANT IN SERVICE			5,543,234,819	2,662,161,725	897,899,724	1,837,922,900	-	34,630,374	87,906,695	22,713,401

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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1925	Summary of Electric Plant by Factor											
1926		S			1,859,962,055	8,312,129	20,533,306	1,766,694,737	-	-	63,693,815	728,069
1927		SE			118,447,880	118,494,194	(21,700)	(23,844)	-	-	-	(769)
1928		DGU			-	368,134,313	174,776,282	899,458	-	-	310	28,780
1929		DGP			-	409,800,443	154,090,345	891,852	-	-	-	28,780
1930		SG			3,188,075,425	1,500,624,641	534,849,707	12,349,719	-	839,051	1,515,297	1,077,655
1931		SO			184,818,888	71,553,211	13,773,624	63,942,430	-	9,286,519	16,707,493	9,630,394
1932		CN			43,110,724	84,436	208,581	229,187	-	24,676,787	6,506,180	11,405,553
1933		SE			-	4,726,451	7,185,051	7,295,516	-	50,418	91,310	276,031
1934		DGU			141,432,079	12,746,331	1,362,769	9,756,402	-	1,565,221	2,816,009	1,590,234
1935		DGP			20,251,879	99,008,679	8,209,774	50,751,809	-	27,906,096	20,965,306	17,919,968
1936		Less Capital Leases			(12,864,111)	(4,809,787)	(175,474)	(6,914,606)	-	(198,397)	(564,181)	(201,666)
1937					5,543,234,819	2,588,675,040	914,792,264	1,905,872,659	-	64,125,694	111,731,538	42,483,028
1938	105	Plant Held For Future Use										
1939			D_SPLIT	S	-	-	-	-	-	-	-	-
1940			P	SG	-	-	-	-	-	-	-	-
1941			T	SG	(2,398,306)	-	(2,398,306)	-	-	-	-	-
1942			P	SG	2,398,305	2,398,305	-	-	-	-	-	-
1943			P	SE	0	0	-	-	-	-	-	-
1944			G	SG	-	-	-	-	-	-	-	-
1945												
1946												
1947					(0)	2,398,305	(2,398,306)	-	-	-	-	-
1948												
1949	114	Electric Plant Acquisition Adjustments										
1950			P	S	-	-	-	-	-	-	-	-
1951			P	SG	38,335,325	38,335,325	-	-	-	-	-	-
1952			P	SG	3,913,465	3,913,465	-	-	-	-	-	-
1953					42,248,790	42,248,790	-	-	-	-	-	-
1954												
1955	115	Accum Provision for Asset Acquisition Adjustments										
1956			P	S	-	-	-	-	-	-	-	-
1957			P	SG	(20,661,458)	(20,661,458)	-	-	-	-	-	-
1958			P	SG	(3,019,185)	(3,019,185)	-	-	-	-	-	-
1959					(23,680,643)	(23,680,643)	-	-	-	-	-	-
1960												
1961	120	Nuclear Fuel										
1962			P	SE	-	-	-	-	-	-	-	-
1963					-	-	-	-	-	-	-	-
1964												
1965	124	Weatherization										
1966			DSM	S	0	-	-	0	-	-	-	-
1967			DSM	SO	(696)	-	-	(696)	-	-	-	-
1968					(696)	-	-	(696)	-	-	-	-
1969												
1970	182W	Weatherization										
1971			DSM	S	-	-	-	-	-	-	-	-
1972			DSM	SG	-	-	-	-	-	-	-	-
1973			DSM	SGCT	-	-	-	-	-	-	-	-
1974			DSM	SO	-	-	-	-	-	-	-	-
1975					-	-	-	-	-	-	-	-
1976												
1977	186W	Weatherization										
1978			DSM	S	-	-	-	-	-	-	-	-
1979			DSM	CN	-	-	-	-	-	-	-	-
1980			DSM	CNP	-	-	-	-	-	-	-	-
1981			DSM	SG	-	-	-	-	-	-	-	-
1982			DSM	SO	-	-	-	-	-	-	-	-
1983					-	-	-	-	-	-	-	-
1984												
1985		Total Weatherization			(696)	-	-	(696)	-	-	-	-
1986												
1987	151	Fuel Stock										
1988			P	DEU	-	-	-	-	-	-	-	-
1989			P	SE	39,313,195	39,313,195	-	-	-	-	-	-
1990			P	SSECT	-	-	-	-	-	-	-	-
1991			P	SSECH	2,336,814	2,336,814	-	-	-	-	-	-
1992					41,650,008	41,650,008	-	-	-	-	-	-
1993												
1994	152	Fuel Stock - Undistributed										
1995			P	SE	-	-	-	-	-	-	-	-
1996					-	-	-	-	-	-	-	-
1997												
1998	25316	DG&T Working Capital Deposit										
1999			P	SE	(218,517)	(218,517)	-	-	-	-	-	-
2000					(218,517)	(218,517)	-	-	-	-	-	-
2001												
2002	25317	DG&T Working Capital Deposit										
2003			P	SE	(423,752)	(423,752)	-	-	-	-	-	-
2004					(423,752)	(423,752)	-	-	-	-	-	-
2005												
2006	25319	Provo Working Capital Deposit										
2007			P	SE	-	-	-	-	-	-	-	-
2008					-	-	-	-	-	-	-	-
2009												
2010		Total Fuel Stock			41,007,740	41,007,740	-	-	-	-	-	-

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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
154	Materials and Supplies										
		MSS	S	28,381,534	22,799,225	1,917,248	3,540,802	-	-	124,258	-
		MSS	SG	857,268	688,654	57,911	106,950	-	-	3,753	-
		MSS	SE	1,103,637	886,565	74,554	137,687	-	-	4,832	-
		MSS	SO	(727)	(584)	(49)	(91)	-	-	(3)	-
		MSS	SNPPS	20,177,057	16,208,471	1,363,014	2,517,234	-	-	88,338	-
		MSS	SNPPH	(5,666)	(4,551)	(383)	(707)	-	-	(25)	-
		MSS	SNPD	(1,119,929)	(899,653)	(75,654)	(139,719)	-	-	(4,903)	-
		MSS	SNPT	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SSGCT	-	-	-	-	-	-	-	-
		MSS	SNPP	-	-	-	-	-	-	-	-
		MSS	SSGCH	-	-	-	-	-	-	-	-
				49,393,174	39,678,127	3,336,641	6,162,156	-	-	216,250	-
163	Stores Expense Undistributed										
		MSS	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit										
		MSS	SNPPS	(73,601)	(59,125)	(4,972)	(9,182)	-	-	(322)	-
				(73,601)	(59,125)	(4,972)	(9,182)	-	-	(322)	-
	Total Materials & Supplies			49,319,573	39,619,002	3,331,669	6,152,974	-	-	215,928	-
165	Prepayments										
		LABOR	S	2,900,866	1,172,658	139,610	986,313	-	157,849	283,987	160,449
		GP	GPS	46,688	22,422	7,563	15,479.95	-	292	740.40	191
		PT	SG	810,462	593,118	217,344	-	-	-	-	-
		P	SE	696,368	696,368	-	-	-	-	-	-
		LABOR	SO	7,746,634	3,131,532	372,822	2,633,905	-	421,528	758,376	428,471
				12,201,019	5,616,099	737,339	3,635,698	-	579,668	1,043,103	589,111
182M	Misc Regulatory Assets										
		DDS2	S	(1,286,545)	(652,564)	(237,478)	(364,614)	-	(16,171)	(15,719)	-
		DEFSG	SG	1,549,591	375,712	1,173,879	-	-	-	-	-
		P	SGCT	2,750,587	2,750,587	-	-	-	-	-	-
		DEFSG	SG-P	(736,419)	(178,551)	(557,867)	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
		LABOR	SO	1,997,962	807,665	96,156	679,320	-	108,718	195,595	110,509
				4,275,176	3,102,849	474,689	314,706	-	92,547	179,876	110,509
186M	Misc Deferred Debits										
		LABOR	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		DEFSG	SG	13,929,377	3,377,304	10,552,073	-	-	-	-	-
		LABOR	SO	64,435	26,047	3,101	21,908	-	3,506	6,308	3,564
		P	SE	1,864,721	1,864,721	-	-	-	-	-	-
		P	SNPPS	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-
				15,858,533	5,268,073	10,555,174	21,908	-	3,506	6,308	3,564
Working Capital											
CWC	Cash Working Capital										
		CWC	S	11,608,463	8,017,413	987,560	1,942,539.85	0	193,984	304,286.12	162,679
		CWC	SO	-	-	-	-	-	-	-	-
		CWC	SE	-	-	-	-	-	-	-	-
				11,608,463	8,017,413	987,560	1,942,540	0	193,984	304,286	162,679
OWC	Other Working Capital										
131	Cash	GP	SNP	(0)	(0)	(0)	(0.00)	-	(0)	(0.00)	(0)
135	Working Funds	GP	SG	662	318	107	219.37	-	4	10.49	3
141	Notes Receivable	GP	SO	131,637	63,219	21,323	43,645.71	-	822	2,087.55	539
143	Other Accounts Receivable	LABOR	SO	4,488,236	1,814,344	216,005	1,526,029	-	244,224	439,387	248,247
232	Accounts Payable	LABOR	S	-	-	-	-	-	-	-	-
232	Accounts Payable	LABOR	SO	(1,203,907)	(486,672)	(57,940)	(409,336)	-	(65,510)	(117,859)	(66,589)
232	Accounts Payable	P	SE	(283,338)	(283,338)	-	-	-	-	-	-
253	Deferred Hedge	P	SG	0	0	-	-	-	-	-	-
2533	Other Deferred Credits - Mi	P	S	-	-	-	-	-	-	-	-
2533	Other Deferred Credits - Mi	P	SE	(1,431,645)	(1,431,645)	-	-	-	-	-	-
230	Asset Retirement Obligatior	P	SE	(608,850)	(608,850)	-	-	-	-	-	-
230	Asset Retirement Obligatior	P	S	-	-	-	-	-	-	-	-
254105	ARO Regulatory Liability	P	S	-	-	-	-	-	-	-	-
254105	ARO Regulatory Liability	P	SE	(117,221)	(117,221)	-	-	-	-	-	-
2533	Cholla Reclamation	P	SSECH	-	-	-	-	-	-	-	-
				975,573	(1,049,846)	179,495	1,160,558	-	179,541	323,625	182,200
Total Working Capital				12,584,036	6,967,567	1,167,055	3,103,098	0	373,525	627,912	344,880
Miscellaneous Rate Base											
18221	Unrec Plant & Reg Study Costs										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
2100	18222	Nuclear Plant - Trojan										
2101			P	S	(175,546)	(175,546)	-	-	-	-	-	-
2102			P	TROJP	561,363	561,363	-	-	-	-	-	-
2103			P	TROJD	820,434	820,434	-	-	-	-	-	-
2104					1,206,251	1,206,251	-	-	-	-	-	-
2105												
2106												
2107												
2108	1869	Misc Deferred Debits-Trojan										
2109			P	S	-	-	-	-	-	-	-	-
2110			P	SNPPN	-	-	-	-	-	-	-	-
2111					-	-	-	-	-	-	-	-
2112												
2113	TOTAL MISCELLANEOUS RATE BASE				1,206,251	1,206,251	-	-	-	-	-	-
2114												
2115	TOTAL RATE BASE ADDITIONS				155,019,777	123,754,033	13,867,620	13,227,687	0	1,049,246	2,073,127	1,048,063
2116	235	Customer Service Deposits										
2117			CUST	S	-	-	-	-	-	-	-	-
2118			CUST	CN	-	-	-	-	-	-	-	-
2119					-	-	-	-	-	-	-	-
2120												
2121	2281	Prov for Property Insurance	LABOR	SO	-	-	-	-	-	-	-	-
2122	2282	Prov for Injuries & Damage	LABOR	SO	(2,306,013)	(932,193)	(110,982)	(784,059)	-	(125,480)	(225,753)	(127,547)
2123	2283	Prov for Pensions and Bene	LABOR	SO	(5,654,188)	(2,285,673)	(272,119)	(1,922,460)	-	(307,669)	(553,531)	(312,737)
2124	2283	Prov for Pensions and Bene	LABOR	SG	-	-	-	-	-	-	-	-
2125	254	Reg Liabilities - Insurance F	LABOR	SE	(148,400)	(59,990)	(7,142)	(50,457)	-	(8,075)	(14,528)	(8,208)
2126					(8,108,601)	(3,277,855)	(390,243)	(2,756,976)	-	(441,224)	(793,811)	(448,492)
2127												
2128	22844	Accum Hydro Relicensing Obligation										
2129			P	S	-	-	-	-	-	-	-	-
2130			P	SG	-	-	-	-	-	-	-	-
2131					-	-	-	-	-	-	-	-
2132												
2133	22843	Accum Misc Oper Prov-Tro	P	TROJD	(643,113)	(643,113)	-	-	-	-	-	-
2134	230	Asset Retirement Obligatior	P	TROJP	(608,780)	(608,780)	-	-	-	-	-	-
2135	254105	ARO Regulatory Liability	P	TROJP	(214,399)	(214,399)	-	-	-	-	-	-
2136	254		P	S	-	-	-	-	-	-	-	-
2137					(1,466,292)	(1,466,292)	-	-	-	-	-	-
2138												
2139	252	Customer Advances for Construction										
2140			D_SPLIT	S	(1,593,020)	-	-	(1,536,894.71)	-	-	(56,125.70)	-
2141			D_SPLIT	SE	-	-	-	-	-	-	-	-
2142			T	SG	(1,906,223)	-	(1,906,223)	-	-	-	-	-
2143			D_SPLIT	SO	-	-	-	-	-	-	-	-
2144			D_SPLIT	CN	-	-	-	-	-	-	-	-
2145					(3,499,244)	-	(1,906,223)	(1,536,895)	-	-	(56,126)	-
2146												
2147	25398	SO2 Emissions										
2148			P	SE	(3,871,633)	(3,871,633)	-	-	-	-	-	-
2149					(3,871,633)	(3,871,633)	-	-	-	-	-	-
2150												
2151	25399	Other Deferred Credits										
2152			D_SPLIT	S	(497,650)	-	-	(480,116.81)	-	-	(17,533.34)	-
2153			LABOR	SO	(669,708)	(270,726)	(32,231)	(227,705.01)	-	(36,442)	(65,562.71)	(37,042)
2154			P	SG	(5,979,876)	(5,979,876)	-	-	-	-	-	-
2155			P	SE	(588,737)	(588,737)	-	-	-	-	-	-
2156					(7,735,971)	(6,839,338)	(32,231)	(707,822)	-	(36,442)	(83,096)	(37,042)
2157												
2158	190	Accumulated Deferred Income Taxes										
2159			D_SPLIT	S	811,860	-	-	783,256.35	-	-	28,603.66	-
2160			P	CN	34,745	34,745	-	-	-	-	-	-
2161			LABOR	SO	3,110,735	1,257,497	149,710	1,057,670	-	169,268	304,533	172,057
2162			P	DGP	200	200	-	-	-	-	-	-
2162			PTD	IBT	82,697	39,794	14,582	27,323	-	-	998	-
2162			P	SG	-	-	-	-	-	-	-	-
2162			P	SG	-	-	-	-	-	-	-	-
2162			CUST	BADDEBT	1,154,288	-	-	-	-	1,154,288	-	-
2164			P	TROJD	36	36	-	-	-	-	-	-
2165			P	SG	11,600,625	11,600,625	-	-	-	-	-	-
2166			P	SE	4,424,890	4,424,890	-	-	-	-	-	-
2167			LABOR	SNP	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)
2168			D_SPLIT	SNPD	603,426	-	-	582,165.54	-	-	21,260.04	-
2169			P	SSGCT	-	-	-	-	-	-	-	-
2170					21,823,502	17,357,788	164,293	2,450,415	-	1,323,556	355,395	172,057
2171												
2172	281	Accumulated Deferred Income Taxes										
2173			P	S	-	-	-	-	-	-	-	-
2174			PT	DGP	-	-	-	-	-	-	-	-
2175			T	SNPT	-	-	-	-	-	-	-	-
2176					-	-	-	-	-	-	-	-
2177												
2178	282	Accumulated Deferred Income Taxes										
2179			GP	S	(546,068,247)	(262,251,562)	(88,452,780)	(181,055,172.60)	-	(3,411,464)	(8,659,754.88)	(2,237,514)
2180			ACCMDIT	DITBAL	(0)	(0)	(0)	(0)	-	(0)	(0)	-
2181			PT	SNP	(2,753,161)	(2,014,837)	(738,324)	-	-	-	-	-
2182			LABOR	SO	(4,126,194)	(1,667,990)	(198,581)	(1,402,932)	-	(224,524)	(403,944)	(228,222)
2183			LABOR	GPS	-	-	-	-	-	-	-	-
2184			P	SE	(4,070,986)	(4,070,986)	-	-	-	-	-	-
2185			P	SG	(4,924,377)	(4,924,377)	-	-	-	-	-	-
2186					(561,942,966)	(274,929,752)	(89,389,685)	(182,458,105)	-	(3,635,988)	(9,063,699)	(2,465,737)
2187												

RESULTS OF OPERATIONS SUMMARY
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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
2188	283	Accumulated Deferred Income Taxes										
2189			GP	S	(2,929,453)	(1,406,882)	(474,516)	(971,293.76)	-	(18,301)	(46,456.37)	(12,003)
2190			P	SG	(1,063,182)	(1,063,182)	-	-	-	-	-	-
2191			P	SE	(3,004,988)	(3,004,988)	-	-	-	-	-	-
2192			LABOR	SO	2,465,280	996,575	118,647	838,211	-	134,146	241,345	136,356
2193			GP	GPS	(3,965,082)	(1,904,247)	(642,269)	(1,314,668.40)	-	(24,771)	(62,879.76)	(16,247)
2194			LABOR	SNP	(2,179,696)	(881,130)	(104,902)	(741,110)	-	(118,607)	(213,387)	(120,560)
2195			P	TROJD	384,207	384,207	-	-	-	-	-	-
2196			P	SSGCT	-	-	-	-	-	-	-	-
2197			P	SGCT	(592,272)	(592,272)	-	-	-	-	-	-
2198			P	SSGCH	-	-	-	-	-	-	-	-
2199					(10,885,187)	(7,471,919)	(1,103,041)	(2,188,862)	-	(27,533)	(81,378)	(12,455)
2200												
2201	TOTAL ACCUMULATED DEF INCOME TAX				(551,004,650)	(265,043,883)	(90,328,433)	(182,196,552)	-	(2,339,965)	(8,789,682)	(2,306,135)
2202	255	Accumulated Investment Tax Credit										
2203			LABOR	S	-	-	-	-	-	-	-	-
2204			LABOR	ITC84	(1,032,278)	(417,293)	(49,680)	(350,981)	-	(56,171)	(101,057)	(57,096)
2205			LABOR	ITC85	(1,830,931)	(740,143)	(88,117)	(622,528)	-	(99,629)	(179,243)	(101,270)
2206			LABOR	ITC86	(876,373)	(354,269)	(42,177)	(297,972)	-	(47,687)	(85,795)	(48,473)
2207			LABOR	ITC88	(126,948)	(51,318)	(6,110)	(43,163)	-	(6,908)	(12,428)	(7,022)
2208			LABOR	ITC89	(257,725)	(104,184)	(12,404)	(87,628)	-	(14,024)	(25,231)	(14,255)
2209			LABOR	ITC90	(48,049)	(19,423)	(2,312)	(16,337)	-	(2,615)	(4,704)	(2,658)
2210			LABOR	DGU	-	-	-	-	-	-	-	-
2211					(4,172,305)	(1,686,630)	(200,801)	(1,418,610)	-	(227,033)	(408,458)	(230,773)
2212												
2213	TOTAL RATE BASE DEDUCTIONS				(579,858,695)	(282,185,631)	(92,857,931)	(188,616,855)	-	(3,044,663)	(10,131,173)	(3,022,441)
2214												
2215												
2216												
2217	108SP	Steam Prod Plant Accumulated Depr										
2218			P	S	-	-	-	-	-	-	-	-
2219			P	SG	(239,306,334)	(239,306,334)	-	-	-	-	-	-
2220			P	SG	(256,903,473)	(256,903,473)	-	-	-	-	-	-
2221			P	SG	(168,131,349)	(168,131,349)	-	-	-	-	-	-
2222			P	SSGCH	(45,187,416)	(45,187,416)	-	-	-	-	-	-
2223					(709,528,572)	(709,528,572)	-	-	-	-	-	-
2224												
2225	108NP	Nuclear Prod Plant Accumulated Depr										
2226			P	SG	-	-	-	-	-	-	-	-
2227			P	SG	-	-	-	-	-	-	-	-
2228			P	SG	-	-	-	-	-	-	-	-
2229					-	-	-	-	-	-	-	-
2230												
2231												
2232	108HP	Hydraulic Prod Plant Accum Depr										
2233			P	S	-	-	-	-	-	-	-	-
2234		Pre-Merger Pacific	P	SG	(40,482,847)	(40,482,847)	-	-	-	-	-	-
2235		Pre-Merger Utah	P	SG	(7,934,116)	(7,934,116)	-	-	-	-	-	-
2236		Post-Merger Pacific	P	SG	(14,481,737)	(14,481,737)	-	-	-	-	-	-
2237		Post-Merger Utah	P	SG	(4,351,199)	(4,351,199)	-	-	-	-	-	-
2238					(67,249,900)	(67,249,900)	-	-	-	-	-	-
2239												
2240	108OP	Other Production Plant - Accum Depr										
2241			P	S	-	-	-	-	-	-	-	-
2242			P	SG	(360,488)	(360,488)	-	-	-	-	-	-
2243			P	SG	-	-	-	-	-	-	-	-
2244			P	SG	(62,403,780)	(62,403,780)	-	-	-	-	-	-
2245			P	SSGCT	(5,500,320)	(5,500,320)	-	-	-	-	-	-
2246					(68,264,588)	(68,264,588)	-	-	-	-	-	-
2247												
2248	108EP	Experimental Plant - Accum Depr										
2249			P	SG	-	-	-	-	-	-	-	-
2250			P	SG	-	-	-	-	-	-	-	-
2251					-	-	-	-	-	-	-	-
2252												
2253	TOTAL PRODUCTION PLANT DEPRECIATION				(845,043,059)	(845,043,059)	-	-	-	-	-	-
2254												
2255	Summary of Prod Plant Depreciation by Factor											
2256		S			-	-	-	-	-	-	-	-
2257		DGP			-	(279,789,181)	-	-	-	-	-	-
2258		DGU			-	(265,198,077)	-	-	-	-	-	-
2259		SG			(794,355,324)	(249,368,066)	-	-	-	-	-	-
2260		SSGCH			(45,187,416)	(45,187,416)	-	-	-	-	-	-
2261		SSGCT			(5,500,320)	(5,500,320)	-	-	-	-	-	-
2262	Total of Prod Plant Depreciation by Factor				(845,043,059)	(845,043,059)	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
108TP	Transmission Plant Accumulated Depr										
		T_Split	SG	(105,686,236)	(2,941,887.19)	(102,744,349.02)	-	-	-	-	-
		T_Split	SG	(105,997,635)	(2,950,555)	(103,047,079)	-	-	-	-	-
		T_Split	SG	(107,612,019)	(2,995,493.36)	(104,616,525.31)	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				(319,295,890)	(8,887,936)	(310,407,954)	-	-	-	-	-
108360	Land and Land Rights										
		D	S	(1,602,022)	-	-	(1,602,022)	-	-	-	-
				(1,602,022)	-	-	(1,602,022)	-	-	-	-
108361	Structures and Improvements										
		D	S	(2,891,139)	-	-	(2,891,139)	-	-	-	-
				(2,891,139)	-	-	(2,891,139)	-	-	-	-
108362	Station Equipment										
		D	S	(50,927,189)	-	-	(50,927,189)	-	-	-	-
				(50,927,189)	-	-	(50,927,189)	-	-	-	-
108363	Storage Battery Equipment										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108364	Poles, Towers & Fixtures										
		D	S	(254,217,371)	-	-	(254,217,371)	-	-	-	-
				(254,217,371)	-	-	(254,217,371)	-	-	-	-
108365	Overhead Conductors										
		D	S	(111,511,075)	-	-	(111,511,075)	-	-	-	-
				(111,511,075)	-	-	(111,511,075)	-	-	-	-
108366	Underground Conduit										
		D	S	(30,131,046)	-	-	(30,131,046)	-	-	-	-
				(30,131,046)	-	-	(30,131,046)	-	-	-	-
108367	Underground Conductors										
		D	S	(49,257,652)	-	-	(49,257,652)	-	-	-	-
				(49,257,652)	-	-	(49,257,652)	-	-	-	-
108368	Line Transformers										
		D	S	(145,890,557)	-	-	(145,890,557)	-	-	-	-
				(145,890,557)	-	-	(145,890,557)	-	-	-	-
108369	Services										
		D	S	(54,920,796)	-	-	(54,920,796)	-	-	-	-
				(54,920,796)	-	-	(54,920,796)	-	-	-	-
108370	Meters										
		C_Meter	S	(30,602,765)	-	-	-	-	-	(30,602,765.11)	-
				(30,602,765)	-	-	-	-	-	(30,602,765)	-
108371	Installations on Customers' Premises										
		D	S	(2,335,549)	-	-	(2,335,549)	-	-	-	-
				(2,335,549)	-	-	(2,335,549)	-	-	-	-
108372	Leased Property										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108373	Street Lights										
		D	S	(7,478,090)	-	-	(7,478,090)	-	-	-	-
				(7,478,090)	-	-	(7,478,090)	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT DEPR				(741,765,252)	-	-	(711,162,487)	-	-	(30,602,765)	-
Summary of Distribution Plant Depr by Factor											
	S			(741,765,252)	-	-	(711,162,487)	-	-	(30,602,765)	-
Total Distribution Depreciation by Factor				(741,765,252)	-	-	(711,162,487)	-	-	(30,602,765)	-
108GP	General Plant Accumulated Depr										
		D_SPLIT	S	(50,628,900)	-	-	(48,845,129.32)	-	-	(1,783,770.28)	-
		G-DGP	SG	(1,961,193)	(1,344,592)	(616,602)	-	-	-	-	-
		G-DGU	SG	(3,726,099)	(2,554,609)	(1,171,491)	-	-	-	-	-
		G-SG	SG	(12,083,872)	(8,293,222)	(3,710,602)	(76,918)	-	-	(3,131)	-
		B_Center	CN	(1,802,318)	-	-	-	-	(1,343,345.91)	-	(458,971.75)
		LABOR	SO	(22,106,984)	(8,936,621)	(1,063,943)	(7,516,515)	-	(1,202,936)	(2,164,217)	(1,222,751)
		P	SE	(65,729)	(65,729)	-	-	-	-	-	-
		G-SG	SSGCT	(8,492)	(5,828)	(2,608)	(54)	-	-	(2)	-
		G-SG	SSGCH	(650,630)	(446,530)	(199,789)	(4,141)	-	-	(169)	-
				(93,034,218)	(21,647,131)	(6,765,035)	(56,442,758)	-	(2,546,282)	(3,951,289)	(1,681,723)

RESULTS OF OPERATIONS SUMMARY

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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
108MP	Mining Plant Accumulated Depr.										
		P	S	-	-	-	-	-	-	-	-
		P	SE	(42,029,817)	(42,029,817)	-	-	-	-	-	-
				(42,029,817)	(42,029,817)	-	-	-	-	-	-
108MP	Less Centralia Situs Depreciation										
		P	S	-	-	-	-	-	-	-	-
				(42,029,817)	(42,029,817)	-	-	-	-	-	-
1081390	Accum Depr - Capital Lease										
		LABOR	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-			
				-	-	-	-	-	-	-	-
1081399	Accum Depr - Capital Lease										
		P	S	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT ACCUM DEPR				(135,064,034)	(63,676,948)	(6,765,035)	(56,442,758)	-	(2,546,282)	(3,951,289)	(1,681,723)
Summary of General Depreciation by Factor											
	S			(50,628,900)	-	-	(48,845,129)	-	-	(1,783,770)	-
	DGP			-	(1,344,592)	(616,602)	-	-	-	-	-
	DGU			-	(2,554,609)	(1,171,491)	-	-	-	-	-
	SE			(42,095,546)	(42,095,546)	-	-	-	-	-	-
	SO			(22,106,984)	(8,936,621)	(1,063,943)	(7,516,515)	-	(1,202,936)	(2,164,217)	(1,222,751)
	CN			(1,802,318)	-	-	-	-	(1,343,346)	-	(458,972)
	SG			(17,771,165)	(8,293,222)	(3,710,602)	(76,918)	-	-	(3,131)	-
	DGP			-	-	-	-	-	(1,343,346)	-	(458,972)
	SSGCT			(8,492)	(8,936,621)	(1,063,943)	(7,516,515)	-	(1,202,936)	(2,164,217)	(1,222,751)
	SE			(650,630)	(65,729)	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
Total General Depreciation by Factor				(135,064,034)	(72,226,939)	(7,626,581)	(63,955,078)	-	(5,092,564)	(6,115,336)	(3,363,446)
TOTAL ACCUM DEPR - PLANT IN SERVICE				(2,041,168,235)	(917,607,943)	(317,172,989)	(767,605,245)	-	(2,546,282)	(34,554,054)	(1,681,723)
111SP	Accum Prov for Amort-Steam										
		P	SSGCH	-	-	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General										
		D_SPLIT	S	(10,854,756)	-	-	(10,472,318.31)	-	-	(382,437.52)	-
		CUST	CN	(792,042)	-	-	-	-	(792,042)	-	-
		I-SG	SG	(224,015)	(200,548)	(23,394)	(70)	-	-	(3)	-
		LABOR	SO	(3,079,249)	(1,244,769)	(148,195)	(1,046,964)	-	(167,555)	(301,451)	(170,315)
		P	SE	-	-	-	-	-	-	-	-
				(14,950,062)	(1,445,317)	(171,589)	(11,519,352)	-	(959,597)	(683,891)	(170,315)
111HP	Accum Prov for Amort-Hydro										
	Pre-Merger Pacific	P	SG	(92,611)	(92,611)	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	(2,649)	(2,649)	-	-	-	-	-	-
	Post-Merger Utah	P	SG	(109,550)	(109,550)	-	-	-	-	-	-
				(204,811)	(204,811)	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant										
		D_SPLIT	S	(580,763)	-	-	(560,301.17)	-	-	(20,461.58)	-
		LABOR	SG	30,126	12,178	1,450	10,243	-	1,639	2,949	1,666
		LABOR	SG	(84,292)	(34,074)	(4,057)	(28,660)	-	(4,587)	(8,252)	(4,662)
		P	SE	(365,642)	(365,642)	-	-	-	-	-	-
		LABOR	SG	(11,421,406)	(4,617,038)	(549,678)	(3,883,351)	-	(621,488)	(1,118,126)	(631,725)
		I-SG	SG	(4,594,437)	(4,113,154)	(479,795)	(1,430)	-	-	(58)	-
		I-SG	SG	(877,774)	(785,824)	(91,666)	(273)	-	-	(11)	-
		CSS_SYS	CN	(28,974,607)	-	-	-	-	(15,936,034)	(5,215,429)	(7,823,144)
		P	SSGCT	-	-	-	-	-	-	-	-
		P	SSGCH	(7,235)	(7,235)	-	-	-	-	-	-
		LABOR	SO	(79,074,244)	(31,965,309)	(3,805,607)	(26,885,747)	-	(4,302,769)	(7,741,166)	(4,373,646)
				(125,950,273)	(41,876,098)	(4,929,353)	(31,349,518)	-	(20,863,238)	(14,100,556)	(12,831,511)
111IP	Less Non-Utility Plant										
		NUTIL	OTH	-	-	-	-	-	-	-	-
				(125,950,273)	(41,876,098)	(4,929,353)	(31,349,518)	-	(20,863,238)	(14,100,556)	(12,831,511)
111390	Accum Amtr - Capital Lease										
		LABOR	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-
TOTAL ACCUM PROV FOR AMORTIZATION				(141,105,146)	(43,526,226)	(5,100,942)	(42,868,870)	-	(21,822,835)	(14,784,447)	(13,001,826)

Docket No. UE-210
Exhibit PPL/919
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Marginal Cost of Service Study

August 2009

Exhibit PPL/919

1. Summaries

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	67.57	67.12	64.99	67.57	113.51	111.37
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	67.57	67.12	64.99	67.57	103.40	101.26
5	15+ kW	(sec)	67.57	67.12	64.99	67.57	110.66	108.53
6	Primary	(pri)	65.12	65.02	62.96	65.12	105.83	103.50
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	67.57	67.12	64.99	67.57	106.63	104.49
10	51-100 kW	(sec)	67.57	67.12	64.99	67.57	108.63	106.49
11	> 101kW	(sec)	67.57	67.12	64.99	67.57	105.39	103.25
12	Primary	(pri)	65.48	65.04	62.96	65.48	102.63	100.50
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	67.56	67.12	64.99	67.56	104.64	102.50
16	301+ kW	(sec)	67.57	67.12	64.99	67.57	104.36	102.23
17	Primary	(pri)	65.45	65.02	62.96	65.45	100.86	98.79
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	67.57	67.12	64.99	67.57	102.53	100.39
21	1 - 4 MW	(pri)	65.46	65.02	62.96	65.46	97.16	95.09
22	> 4 MW	(sec)	67.57	67.11	64.99	67.57	92.59	90.45
23	> 4 MW	(pri)	65.46	65.02	62.96	65.46	90.29	88.22
24								
25	Trans	(trn)	64.12	63.69	61.67	64.12	81.66	79.63
26								
27								
28	Schedule 41- Irrigation	(sec)	67.56	67.12	64.99	67.56	114.15	112.01
29	Schedule 33*- Irrigation	(sec)	67.57	67.12	64.99	67.57	117.23	115.09

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) Tab 2.11 (10 Yr FC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(C) Tab 2.3 (Table 4:) `20 Year Marginal Cost By Load Class December 2010 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
(D) Column (A)
(E) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(F) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2010 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'

Energy costs include both generation and transmission energy-related costs.
* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2010 Dollars

			(A)	(B)
			1 Year	10 & 20 Year
Line	Description		1&3 Phase	1&3 Phase
1	Res - Schedule 4	(sec)	$12.96	$30.63
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	14.34	45.93
5	15+ kW	(sec)	26.55	81.06
6	Primary	(pri)	105.04	118.21
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	29.41	92.38
10	51-100 kW	(sec)	31.07	103.62
11	> 101kW	(sec)	68.24	147.36
12	Primary	(pri)	107.28	112.92
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	88.37	184.08
16	301+ kW	(sec)	88.38	184.29
17	Primary	(pri)	127.28	133.91
18				
19	Total			
20	1 - 4 MW	(sec)	237.12	328.48
21	1 - 4 MW	(pri)	237.06	239.02
22	> 4 MW	(sec)	237.12	326.51
23	> 4 MW	(pri)	237.06	237.06
24	Trans	(trn)	3,709.57	3,709.57
25				
26				
27	Schedule 41- Irrigation	(sec)	10.35	120.17
28	Schedule 41- Irrigation	(sec)	10.35	120.17
29	Schedule 33*- Irrigation	(sec)	10.69	142.43

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead and maintenance, service drops, service drop overhead and maintenance, customer accounting and informational expenses, and billing expenses.

* Schedule 33 Cost of Service results are provided for informational purposes only.

Sources:
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrigation Sch 41	Irrigation Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Peak Mw @ Meter	System	886	79	72	0	71	116	145	3	31	163	14	90	60	7	156	46	21	18
2		Feeder	1,084	76	67	0	67	110	143	3	31	162	14	89	58	6	154	0	16	14
3		Transformer	2,402	271	109	0	109	158	200	4	41	194	17	143	92	18	236	69	98	84
4																				
5	Demand Loss Factor		1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.0819	1.1131	1.0819	1.1131	1.0819	1.0498	1.1131	1.1131
6																				
7	Peak Mw @ Generator	System	986	88	80	0	79	129	161	3	35	181	15	101	65	8	169	49	23	20
8		Feeder	1,207	85	75	0	74	122	159	3	35	181	15	100	63	7	166	N/A	18	16
9		Transformer	2,674	302	121	N/A	121	176	223	N/A	46	216	N/A	160	N/A	20	N/A	N/A	109	94
10																				
11	Energy																			
12	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
13	Energy Loss Factor		1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0577	1.0918	1.0577	1.0918	1.0577	1.0361	1.0918	1.0918
14	Energy - Annual Mwh	@ Generator	5,934,856	636,009	469,754	1,218	471,647	734,164	1,007,067	19,302	225,167	1,177,485	99,352	649,344	438,677	59,334	1,242,998	419,485	149,349	128,883
15																				
16	Customer																			
17	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
18	Average Customers																		2,834	756
19																				
20	Unit Costs																			
21																				
22	Generation	$ / System Peak Kw	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48	$74.48
23	Transmission	$ / System Peak Kw	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34
24	Poles, Cond., Subst.	$ / Feeder Kw	$83.22	$87.55	$87.55	$87.55	$67.00	$67.00	$67.00	$67.00	$69.43	$69.43	$69.43	$56.87	$56.87	$27.17	$26.04	$0.00	$151.53	$174.56
25	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
26																				
27	Energy - @ Generator																			
28	Generation	$ / Kwh	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571
29	Transmission	$ / Kwh	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381
30																				
31	Poles	$ / Cust / Year	$98.51	$112.87	$112.87	$112.87	$48.31	$48.31	$48.31	$48.31	$56.87	$56.87	$56.87	$16.84	$16.84	$0.00	$0.00	$0.00	$303.41	$383.21
32	Conductor	$ / Cust / Year	$39.46	$45.21	$45.21	$45.21	$19.34	$19.34	$19.34	$19.34	$22.77	$22.77	$22.77	$6.75	$6.75	$0.00	$0.00	$0.00	$121.51	$153.49
33	Transformers	$ / Cust / Year	$74.10	$220.96	$495.99	$0.00	$687.94	$802.95	$881.83	$0.00	$1,068.93	$1,071.19	$0.00	$1,072.72	$0.00	$1,072.72	$0.00	$0.00	$892.92	$1,044.20
34	Service Drop	$ / Cust / Year	$70.74	$91.06	$217.90	$0.00	226.61	236.74	521.65	-	521.43	521.41	-	$936.36	$0.00	$936.36	$0.00	$0.00	$0.00	$0.00
35	Meters	$ / Cust / Year	$15.52	$18.36	$38.03	$1,197.78	36.76	46.47	207.64	1,197.78	209.44	209.65	1,197.78	$262.21	$1,197.78	$262.21	$1,197.78	$42,868	$37.38	$45.05
36	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80	75.74	75.74	75.74	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
37	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60	32.60	32.60	32.60	238.22	$238.22	$238.22	$238.22	$238.22	$33.07	$33.02
38	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
39	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.98	$182.98	$182.98	$182.98	$182.98	$14.72	$14.32
40	Total Commitment & Billing	$ / Cust / Year	$367.57	$551.16	$972.70	$1,418.56	$1,108.54	$1,243.39	$1,768.36	$1,355.01	$2,208.97	$2,211.43	$1,606.95	$3,941.77	$2,868.25	$3,918.18	$2,844.66	$44,515	$1,442.08	$1,709.18

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) 'Customer Loads12 Months Ended December 2010'
Lines 12 & 17 Tab 17.2 (Cust Data 2:) 'Customers and MWh's12 Months Ended December 2010 - Normalized'
Line 13 Tab 16.1 (Losses:) 'Energy Loss Factors'
Line 22 Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 23 Tab 6.1 (Transm1:) 'Marginal Transmission Investment and O&M Expenses'
Line 24 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'
Line 28 Tab 5.1 (Energy:) 'Marginal Generation Energy Costs'
Line 29 Tab 2.6 (Table 6:) 'Marginal Cost of Transmission Investment and Associated Expenses'
Lines 31 - 39 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$161,795	$73,417	$6,521	$5,949	$15	$5,886	$9,641	$12,021	$238	$2,603	$13,514	$1,145	$7,499	$4,840	$571	$12,603	$3,615	$1,717	$1,481	
2	Transmission	$163,662	$74,265	$6,597	$6,017	$15	$5,954	$9,752	$12,160	$240	$2,633	$13,670	$1,158	$7,586	$4,896	$578	$12,748	$3,657	$1,736	$1,498	
3	Distribution																				
4	Poles	$43,918	$27,466	$2,083	$1,832	$4	$1,177	$1,929	$2,521	$49	$584	$3,042	$257	$1,143	$726	$8	$143	$0	$953	$973	
5	Conductor	$73,160	$44,797	$3,361	$2,957	$8	$2,072	$3,393	$4,436	$86	$1,015	$5,291	$448	$2,193	$1,391	$19	$306	$0	$1,387	$1,410	
6	Substations	$53,934	$28,171	$1,979	$1,741	$4	$1,738	$2,846	$3,720	$72	$810	$4,221	$357	$2,323	$1,474	$168	$3,884	$0	$426	$368	
7	Subtotal: Pole, Cond, Subs	$171,013	$100,434	$7,422	$6,529	$17	$4,987	$8,168	$10,677	$207	$2,410	$12,554	$1,062	$5,659	$3,590	$195	$4,333	$0	$2,766	$2,751	
8	Transformers	$6,968	$4,040	$592	$238	$0	$237	$344	$437	$0	$90	$423	$0	$313	$0	$39	$0	$0	$214	$184	
9	Distribution subtotal	$177,981	$104,474	$8,014	$6,768	$17	$5,224	$8,513	$11,114	$207	$2,500	$12,977	$1,062	$5,972	$3,590	$235	$4,333	$0	$2,980	$2,935	
10																					
11	Total Demand Related	$503,438	$252,156	$21,132	$18,734	$47	$17,064	$27,906	$35,295	$685	$7,736	$40,161	$3,365	$21,057	$13,326	$1,384	$29,684	$7,272	$6,433	$5,914	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$766,783	$330,631	$35,432	$26,170	$68	$26,275	$40,900	$56,104	$1,075	$12,544	$65,598	$5,535	$36,175	$24,439	$3,305	$69,247	$23,370	$8,320	$7,180	$1,595
16	Transmission Energy Related	$52,473	$22,626	$2,425	$1,791	$5	$1,798	$2,799	$3,839	$74	$858	$4,489	$379	$2,476	$1,672	$226	$4,739	$1,599	$569	$491	$109
17	Total Energy	$819,256	$353,257	$37,857	$27,961	$73	$28,074	$43,699	$59,943	$1,149	$13,402	$70,087	$5,914	$38,650	$26,111	$3,532	$73,986	$24,969	$8,890	$7,671	$1,704
18																					
19	Customer Related Marginal Cost																				
20	Poles	$61,601	$47,136	$7,297	$1,058	$4	$216	$170	$98	$3	$14	$33	$3	$1	$1	$0	$0	$0	$1,853	$789	$3,714
21	Conductor	$23,235	$18,881	$2,922	$423	$1	$87	$68	$39	$1	$5	$14	$1	$1	$0	$0	$0	$0	$742	$317	$47
22	Transformers	$68,657	$35,458	$14,284	$4,648	$0	$3,090	$2,830	$1,794	$0	$246	$613	$0	$129	$0	$3	$0	$0	$5,454	$2,153	$107
23	Service Drops	$45,223	$33,849	$5,887	$2,042	$0	$1,018	$834	$1,060	$0	$120	$298	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,510	$7,428	$1,187	$356	$41	$165	$164	$422	$60	$48	$120	$62	$32	$67	$1	$41	$86	$228	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,442	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$31
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,134	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$248,830	$175,881	$35,632	$9,115	$48	$4,979	$4,382	$3,596	$68	$509	$1,265	$84	$476	$161	$8	$97	$89	$8,523	$3,416	$3,915
30																					
31	Total Revenue @ Full MC																				
32	Generation	$928,578	$404,048	$41,953	$32,119	$83	$32,161	$50,541	$68,125	$1,313	$15,147	$79,112	$6,680	$43,674	$29,279	$3,876	$81,850	$26,985	$10,037	$8,661	$1,595
33	Transmission	$216,135	$96,891	$9,022	$7,808	$20	$7,752	$12,551	$15,999	$314	$3,491	$18,159	$1,537	$10,062	$6,568	$804	$17,487	$5,256	$2,305	$1,989	$109
34	Distribution	$376,699	$239,798	$38,406	$14,939	$22	$9,635	$12,415	$14,106	$211	$2,885	$13,934	$1,067	$6,217	$3,592	$239	$4,333	$0	$11,029	$6,195	$3,871
35	Customer - Billing	$18,233	$15,442	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$31
36	Customer - Metering	$18,829	$14,127	$2,309	$519	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,134	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,565,784	$776,439	$94,445	$55,784	$167	$50,003	$75,898	$98,783	$1,901	$21,606	$111,410	$9,353	$60,049	$39,536	$4,921	$103,729	$32,328	$23,811	$16,994	$5,619
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,571,524	$781,295	$94,621	$55,810	$167	$50,116	$75,987	$98,835	$1,903	$21,647	$111,513	$9,363	$60,184	$39,598	$4,923	$103,767	$32,330	$23,846	$17,001	$5,619

Source: Tab 2.3 (Table 3:) '20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 7) x (Table 3, Row 22)/1000
Line 2 Transmission (Table 3, Row 7) x (Table 3, Row 23)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 8) x (Table 7, Row 1 - 3) x (1 + .3612) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 9) x (Table 7, Row 7) x (1 + .3612) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 14) x (Table 3, Row 28 - 29)
Lines 20-29 Commitment Related (Table 3, Row 17) x (Table 7, Row 13 - 27) including O&M Adders

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 5

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs
In Nominal Dollars

Year		(A) Resource Cost (Mills / kWh) (B) + (C)	(B) Energy Only (Mills / kWh)	(C) Capacity Only (Mills / kWh)	(D) Capacity Only ($ / kW)
2010		79.34	61.88	17.46	$74.50
2011		78.19	60.36	17.83	$76.06
2012		76.81	58.62	18.19	$77.59
2013		77.15	58.62	18.53	$79.05
2014		79.47	60.59	18.88	$80.55
2015		82.45	63.21	19.24	$82.08
2016		83.99	64.38	19.61	$83.64
2017		85.46	65.48	19.98	$85.23
2018		86.93	66.57	20.36	$86.86
2019		88.56	67.82	20.74	$88.50
2020		90.28	69.14	21.14	$90.18
2021		90.11	68.57	21.54	$91.89
2022		90.24	68.29	21.95	$93.65
2023		90.61	68.24	22.37	$95.42
2024		90.39	67.60	22.79	$97.23
2025		90.41	67.19	23.22	$99.08
2026		90.37	66.70	23.67	$100.97
2027		91.06	66.94	24.12	$102.88
2028		92.13	67.55	24.58	$104.84
2029		92.90	67.86	25.04	$106.83
2010	**1 year -**				
|	Sum of PV Costs @ 8.53%	79.35	61.89	17.46	$74.50
2010 - 2014	**5 year -**				
|	Sum of PV Costs @ 8.53%	334.24	256.80	77.44	$330.35
|	Annual Cost of R/E @ 22.58%	75.48	57.99		
|	Annual Cost of Capacity @ 22.58%			17.49	$74.59
2010 - 2019	**10 years -**				
|	Sum of PV Costs @ 8.53%	576.17	442.17	134.00	$571.62
|	Annual Cost of R/E @ 13.04%	75.13	57.66		
|	Annual Cost of Capacity @ 13.04%			17.47	$74.54
2010 - 2029	**20 years -**				
|	Sum of PV Costs @ 8.53%	860.81	655.40	205.41	$876.24
|	Annual Cost of R/E @ 8.50%	73.17	55.71		
|	Annual Cost of Capacity @ 8.50%			17.46	$74.48

Footnotes:
(B) Tab 5.1 (Energy:) `Marginal Generation Energy Costs'
(C) Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item		$'s	
1	Growth Related Investments - (2010 to 2014 in $000's)		$802,608	
2				
3	System Growth MW's from 2010 to 2014		913	mW
4				
5	Marginal Investment	(growth invest / mWh)	$879.09	/ kW
6				
7	Annualized Investment	x 8.68%	76.31	/ kW
8	Admin. & General Factor	x 1.71%	15.03	
9	Annual O&M Expenses	x 1.205%	10.59	/ kW
10	Annualized Marginal Cost		$101.93	/ kW
11				
12	Marginal Cost of Demand-Related Transmission		$75.34	/ kW
13				
14	Marginal Cost of Energy-Related Transmission	(Line 10 - Line 12)	$26.59	/ kW
15	Marginal Cost of Energy-Related Transmission		$0.00381	/ kWh
16	$26.59 / (8760 x 79.62% LF))			

Sources:
Tab 6.2 (Transm2:) `2010-2014 Forecasted Transmission'
Tab 6.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'

Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
December 2010 Dollars

Line	Description		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
			(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Costs ($/kW)																			
1	Poles		16.72	18.05	18.05	18.05	11.62	11.62	11.62	11.62	12.36	12.36	12.36	8.44	8.44	0.90	0.63	NA	38.35	45.36
2	Conductors		27.27	29.12	29.12	29.12	20.45	20.45	20.45	20.45	21.50	21.50	21.50	16.19	16.19	1.91	1.35	NA	55.82	65.73
3	Substation		17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	NA	17.15	17.15
4	Dist. O&M @ of Total Investment	36.12%	22.08	23.23	23.23	23.23	17.78	17.78	17.78	17.78	18.42	18.42	18.42	15.09	15.09	7.21	6.91	NA	40.21	46.32
5	Total $/ Feeder kW		$83.22	$87.55	$87.55	$87.55	$67.00	$67.00	$67.00	$67.00	$69.43	$69.43	$69.43	$56.87	$56.87	$27.17	$26.04	-	$151.53	$174.56
6																				
7	Transformers		1.11	1.44	1.44	NA	1.44	1.44	1.44	NA	1.44	1.44	NA	1.44	NA	1.44	NA	NA	1.44	1.44
8	Dist. O&M @ of Total Investment	36.12%	0.40	0.52	0.52	NA	0.52	0.52	0.52	NA	0.52	0.52	NA	0.52	NA	0.52	NA	NA	0.52	0.52
9	Total $/ Transformer kW		$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
10																				
11																				
12	Commitment Related Costs ($/Customer)																			
13	Poles		72.37	82.92	82.92	82.92	35.49	35.49	35.49	35.49	41.78	41.78	41.78	12.37	12.37	-	-	NA	222.90	281.52
14	Conductors		28.99	33.21	33.21	33.21	14.21	14.21	14.21	14.21	16.73	16.73	16.73	4.96	4.96	-	-	NA	89.27	112.76
15	Transformers		54.44	162.33	364.38	NA	505.39	589.88	647.83	NA	785.29	786.95	NA	788.07	NA	788.07	NA	NA	655.98	767.12
16	Dist. O&M @ of Total Investment	36.12%	56.27	100.58	173.56	41.95	200.50	231.02	251.95	17.95	304.78	305.38	21.13	290.91	6.26	284.65	-	NA	349.70	419.50
17	Total Commitment Related		$212.07	$379.04	$654.07	$158.08	$755.59	$870.60	$949.48	$67.65	$1,148.58	$1,150.84	$79.64	$1,096.31	$23.59	$1,072.72	$0.00	$0.00	$1,317.85	$1,580.90
18																				
19	Billing Related Costs ($/Customer/Yr)																			
20	Service Drop		51.97	66.90	160.08	NA	166.48	173.92	383.23	NA	383.07	383.05	NA	687.89	NA	687.89	NA	NA	NA	NA
21	Service Drop O&M @	36.12%	18.77	24.16	57.82	NA	60.13	62.82	138.42	NA	138.36	138.36	NA	248.47	NA	248.47	NA	NA	NA	NA
22	Meter		10.88	12.87	26.65	$839.43	25.76	32.57	145.52	839.43	146.78	146.93	839.43	183.76	839.43	183.76	839.43	30,042.75	26.20	31.57
23	Meter O&M at	42.69%	4.64	5.49	11.38	358.35	11.00	13.90	62.12	358.35	62.66	62.72	358.35	78.45	358.35	78.45	358.35	12,825.25	11.18	13.48
24	Meter Reading		14.00	17.36	17.36	17.36	16.80	16.80	16.80	16.80	$75.74	$75.74	$75.74	114.93	114.93	114.93	114.93	114.93	26.74	26.67
25	Billing & Collections		32.27	30.49	30.49	30.49	32.60	32.60	32.60	32.60	$32.60	$32.60	$32.60	238.22	238.22	238.22	238.22	238.22	33.07	33.02
26	Uncollectables		10.15	2.73	2.73	2.73	25.17	25.17	25.17	25.17	$180.30	$180.30	$180.30	1,110.75	1,110.75	1,110.75	1,110.75	1,110.75	12.33	9.21
27	Customer Service / Other		12.82	12.11	12.11	12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.98	182.98	182.98	182.98	182.98	14.72	14.32
28	Total Billing Related		$155.50	$172.12	$318.63	$1,260.48	$352.95	$372.79	$818.87	$1,287.36	$1,060.40	$1,060.59	$1,527.31	$2,845.45	$2,844.66	$2,845.45	$2,844.66	$44,514.88	$124.23	$128.28
29																				
30																				
31	Monthly Billing Related (Line 28 / 12)		$12.96	$14.34	$26.55	$105.04	$29.41	$31.07	$68.24	$107.28	$88.37	$88.38	$127.28	$237.12	$237.06	$237.12	$237.06	$3,709.57	$10.35	$10.69
32																				
33	Total Distribution (Comm & Billing Costs)		$367.57	$551.16	$972.70	$1,418.56	$1,108.54	$1,243.39	$1,768.36	$1,355.01	$2,208.97	$2,211.43	$1,606.95	$3,941.76	$2,868.25	$3,918.17	$2,844.66	$44,514.88	$1,442.08	$1,709.18
34	Line 17 + Line 28																			
35	Monthly Commitment & Bill (Line 33 / 12)		$30.63	$45.93	$81.06	$118.21	$92.38	$103.62	$147.36	$112.92	$184.08	$184.29	$133.91	$328.48	$239.02	$326.51	$237.06	$3,709.57	$120.17	$142.43

Sources: Lines

Line 1 - 2 Tab 8.1 (PC 1:) 'Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 3 Tab 7.1 (Dist Sub 1:) 'Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 36.12%
Tab 10.1 (Dist OM:) 'Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 36.12% Factor)
Line 7 Tab 9.2 (XFMR 2:) 'Transformer Demand Costs'
Line 13 - 14 Tab 8.1 (PC 1:) 'Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 15 Tab 9.1 (XFMR 1:) 'Transformer Commitment Costs'
Line 20 Tab 12.1 (Services 1:) 'Weighted Average Installed Service Drop Costs'
Line 22 Tab 11.1 (Meters 1:) 'Weighted Average Installed Meter Costs'
Line 23 Tab 11.5 (Meters 5:) 'Distribution Meters Expense Loading Factor' (for 42.69% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) 'Summary of Customer Accounting Expense By Schedule'

* Schedule 33 Cost of Service results are provided for informational purposes only.

Billing Costs

PacifiCorp
Oregon Marginal Cost Study
Total 20 Year Demand Costs Divided by Billing kW
December 2010 Dollars
(Dollars in 000's)

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
		Total	(sec)	0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	> 101kW (sec)	Primary (pri)	0-300 kW (sec)	301+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 M (pri)	> 4 MW (sec)	> 4 M (pri)	Trans (trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation -	$161,795	$73,417	$6,521	$5,949	$15	$5,886	$9,641	$12,021	$238	$2,603	$13,514	$1,145	$7,499	$4,840	$571	$12,603	$3,615	$1,717	$1,481
2	Transmission -	$163,662	$74,265	$6,597	$6,017	$15	$5,954	$9,752	$12,160	$240	$2,633	$13,670	$1,158	$7,586	$4,896	$578	$12,748	$3,657	$1,736	$1,498
3																				
4	Distribution -																			
5	Poles, Wire, Sub	$171,013	$100,434	$7,422	$6,529	$17	$4,987	$8,168	$10,677	$207	$2,410	$12,554	$1,062	$5,659	$3,590	$195	$4,333	$0	$2,766	$2,751
6	Transformers	$6,968	$4,040	$592	$238	$0	$237	$344	$437	$0	$90	$423	$0	$313	$0	$39	$0	$0	$214	$184
7	Distribution Subtotal	$177,981	$104,474	$8,014	$6,768	$17	$5,224	$8,513	$11,114	$207	$2,500	$12,977	$1,062	$5,972	$3,590	$235	$4,333	$0	$2,980	$2,935
8																				
9	Total Demand Related	$503,438	$252,156	$21,132	$18,734	$47	$17,064	$27,906	$35,295	$685	$7,736	$40,161	$3,365	$21,057	$13,326	$1,384	$29,684	$7,272	$6,433	$5,914
10																				
11	Average Billing kW	5,309,663	3,585,565	301,351	141,484	399	108,871	158,141	199,971	3,848	41,138	193,793	16,855	143,412	91,794	17,994	236,113	68,934	97,809	78,140
12																				
13	Generation -		$20.48	$21.64	$42.05	$37.55	$54.06	$60.96	$60.11	$61.85	$63.27	$69.73	$67.93	52.29	52.73	31.73	53.38	52.44	17.55	18.95
14	Transmission -		$20.71	$21.89	$42.53	$37.55	$54.69	$61.67	$60.81	$62.36	$64.00	$70.54	$68.70	52.90	53.34	32.12	53.99	53.05	17.75	19.17
15																				
16	Distribution -																			
17	Poles, Wire, Sub		$28.01	$24.63	$46.15	$41.78	$45.81	$51.65	$53.39	$53.84	$58.58	$64.78	$63.04	39.46	39.11	10.86	18.35	0.00	28.28	35.21
18	Transformers		$1.13	$1.96	$1.68	$0.00	$2.18	$2.18	$2.19	$0.00	$2.18	$2.18	$0.00	2.18	0.00	2.19	0.00	0.00	2.18	2.35
19	Distribution subtotal		$29.14	$26.59	$47.83	$41.78	$47.98	$53.83	$55.58	$53.84	$60.76	$66.96	$63.04	41.64	39.11	13.05	18.35	0.00	30.47	37.56
20																				
21																				
22																				
23																				
24	Total Demand Related		$70.33	$70.13	$132.41	$116.89	$156.73	$176.46	$176.50	$178.05	$188.04	$207.24	$199.67	$146.83	$145.18	$76.91	$125.72	$105.49	$65.77	$75.69
25																				
26	Monthly Demand Costs		$5.86	$5.84	$11.03	$9.74	$13.06	$14.71	$14.71	$14.84	$15.67	$17.27	$16.64	$12.24	$12.10	$6.41	$10.48	$8.79	$5.48	$6.31

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage @ Meter
December 2010 Dollars

Line	Description		(A) Marginal Cost (000)s	(B) Mills / kWh	(C) % of Total
	Demand Related Marginal Cost -				
1	Generation		$161,795	12.67	10.3%
2	Transmission		163,662	12.81	10.4%
3	Dist. Poles, Cond., Subst.		171,013	13.39	10.9%
4	Dist. Transformers		6,968	0.55	0.4%
5	Total Demand Related		$503,438	39.42	32.0%
6					
7	Energy Related Marginal Cost -				
8					
9	Generation		$766,783	60.04	48.8%
10	Transmission		52,473	4.11	3.3%
11	Total Energy Related		$819,256	64.14	52.1%
12					
13	Commitment & Billing -				
14	Commitment		153,493	12.02	9.8%
15	Billing		95,337	7.46	6.1%
16	Total Commitment & Billing		$248,830	19.48	15.8%
17					
18					
19	TOTAL MARGINAL COST		$1,571,524	123.04	100.0%
20					
21					
22	Note: Total MWh =	12,772,237			

PacifiCorp
Oregon Marginal Cost Study
10 Year Run Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

Line	Description		(A)	(B)	(C)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
			(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(tm)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Peak MW @ Meter	System	886	79	72	0	71	116	145	3	31	163	14	90	60	7	156	46	21	18
2		Feeder	1,084	76	67	0	67	110	143	3	31	162	14	89	58	6	154	0	16	14
3		Transformer	2,402	271	109	0	109	158	200	4	41	194	17	143	92	18	236	69	98	84
	Demand Loss Factor		1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.0819	1.1131	1.0819	1.1131	1.0819	1.0498	1.1131	1.1131
4	Peak MW @ Generator	System	986	88	80	0	79	129	161	3	35	181	15	101	65	8	169	49	23	20
5		Feeder	1,207	85	75	0	74	122	159	3	35	181	15	100	63	7	166	-	18	16
6		Transformer	2,674	302	121	N/A	121	176	223	N/A	46	216	N/A	160	N/A	20	N/A	N/A	109	94
7																				
8																				
9	Energy																			
10	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
11	Energy Loss Factor		1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0577	1.0918	1.0577	1.0918	1.0577	1.0361	1.0918	1.0918
12	Energy - Annual Mwh	@ Generator	5,934,856	636,009	469,754	1,218	471,647	734,164	1,007,067	19,302	225,167	1,177,485	99,352	649,344	438,677	59,334	1,242,998	419,485	149,349	128,883
13																				
14																				
15	Customer																			
16	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
17	Average Customers																		2,834	756
18																				
19	Unit Costs																			
20																				
21	Generation	$ / System Peak kW	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54	$74.54
22	Transmission	$ / System Peak kW	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34	$75.34
23	Poles, Cond., Subst.	$ / Feeder kW	$83.22	$87.55	$87.55	$87.55	$67.00	$67.00	$67.00	$67.00	$69.43	$69.43	$69.43	$56.87	$56.87	$27.17	$26.04	$0.00	$151.53	$174.56
24	Transformers	$ / Xfmr kW	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
25																				
26																				
27	Energy @ Generator	$ / Kwh	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147	$0.06147
28																				
29																				
30	Commitment & Billing	$ / Cust. / Year	$367.57	$551.16	$972.70	1,418.56	$1,108.54	$1,243.39	$1,768.36	$1,355.01	$2,208.97	$2,211.43	$1,606.95	3,941.76	$2,868.25	$3,918.17	$2,844.66	$44,514.88	1,442.08	1,709.18

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation -	$163,408	$73,477	$6,527	$5,953	$15	$5,890	$9,648	$12,031	$238	$2,605	$13,525	$1,146	$7,505	$4,844	$572	$12,613	$3,618	$1,718	$1,483
2	Transmission -	$165,160	$74,265	$6,597	$6,017	$15	$5,954	$9,752	$12,160	$240	$2,633	$13,670	$1,158	$7,586	$4,896	$578	$12,748	$3,657	$1,736	$1,498
3																				
4	Distribution -																			
5	Poles, Conductor, Substations	$173,761	$100,430	$7,422	$6,529	$17	$4,988	$8,169	$10,677	$208	$2,410	$12,553	$1,063	$5,659	$3,590	$196	$4,332	$0	$2,767	$2,751
6	Transformers	$7,149	$4,038	$592	$238	$0	$238	$345	$436	$0	$90	$423	$0	$313	$0	$39	$0	$0	$213	$184
7	Distribution subtotal	$180,910	$104,468	$8,014	$6,767	$17	$5,226	$8,514	$11,113	$208	$2,500	$12,976	$1,063	$5,972	$3,590	$235	$4,332	$0	$2,980	$2,935
8																				
9	Total Demand Related	$509,478	$252,210	$21,138	$18,737	$47	$17,070	$27,914	$35,304	$686	$7,738	$40,171	$3,367	$21,063	$13,330	$1,385	$29,693	$7,275	$6,434	$5,916
10	(Lines 1+2+7)																			
11																				
12																				
13	Energy Related Marginal Cost																			
14																				
15	Total Energy Related	$852,261	$364,830	$39,097	$28,877	$75	$28,993	$45,131	$61,907	$1,187	$13,842	$72,383	$6,107	$39,917	$26,967	$3,647	$76,410	$25,787	$9,181	$7,923
16																				
17																				
18	Customer Related Marginal Cost																			
19																				
20	Commitment & Billing Rel.	$248,434	$175,876	$35,632	$9,116	$48	$4,978	$4,383	$3,597	$68	$508	$1,265	$84	$477	$161	$8	$97	$89	$8,523	$3,524
21																				
22																				
23	Total Revenue @ Full MC	$1,610,173	$792,916	$95,867	$56,730	$170	$51,041	$77,428	$100,808	$1,941	$22,088	$113,819	$9,558	$61,457	$40,458	$5,040	$106,200	$33,151	$24,138	$17,363

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs by Load Class
December 2010 Dollars
(Dollars in 000's)

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
		Total	(sec)	0-15 kW (sec)	15+ kW (sec)	(pri)	0-50 kW (sec)	51-100 kW (sec)	> 101kW (sec)	Primary (pri)	0-300 kW (sec)	301+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Peak MW @ Meter	System	886	79	72	0	71	116	145	3	31	163	14	90	60	7	156	46	21	18
	Demand Loss Factor		1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.0819	1.1131	1.0819	1.1131	1.0819	1.0498	1.1131	1.1131
2	Peak MW @ Generator	System	986	88	80	0	79	129	161	3	35	181	15	101	65	8	169	49	23	20
3																				
4	Energy																			
5	Energy - Annual Mwh @ Meter	12,517,399	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
6	Energy Loss Factor		1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0577	1.0918	1.0577	1.0918	1.0577	1.0361	1.0918	1.0918
7	Energy - Annual Mwh @ Generator	13,585,860	5,934,856	636,009	469,754	1,218	471,647	734,164	1,007,067	19,302	225,167	1,177,485	99,352	649,344	438,677	59,334	1,242,998	419,485	149,349	128,883
8																				
9	Customer																			
10	Average Customers	563,709	478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
11																			2,834	756
12	Unit Costs																			
13																				
14	Generation - $ / System Peak Kw		$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59	$74.59
15	Energy @ Generator $ / Kwh		$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799	$0.05799
16	Billing Related Costs		$155.50	$172.12	$318.63	$1,260.48	$352.95	372.79	$818.87	$1,287.36	$1,060.40	$1,060.59	$1,527.31	$2,845.45	$2,844.66	$2,845.45	$2,844.66	$44,514.88	$37.38	$45.05
17																			$86.85	$83.23
18	Marginal Costs $000																			
19																				
20	Total Demand Related	$160,314	$73,526	$6,531	$5,957	$15	$5,894	$9,655	$12,039	$238	$2,607	$13,534	$1,146	$7,510	$4,847	$572	$12,621	$3,620	$1,719	$1,484
21																				
22	Total Energy Related	$787,842	$344,162	$36,882	$27,241	$71	$27,351	$42,574	$58,400	$1,119	$13,057	$68,282	$5,761	$37,655	$25,439	$3,441	$72,081	$24,326	$8,661	$7,474
23																				
24	Billing Related Costs	$94,813	$74,403	$11,127	$2,986	$43	$1,585	$1,314	$1,666	$64	$244	$607	$79	$344	$159	$6	$97	$89	$475	$156
25																				
26	Total Revenue @ Full MC	$1,042,969	$492,091	$54,540	$36,184	$129	$34,830	$53,543	$72,105	$1,421	$15,908	$82,423	$6,986	$45,509	$30,445	$4,019	$84,799	$28,035	$10,855	$9,113

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs by Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(tm)	(sec)	(sec)
	Billing Units																			
	Energy																			
1	Energy - Annual Mwh @ Meter	12,772,237	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
2	Energy Loss Factor		1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0577	1.0918	1.0577	1.0918	1.0577	1.0361	1.0918	1.0918
3	Energy - Annual Mwh @ Generator	13,864,092	5,934,856	636,009	469,754	1,218	471,647	734,164	1,007,067	19,302	225,167	1,177,485	99,352	649,344	438,677	59,334	1,242,998	419,485	149,349	128,883
4																				
5	Customer																			
6	Average Customers	571,879	478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
7																			2,834	756
8	Unit Costs																			
9																				
10	Energy @ Generator $ / Kwh		$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189	$0.06189
11																				
12	Billing Related Costs		$155.50	$172.12	$318.63	1,260.48	$352.95	372.79	$818.87	$1,287.36	$1,060.40	$1,060.59	$1,527.31	$2,845.45	$2,844.66	$2,845.45	$2,844.66	$44,514.88	$37.38	$45.05
13																			$86.85	$83.23
14																				
15	Marginal Costs $000																			
16																				
17	Total Energy Related	$857,980	$367,279	$39,359	$29,071	$75	$29,188	$45,434	$62,322	$1,195	$13,934	$72,869	$6,148	$40,185	$27,148	$3,672	$76,923	$25,960	$9,242	$7,976
18																				
19	Billing Related Costs	$95,443	$74,403	$11,127	$2,986	$43	$1,585	$1,314	$1,666	$64	$244	$607	$79	$344	$159	$6	$97	$89	$475	$156
20																				
21																				
22	Total Revenue @ Full MC	$953,423	$441,682	$50,486	$32,057	$118	$30,773	$46,748	$63,988	$1,259	$14,178	$73,476	$6,227	$40,529	$27,307	$3,678	$77,020	$26,049	$9,717	$8,132

* Schedule 33 Cost of Service results are provided for informational purposes only.

Exhibit PPL/919

2. Street Lighting

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Commitment & Billing Related Cost per Customer

Line	Description	Schedule 51 Wood Pole Installations Company Owned										Schedule 53 Customer Owned	Schedule 54 Customer Owned
		70 Watt HPSV	100 Watt HPSV	150 Watt HPSV	200 Watt HPSV	250 Watt HPSV	400 Watt HPSV	100 Watt MH	175 Watt MH	250 Watt MH	400 Watt MH		
1	Light Installation Cost - per lamp	$149.88	$145.53	$152.36	$164.00	$160.64	$219.32	$197.25	$205.61	$212.51	$223.28	N. A.	N. A.
2													
3	Distribution Commitment Costs - per customer												
4	Acct. 364 Poles	$82.92	82.92	82.92	82.92	82.92	82.92	82.92	82.92	82.92	82.92	$82.92	$82.92
5	Acct. 365 Conductors	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21
6	Acct. 368 Transformers	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	162.33	364.38
7	Dist O&M at 36.1% of Total Investment	$41.95	$41.95	$41.95	$41.95	$41.95	$41.95	$41.95	$41.95	$41.95	$41.95	$100.58	$173.56
8	Acct. 370 Meters												$12.87
9	Meters at 42.69% of Total Investment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$5.49
10	Total Commitment Related	$158.08	$158.08	$158.08	$158.08	$158.08	$158.08	$158.08	$158.08	$158.08	$158.08	$379.04	$672.43
11													
12	Billing Costs per Customer	$41.16	$41.16	$41.16	$41.16	$41.16	$41.16	$41.16	$41.16	$41.16	$41.16	$41.16	$58.52
13													
14	Total Marginal Commitment & Billing Cost per Cust.	$199.24	$199.24	$199.24	$199.24	$199.24	$199.24	$199.24	$199.24	$199.24	$199.24	$420.20	$730.96

Sources:
Line 1 "Distribution Cost Development For Street Lighting"
Line 4 `Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 5 `Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 6 `Transformer Commitment Costs By Customer Load Class'
Line 7 Sum of lines 4 to 6 multiplied by
Distribution O&M Expense Loading Factor as a Percent of Dist. Plant'
Line 14 Sum of Commitment & Billing Costs per Customer

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Full Marginal Cost by Schedule

Line	Description	Units	Schedule 51 – High Pressure Sodium Vapor: 5,800 Lumen 70 Watt *No New Service*	HPS: 9,500 Lumen 100 Watt	HPS: 16,000 Lumen 150 Watt	HPS: 22,000 Lumen 200 Watt *No New Service*	HPS: 27,500 Lumen 250 Watt	HPS: 50,000 Lumen 400 Watt	Schedule 51 – Metal Halide: 9,000 Lumen 100 Watt	MH: 12,000 Lumen 175 Watt	MH: 19,500 Lumen 250 Watt	MH: 32,000 Lumen 400 Watt	Schedule 53 Customer Owned	Schedule 54 Customer Owned	Total Streetlighting
	Energy														
1	Generation Energy $/kWh @ Generator	$/kWh	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	$0.05571	
2	Transmission Energy $/kWh @ Generator	$/kWh	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	$0.00381	
3															
4	Energy @ Meter 2008	kWh	1,753,087	6,557,611	31,849	5,887,146	56,756	2,328,125	0	0	718	0	9,277,495	1,004,784	
5	Energy @ Meter 2010		1,697,104	6,348,198	30,832	5,699,146	54,944	2,253,778	0	0	695	0	9,316,113	815,719	
6	Losses		1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	
7	Energy @ Generator - (5)*(6)	kWh	1,852,898	6,930,963	33,662	6,222,328	59,988	2,460,675	0	0	759	0	10,171,332	890,602	28,623,206
8															
9	Generation Energy Related Marginal Costs - (1)*(7)	$	$103,225	$386,124	$1,875	$346,646	$3,342	$137,084	$0	$0	$42	$0	$566,645	$49,615	$1,594,599
10	Transmission Energy Related Marginal Costs - (2)*(7)	$	$7,064	$26,423	$128	$23,722	$229	$9,381	$0	$0	$3	$0	$38,777	$3,395	$109,122
11															
12	Commitment														
13	Total of Monthly Lamp Billing Units 2008	#	56,551	149,058	498	69,268	494	13,228	-	-	8	-			
14	Number of Lamps 2008 - (13) / 12	#	4,713	12,422	42	5,772	41	1,102	-	-	1	-			
15	Escalation factor		0.968	0.968	0.968	0.968	0.968	0.968	0.968	0.968	0.968	0.968			
16	Number of Lamps 2010		4,562	12,025	40	5,588	40	1,067	-	-	1	-			
17	Light Installation Cost	$/Lamp	$149.88	$145.53	$152.36	$164.00	$160.64	$219.32	$197.25	$205.61	$212.51	$223.28			
18	Light Installation Related		$683,749	$1,749,974	$6,121	$916,452	$6,402	$234,040	$0	$0	$137	$0			$3,596,876
19															
20	Average customers - 2010	#	117	292	13	185	13	65	-	-	1	-	250	105	1,041
21															
22															
23	Acct. 364 Poles		$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	$82.92	
24	Acct. 365 Conductors		$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	$33.21	
25	Acct. 368 Transformers		N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	N. A.	$162.33	$364.38	
26	Acct. 370 Meters													$12.87	
27															
28	Acct. 364 Poles with O&M		$13,206	$32,958	$1,467	$20,881	$1,467	$7,337	$0	$0	$113	$0	$28,218	$11,851	$117,498
29	Acct. 365 Conductors with O&M		$5,289	$13,200	$588	$8,363	$588	$2,938	$0	$0	$45	$0	$11,301	$4,747	$47,059
30	Acct. 368 Transformers with O&M		N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	$55,240	$52,079	$107,320
31	Acct. 370 Meter with O&M		N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	$1,928	$1,928
32	Total Poles, Conductors, Transfomers		$18,495	$46,158	$2,055	$29,244	$2,055	$10,275	$0	$0	$158	$0	$94,760	$70,605	$273,805
33															
34	Total Commitment Marginal Cost		$702,244	$1,796,133	$8,176	$945,696	$8,457	$244,315	$0	$0	$295	$0	$94,760	$70,605	$3,870,681
35															
36	Billing / Customer														
37	Billing Related	$/Customer	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	$29.69	
38	Meter Reading	$/Customer	-	-	-	-	-	-	-	-	-	-	-	$17.36	
39	Customer Other	$/Customer	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	$11.47	
40															
41	Billing Related	$	3,474	8,671	386	5,493	386	1,930	-	-	30	-	7,423	3,118	$30,911
42	Meter Reading	$	-	-	-	-	-	-	-	-	-	-	-	1,823	$1,823
43	Customer Other	$	1,342	3,350	149	2,122	149	746	-	-	11	-	2,868	1,204	$11,941
44	Total Billing Related Marginal Cost		$4,816	$12,020	$535	$7,616	$535	$2,676	$0	$0	$41	$0	$10,291	$6,145	$44,675
45															
46	Total Marginal Cost		$817,349	$2,220,700	$10,715	$1,323,680	$12,563	$393,456	$0	$0	$382	$0	$710,473	$129,761	$5,619,078
															$3,915,356

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$978,338	$566,645	$49,615	$1,594,599
Transmission	$66,950	$38,777	$3,395	$109,122
Distribution	$3,705,316	$94,760	$70,605	$3,870,681
Customer - Billing	$20,370	7,423	3,118	$30,911
Customer - Metering	-		1,823	$1,823
Customer - Other	7,869	2,868	1,204	$11,941
	$4,778,844	$710,473	$129,761	$5,619,078

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$978.34	$566.64	$49.62	$1,594.60
Transmission	$66.95	$38.78	$3.40	$109.12
Distribution	$3,705.32	$94.76	$70.61	$3,870.68
Customer - Billing	$20.37	$7.42	$3.12	$30.91
Customer - Metering	$0.00	$0.00	$1.82	$1.82
Customer - Other	$7.87	$2.87	$1.20	$11.94

PacifiCorp
Oregon Marginal Cost Study
Distribution Cost Development
For Street Lighting Service
Fully-Loaded Overheads
Wood Pole Installations
Schedule 51

Line No.	Description		High Pressure Sodium Vapor						Metal Halide			
			5,800 Lumen 70 Watt *No New Service **	9,500 Lumen 100 Watt	16,000 Lumen 150 Watt	22,000 Lumen 200 Watt *No New Service **	27,500 Lumen 250 Watt	50,000 Lumen 400 Watt	9,000 Lumen 100 Watt	12,000 Lumen 175 Watt	19,500 Lumen 250 Watt	32,000 Lumen 400 Watt
	Installed Costs											
1	Cost per unit including pole, luminaire, p.e.	2008 $ *	763.17	765.17	$818.60	848.60	$867.60	1,309.50	$938.67	$897.17	$943.60	$1,290.50
2	Index		1.0592	1.0005	1.0005	1.0592	1.0005	1.0005	1.0005	1.0005	1.0005	1.0005
3	Control, mast arm and wiring	2010 $	808.38	765.56	819.02	898.88	868.04	1,310.17	939.15	897.62	944.08	1,291.16
4	Transformer Cost	2008 $	4.95	6.98	10.20	14.20	18.20	27.92	6.98	$ 12.41	$ 18.20	27.92
5	Index		0.9134	0.9134	0.9134	0.9134	0.9134	0.9134	0.9134	0.9134	0.9134	0.9134
6	Revised Transformer Cost	2010 $	4.52	6.38	9.32	12.97	16.62	25.50	6.38	11.33	16.62	25.50
7	Total Installed Cost		812.91	771.93	828.34	911.85	884.66	1,335.67	945.52	908.96	960.70	1,316.66
8												
9												
10	Annual Cost @	10.77%	$87.55	$83.14	$89.21	$98.21	$95.28	$143.85	$101.83	$97.89	$103.47	$141.80
11												
12	*Operation & Maintenance*											
13	Annual Main. Per Unit		$62.33	$62.39	$63.15	$65.80	$65.36	$75.47	$95.42	$107.71	$109.04	$81.47
14												
15	TOTAL COST PER UNIT		$149.88	$145.53	$152.36	$164.00	$160.64	$219.32	$197.25	$205.61	$212.51	$223.28
16												
17	Total Number of Units		56,551	149,058	498	69,268	494	13,228	-	-	1.0000	-
18												
19	Annual Maintenance Per Unit											
20	Percentage of Installed Cost		7.71%	8.15%	7.71%	7.32%	7.53%	5.76%	10.16%	12.00%	11.55%	6.31%
21	Installed Cost		808.38	765.56	819.02	898.88	868.04	1,310.17	939.15	897.62	944.08	1,291.16
22	Annual Maintenance Per Unit		$62.33	$62.39	$63.15	$65.80	$65.36	$75.47	$95.42	$107.71	$109.04	$81.47
23												
24	Installed Cost											
25	Without Pole (Functional)		$688.00	$690.00	$697.00	$727.00	$746.00	$861.00	N/A	$822.00	$822.00	$842.00
26	Units (Functional)		4,713	12,420	42	5,772	41	1,102	N/A	-	1	-
27	Without Pole (Decorative Series 1)		N/A	$1,386.00	$1,071.00	N/A	N/A	N/A	$862.00	$1,054.00	N/A	N/A
28	Units (Decorative Series 1)		N/A	-	-	N/A	N/A	N/A	-	-	N/A	N/A
29	Without Pole (Decorative Series 2)		N/A	$865.00	$874.00	N/A	N/A	N/A	$865.00	$851.00	N/A	N/A
30	Units (Decorative Series 2)		N/A	-	-	N/A	N/A	N/A	-	-	N/A	N/A
31	Without Pole (Weighted)		$688.00	$690.00	$697.00	$727.00	$746.00	$861.00	$ 863.50	$822.00	$822.00	$842.00
32	Wood Pole Cost		$451.00	$451.00	$608.00	$608.00	$608.00	$897.00	$451.00	$451.00	$608.00	$897.00
33	Percent of Wood Pole Utilized		16.67%	16.67%	20.00%	20.00%	20.00%	50.00%	16.67%	16.67%	20.00%	50.00%
34	Adjusted Wood Pole Cost		$75.17	$75.17	$121.60	$121.60	$121.60	$448.50	$75.17	$75.17	$121.60	$448.50
35	Installed Cost for Analysis		$763.17	$765.17	$818.60	$848.60	$867.60	$1,309.50	$938.67	$897.17	$943.60	$1,290.50
36												
37	Assumptions:											
38	70 Watt It is assumed, one new wood pole is to be installed per six new lights, therefore, 1/6 X unit cost of wood pole will be utilized here as a component.											
39	100 Watt It is assumed, one new wood pole is to be installed per six new lights, therefore, 1/6 X unit cost of wood pole will be utilized here as a component.											
40	200 Watt It is assumed, one new wood pole is to be installed per five new lights, therefore, 1/5 X unit cost of wood pole will be utilized here as a component.											
41	400 Watt It is assumed, one new wood pole is to be installed per two new lights, therefore, 1/2 X unit cost of wood pole will be utilized here as a component.											
42												
43												
44	* Cost per unit including pole, luminaire, e.g. for the 5,800 Lumen and 22,000 Lumen High Pressure Sodium Vapor lamps are in 2005 dollars ($).											

Streetlight 4

PacifiCorp
Oregon Marginal Cost Study
Cost of Streetlighting Transformer

Transformer Cost Per Light - 70 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	83 watts	
+ Ballast (Encasement) Loss	3.0%	2.49	
+ Circuit Loss	5.0%	4.15	
		89.64	
Transformer Cost = Total Watts/25,000 X Installed Cost			
89,6/25000 X $1381 =			$ 4.95

Transformer Cost Per Light - 200 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	238 watts	
+ Ballast (Encasement) Loss	3.0%	7.14	
+ Circuit Loss	5.0%	11.9	
		257.04	
Transformer Cost = Total Watts/25,000 X Installed Cost			
246.24/25000 X $138 =			$ 14.20

Transformer Cost Per Light - 100 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	117 watts	
+ Ballast (Encasement) Loss	3.0%	3.51	
+ Circuit Loss	5.0%	5.85	
		126.36	
Transformer Cost = Total Watts/25,000 X Installed Cost			
126.36/25000 X $13: =			$ 6.98

Transformer Cost Per Light - 400 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	468 watts	
+ Ballast (Encasement) Loss	3.0%	14.04	
+ Circuit Loss	5.0%	23.4	
		505.44	
Transformer Cost = Total Watts/25,000 X Installed Cost			
508.68/25000 X $138 =			$ 27.92

Source:
Study by Tom Yousko 11/96
Transformer Regression

Transformer Cost Per Light - 150 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	171 watts	
+ Ballast (Encasement) Loss	3.0%	5.13	
+ Circuit Loss	5.0%	8.55	
		184.68	
Transformer Cost = Total Watts/25,000 X Installed Cost			
246.24/25000 X $13: =			$ 10.20

Transformer Cost Per Light - 175 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	208 watts	
+ Ballast (Encasement) Loss	3.0%	6.24	
+ Circuit Loss	5.0%	10.4	
		224.64	
Transformer Cost = Total Watts/25,000 X Installed Cost			
246.24/25000 X $138 =			$ 12.41

Transformer Cost Per Light - 250 Watt

Assume Installed Cost 25 KVA Transformer is			$ 1,381
Lamp Line Watts	=	305 watts	
+ Ballast (Encasement) Loss	3.0%	9.15	
+ Circuit Loss	5.0%	15.25	
		329.4	
Transformer Cost = Total Watts/25,000 X Installed Cost			
508.68/25000 X $13: =			$ 18.20

Exhibit PPL/919

3. Generation Capacity

Capacity

PacifiCorp
Oregon Marginal Cost Study
Marginal Capacity Costs
Based on Avoided Capacity Costs

Calendar Year (12 Mo Ended Dec)	(A) Projected Capacity $/kW	(B) Present Value Factors @ 8.53%	(C) PV of Capacity $/kW (A) x (B)	(D) Capacity Mills/kWh (A) / 0.487 / 8760	(E) PV of Capacity Mills/kWh (B) * (D)
2010	$74.50	1.0000	74.50	17.46	17.46
2011	$76.06	0.9214	70.08	17.83	16.43
2012	$77.59	0.8490	65.87	18.19	15.44
2013	$79.05	0.7823	61.84	18.53	14.50
2014	$80.55	0.7208	58.06	18.88	13.61
2015	$82.08	0.6642	54.52	19.24	12.78
2016	$83.64	0.6120	51.19	19.61	12.00
2017	$85.23	0.5639	48.06	19.98	11.27
2018	$86.86	0.5196	45.13	20.36	10.58
2019	$88.50	0.4788	42.37	20.74	9.93
2020	$90.18	0.4412	39.79	21.14	9.33
2021	$91.89	0.4065	37.35	21.54	8.76
2022	$93.65	0.3746	35.08	21.95	8.22
2023	$95.42	0.3452	32.94	22.37	7.72
2024	$97.23	0.3181	30.93	22.79	7.25
2025	$99.08	0.2931	29.04	23.22	6.81
2026	$100.97	0.2701	27.27	23.67	6.39
2027	$102.88	0.2489	25.61	24.12	6.00
2028	$104.84	0.2293	24.04	24.58	5.64
2029	$106.83	0.2113	22.57	25.04	5.29

			$/kW	mills / kWh
2010	1 Year -	Sum of PV Costs @ 8.53%	74.50	17.46
2010 - 2014	5 Year -	Short Run -		
		Sum of PV Costs @ 8.53%	$330.35	$77.44
		Annual Cost of Capacity @ 22.58%	74.59	17.49
2010 - 2019	10 Years -	Medium Run -		
		Sum of PV Costs @ 8.53%	$571.62	134.00
		Annual Cost of Capacity @ 13.04%	74.54	17.47
2010 - 2029	20 Years -	Long Run -		
		Sum of PV Costs @ 8.53%	$876.24	205.41
		Annual Cost of Capacity @ 8.50%	74.48	17.46

Footnote: Source: Ore Commission Approved - AC Study (2007 08 13).xls
Column A: Total Cost of Simple Cycle: Table 8, Page 1, column (f)

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Calendar Year (12 Mo Ended Dec)	SCCT Fixed Costs ($/kW-yr) (1)	SCCT Fixed Costs ($/kW-mo) (2)	CCCT Fixed Costs ($/kW-yr) (3)	CCCT Fixed Costs ($/kW-mo) (4)	Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	Capitalized Energy Cost 48.7% CF ($/MWh) (6)	Purchase Cost ($/MWh) (7)	Updated Gas Price ($/MMBtu) (8)	CCCT Energy Costs 7270 Btu/kWh ($/MWh) (9)	Variable Avoided Energy Cost ($/MWh) (7) + (9) =(10)	Capitalized Energy Cost 48.7% CF ($/MWh) (6)=(11)	Total Avoided Energy Cost ($/MWh) (10) + (11) =(12)	Present Value Factors (13) @ 8.53%	Present Value of Energy (14) (12)*(13)
2010	74.50	6.21	90.39	7.53	1.32	3.72	0.00	8.00	58.16	58.16	3.72	61.88	1.0000	61.89
2011	76.06	6.34	92.27	7.69	1.35	3.80	0.00	7.78	56.56	56.56	3.80	60.36	0.9214	55.62
2012	77.59	6.47	94.12	7.84	1.38	3.87	0.00	7.53	54.74	54.74	3.87	58.62	0.8490	49.77
2013	79.05	6.59	95.92	7.99	1.41	3.95	0.00	7.52	54.67	54.67	3.95	58.62	0.7823	45.86
2014	80.55	6.71	97.74	8.15	1.43	4.03	0.00	7.78	56.56	56.56	4.03	60.59	0.7208	43.67
2015	82.08	6.84	99.60	8.30	1.46	4.11	0.00	8.13	59.11	59.11	4.11	63.21	0.6642	41.99
2016	83.64	6.97	101.49	8.46	1.49	4.18	0.00	8.28	60.20	60.20	4.18	64.38	0.6120	39.40
2017	85.23	7.10	103.42	8.62	1.52	4.26	0.00	8.42	61.21	61.21	4.26	65.48	0.5639	36.92
2018	86.86	7.24	105.38	8.78	1.54	4.34	0.00	8.56	62.23	62.23	4.34	66.57	0.5196	34.59
2019	88.50	7.38	107.38	8.95	1.57	4.43	0.00	8.72	63.39	63.39	4.43	67.82	0.4788	32.47
2020	90.18	7.52	109.42	9.12	1.60	4.51	0.00	8.89	64.63	64.63	4.51	69.14	0.4412	30.51
2021	91.89	7.66	111.50	9.29	1.63	4.60	0.00	8.80	63.98	63.98	4.60	68.57	0.4065	27.88
2022	93.65	7.80	113.62	9.47	1.66	4.68	0.00	8.75	63.61	63.61	4.68	68.29	0.3746	25.58
2023	95.42	7.95	115.78	9.65	1.70	4.77	0.00	8.73	63.47	63.47	4.77	68.24	0.3452	23.56
2024	97.23	8.10	117.98	9.83	1.73	4.86	0.00	8.63	62.74	62.74	4.86	67.60	0.3181	21.51
2025	99.08	8.26	120.22	10.02	1.76	4.96	0.00	8.56	62.23	62.23	4.96	67.19	0.2931	19.69
2026	100.97	8.41	122.51	10.21	1.80	5.05	0.00	8.48	61.65	61.65	5.05	66.70	0.2701	18.02
2027	102.88	8.57	124.84	10.40	1.83	5.15	0.00	8.50	61.80	61.80	5.15	66.94	0.2489	16.66
2028	104.84	8.74	127.20	10.60	1.86	5.24	0.00	8.57	62.30	62.30	5.24	67.55	0.2293	15.49
2029	106.83	8.90	129.62	10.80	1.90	5.34	0.00	8.60	62.52	62.52	5.34	67.86	0.2113	14.34

				Mills / kWh
2010	1 Year -	Sum of PV Costs		61.89
2010 - 2014	5 Year -	Short Run -		
		Sum of PV Costs	@ 8.53% =	256.80
		Annual Cost of Energy	@ 22.58% =	57.99
2010 - 2019	10 Years -	Medium Run -		
		Sum of PV Costs	@ 8.53% =	442.17
		Annual Cost of Energy	@ 13.04% =	57.66
2010 - 2029	20 Years -	Long Run -		
		Sum of PV Costs	@ 8.53% =	655.40
		Annual Cost of Energy	@ 8.50% =	55.71

Footnote:
Source: Ore Commission Approved - AC Study (2007 08 13).xls
Column A: Total Cost of Simple Cycle: Table 8, Page 1, column (f)
Column C: Total Cost of Combined Cycle: Table 8, Page 2, column (f)
Column H: Gas Price: Table 9, Column (d)
Column I: Heat Rate: for CCCT: Table 8, Page 3

Avoided Costs

	PacifiCorp Marginal Generation Costs Filed					
	12 Months Ended December			12 Months Ended December		
Calendar Year	Avoided Simple Cycle CT Fixed Costs ($/kW-yr)	Avoided Combined Cycle CT Fixed Costs ($/kW-yr)	Gas Price ($/MMBtu)	Avoided Firm Capacity Costs ($/kW-yr)	Combined Cycle CT Fixed Cost ($/kW-yr)	Gas Price ($/MMBtu)
2010	74.50	90.39	8.00	74.50	90.39	8.00
2011	76.06	92.27	7.78	76.06	92.27	7.78
2012	77.59	94.12	7.53	77.59	94.12	7.53
2013	79.05	95.92	7.52	79.05	95.92	7.52
2014	80.55	97.74	7.78	80.55	97.74	7.78
2015	82.08	99.60	8.13	82.08	99.60	8.13
2016	83.64	101.49	8.28	83.64	101.49	8.28
2017	85.23	103.42	8.42	85.23	103.42	8.42
2018	86.86	105.38	8.56	86.86	105.38	8.56
2019	88.50	107.38	8.72	88.50	107.38	8.72
2020	90.18	109.42	8.89	90.18	109.42	8.89
2021	91.89	111.50	8.80	91.89	111.50	8.80
2022	93.65	113.62	8.75	93.65	113.62	8.75
2023	95.42	115.78	8.73	95.42	115.78	8.73
2024	97.23	117.98	8.63	97.23	117.98	8.63
2025	99.08	120.22	8.56	99.08	120.22	8.56
2026	100.97	122.51	8.48	100.97	122.51	8.48
2027	102.88	124.84	8.50	102.88	124.84	8.50
2028	104.84	127.20	8.57	104.84	127.20	8.57
2029	106.83	129.62	8.60	106.83	129.62	8.60

Source: Ore Commission Approved - AC Study (2007 08 13).xls
Total Cost of Simple Cycle: Table 8, Page 1, column (f)
Total Cost of Combined Cycle: Table 8, Page 2, column (f)
Gas Price: Table 9, Column (b)

(Fiscal Year):
(Previous Year * 75%)+(Current Year * 25%)

(Calendar Year):
(Previous Year * 0%)+(Current Year * 100%)

Previous Yr = 0%
Current Yr = 100%

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
December 2010 Dollars

Line	Item		(A) Total	(B) Demand Related	(C) Energy Related	
			(B) + (C)			
1	2010 Forecasted		222,610	189,195	33,415	
2	2011 Forecasted		245,958	190,266	55,692	
3	2012 Forecasted		152,842	100,863	51,979	
4	2013 Forecasted		96,192	62,034	34,158	
5	2014 Forecasted		85,006	50,848	34,158	
6						
7	Growth Related Investments - (2010 to 2014 in $000's)		$802,608	$593,206	$209,402	
8						
9	System Growth mW's from 2010-2014		913	913	913	mW
10						
11	Marginal Investment	(7) / (9)	$879.09	$649.73	$229.36	/kW
12						
13	Annualized Investment	(11) x 8.68%	$76.31	$56.40	$19.91	/kW
14	Admin. & General Factor	(11) x 1.71%	$15.03	$11.11	$3.92	/kW
15	Annual O&M Expenses	(11) x 1.205%	$10.59	$7.83	$2.76	/kW
16						
17	Annualized Marginal Cost	Sum (13) to (15)	$101.93	$75.34	$26.59	/kW
18						
19	Marginal Cost of Energy-Related Transmission				$0.00381	/kWh
20	$26.59 / 8760 hours / 79.62% Load Factor))					

Footnote:

Lines 1-7	Tab 6.2 (Transm2:) `2010-2014 Forecasted Transmission'	
Line 9	Peak Load Forecast Detail, Dec. 16, 2008 - Forecasting Dept.	
Line 13	Tab 15.1 (Charge 1:) `Calculation of Annual Charges'	(for 8.68% factor)
Line 14	Tab 15.1 (Charge 1:) `Calculation of Annual Charges'	(for 1.71% factor)
Line 15	Tab 6.3 (Tran_OM:) `Transmission O & M Expenses'	(for 1.205% factor)
Line 20	See Tab "TransLF"	

PacifiCorp
Oregon Marginal Cost Study
2010-2014 Forecasted Transmission
December 2010 Dollars(in 000's)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Forecast			Total
Line	Description	2010	2011	2012	2013	2014	
1	Bulk Power Lines (grid)	45,000	75,000	70,000	46,000	46,000	
2	price adjustment factor	0.975	0.975	0.975	0.975	0.975	
3	Adjusted Bulk Power Lines (grid)	43,886	73,144	68,268	44,862	44,862	275,021
4							
5	Growth Related Major Projects (local)	183,260	177,200	86,720	52,633	41,163	
6	price adjustment factor	0.975	0.975	0.975	0.975	0.975	
7	Adjusted Growth Related Major Projects (local)	178,724	172,814	84,574	51,330	40,144	527,587
8							
9	Bulk Power Lines - Demand Related	10,471	17,452	16,289	10,704	10,704	
10	Line (3) x Demand Factor 23.86%						
11							
12	Bulk Power Lines - Energy Related	33,415	55,692	51,979	34,158	34,158	209,401
13	Line (3) - Line (9)						
14							
15	Total Growth Demand Related	189,195	190,266	100,863	62,034	50,848	593,207
16	Line (7) + Line (9)						
17							
18	$ Demand Related	$189,195	$190,266	$100,863	$62,034	$50,848	$593,206
19	$ Energy Related	$33,415	$55,692	$51,979	$34,158	$34,158	$209,402
20							
21	Total Marginal Transmission Investment	$222,610	$245,958	$152,842	$96,192	$85,006	$802,608

Footnotes:

Line 1 & 5 Bulk power line & growth related projects data provided in 2007 dollars; no price adjustment required.
Line 10 Demand Portion of Transmission = 17.46 / (17.46+55.71) = $\boxed{23.86\%}$

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Line	Description	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	
1	Transmission O&M Exp.	97,034	83,874	103,968	123,213	102,419	105,962	105,324	115,283	136,930	154,195	
2	Wheeling	74,244	71,336	78,405	94,737	76,949	77,497	76,944	83,360	94,111	106,592	
3	Net Transmission O&M Line (1) - (2)	22,789	12,538	25,563	28,476	25,469	28,465	28,379	31,922	42,820	47,603	
4	Transmission Plant	2,102,335	2,135,940	2,172,469	2,232,246	2,299,173	2,396,665	2,487,677	2,578,317	2,688,839	2,874,659	
5	Tran. O&M Loading Line (3) / (4)	1.084%	0.587%	1.177%	1.276%	1.108%	1.188%	1.141%	1.238%	1.593%	1.656%	1.205%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(3) page 321, line 96

Exhibit PPL/919
6. Dist. Substation

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
December 2010 Dollars

Line		
1	Incremental Substation Cost - $ / kW	$159.23
2		
3	Annual Distribution Carrying Charge	10.77%
4		
5	Substation Marginal Cost - $ / kW	$17.15 / kW

Dist Sub 2

PacifiCorp
Marginal Cost Study
Substation Investment

In Service Year	Substation Capacity Project	State	Capacity Increase (MVA)	Installed Cost (Dollars in 000's)	Cost Per MVA (Dollars in 000's)
2008	Umapine Sub: Increase Capacity	WA	7.5	$710	$95
2008	Yew Ave 115-12.5 kV sub and tap line	OR	25.0	$9,211	$368
2008	Hopland Substation - Increase Capacity	WA	15.6	$2,200	$141
2008	Lucern Sub - Convert Sub to 115 kV	CA	5.0	$800	$160
2008	Weed Substation - Convert to 115 kV and Incre	CA	12.5	$3,800	$304
2009	Texum Sub - Rebuild Sub & Increase Capacity	OR	8.0	$3,800	$475
2009	West Grants Pass Area Sub (South River)	OR	25.0	$6,076	$243
2010	Stevens Road Sub - Install 2nd Transformer	OR	25.0	$2,250	$90
2010	River Road Substation - Increase Capacity (25	WA	25.0	$2,000	$80
2010	China Hat Substation - Increase Capacity (25 M	OR	25.0	$2,100	$84
2011	Independence Sub - Install 2nd Transformer	OR	25.0	$2,500	$100
2011	Vine Street & Oremet Overload Relief Project -	OR	25.0	$4,000	$160
2011	Barnes Butte Substation	OR	25.0	$5,500	$220
2012	Griffin Creek Sub: Increase Capacity	OR	25.0	$2,800	$112
2012	Takelma Sub - Capacity Solution	OR	13.0	$1,500	$115
2012	Shevlin Park Sub: Increase Capacity	OR	25.0	$2,300	$92
2008	Ammon Sub - Increase capacity; Replace transf	ID	3.5	$322	$92
2008	Burton Sub - Increase capacity	UT	4.3	$355	$83
2008	Clifton Sub - Increase Capacity	ID	5.8	$355	$61
2008	Commerce Sub - New 138kV Sub	UT	30	$5,749	$192
2008	Cozydale Sub - Build New 138-12 5kV Sub	UT	30.0	$4,859	$162
2008	Garden City Sub - Increase Capacity	UT	3.8	$355	$95
2008	Grantsville Sub - Cap Incr 46-12.5kV - 25MVA	UT	8.4	$1,591	$189
2008	Henefer Sub - Increase Capacity	UT	3.6	$355	$99
2008	Riverston Sub - Capacity Increase 25MVA	WY	25.0	$2,427	$97
2009	Central Sub - 46-12 5kV Increase Capacity	UT	12	$425	$35
2009	Copper Hills Sub - New 138-12 5kV Sub	UT	30	$5,439	$181
2009	Decade Sub - 1 & 2 New 138 12 5kV 60MVA Su	UT	60.0	$7,670	$128
2009	East Layton Sub - Install 2nd 30MVA Trnsmr-Di	UT	30	$4,547	$152
2009	Granger - 1 Incr Cap of 46-12 5kV & Dist Feede	UT	14.0	$1,660	$119
2009	Morton Court - Instl 2nd 138-12 5kV Trnsfm	UT	30	$5,342	$178
2009	Oqurrh - Increase capacity	UT	700.0	$51,500	$74
2009	Pine Canyon - Install 2nd 138-12.5 kV XFMR	UT	30	$4,873	$162
2009	Shoreline - New 138-12.5kV Sub	UT	60.0	$9,266	$154
2009	Spanish Valley - 69-12.5kV Incr Capacity	UT	9.0	$424	$47
2009	Summit Creek - Increase Capacity	UT	16.0	$1,238	$77
2009	Three Peaks - 345kV Source Cedar City	UT	450.0	$44,376	$99
2009	Chimney Butte 230-69kV	WY	75	$25,000	$333
2009	White Rock - New 138-12.5kV Sub	UT	16.0	$4,712	$295
2010	90th South - Inst 2nd 138-12.5 kV XFMR	UT	30	$4,601	$153
2010	Eden Sub - Increase Capacity	UT	10	$1,185	$119
2010	Farmington - Install 2nd Xfmr	UT	30	$4,580	$153
2010	Juab - 46/12.5 kV Increase Capacity	UT	8.5	$924	$109
2010	Moab - Increase Capacity	UT	9.0	$1,520	$169
2010	Rainbow - Increase Capacity 12.5MVA	WY	12.5	$2,887	$231
2010	Saratoga - Add 2nd Trnsf Rebld Tran Jumber	UT	30.0	$6,115	$204
2010	Silver Creek - Install 2nd 138-12.5, 30 MVA Xfm	UT	30	$4,334	$144
2010	Sky Park - 138-12.5kv 30MVA substation	UT	30	$5,166	$172
2010	Summit Park - Increase Capacity	UT	23.0	$3,000	$130
2010	Vickers - 46/12.5 kV Increase Capacity	UT	8.0	$1,541	$193
2011	American Fork - 2nd 138-12.5 kV 30 MVA xfmr	UT	30	$4,539	$151
2011	Brian Head - Convert to 69kV	UT	14.0	$2,054	$147
2011	Downey - Increase Capacity	ID	5.0	$616	$123
2011	Malad - Increase Capacity	ID	16.0	$3,081	$193
2011	Pleasant View - Increase capacity	UT	10.0	$2,054	$205
2011	Preston - Increase capacity	ID	10	$1,027	$103
2011	Richfield #2 - 46-12.5 kV Increase Capacity	UT	13.0	$2,157	$166
2011	Saddleback - New 138-12.5 kV Sub & Transmis	UT	30	$7,000	$233
2011	Sugarmill - Add 161/12.5, 30 MVA Xfmr	ID	30	$5,186	$173
2011	Wolf Creek - 138-12.5kV	UT	30.0	$4,000	$133
2012	Fiddlers Canyon - New 138-12.5 kV Sub Site	UT	30	$5,063	$169
			1873.5	**$307,017**	

Incremental Substation Cost		
	Pacific $'s	$51,547
	Plateau $'s	$255,470
2007 Actual		$307,017
Incremental Substation Cost		**Indexed to 2010**
	Pacific $'s	$51,054
	Plateau $'s	$247,255
	Total $'s	$298,309

2007 Incremental Substation Cost $/kVa $ 159.23

INDEX	**2008**	**2010**	**Escalation Factor**
Pacific	595.6	589.9	0.9904
Plateau	531.8	514.7	0.9678

Exhibit PPL/919

7. Dist. Poles & Conductor

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Feeder Study Results
Annual Demand and Commitment Costs
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand				Commitment			
			Investment $/kW		Annual $/kW		Investment $/Customer		Annual $/Customer	
Line	Load Class		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 10.77%	(B) x 10.77%			(E) x 10.77%	(F) x 10.77%
1	Res - Schedule 4	(sec)	$155.21	$253.21	$16.72	$27.27	$671.95	$269.13	$72.37	$28.99
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$167.63	$270.38	$18.05	$29.12	$769.89	$308.35	$82.92	$33.21
5	15+ kW	(sec)	$167.63	$270.38	$18.05	$29.12	$769.89	$308.35	$82.92	$33.21
6	Primary	(pri)	$167.63	$270.38	$18.05	$29.12	$769.89	$308.35	$82.92	$33.21
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$107.90	$189.90	$11.62	$20.45	$329.52	$131.98	$35.49	$14.21
10	51-100 kW	(sec)	$107.90	$189.90	$11.62	$20.45	$329.52	$131.98	$35.49	$14.21
11	> 101kW	(sec)	$107.90	$189.90	$11.62	$20.45	$329.52	$131.98	$35.49	$14.21
12	Primary	(pri)	$107.90	$189.90	$11.62	$20.45	$329.52	$131.98	$35.49	$14.21
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$114.75	$199.66	$12.36	$21.50	$387.93	$155.37	$41.78	$16.73
16	301+ kW	(sec)	$114.75	$199.66	$12.36	$21.50	$387.93	$155.37	$41.78	$16.73
17	Primary	(pri)	$114.75	$199.66	$12.36	$21.50	$387.93	$155.37	$41.78	$16.73
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$78.39	$150.33	$8.44	$16.19	$114.88	$46.01	$12.37	$4.96
21	1 - 4 MW	(pri)	$78.39	$150.33	$8.44	$16.19	$114.88	$46.01	$12.37	$4.96
22	> 4 MW	(sec)	$8.33	$17.71	$0.90	$1.91	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$5.88	$12.49	$0.63	$1.35	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$356.12	$518.28	$38.35	$55.82	$2,069.63	$828.92	$222.90	$89.27
26	Irrigation - Schedule 33*	(sec)	$421.19	$610.34	$45.36	$65.73	$2,613.97	$1,046.94	$281.52	$112.76
26										
27	The $/kW are in terms of "Feeder" kW's.									

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Three Phase Costs as Demand

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Demand		Commitment		2010 Demand		2010 Commitment	
Line	Poles Cost	Conductor Cost	Poles Cost	Conductor Cost	Poles Cost	Conductor Cost	Poles Cost	Conductor Cost
					(D) x 0.9867	(C) x 1.0106	(B) x 0.9867	(A) x 1.0106
1	Res - Schedule 4							
2	$157.30	$250.56	$681.01	$266.31	$155.21	$253.21	$671.95	$269.13
3								
4	GS - Schedule 23							
5	$169.89	$267.54	$780.26	$305.12	$167.63	$270.38	$769.89	$308.35
6	$169.89	$267.54	$780.26	$305.12	$167.63	$270.38	$769.89	$308.35
7	$169.89	$267.54	$780.26	$305.12	$167.63	$270.38	$769.89	$308.35
8								
9	GS - Schedule 28							
10	$109.36	$187.91	$333.96	$130.59	$107.90	$189.90	$329.52	$131.98
11	$109.36	$187.91	$333.96	$130.59	$107.90	$189.90	$329.52	$131.98
12	$109.36	$187.91	$333.96	$130.59	$107.90	$189.90	$329.52	$131.98
13	$109.36	$187.91	$333.96	$130.59	$107.90	$189.90	$329.52	$131.98
13	$109.36	$187.91	$333.96	$130.59	$107.90	$189.90	$329.52	$131.98
14								
15	GS - Schedule 30							
16	$116.29	$197.56	$393.15	$153.74	$114.75	$199.66	$387.93	$155.37
17	$116.29	$197.56	$393.15	$153.74	$114.75	$199.66	$387.93	$155.37
18	$116.29	$197.56	$393.15	$153.74	$114.75	$199.66	$387.93	$155.37
19								
20	LPS - Schedule 48T							
21	$79.45	$148.76	$116.43	$45.53	$78.39	$150.33	$114.88	$46.01
22	$79.45	$148.76	$116.43	$45.53	$78.39	$150.33	$114.88	$46.01
23	$8.45	$17.52	$0.00	$0.00	$8.33	$17.71	$0.00	$0.00
24	$5.96	$12.36	$0.00	$0.00	$5.88	$12.49	$0.00	$0.00
25								
26	Irrigation - Schedule 41							
27	$360.92	$512.84	$2,097.53	$820.23	$356.12	$518.28	$2,069.63	$828.92
28								
29	Irrigation - Schedule 33*							
30	$426.87	$603.94	$2,649.20	$1,035.96	$421.19	$610.34	$2,613.97	$1,046.94

Pacific Region			
	Index		Escalation Factor
	2008	2010	2008 - 2010
Poles	527.2	520.2	0.9867
Conductors	686.9	694.2	1.0106

Footnotes:
Escalation Factors: Cost Trends of Electric Utility Construction, Table A14
Pole and conductor costs from Distribution Feeder Model.

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Feeder Distribution Model
Inputs & Calculations

Line	Class		(A) Annual MWH	(B) Number of Customers	(C) Average MWh per Customer (A) / (B)	(D) Hours in Study Period	(E) Average kW / customer per hour (C)/(D)x1000	(F) Feeder Load Factor
1	Res - Schedule 4	(sec)	5,546,125	469,380	11.82	8,760	1.35	57.23%
2	GS - Schedule 23 - 0-15 kW	(sec)	660,613	65,352	10.11	8,760	1.15	87.31%
3	GS - Schedule 23 - 15+ kW	(sec)	487,926	9,474	51.50	8,760	5.88	73.31%
4	GS - Schedule 23 - Primary	(pri)	1,278	34	37.60	8,760	4.29	74.74%
5	GS - Schedule 28 - 0-50 kW	(sec)	441,213	4,459	98.95	8,760	11.30	73.73%
6	GS - Schedule 28 - 51-100 kW	(sec)	686,792	3,500	196.23	8,760	22.40	70.07%
7	GS - Schedule 28 - > 101kW	(sec)	942,085	2,020	466.38	8,760	53.24	73.54%
8	GS - Schedule 28 - Primary	(pri)	18,798	50	375.96	8,760	42.92	72.65%
9	GS - Schedule 30 - 0-300 kW	(sec)	210,232	240	875.96	8,760	100.00	75.49%
10	GS - Schedule 30 - 301+ kW	(sec)	1,099,384	597	1,841.51	8,760	210.22	75.79%
11	GS - Schedule 30 - Primary	(pri)	96,013	55	1,745.69	8,760	199.28	75.77%
12	Irrigation - Sch 41	(sec)	130,845	6,142	21.30	8,760	2.43	95.17%
13	Schedule 33*- Irrigation	(sec)	104,533	2,187	47.80	8,760	5.46	95.17%
13	LPS - Schedule 48T - 1 - 4 MW	(sec)	649,403	123	5,279.70	8,760	602.71	75.95%
14	LPS - Schedule 48T - 1 - 4 MW	(pri)	459,309	57	8,058.05	8,760	919.87	81.13%
15	LPS - Schedule 48T - > 4 MW	(sec)	59,339	2	29,669.60	8,760	3,386.94	95.84%
16	LPS - Schedule 48T - > 4 MW	(pri)	1,301,457	34	38,278.15	8,760	4,369.65	87.24%
17	Total -		12,895,345	563,706				

Customer Distribution on the Hypothetical Feeder Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Hypothetical Feeder Branch						
		1	2	3	4	5	6	7
17	Res - Schedule 4 (sec)	1.30%	1.30%	1.30%	4.01%	4.01%	4.01%	84.08%
18	GS - Schedule 23 - 0-15 kW (sec)	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%
19	GS - Schedule 23 - 15+ kW (sec)	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%
20	GS - Schedule 23 - Primary (pri)	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%
21	GS - Schedule 28 - 0-50 kW (sec)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
22	GS - Schedule 28 - 51-100 kW (sec)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
23	GS - Schedule 28 - > 101kW (sec)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
24	GS - Schedule 28 - Primary (pri)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
25	GS - Schedule 30 - 0-300 kW (sec)	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%
26	GS - Schedule 30 - 301+ kW (sec)	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%
27	GS - Schedule 30 - Primary (pri)	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%
28	Irrigation - Sch 41	3.81%	3.81%	3.81%	13.14%	13.14%	13.14%	49.13%
29	Schedule 33*- Irrigation	5.97%	5.97%	5.97%	11.40%	11.40%	11.40%	47.88%
29	LPS - Schedule 48T - 1 - 4 MW (sec)	-	-	-	1.68%	1.68%	1.68%	94.95%
30	LPS - Schedule 48T - 1 - 4 MW (pri)	-	-	-	1.68%	1.68%	1.68%	94.95%
31	LPS - Schedule 48T - > 4 MW (sec)		Large Customer are on dedicated feeder and are not included here					
32	LPS - Schedule 48T - > 4 MW (pri)		Large Customer are on dedicated feeder and are not included here					

33	System property records & engineering information				
34	Number of pole miles in Oregon	14,146	ok	Poles per mile	26.27
35	Number of trench miles in Oregon	4,831	ok	Customers per mile	29.70
36	Number of feeders in Oregon	604		MWH per customer	22.88
37	Number of poles in Oregon	371,574	ok	MWH per feeder	21,350

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp

Oregon Feeder Model Study

Customer Distribution on the Hypothetical Feeder Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	1.30%	1.30%	1.30%	4.01%	4.01%	4.01%	84.08%	100.00%
2	GS 0-15 kW (sec) (23)	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%	100.00%
3	GS >15 kW (sec) (23)	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%	100.00%
4	GS (pri) (23)	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%	100.00%
5	GS < 50 kW (sec) (28)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%	100.00%
6	GS 51-100 kW (sec) (28)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%	100.00%
7	GS > 100 kW (sec) (28)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%	100.00%
8	GS (pri) (28)	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%	100.00%
9	GS 0-300 kW (sec) (30)	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%	100.00%
10	GS >300 kW (sec) (30)	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%	100.00%
11	GS (pri) (30)	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%	100.00%
12	Irrigation	3.81%	3.81%	3.81%	13.14%	13.14%	13.14%	49.13%	100.00%
13	USBR / UKRB	5.97%	5.97%	5.97%	11.40%	11.40%	11.40%	47.88%	100.00%
14	Large GS 1 - 4 MW (sec)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
15	Large GS 1 - 4 MW (pri)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-

PacifiCorp
Oregon Feeder Model Study
Average Customers by Hypothetical Feeder Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	10.07	10.07	10.07	31.16	31.16	31.16	653.44	777.12
2	GS 0-15 kW (sec) (23)	1.75	1.75	1.75	4.31	4.31	4.31	90.01	108.20
3	GS >15 kW (sec) (23)	0.25	0.25	0.25	0.62	0.62	0.62	13.05	15.69
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.06
5	GS < 50 kW (sec) (28)	0.04	0.04	0.04	0.19	0.19	0.19	6.71	7.38
6	GS 51-100 kW (sec) (28)	0.03	0.03	0.03	0.15	0.15	0.15	5.26	5.79
7	GS > 100 kW (sec) (28)	0.02	0.02	0.02	0.09	0.09	0.09	3.04	3.34
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.36	0.40
10	GS >300 kW (sec) (30)	0.01	0.01	0.01	0.02	0.02	0.02	0.90	0.99
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.09
12	Irrigation	0.39	0.39	0.39	1.34	1.34	1.34	5.00	10.17
13	USBR / UKRB	0.20	0.20	0.20	0.39	0.39	0.39	1.64	3.43
14	Large GS 1 - 4 MW (sec)	-	-	-	0.00	0.00	0.00	0.19	0.20
15	Large GS 1 - 4 MW (pri)	-	-	-	0.00	0.00	0.00	0.09	0.09
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	12.77	12.77	12.77	38.28	38.28	38.28	779.89	933.03

Source - 'Feeder Model Inputs and Assumptions ' (Inputs) Tab 8.4
Source - 'Customer Distribution on the Hypothetical Feeder Branch' (Cust_Dist) Tab 8.5
Customers multiplied by Customer Distribution on the Hypothetical Feeder Branch divided by feeders in the state.
For Example 10.07 is 469,380 Residential Customers X 1.296% customer on Branch 1 divided by 604 feeders.

Percent of Customers

1	Residential	78.88%	78.88%	78.88%	81.39%	81.39%	81.39%	83.79%	83.29%
2	GS 0-15 kW (sec) (23)	13.73%	13.73%	13.73%	11.26%	11.26%	11.26%	11.54%	11.60%
3	GS >15 kW (sec) (23)	1.99%	1.99%	1.99%	1.63%	1.63%	1.63%	1.67%	1.68%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	0.29%	0.29%	0.29%	0.49%	0.49%	0.49%	0.86%	0.79%
6	GS 51-100 kW (sec) (28)	0.23%	0.23%	0.23%	0.39%	0.39%	0.39%	0.67%	0.62%
7	GS > 100 kW (sec) (28)	0.13%	0.13%	0.13%	0.22%	0.22%	0.22%	0.39%	0.36%
8	GS (pri) (28)	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%
9	GS 0-300 kW (sec) (30)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.05%	0.04%
10	GS >300 kW (sec) (30)	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.12%	0.11%
11	GS (pri) (30)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
12	Irrigation	3.04%	3.04%	3.04%	3.49%	3.49%	3.49%	0.64%	1.09%
13	USBR / UKRB	1.60%	1.60%	1.60%	1.02%	1.02%	1.02%	0.21%	0.37%
14	Large GS 1 - 4 MW (sec)	-	-	-	0.01%	0.01%	0.01%	0.02%	0.02%
15	Large GS 1 - 4 MW (pri)	-	-	-	0.00%	0.00%	0.00%	0.01%	0.01%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads

19	1,2,3,6	12.8	12.8	12.8			38.3		76.6
20	1,2,3,4,5,6,7	12.8	12.8	12.8	38.3	38.3	38.3	779.9	933.0
21									
22	1,2,3,6	16.7%	16.7%	16.7%			50.0%		100.0%
23	1,2,3,4,5,6,7	1.4%	1.4%	1.4%	4.1%	4.1%	4.1%	83.6%	100.0%

PacifiCorp
Oregon Feeder Model Study
Feeder kW Load by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total

Feeder kW Loads

1	Residential	23.7	23.7	23.7	73.4	73.4	73.4	1,540.0	1,831.5
2	GS 0-15 kW (sec) (23)	2.3	2.3	2.3	5.7	5.7	5.7	119.0	143.0
3	GS >15 kW (sec) (23)	2.0	2.0	2.0	5.0	5.0	5.0	104.6	125.8
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
5	GS < 50 kW (sec) (28)	0.6	0.6	0.6	2.9	2.9	2.9	102.7	113.1
6	GS 51-100 kW (sec) (28)	0.9	0.9	0.9	4.7	4.7	4.7	168.3	185.2
7	GS > 100 kW (sec) (28)	1.2	1.2	1.2	6.2	6.2	6.2	219.9	242.1
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	4.4	4.9
9	GS 0-300 kW (sec) (30)	0.4	0.4	0.4	1.2	1.2	1.2	47.8	52.6
10	GS >300 kW (sec) (30)	2.1	2.1	2.1	6.3	6.3	6.3	249.0	274.1
11	GS (pri) (30)	0.2	0.2	0.2	0.6	0.6	0.6	21.8	23.9
12	Irrigation	1.0	1.0	1.0	3.4	3.4	3.4	12.8	26.0
13	USBR / UKRB	1.2	1.2	1.2	2.4	2.4	2.4	9.9	20.8
14	Large GS 1 - 4 MW (sec)	-	-	-	2.7	2.7	2.7	153.5	161.6
15	Large GS 1 - 4 MW (pri)	-	-	-	1.8	1.8	1.8	101.6	107.0
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	35.7	35.7	35.7	116.4	116.4	116.4	2,855.7	3,312.0

Source - 'Feeder Model Inputs and Assumptions ' (Inputs) Tab 8.4
Source - 'Average Customers by Hypothetical Feeder Branch' (Cust) Tab 8.6
Customers multiplied by feeder kW per customer.
For Example 23.7 is 10.07 Residential Customers multiplied by 2.36 average feeder kW per Customer.

Percent of Branch Load

1	Residential	66.43%	66.43%	66.43%	63.09%	63.09%	63.09%	53.93%	55.30%
2	GS 0-15 kW (sec) (23)	6.49%	6.49%	6.49%	4.89%	4.89%	4.89%	4.17%	4.32%
3	GS >15 kW (sec) (23)	5.71%	5.71%	5.71%	4.30%	4.30%	4.30%	3.66%	3.80%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	1.60%	1.60%	1.60%	2.47%	2.47%	2.47%	3.60%	3.41%
6	GS 51-100 kW (sec) (28)	2.63%	2.63%	2.63%	4.05%	4.05%	4.05%	5.89%	5.59%
7	GS > 100 kW (sec) (28)	3.44%	3.44%	3.44%	5.29%	5.29%	5.29%	7.70%	7.31%
8	GS (pri) (28)	0.07%	0.07%	0.07%	0.11%	0.11%	0.11%	0.16%	0.15%
9	GS 0-300 kW (sec) (30)	1.11%	1.11%	1.11%	1.04%	1.04%	1.04%	1.67%	1.59%
10	GS >300 kW (sec) (30)	5.77%	5.77%	5.77%	5.42%	5.42%	5.42%	8.72%	8.28%
11	GS (pri) (30)	0.50%	0.50%	0.50%	0.47%	0.47%	0.47%	0.76%	0.72%
12	Irrigation	2.78%	2.78%	2.78%	2.93%	2.93%	2.93%	0.45%	0.78%
13	USBR / UKRB	3.47%	3.47%	3.47%	2.03%	2.03%	2.03%	0.35%	0.63%
14	Large GS 1 - 4 MW (sec)	-	-	-	2.34%	2.34%	2.34%	5.37%	4.88%
15	Large GS 1 - 4 MW (pri)	-	-	-	1.55%	1.55%	1.55%	3.56%	3.23%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads

1,2,3,6	35.7	35.7	35.7			116.4		223.6
1,2,3,4,5,6,7	35.7	35.7	35.7	116.4	116.4	116.4	2,855.7	3,312.0

1,2,3,6	16.0%	16.0%	16.0%			52.1%		100.0%
1,2,3,4,5,6,7	1.1%	1.1%	1.1%	3.5%	3.5%	3.5%	86.2%	100.0%

PacifiCorp
Oregon Feeder Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Account 364 Pole Cost per Mile: Adjustment Factor	Account 364 Pole Cost per Mile: Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR	$ 29,819	0.990	$ 29,521	$ 11,544	$ 41,363
3 Phase - 1/0 ACSR 1\0 ACSR	$ 35,873	0.990	$ 35,514	$ 23,754	$ 59,627
3 Phase - 447 AAC & 4\0 AAC	$ 41,961	0.990	$ 41,541	$ 39,106	$ 81,067
3 Phase -795 AAC & 477 AAC	$ 44,996	0.990	$ 44,546	$ 92,427	$ 137,423

	State Specific Account 364 Pole Statistics			Adjustment
State	**Poles**	**Pole Miles**	**Poles / Mile**	**Factor**
California	55,376	2,295	24.13	0.909
Idaho	101,768	4,392	23.17	0.873
Oregon	371,574	14,146	26.27	0.990
Utah	363,003	11,505	31.55	1.189
Washington	98,596	3,545	27.81	1.048
Wyoming	154,013	7,246	21.25	0.801
Total	1,144,330	43,129	26.53	1.000

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSI	3 Phase - 1/0 ACSR 1\0	Total	
Poles	$ 46,375	$ 103,611	$ 149,986	
Conductors	$ 18,135	$ 69,301	$ 87,436	
Total	$ 64,510	$ 172,912	$ 237,422	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 186,454		$ 199,940	
Conductors	$ 175,523		$ 414,847	
Total	$ 361,976		$ 614,787	

Miles per Branch	4.49
Single Phase Miles Per Branch	1.57
Three Phase Miles Per Branch	2.92

Source: Input Tab

Commitment and Demand Costs Per Branch

	Poles			Conductor		
Wire Sizes	**Total Cost**	**Commitment**	**Demand**	**Total Cost**	**Commitment**	**Demand**
Branches 1,2,3,4,5						
1 Phase -1/0 ACSR	$ 46,375	$ 46,375	$ -	$ 18,135	$ 18,135	N/A
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 86,125	$ 17,486	$ 69,301	$ 33,679	$ 35,622
Total Branches 1,2,3,4,5	$ 149,986	$ 132,501	$ 17,486	$ 87,436	$ 51,814	$ 35,622
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 186,454	N/A	$ 186,454	$ 175,523	N/A	$ 175,523
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 199,940	N/A	$ 199,940	$ 414,847	N/A	$ 414,847
Total All Branches	$ 1,136,324	$ 662,503	$ 473,821	$ 1,027,549	$ 259,069	$ 768,480

PacifiCorp
Oregon Feeder Model Study
Calculation of Hypothetical Feeder Model Branch Cost

Conductors Type	(A)	(B)	(C)	(D)	(E)	(F)
	Total Cost		Commitment Cost		Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total segment	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 2						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 3						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 4						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 5						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 6						
3 Phase - 447 AAC & 4\0 A	$ 186,454	$ 175,523	NA	NA	$ 186,454	$ 175,523
Total Segments	$ 186,454	$ 175,523	$ -	$ -	$ 186,454	$ 175,523
Branch 7						
3 Phase -795 AAC & 477 A	$ 199,940	$ 414,847	NA	NA	$ 199,940	$ 414,847
Total segment	$ 199,940	$ 414,847	$ -	$ -	$ 199,940	$ 414,847

Source - 'System-wide Pole and Conductor Costs' (Line_Cost) Tab 8.8

PacifiCorp
Oregon Feeder Model Study
Poles Demand Calculations
Branch 6 & 7 Cost Assignment

Line	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	15.98%	15.98%	15.98%	NA	NA	52.07%	NA	100.00%	
2	Branch 6 Cost	$ 29,792	$ 29,792	$ 29,792	NA	NA	$ 97,078	NA	$ 186,454	**$ / kW**
3	% Demand	1.08%	1.08%	1.08%	3.51%	3.51%	3.51%	86.22%	100.00%	
4	Branch 7 Cost	$ 2,156	$ 2,156	$ 2,156	$ 7,027	$ 7,027	$ 7,027	$ 172,391	$ 199,940	
5	Branch Demand Cost	$ 17,486	$ 17,486	$ 17,486	$ 17,486	$ 17,486	NA	NA		Average
6	Total	$ 49,434	$ 49,434	$ 49,434	$ 24,512	$ 24,512	$ 104,104	$ 172,391	$ 473,821	$ 143.06
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 32,840	$ 32,840	$ 32,840	$ 15,465	$ 15,465	$ 65,680	$ 92,967	$ 288,098	$ 157.30
11	GS 0-15 kW (sec) (23)	$ 3,207	$ 3,207	$ 3,207	$ 1,199	$ 1,199	$ 5,093	$ 7,181	$ 24,293	$ 169.89
12	GS >15 kW (sec) (23)	$ 2,821	$ 2,821	$ 2,821	$ 1,055	$ 1,055	$ 4,481	$ 6,317	$ 21,370	$ 169.89
13	GS (pri) (23)	$ 7	$ 7	$ 7	$ 3	$ 3	$ 12	$ 16	$ 55	$ 169.89
14	GS < 50 kW (sec) (28)	$ 793	$ 793	$ 793	$ 606	$ 606	$ 2,574	$ 6,202	$ 12,368	$ 109.36
15	GS 51-100 kW (sec) (28)	$ 1,299	$ 1,299	$ 1,299	$ 993	$ 993	$ 4,216	$ 10,159	$ 20,257	$ 109.36
16	GS > 100 kW (sec) (28)	$ 1,698	$ 1,698	$ 1,698	$ 1,297	$ 1,297	$ 5,510	$ 13,278	$ 26,477	$ 109.36
17	GS (pri) (28)	$ 34	$ 34	$ 34	$ 26	$ 26	$ 111	$ 268	$ 535	$ 109.36
18	GS 0-300 kW (sec) (30)	$ 547	$ 547	$ 547	$ 255	$ 255	$ 1,083	$ 2,887	$ 6,121	$ 116.29
19	GS >300 kW (sec) (30)	$ 2,850	$ 2,850	$ 2,850	$ 1,328	$ 1,328	$ 5,641	$ 15,035	$ 31,881	$ 116.29
20	GS (pri) (30)	$ 249	$ 249	$ 249	$ 116	$ 116	$ 493	$ 1,313	$ 2,785	$ 116.29
21	Irrigation	$ 1,372	$ 1,372	$ 1,372	$ 719	$ 719	$ 3,054	$ 771	$ 9,379	$ 360.92
22	USBR / UKRB	$ 1,716	$ 1,716	$ 1,716	$ 498	$ 498	$ 2,116	$ 600	$ 8,862	$ 426.87
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 572	$ 572	$ 2,431	$ 9,264	$ 12,840	$ 79.45
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 379	$ 379	$ 1,610	$ 6,133	$ 8,501	$ 79.45
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 49,434	$ 49,434	$ 49,434	$ 24,512	$ 24,512	$ 104,104	$ 172,391	$ 473,821	

Sources: Line 1 & 3 - 'Feeder kW Load by Branch' (kW) Tab 8.7
Line 2 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $186,454
Line 1 X $186,454
Line 4 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $199,940
Line 3 X $199,940
Line 5 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9
Line 7 to 18 - Line 6 X Percent of Branch Load 'Feeder kW Load by Branch' (kW) Tab 8.7

PacifiCorp
Oregon Feeder Model Study
Conductor Demand Calculations
Branch 6 & 7 Cost Assignment

Line	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	15.98%	15.98%	15.98%	NA	NA	52.07%	NA	100.00%	
2	Branch 6 Cost	$ 28,045	$ 28,045	$ 28,045	NA	NA	$ 91,386	NA	$ 175,523	$ / kW
3	% Demand	1.08%	1.08%	1.08%	3.51%	3.51%	3.51%	86.22%	100.00%	
4	Branch 7 Cost	$ 4,474	$ 4,474	$ 4,474	$ 14,579	$ 14,579	$ 14,579	$ 357,687	$ 414,847	
5	Branch Demand Cost	$ 35,622	$ 35,622	$ 35,622	$ 35,622	$ 35,622	NA	NA		average
6	Total	$ 68,142	$ 68,142	$ 68,142	$ 50,201	$ 50,201	$ 105,966	$ 357,687	$ 768,480	$ 232.03
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 45,268	$ 45,268	$ 45,268	$ 31,672	$ 31,672	$ 66,855	$ 192,894	$ 458,898	$ 250.56
11	GS 0-15 kW (sec) (23)	$ 4,420	$ 4,420	$ 4,420	$ 2,456	$ 2,456	$ 5,184	$ 14,900	$ 38,258	$ 267.54
12	GS >15 kW (sec) (23)	$ 3,888	$ 3,888	$ 3,888	$ 2,161	$ 2,161	$ 4,561	$ 13,107	$ 33,654	$ 267.54
13	GS (pri) (23)	$ 10	$ 10	$ 10	$ 6	$ 6	$ 12	$ 34	$ 86	$ 267.54
14	GS < 50 kW (sec) (28)	$ 1,093	$ 1,093	$ 1,093	$ 1,241	$ 1,241	$ 2,620	$ 12,869	$ 21,252	$ 187.91
15	GS 51-100 kW (sec) (28)	$ 1,791	$ 1,791	$ 1,791	$ 2,033	$ 2,033	$ 4,291	$ 21,078	$ 34,807	$ 187.91
16	GS > 100 kW (sec) (28)	$ 2,341	$ 2,341	$ 2,341	$ 2,657	$ 2,657	$ 5,609	$ 27,549	$ 45,494	$ 187.91
17	GS (pri) (28)	$ 47	$ 47	$ 47	$ 54	$ 54	$ 113	$ 556	$ 919	$ 187.91
18	GS 0-300 kW (sec) (30)	$ 754	$ 754	$ 754	$ 522	$ 522	$ 1,102	$ 5,989	$ 10,399	$ 197.56
19	GS >300 kW (sec) (30)	$ 3,928	$ 3,928	$ 3,928	$ 2,720	$ 2,720	$ 5,742	$ 31,195	$ 54,162	$ 197.56
20	GS (pri) (30)	$ 343	$ 343	$ 343	$ 238	$ 238	$ 502	$ 2,725	$ 4,731	$ 197.56
21	Irrigation	$ 1,891	$ 1,891	$ 1,891	$ 1,473	$ 1,473	$ 3,109	$ 1,599	$ 13,326	$ 512.84
22	USBR / UKRB	$ 2,366	$ 2,366	$ 2,366	$ 1,021	$ 1,021	$ 2,154	$ 1,245	$ 12,538	$ 603.94
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,172	$ 1,172	$ 2,475	$ 19,221	$ 24,040	$ 148.76
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 776	$ 776	$ 1,638	$ 12,726	$ 15,916	$ 148.76
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 68,142	$ 68,142	$ 68,142	$ 50,201	$ 50,201	$ 105,966	$ 357,687	$ 768,480	

Sources: Line 1 & 3 - 'Feeder kW Load by Branch' (kW) Tab 8.7
Line 2 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $175,523
Line 1 X $175,523
Line 4 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $414,847
Line 3 X $414,847
Line 5 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9
Line 7 to 18 - Line 6 X Percent of Branch Load 'Feeder kW Load by Branch' (kW) Tab 8.7

PacifiCorp
Oregon Feeder Model Study
Poles Commitment Calculations
Branch 1, 2, 3, 4 & 5 Cost Assignment

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	16.67%	16.67%	16.67%	NA	NA	49.99%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per**
3	% customer	1.37%	1.37%	1.37%	4.10%	4.10%	4.10%	83.59%	100.00%	**Customer**
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	NA	NA		average
6	Total	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ -	$ -	$ 662,503	$ 710.05
7										
8									Total	**$ Per**
9									Commitment	**Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 104,514	$ 104,514	$ 104,514	$ 107,843	$ 107,843	$ -	$ -	$ 529,228	$ 681.01
12	GS 0-15 kW (sec) (23)	$ 18,199	$ 18,199	$ 18,199	$ 14,914	$ 14,914	$ -	$ -	$ 84,424	$ 780.26
13	GS >15 kW (sec) (23)	$ 2,638	$ 2,638	$ 2,638	$ 2,162	$ 2,162	$ -	$ -	$ 12,239	$ 780.26
14	GS (pri) (23)	$ 10	$ 10	$ 10	$ 8	$ 8	$ -	$ -	$ 44	$ 780.26
15	GS < 50 kW (sec) (28)	$ 388	$ 388	$ 388	$ 650	$ 650	$ -	$ -	$ 2,465	$ 333.96
16	GS 51-100 kW (sec) (28)	$ 305	$ 305	$ 305	$ 510	$ 510	$ -	$ -	$ 1,935	$ 333.96
17	GS > 100 kW (sec) (28)	$ 176	$ 176	$ 176	$ 294	$ 294	$ -	$ -	$ 1,117	$ 333.96
18	GS (pri) (28)	$ 4	$ 4	$ 4	$ 7	$ 7	$ -	$ -	$ 28	$ 333.96
19	GS 0-300 kW (sec) (30)	$ 31	$ 31	$ 31	$ 32	$ 32	$ -	$ -	$ 156	$ 393.15
20	GS >300 kW (sec) (30)	$ 77	$ 77	$ 77	$ 79	$ 79	$ -	$ -	$ 388	$ 393.15
21	GS (pri) (30)	$ 7	$ 7	$ 7	$ 7	$ 7	$ -	$ -	$ 36	$ 393.15
22	Irrigation	$ 4,027	$ 4,027	$ 4,027	$ 4,625	$ 4,625	$ -	$ -	$ 21,329	$2,097.53
23	USBR / UKRB	$ 2,125	$ 2,125	$ 2,125	$ 1,352	$ 1,352	$ -	$ -	$ 9,079	$2,649.20
24	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 12	$ 12	$ -	$ -	$ 24	$ 116.43
25	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 5	$ 5	$ -	$ -	$ 11	$ 116.43
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ -	$ -	$ 662,503	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Feeder Branch' (Cust) Tab 8.6
Line 2 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Feeder Branch' (Cust) Tab 8.6

PacifiCorp
Oregon Feeder Model Study
Conductor Commitment Calculations
Branch 1, 2, 3, 4 & 5 Cost Assignment

	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	16.67%	16.67%	16.67%	NA	NA	49.99%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per**
3	% customer	1.37%	1.37%	1.37%	4.10%	4.10%	4.10%	83.59%	100.00%	**Customer**
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	NA	NA		average
6	Total	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ -	$ -	$ 259,069	$ 277.66
7										
8									Total	**$ Per**
9									Commitment	**Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 40,870	$ 40,870	$ 40,870	$ 42,172	$ 42,172	$ -	$ -	$ 206,952	$ 266.31
12	GS 0-15 kW (sec) (23)	$ 7,117	$ 7,117	$ 7,117	$ 5,832	$ 5,832	$ -	$ -	$ 33,014	$ 305.12
13	GS >15 kW (sec) (23)	$ 1,032	$ 1,032	$ 1,032	$ 845	$ 845	$ -	$ -	$ 4,786	$ 305.12
14	GS (pri) (23)	$ 4	$ 4	$ 4	$ 3	$ 3	$ -	$ -	$ 17	$ 305.12
15	GS < 50 kW (sec) (28)	$ 152	$ 152	$ 152	$ 254	$ 254	$ -	$ -	$ 964	$ 130.59
16	GS 51-100 kW (sec) (28)	$ 119	$ 119	$ 119	$ 200	$ 200	$ -	$ -	$ 757	$ 130.59
17	GS > 100 kW (sec) (28)	$ 69	$ 69	$ 69	$ 115	$ 115	$ -	$ -	$ 437	$ 130.59
18	GS (pri) (28)	$ 2	$ 2	$ 2	$ 3	$ 3	$ -	$ -	$ 11	$ 130.59
19	GS 0-300 kW (sec) (30)	$ 12	$ 12	$ 12	$ 12	$ 12	$ -	$ -	$ 61	$ 153.74
20	GS >300 kW (sec) (30)	$ 30	$ 30	$ 30	$ 31	$ 31	$ -	$ -	$ 152	$ 153.74
21	GS (pri) (30)	$ 3	$ 3	$ 3	$ 3	$ 3	$ -	$ -	$ 14	$ 153.74
22	Irrigation	$ 1,575	$ 1,575	$ 1,575	$ 1,809	$ 1,809	$ -	$ -	$ 8,341	$ 820.23
23	USBR / UKRB	$ 831	$ 831	$ 831	$ 529	$ 529	$ -	$ -	$ 3,550	$1,035.96
24	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 5	$ 5	$ -	$ -	$ 9	$ 45.53
25	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 2	$ 2	$ -	$ -	$ 4	$ 45.53
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 51,814	$ 51,814	$ 51,814	$ 51,812	$ 51,812	$ -	$ -	$ 259,065	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Feeder Branch' (Cust) Tab 8.6
Line 2 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Feeder Model Branch Cost' (Br_Cost) Tab 8.9
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Feeder Branch' (Cust) Tab 8.6

PacifiCorp
Oregon Feeder Model Study
Dedicated Feeder Trunk Costs
For Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 44,546	$ 92,427	$ 44,546	$ 92,427
2 Average Trunk Length	0.67 miles		0.67 miles	
3 Total Construction Cost	$ 29,846	$ 61,926	$ 29,846	$ 61,926
4 Customer Peak Demand	5,009 kW		3,534 kW	
5 Demand Cost $/kW	$5.96	$12.36	$8.45	$17.52

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (Line_Cost) Tab 8.8
Line 2 - Distribution Engineering Studies
Line 4 - 'Feeder Model Inputs and Assumptions ' (Inputs) Tab 8.4
Line 5 - Line 3 divided by Line 4

PacifiCorp
Oregon Feeder Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

	(A)	(B)	(C)	(D)	(E)	(F)		
	COMMITMENT $/Customer		Demand $/feeder kW		Typical feeder		Demand $/feeder kW	
CLASS	Poles	Conductor	Poles	Conductor	CUSTOMERS	kW	Poles	Conductor
Residential	$ 681.01	$ 266.31	$ 157.30	$ 250.56	777.1	1,831.51	$ 288,098	$ 458,898
GS 0-15 kW (sec) (23)	$ 780.26	$ 305.12	$ 169.89	$ 267.54	108.2	143.00	$ 24,293	$ 38,258
GS >15 kW (sec) (23)	$ 780.26	$ 305.12	$ 169.89	$ 267.54	15.7	125.79	$ 21,370	$ 33,654
GS (pri) (23)	$ 780.26	$ 305.12	$ 169.89	$ 267.54	0.1	0.32	$ 55	$ 86
GS < 50 kW (sec) (28)	$ 333.96	$ 130.59	$ 109.36	$ 187.91	7.4	113.10	$ 12,368	$ 21,252
GS 51-100 kW (sec) (28)	$ 333.96	$ 130.59	$ 109.36	$ 187.91	5.8	185.23	$ 20,257	$ 34,807
GS > 100 kW (sec) (28)	$ 333.96	$ 130.59	$ 109.36	$ 187.91	3.3	242.11	$ 26,477	$ 45,494
GS (pri) (28)	$ 333.96	$ 130.59	$ 109.36	$ 187.91	0.1	4.89	$ 535	$ 919
GS 0-300 kW (sec) (30)	$ 393.15	$ 153.74	$ 116.29	$ 197.56	0.4	52.63	$ 6,121	$ 10,399
GS >300 kW (sec) (30)	$ 393.15	$ 153.74	$ 116.29	$ 197.56	1.0	274.15	$ 31,881	$ 54,162
GS (pri) (30)	$ 393.15	$ 153.74	$ 116.29	$ 197.56	0.1	23.95	$ 2,785	$ 4,731
Irrigation	$ 2,097.53	$ 820.23	$ 360.92	$ 512.84	10.2	25.99	$ 9,379	$ 13,326
USBR / UKRB	$ 2,649.20	$ 1,035.96	$ 426.87	$ 603.94	3.4	20.76	$ 8,862	$ 12,538
Large GS 1 - 4 MW (sec)	$ 116.43	$ 45.53	$ 79.45	$ 148.76	0.2	161.61	$ 12,840	$ 24,040
Large GS 1 - 4 MW (pri)	$ 116.43	$ 45.53	$ 79.45	$ 148.76	0.1	107.00	$ 8,501	$ 15,916
Total -	$ 710.05	$ 277.66	$ 143.06	$ 232.03	933.0	3,312.0		
Large GS + 4 MW (sec)	$ -	$ -	$ 8.45	$ 17.52	-	3,534.07	$ 29,846	$ 61,926
Large GS + 4 MW (pri)	$ -	$ -	$ 5.96	$ 12.36	-	5,008.79	$ 29,846	$ 61,926
							$ 533,513	$ 892,332

	COMMITMENT	Demand	Total
Poles	$ 662,503	$ 533,513	$ 1,196,016
Conductor	$ 259,069	$ 892,332	$ 1,151,401
Total	$ 921,572	$ 1,425,845	$ 2,347,417

Source : Column (A) - Poles Commitment Calculations' (Br_Commit_P) Tab 8.12
Column (B) - Conductor Demand Calculations' (Br_Commit_C) Tab 8.13
Column (C) - Poles Demand Calculations' (Br_Demand_P) Tab 8.10
Column (D) - Conductor Demand Calculations' (Br_Demand_C) Tab 8.11
Column (E) - Average Customers by Hypothetical Feeder Branch' (Cust) Tab 8.6
Column (F) - Feeder kW Load by Branch' (kW) Tab 8.7

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran.	(D) # Cust. / Tran.	(E) Transformer $ / Cust.	(F) Average Customers	(G) Tot. Trans. Commitment $
				(A) x (B)		(C) / (D)		(E) x (F)
1	Res - Schedule 4	100.00%	203.60	203.60	3.74	$54.44	478,485	$26,048,723
2								
3	GS - Schedule 23							
4	1 Phase	83.40%	203.60	169.81	2.54	$66.85		
5	3 Phase	16.60%	788.07	130.80	1.37	$95.47		
6	0-15 kW	100.00%				$162.33	64,649	$10,494,394
7								
8	1 Phase	42.59%	203.60	86.71	2.54	$34.14		
9	3 Phase	57.41%	788.07	452.43	1.37	$330.24		
10	15+ kW	100.00%				$364.38	9,372	$3,414,957
11								
12	Primary	100.00%	-	-	0.00	0	34	$0
13								
14	GS - Schedule 28							
15	1 Phase	29.11%	203.60	59.27	1.65	$35.92		
16	3 Phase	70.89%	788.07	558.67	1.19	$469.47		
17	0-50 kW	100.00%				$505.39	4,491	$2,269,714.58
18								
19	1 Phase	13.43%	203.60	27.34	1.65	$16.57		
20	3 Phase	86.57%	788.07	682.24	1.19	$573.31		
21	51-100 kW	100.00%				$589.88	3,525	$2,079,329
22								
23	1 Phase	2.67%	203.60	5.44	1.65	$3.30		
24	3 Phase	97.33%	788.07	767.00	1.19	$644.54		
25	> 101kW	100.00%				$647.83	2,034	$1,317,696
26								
27	Primary	100.00%	-	-	0.00	0	50	$0
28								
29	GS - Schedule 30							
30	1 Phase	0.42%	203.60	0.85	1.71	$0.50		
31	3 Phase	99.58%	788.07	784.79	1.00	$784.79		
32	0-300 kW	100.00%				$785.29	230	$180,616
33								
34	1 Phase	0.17%	203.60	0.34	1.71	$0.20		
35	3 Phase	99.83%	788.07	786.75	1.00	$786.75		
36	301+ kW	100.00%				$786.95	572	$450,135
37								
38	Primary	100.00%	-	-	0.00	0	52	$0
39								
40	LPS - Schedule 48T							
41	1 - 4 MW (sec)	100.00%	788.07	788.07	1.00	788.07	121	$95,356
42	1 - 4 MW (pri)	100.00%	-	-	0.00	0	56	$0
43	> 4 MW (sec)	100.00%	788.07	788.07	1.00	788.07	2	$1,576
44	> 4 MW (pri)	100.00%	-	-	0.00	0	34	$0
45	Trans (trn)	100.00%	-	-	0.00	0	2	$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	19.66%	203.60	40.04	1.75	$22.88		
49	3 Phase	80.34%	788.07	633.10	1.00	$633.10		
50	Total	100.00%				$655.98	6,108	$4,006,726
51								
52	Schedule 33*- Irrigation							
53	1 Phase	3.12%	203.60	6.35	1.75	$3.63		
54	3 Phase	96.88%	788.07	763.49	1.00	$763.49		
55	Total	100.00%				$767.12	2,062	$1,581,798

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Annual MWh's	(C) Transformer Peak kW's	(D) Tot. Trans. Demand $ (A) x (C)
1	Res - Schedule 4	(sec)	$1.11	5,435,846	2,402,329	$2,666,585
2						
3	GS - Schedule 23					
4	0-15 kW	(sec)	$1.44	582,532	271,216	$390,550
5	15+ kW	(sec)	$1.44	430,256	108,943	$156,878
6	Primary	(pri)	$0.00	1,152	0	$0
7						
8	GS - Schedule 28					
9	0-50 kW	(sec)	$1.44	431,990	108,871	$156,775
10	51-100 kW	(sec)	$1.44	672,435	158,141	$227,723
11	> 101kW	(sec)	$1.44	922,391	199,971	$287,958
12	Primary	(pri)	$0.00	18,249	0	$0
13						
14	GS - Schedule 30					
15	0-300 kW	(sec)	$1.44	206,234	41,138	$59,239
16	301+ kW	(sec)	$1.44	1,078,480	193,793	$279,062
17	Primary	(pri)	$1.44	93,931	0	$0
18						
19						
20	LPS - Schedule 48T					
21	1 - 4 MW	(sec)	$1.44	594,746	143,412	$206,513
22	1 - 4 MW	(pri)	$0.00	414,743	0	$0
23	> 4 MW	(sec)	$1.44	54,345	17,994	$25,912
24	> 4 MW	(pri)	$0.00	1,175,179	0	$0
25	Trans	(trn)	$0.00	404,889	0	$0
26						
27	Irrigation - Schedule 41 (Average)					
28	Secondary	(sec)	$1.44	136,792	97,809	$140,845
29						
30	Irrigation - Schedule 33* (Average)					
31	Secondary	(sec)	$1.44	118,046	84,406	$121,544
32						
30	Totals			12,654,191	3,743,616	$4,598,040

Footnote: Residential $/kW is decreased by 23% (1/1.3) to account for higher transformer load capacities at the time of residential peak.

* Schedule 33 Cost of Service results are provided for informational purposes oı

XFMR 3

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

Line	Description	(A) Demand Related	(B) Adjusted for System Power Factor of .95	(C) Commitment Related	(D) Indexed to 2010	(E) Annualized $ @ 10.77%
			(A) / .95		(B) or (C) x 0.9134	(D) x 10.77%
1	1 Phase $/kW	$13.87	$14.60		$13.34	$1.44
2						
3	3 Phase $/kW	$13.87	$14.60		$13.34	$1.44
4						
5	1 Phase			$2,069.70	$1,890.47	$203.60
6	$/Transformer					
7						
8	3 Phase			$5,941.29		
9	Dummy Variable					
10						
11	3 Phase			$8,010.99	$7,317.24	$788.07
12	$/Transformer					

Pacific Region		
Index		Escalation Factor
2008	2010	2008 - 2010
530.0	484.1	0.9134

Footnotes: Escalation Factors: Cost Trends of Electric Utility Construction, Table A13

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	33,064,114	34,852,307	42,485,996	48,122,256	48,559,856	48,811,823	71,993,550	67,011,911	68,781,531	71,602,482
2	Less:										
3	585 St Ltg & Signal Systems	265,823	-	-	-	-	13,067	89,965	45,553	48,057	75,549
4	586 Meter Expense	2,283,801	-	-	1,479,307	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057
5	587 Customer Installation Expense	1,328,126	332,819	132,472	11,531	9,542	90,751	62,896	-	-	3,636,287
6	596 Main. of St Ltg & Signal Systems	239,770	249,477	289,510	609,632	814,491	756,545	885,374	843,436	851,273	945,804
7	597 Main. of Meters	256,703	1,047,453	674,571	664,777	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945
8											
9	Total Adjusted Distribution O & M Expense	28,689,891	33,222,557	41,389,443	45,357,009	45,110,206	44,750,901	67,825,184	62,652,513	64,154,665	63,177,840
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	1,162,012,609	1,192,703,978	1,235,859,101	1,271,410,972	1,303,063,520	1,341,098,219	1,384,196,236	1,431,636,624	1,476,365,173	1,530,307,351
15	Less:										
16	370 Meters	54,919,747	56,597,405	55,765,666	56,108,548	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811
17	373 Street Lighting	13,742,452	14,339,640	15,038,442	15,408,466	16,135,274	16,827,066	17,637,977	18,351,472	19,120,699	20,208,050
18											
19	Adjusted Distribution Plant	1,093,350,410	1,121,766,933	1,165,054,993	1,199,893,958	1,229,861,243	1,267,442,464	1,309,852,465	1,355,189,989	1,398,787,483	1,450,930,490
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	2.62%	2.96%	3.55%	3.78%	3.67%	3.53%	5.18%	4.62%	4.59%	4.35%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	3.89%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	10.77%									
31											
32	Annualized Distribution O & M Loading Factor	36.12%									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Exhibit PPL/919

10. Cust. Meters and O&M

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	469,380	100.00%	100.00%		$101	$101.01	$101.01	
2	Annualized - (Line 1) x 10.77%						$10.88	$10.88	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	50,770	77.69%	93.15%		$86	$66.67	$79.94	
7	kW = 0, 3 Phase	3,767	5.76%		34.73%	$252	$14.55		$87.65
8	kW > 1, 1 Phase	3,735	5.72%	6.85%		$191	$10.91	$13.08	
9	kW > 1, 3 Phase	7,080	10.83%		65.27%	$252	$27.34		$164.75
10	Total 0-15 kW	65,352	100.00%	100.00%	100.00%		$119.47	$93.02	$252.40
11	Annualized - (Line 10) x 10.77%						$12.87	$10.02	$27.18
12									
13	15+ kW								
14	1 Phase	4,035	42.59%	100.00%		$207	$88.15	$206.97	
15	3 Phase W/O KVAR	4,579	48.33%		84.19%	$252	$121.99		$212.49
16	3 Phase With KVAR	860	9.08%		15.81%	$411	$37.30		$64.97
17	Total 15+ kW	9,474	100.00%	100.00%	100.00%		$247.44	$206.97	$277.46
18	Annualized - (Line 17) x 10.77%						$26.65	$22.29	$29.88
19									
20	Primary								
21	12.47 KV 4-wire Wye OH	34	100.00%		100.00%	$7,794	$7,794.11		$7,794.11
22	Annualized - (Line 21) x 10.77%						$839.43	$0.00	$839.43
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	1	0.02%	0.08%		$207	$0.05	$0.16	
27	kW = 0, 3 Phase	2	0.04%		0.06%	$252	$0.11		$0.16
28	kW > 1, 1 Phase	1,297	29.09%	99.92%		$207	$60.20	$206.81	
29	kW > 1, 3 Phase	3,159	70.85%		99.94%	$252	$178.81		$252.24
30	Total 0-50 kW	4,459	100.00%	100.00%	100.00%		$239.17	$206.97	$252.40
31	Annualized - (Line 30) x 10.77%						$25.76	$22.29	$27.18
32									
33	51-100 kW								
34	1 Phase	470	13.43%	100.00%		$207	$27.79	$206.97	
35	3 Phase W/O KVAR	1,791	51.17%		59.11%	$252	$129.16		$149.19
36	3 Phase With KVAR	1,239	35.40%		40.89%	$411	$145.46		$168.02
37	Total 51-100 kW	3,500	100.00%	100.00%	100.00%		$302.41	$206.97	$317.21
38	Annualized - (Line 37) x 10.77%						$32.57	$22.29	$34.16
39									
40	> 101kW								
41	1 Phase	54	2.67%	100.00%		$849	$22.70	$849.07	
42	3 Phase W/O KVAR	873	43.22%		44.40%	$1,365	$589.91		$606.12
43	3 Phase With KVAR	1,093	54.11%		55.60%	$1,365	$738.58		$758.86
44	Total > 101kW	2,020	100.00%	100.00%	100.00%		$1,351.19	$849.07	$1,364.98
45	Annualized - (Line 44) x 10.77%						$145.52	$91.44	$147.01
46									
47	Primary								
48	12.47 KV 4-wire Wye OH	50	100.00%		100.00%	$7,794	$7,794.11		$7,794.11
49	Annualized - (Line 48) x 10.77%						$839.43	$0.00	$839.43

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2008.

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
GS - Schedule 30 / LPS - Schedule 48T / Irrigation - Schedule 41 (Annual)

Line	Load Class	(A) Customers	(B) % of Customers: 1 & 3 Phase	(C) % of Customers: 1 Phase	(D) % of Customers: 3 Phase	(E) Metering Cost	(F) Weighted Metering Cost: 1 & 3 Phase	(G) Weighted Metering Cost: 1 Phase	(H) Weighted Metering Cost: 3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E) (F) x 10.77%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	1	0.42%	100.00%		$849	$3.54	$849.07	
4	3 Phase W/O KVAR	43	17.92%		17.99%	$1,365	$244.56		$245.58
5	3 Phase With KVAR	196	81.67%		82.01%	$1,365	$1,114.73		$1,119.40
6	Total 0-300 kW	240	100.00%	100.00%	100.00%		$1,362.83	$849.07	$1,364.98
7	Annualized - (Line 6) x 10.77%						$146.78	$91.44	$147.01
8									
9	301+ kW								
10	1 Phase	1	0.17%	0.00%		$921	$1.54	$0.00	
11	3 Phase W/O KVAR	79	13.23%		13.26%	$1,365	$180.63		$180.93
12	3 Phase With KVAR	517	86.60%		86.74%	$1,365	$1,182.07		$1,184.05
13	301+ kW	597	100.00%	0.00%	100.00%		$1,364.24	$0.00	$1,364.98
14	Annualized - (Line 13) x 10.77%						$146.93	$0.00	$147.01
15									
16	Primary								
17	12.47 KV 4-wire Wye OH	55	100.00%		100.00%	$7,794	$7,794.11		$7,794.11
18	Annualized - (Line 17) x 10.77%						$839.43		$839.43
19									
20	LPS - Schedule 48T								
21	1 - 4 MW (sec)	123	100.00%		100.00%	$1,706	$1,706.22		$183.76
22	1 - 4 MW (pri)	57	100.00%		100.00%	$7,794	$7,794.11		$839.43
23	> 4 MW (sec)	2	100.00%		100.00%	$1,706	$1,706.22		$183.76
24	> 4 MW (pri)	34	100.00%		100.00%	$7,794	$7,794.11		$839.43
25	Trans (trn)	2	100.00%		100.00%	$278,949	$278,948.50		$30,042.75
26		218							
27	Irrigation - Schedule 41 (Annual)								
28	0 - 50 kW								
29	kW = 0, 1 Phase	169	2.75%	13.99%		$86	$2.36	$12.01	
30	kW = 0, 3 Phase	718	11.69%		14.55%	$252	$29.50		$36.72
31	kW > 1, 1 Phase	1,038	16.90%	85.93%		$191	$32.24	$163.96	
32	kW > 1, 3 Phase	3,746	60.98%		75.91%	$252	$153.91		$191.59
33									
34	51 - 300 kW								
35	1 Phase	1	0.02%	0.08%		$207	$0.03	$0.17	
36	3 Phase W/O KVAR	334	5.44%		6.77%	$252	$13.72		$17.08
37	3 Phase With KVAR	122	1.99%		2.47%	$411	$8.16		$10.16
38									
39	> 300 kW								
40	1 Phase	-	0.00%	0.00%		$921	$0.00	$0.00	
41	3 Phase W/O KVAR	3	0.05%		0.06%	$1,365	$0.67		$0.83
42	3 Phase With KVAR	12	0.20%		0.24%	$1,365	$2.67		$3.32
43	Total Irrigation	6,143	100.00%	100.00%	100.00%		$243.26	$176.14	$259.70
44							$26.20	$18.97	$27.97
45									
46	Primary	-	100.00%		100.00%	$0	$0.00		$0.00
47							$0.00	$0.00	$0.00
46	Irrigation - Schedule 33* (Annual)								
47	0 - 50 kW								
48	kW = 0, 1 Phase	61	2.68%	85.92%		$86	$2.30	$73.73	
49	kW = 0, 3 Phase	208	9.14%		9.43%	$252	$23.07		$23.81
50	kW > 1, 1 Phase	10	0.44%	14.08%		$191	$0.84	$26.88	
51	kW > 1, 3 Phase	1,369	60.15%		62.09%	$252	$151.82		$156.71
52									
53	51 - 300 kW								
54	1 Phase	-	0.00%	0.00%		$207	$0.00	$0.00	
55	3 Phase W/O KVAR	24	1.05%		1.09%	$252	$2.66		$2.75
56	3 Phase With KVAR	596	26.19%		27.03%	$411	$107.60		$111.07
57									
58	> 300 kW								
59	1 Phase	-	0.00%	0.00%		$921	$0.00	$0.00	
60	3 Phase W/O KVAR	2	0.09%		0.09%	$1,365	$1.20		$1.24
61	3 Phase With KVAR	6	0.26%		0.27%	$1,365	$3.60		$3.71
62	Total Irrigation	2,276	100.00%	100.00%	100.00%		$293.09	$100.61	$299.29
46							$31.57	$10.84	$32.23

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2008.
* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Increment Three Phase
Meter and Services Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
Line	Load Class	Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
				(B) - (A)	(C) x 10.77%			(F) - (E)	(G) x 10.77%
1	Residential	$101.01	$252.40	$151.39	$16.30	$563.52	$804.52	$241.00	$25.96
2									
3	0-15 kW	$85.82	$252.40	$166.58	$17.94	$680.58	$905.38	$224.80	$24.21
4									
5	16-100 kW	$206.97	$252.40	$45.43	$4.89	$1,233.42	$1,674.00	$440.57	$47.45
6									
7	101-1000 kW	$920.76	$1,364.98	$444.22	$47.84	$3,622.67	$3,556.57	($66.10)	($7.12)
8									
9	1 - 4 MW	N.A.	$1,706.22	$1,706.22	$183.76	N.A.	$6,387.06	$6,387.06	$687.89

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2008 Dollars	(C) Indexed to 2010	(D) Percent Use	(E) Total Installed Cost per Service
	Residential					
1	Overhead (small load)	DM221A	$85.00	$85.82	57.00%	$48.92
2	Overhead (all electric)	DM221D	$120.00	$121.15	43.00%	$52.10
3					100.00%	$101.01
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase OH	DM221A	$85.00	$85.82	100.00%	$85.82
7				$169.11		
8	kW = 0, 3 Phase OH	DM241A	$250.00	$252.40	100.00%	$252.40
9						
10	kW > 1, 1 Phase OH	DM221B	$189.00	$190.81	100.00%	$190.81
11						
12	kW > 1, 3 Phase OH	DM241A	$250.00	$252.40	100.00%	$252.40
13				$125.27		
14				$59.55		$184.81
15	15 - 100 kW					
16	1 Phase OH	DM221C	$205.00	$206.97	100.00%	$206.97
17				$229.68		
18	3 Phase wo / KVAR OH	DM241A	$250.00	$252.40	100.00%	$252.40
19						
20	3 Phase with KVAR OH	DM241B	$407.00	$410.91	100.00%	$410.91
21						
22						
23	100 - 300 kW					
24	1 Phase OH	DM231ABB	$841.00	$849.07	100.00%	$849.07
25						
26	3 Phase wo / KVAR OH	DM271AEC	$1,352.00	$1,364.98	100.00%	$1,364.98
27						
28	3 Phase with KVAR OH	DM271AEC	$1,352.00	$1,364.98	100.00%	$1,364.98
29						
30						
31	300-1000 kW					
32	W/O KVAR, 1 Phase OH	DM231AFE	$912.00	$920.76	100.00%	$920.76
33						
34	W/O KVAR, 3 Phase OH	DM271AEC	$1,352.00	$1,364.98	100.00%	$1,364.98
35						
36	W/KVAR, 3 Phase OH	DM271AEC	$1,352.00	$1,364.98	100.00%	$1,364.98
37						
38						
39	1000 kW and over					
40	Secondary Volt(1) OH	DM271AFG	$1,690.00	$1,706.22	100.00%	$1,706.22
41						
42	Primary Metering					
43	13.8 KV 3-wire OH	DM101ACBI	$6,552.00	$6,614.90		$6,614.90
44	12.47 KV 4-wire Wye OH	DM121ABBI	$7,720.00	$7,794.11		$7,794.11
45	24.9 KV 4-wire Wye OH	DM121AGBI	$10,559.00	$10,660.37		$10,660.37
46	35 KV 4-wire Wye OH	DM131ABH	$24,297.00	$24,530.25		$24,530.25

Further Breakdown of Overhead

% of Overhead Which Are Small Load 57.00%
% of Overhead Which Are All Electric 43.00%

Pacific Region		
Index		Escalation Factor
2008	2010	2008 - 2010
333.8	337.0	1.0096

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

Line	Description	(A) 1998	(B) 1999	(C) 2000	(D) 2001	(E) 2002	(F) 2003	(G) 2004	(H) 2005	(I) 2006	(J) 2007
	Distribution Meters Expenses										
1	586 Meter Expense	2,283,801	-	-	1,479,307	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057
2	597 Main. of Meters	256,703	1,047,453	674,571	664,777	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945
3											
4	Total Adjusted Distribution Meters Expens	2,540,504	1,047,453	674,571	2,144,084	2,625,617	3,200,559	3,130,131	3,470,409	3,727,536	3,767,002
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	54,919,747	56,597,405	55,765,666	56,108,548	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	4.63%	1.85%	1.21%	3.82%	4.60%	5.63%	5.52%	5.97%	6.38%	6.37%
16	Line 3 / Line 4										
17											
18	Average Meter O&M Loading	4.60%									
19	Average of Line 5										
20											
21	Distribution Annual Charge	10.77%									
22											
23	Annualized Meter O&M Loading Factor	$\boxed{42.69\%}$									
24	Line 6 / Line 7										

Exhibit PPL/919

11. Cust. Service Drop

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers			Service Drop Cost	Weighted Service Drop Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase		1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	469,380	100.00%	100.00%		$482	$482.50	$482.50	
2	Annualized - Line 1 x 10.77%						$51.97	$51.97	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	50,770	77.69%	93.15%		$564	$437.79	$524.91	
7	kW = 0, 3 Phase	3,767	5.76%		34.73%	$805	$46.37		$279.40
8	kW > 1, 1 Phase	3,735	5.72%	6.85%		$681	$38.90	$46.64	
9	kW > 1, 3 Phase	7,080	10.83%		65.27%	$905	$98.09		$590.96
10	Total 0-15 kW	65,352	100.00%	100.00%	100.00%		$621.15	$571.55	$870.36
11	Annualized - Line 10 x 10.77%						$66.90	$61.56	$93.74
12									
13	15+ kW								
14	1 Phase	4,035	42.59%	100.00%		$1,233	$525.32	$1,233.42	
15	3 Phase W/O KVAR	4,579	48.33%		84.19%	$1,674	$809.08		$1,409.31
16	3 Phase With KVAR	860	9.08%		15.81%	$1,674	$151.96		$264.69
17	Total 15+ kW	9,474	100.00%	100.00%	100.00%		$1,486.36	$1,233.42	$1,674.00
18	Annualized - Line 17 x 10.77%						$160.08	$132.84	$180.29
19									
20	Primary								
21	12.47 KV 4-wire Wye OH	34	100.00%		100.00%	$1,674		$1,674.00	$0.00
22	Annualized - (Line 21) x 10.77%					$180.29	$0.00	$180.29	$0.00
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	1	0.02%	0.08%		$1,233	$0.28	$0.95	
27	kW = 0, 3 Phase	2	0.04%		0.06%	$1,674	$0.75		$1.06
28	kW > 1, 1 Phase	1,297	29.09%	99.92%		$1,233	$358.77	$1,232.47	
29	kW > 1, 3 Phase	3,159	70.85%		99.94%	$1,674	$1,185.95		$1,672.94
30	Total 0-50 kW	4,459	100.00%	100.00%	100.00%		$1,545.75	$1,233.42	$1,674.00
31	Annualized - Line 30 x 10.77%						$166.48	$132.84	$180.29
32									
33	51-100 kW								
34	1 Phase	470	13.43%	100.00%		$1,233	$165.63	$1,233.42	
35	3 Phase W/O KVAR	1,791	51.17%		59.11%	$1,674	$856.61		$989.48
36	3 Phase With KVAR	1,239	35.40%		40.89%	$1,674	$592.60		$684.52
37	Total 51-100 kW	3,500	100.00%	100.00%	100.00%		$1,614.84	$1,233.42	$1,674.00
38	Annualized - Line 37 x 10.77%						$173.92	$132.84	$180.29
39									
40	> 101kW								
41	1 Phase	54	2.67%	100.00%		$3,623	$96.84	$3,622.67	
42	3 Phase W/O KVAR	873	43.22%		44.40%	$3,557	$1,537.07		$1,579.29
43	3 Phase With KVAR	1,093	54.11%		55.60%	$3,557	$1,924.42		$1,977.28
44	Total > 101kW	2,020	100.00%	100.00%	100.00%		$3,558.33	$3,622.67	$3,556.57
45	Annualized - Line 44 x 10.77%						$383.23	$390.16	$383.04
46									
47	Primary								
48	12.47 KV 4-wire Wye OH	50	100.00%		100.00%	$0	$0.00		$0.00
49	Annualized - (Line 48) x 10.77%						$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2008.

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
GS - Schedule 30 / LPS - Schedule 48T / Irrigation - Schedule 41 (Annual)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers			Service	Weighted Service Drop Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Drop Cost	1 & 3 Phase	1 Phase	Annualized 3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	
1	GS - Schedule 30								
2									
3	0-300 kW								
4	1 Phase	1	0.42%	100.00%		$3,623	$15.09	$3,622.67	
5	3 Phase W/O KVAR	43	17.92%		17.99%	$3,557	$637.22		$639.88
6	3 Phase With KVAR	196	81.67%		82.01%	$3,557	$2,904.53		$2,916.68
7	Total 0-300 kW	240	100.00%	100.00%	100.00%	$10,736	$3,556.84	$3,622.67	$3,556.56
8	Annualized - Line 7 x 10.77%						$383.07	$390.16	$383.04
9									
10	301+ kW								
11	1 Phase	1	0.17%	100.00%		$3,623	$6.07	$3,622.67	
12	3 Phase W/O KVAR	79	13.23%		13.26%	$3,557	$470.63		$471.42
13	3 Phase With KVAR	517	86.60%		86.74%	$3,557	$3,079.98		$3,085.14
14	Total 301+ kW	597	100.00%	100.00%	100.00%		$3,556.68	$3,622.67	$3,556.56
15	Annualized - Line 14 x 10.77%						$383.05	$390.16	$383.04
16									
17	Primary								
18	12.47 KV 4-wire Wye OH	55	100.00%		100.00%	$0	$0.00		$0.00
19	Annualized - Line 18 x 10.77%						$0.00		$0.00
20									
21	LPS - Schedule 48T								
22	1 - 4 MW (sec)	123	100.00%		100.00%	$6,387	$6,387.06		$687.89
23	1 - 4 MW (pri)	57	100.00%		100.00%	$0	$0.00		$0.00
24	> 4 MW (sec)	2	100.00%		100.00%	$6,387	$6,387.06		$687.89
25	> 4 MW (pri)	34	100.00%		100.00%	$0	$0.00		$0.00
26	Trans (trn)	2	100.00%		100.00%	$0	$0.00		$0.00

Footnote:
3 Phase With KVAR
Column (E) - see Tab 12.3 (Services 3:) `Summary of Average Installed Costs Service Drops'

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

Line	Load Class	(A) Service Conductor	(B) Cost	(C) Indexed to 2010	(D) Percent Use	(E) Total Cost per Service
				(B) x 0.9793 - OH (B) x 1.0263 - UG		
	Residential					
1	OH - small load	#2 Triplex*	$431	$422	18.65%	$78.73
2	OH - all electric	1/0 Triplex	$503	$493	14.07%	$69.32
3	UG - small load	1/0 Triplex	$425	$436	0.67%	$2.93
4	UG - all electric	4/0 Triplex	$485	$498	66.60%	$331.52
5						$482.50
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	$567	$555	32.73%	$181.71
8		UG - 1/0 Triplex	$553	$568	67.27%	$381.81
9						$563.52
10						
11	kW = 0, 3 Phase	OH - 1/0 Quadruplex	$761	$745	32.73%	$243.88
12		UG - 1/0 Quadruplex	$812	$833	67.27%	$560.64
13						$804.52
14						
15	kW > 1, 1 Phase	OH - 4/0 Triplex	$803	$786	32.73%	$257.34
16		UG - 4/0 Triplex	$613	$629	67.27%	$423.24
17						$680.58
18						
19	kW > 1, 3 Phase	OH - 4/0 Quadruplex	$968	$948	32.73%	$310.22
20		UG - 4/0 Quadruplex	$862	$885	67.27%	$595.16
21						$905.38
22	15 - 100 kW					
23	1 Phase	OH - 2-4/0 Triplex	$1,481	$1,450	32.73%	$474.63
24		UG - 2-4/0 Triplex	$1,099	$1,128	67.27%	$758.79
25						$1,233.42
26						
27	3 Phase WO / KVAR	OH - 2-4/0 Quadruplex	$1,785	$1,748	32.73%	$572.05
28		UG - 2-4/0 Quadruplex	$1,596	$1,638	67.27%	$1,101.94
29						$1,674.00
30						
31	3 Phase W / KVAR	OH - 2-4/0 Quadruplex	$1,785	$1,748	32.73%	$572.05
32		UG - 2-4/0 Quadruplex	$1,596	$1,638	67.27%	$1,101.94
33						$1,674.00
34	100-1000 kW					
35	W/O KVAR, 1 Phase	3-500 & 350N	$3,561	$3,487	32.73%	$1,141.22
36		3- 750 & 500 N	$3,594	$3,689	67.27%	$2,481.44
37						$3,622.67
38						
39	W/O KVAR, 3 Phase	OH - 3-4/0 Quadruplex	$3,428	$3,357	32.73%	$1,098.60
40		4-350 Quad	$3,560	$3,654	67.27%	$2,457.97
41						$3,556.57
42						
43	W/KVAR, 3 Phase	OH - 3-4/0 Quadruplex	$3,428	$3,357	32.73%	$1,098.60
44		4-350 Quad	$3,560	$3,654	67.27%	$2,457.97
45						$3,556.57
46	1000 kW and Over					
47	Secondary Volt(1)	3-500 kcmil Quad.	$5,687	$5,569	32.73%	$1,822.56
48		4-500 kcmil Quad.	$6,611	$6,785	67.27%	$4,564.51
49						$6,387.06
50						
51	Primary Volt	—	—	—		—

Pacific Region			
	Index		Escalation Factor
Service Type	2008	2010	2008 - 2010
Overhead	486.9	476.8	0.9793
Underground	353.3	362.6	1.0263

		Weighted %
Overhead % =	32.73%	
% of Overhead Which Are Small Load=	57.00%	18.65%
% of Overhead Which Are All Electric=	43.00%	14.07%
Underground % =	67.27%	
% of Underground Which Are Small Load=	1.00%	0.67%
% of Underground Which Are All Electric=	99.00%	66.60%
Total OH & UG		100.00%

Exhibit PPL/919
12. Cust. Acctg.,
Service & Info

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2010 Dollars

Line	FERC Account	Description	(A) Sch. 4 Res	(B) Sch. 23 Com	(C) Sch. 28 Com	(D) Sch. 30 Com	(E) Sch. 48T Ind	(F) Sch. 41 Irrigation	(G) Sch. 33* Irrigation	(H) Streetlighting	(I) Total
1		Average Number of Customers	478,485	74,055	10,100	854	215	2,834	756	1,041	567,584
2											
3		Write-offs By Schedule	1,372,331	57,241	71,861	43,522	67,501	9,875	1,972	-	1,622,330
4											
5	901										
6	Supervision	Account 902 + 903 + 904	$26,995,625	$3,746,186	$753,142	$246,494	$314,740	$204,441	$52,118	$32,660	$32,293,287
7		% of Total 902 + 903 +904	83.60%	11.60%	2.33%	0.76%	0.97%	0.63%	0.16%	0.10%	100.00%
8		Total 901 $	$2,946,291	$408,857	$82,198	$26,902	$34,351	$22,313	$5,688	$3,565	$3,524,476
9		Dollars Per Customer	$6.16	$5.52	$8.14	$31.50	$159.77	$7.87	$7.52	$3.42	$6.21
10	902										
11	Meter Reading Expense	902 Weighting Factor	1.00	1.24	1.20	5.41	8.21	1.91	1.91	0.12	
12		Weighted Customers	478,485	91,828	12,120	4,620	1,765	5,413	1,445	125	594,357
13		% of Total $	80.50%	15.45%	2.04%	0.78%	0.30%	0.91%	0.24%	0.02%	100.00%
14		Total 902 $	$6,698,382	$1,285,517	$169,670	$64,678	$24,711	$75,780	$20,174	$1,749	$8,320,486
15		Dollars Per Customer	$14.00	$17.36	$16.80	$75.74	$114.93	$26.74	$26.67	$1.68	$14.66
16	903										
17	Cust. Receipts & Collect.	903 Weighting Factor	1.00	0.94	1.01	1.01	7.38	1.02	1.02	0.92	
18		Weighted Customers	478,485	69,971	10,202	863	1,587	2,904	775	958	564,969
19		% of Total $	84.69%	12.38%	1.81%	0.15%	0.28%	0.51%	0.14%	0.17%	100.00%
20		Total 903 $	$15,442,060	$2,258,157	$329,236	$27,838	$51,218	$93,723	$24,977	$30,911	$18,233,143
21		Dollars Per Customer	$32.27	$30.49	$32.60	$32.60	$238.22	$33.07	$33.02	$29.69	$32.12
22	904										
23	Uncollectibles	Total 904 $	$4,855,183	$202,513	$254,236	$153,977	$238,812	$34,937	$6,968	$0	$5,739,658
24		% of Write-offs	84.59%	3.53%	4.43%	2.68%	4.16%	0.61%	0.12%	0.00%	
25		Dollars Per Customer	$10.15	$2.73	$25.17	$180.30	$1,110.75	$12.33	$9.21	$0.00	$10.11
26	905										
27	Misc Cust Acct Expense	Account 902 + 903 + 904	$26,995,625	$3,746,186	$753,142	$246,494	$314,740	$204,441	$52,118	$32,660	$32,293,287
28		% of Total 902 + 903 +904	83.60%	11.60%	2.33%	0.76%	0.97%	0.63%	0.16%	0.10%	100.00%
29		Total 905 $	$317,337	$44,037	$8,853	$2,898	$3,700	$2,403	$613	$384	$379,612
30		Dollars Per Customer	$0.66	$0.59	$0.88	$3.39	$17.21	$0.85	$0.81	$0.37	$0.67
31	907-910										
32	Supervision, Cust. Assist.	Average Number of customers	478,485	74,055	10,100	854	215	2,834	756	1,041	567,584
33	Info & Instructional Exp.,	% of Total	84.30%	13.05%	1.78%	0.15%	0.04%	0.50%	0.13%	0.18%	100.13%
34	Misc Cust Svc & Info Exp.		$2,870,123	$444,208	$60,583	$5,123	$1,290	$17,000	$4,531	$6,244	$3,404,571
35		Dollars Per Customer	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$5.99	$6.00	$6.00
36											
37	Total 901 - 910	Total 901 - 910 $	$33,129,376	$4,643,289	$904,776	$281,416	$354,080	$246,157	$62,950	$42,853	$39,601,946
38											
39		Dollars Per Customer	$69.24	$62.70	$89.58	$329.53	$1,646.88	$86.85	$83.23	$41.16	$69.77

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2010 Dollars

Line	Description	(A) Actual 2003 Dollars	(B) Actual 2004 Dollars	(C) Actual 2005 Dollars	(D) Actual 2006 Dollars	(E) Actual 2007 Dollars	(F) Adjusted 2010 Dollars
							[(A) x 1.1444+ (B) x 1.1225+ (C) x 1.1011+ (D) x 1.0801+ (E) x 1.0595] / 5
	Customer Accounting						
1	901 Supervision	3,025,374	3,174,507	3,981,235	4,869,032	900,404	$3,524,476
2	902 Meter Reading Expense	6,581,669	7,168,249	7,441,361	7,127,052	9,563,375	$8,320,486
3	903 Cust Records & Collection	14,670,810	15,439,733	17,239,535	17,663,200	17,918,701	$18,233,143
4	904 Uncollectible Accounts	8,406,244	3,642,666	5,085,904	5,205,538	3,555,170	$5,739,658
5	905 Misc Cust Acct Expense	389,396	377,084	405,292	417,356	124,686	$379,612
6	Total	33,073,493	29,802,239	34,153,327	35,282,178	32,062,336	$36,197,375
7							
8	Customer Service & Info Expense						
9	907 Supervision	967,318	1,293,118	878,667	429,900	138,616	$827,445
10	908 Cust Assistance Expense	871,273	1,388,517	1,301,282	2,358,698	2,488,601	$1,834,568
11	909 Info & Instructional Expense	302,597	329,063	199,651	996,352	1,248,551	$666,900
12	910 Misc Cust Svc & Info Expense	141,635	95,307	94,643	3,238	1,429	$75,658
13	Total	2,282,823	3,106,005	2,474,243	3,788,188	3,877,197	$3,404,571
14							$39,601,946
15	Distribution Expenses						
16	586 Meter Expenses	$2,010,097	$1,892,897	$2,122,259	$2,058,440	$2,206,057	$2,264,518
17	597 Meter Maintenance	$1,190,462	$1,237,234	$1,348,150	$1,669,096	$1,560,945	$1,538,444
18		$3,200,559	$3,130,131	$3,470,409	$3,727,536	$3,767,002	$3,802,962
19							
20							
21	(1) Inflation Adjustment -	1.1444	1.1225	1.1011	1.0801	1.0595	

Source:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Pacificorp
Oregon Marginal Cost Study
Account 903 Cust. Bill & Acctng
Weighting Factors

			(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Description	Residential	Small GS	Large GS	Industrial	Irrigation	Streetlighting	Total
	System customers -	June 2008 Total PacifiCorp Customers	1,461,432	197,965	29,582	666	23,458	31,136	1,744,240
1	FERC Accounts								
2	903.0	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
3	(Weighted on Customers)	Weighted customers	1,461,432	197,965	29,582	666	23,458	31,136	1,744,240
4		% of Total	83.79%	11.35%	1.70%	0.04%	1.34%	1.79%	100.00%
5		Total $	$669,157	$90,644	$13,545	$305	$10,741	$14,257	$798,649
6									
7	903.1	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
8	Customer Records& Customer System Expense	Weighted customers	1,461,432	197,965	29,582	666	23,458	31,136	1,744,240
9	(Weighted on Customers)	% of Total	83.79%	11.35%	1.70%	0.04%	1.34%	1.79%	100.00%
10		Total $	$3,745,860	$507,412	$75,823	$1,708	$60,127	$79,807	$ 4,470,735
11									
12	903.2	Weighting	1.00	1.01	1.14	29.60	1.00	1.00	(Weighted on m
13	Customer Accounting-Billing	Weighted customers	1,461,432	200,197	33,679	19,721	23,371	31,020	1,769,421
14	(Weighted on manual billing)	% of Total	82.59%	11.31%	1.90%	1.11%	1.32%	1.75%	100.00%
15		Total $	$7,669,828	$1,050,666	$176,754	$103,500	$122,653	$162,799	$ 9,286,200
16									
17	903.3	Weighting	1.00	0.79	0.93	2.49	1.09	0.72	(Weighted on W
18	Customer Accounting-Collections	Weighted customers	1,461,432	157,295	27,592	1,656	25,592	22,333	1,695,900
19	(Weighted on Writeoffs)	% of Total	86.17%	9.28%	1.63%	0.10%	1.51%	1.32%	100.00%
20		Total $	$10,290,712	$1,107,596	$194,288	$11,663	$180,204	$157,259	$ 11,941,722
21									
22	903.5	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
23	Customer Acct - Requests	Weighted customers	1,461,432	197,965	29,582	666	23,458	31,136	1,744,240
24	(Weighted on Customers)	% of Total	83.79%	11.35%	1.70%	0.04%	1.34%	1.79%	100.00%
25		Total $	$435,322	$58,968	$8,812	$198	$6,988	$9,275	$519,562
26									
27	903.6	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	(Weighted on C
28	Customer Acct - Common	Weighted customers	1,461,432	197,965	29,582	666	23,458	31,136	1,744,240
29		% of Total	83.79%	11.35%	1.70%	0.04%	1.34%	1.79%	100.00%
30		Total $	$13,954,906	$1,890,323	$282,471	$6,363	$223,997	$297,313	$16,655,373
31									
126									
127	Total Acct. 903	Total 903 $	$36,765,784	$4,705,609	$751,693	$123,737	$604,709	$720,710	$43,672,242
128		Dollars Per Customer	$25.16	$23.77	$25.41	$185.70	$25.78	$23.15	
129									
130		Weighting Factor for 903	1.00	0.94	1.01	7.38	1.02	0.92	

Exhibit PPL/919

13. A&G Expense

Loading Factor

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses (000)	(B) Electric Plant in Service (000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
1998	$338,402	$11,784,334	2.87%
1999	$209,710	$12,110,787	1.73%
2000	$100,360	$11,910,796	0.84%
2001	$180,629	$12,289,187	1.47%
2002	$277,395	$12,690,449	2.19%
2003	$251,357	$13,208,159	1.90%
2004	$244,893	$13,688,398	1.79%
2005	$236,709	$14,335,797	1.65%
2006	$238,645	$15,317,103	1.56%
2007	$180,356	$16,417,338	1.10%
10 Year Average A&G to EPIS Loading Factor			1.71%

Footnotes:
(A) FERC Form 1 Page 322-323 (2007)
(B) FERC Form 1 Page 206-207 (2007)

Charge 1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

Line	Description	(A) 20 years - Generation	(B) 10 years - Generation	(C) 5 years - Generation	(D) System Transmission	(E) Distribution
1	Levelized Income Taxes *	NA	NA	NA	2.02%	2.04%
2	Levelized Property Tax *	NA	NA	NA	1.12%	1.12%
3	Total	NA	NA	NA	3.14%	3.16%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$31.40	$31.60
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	58	50
9						
10	Nominal Interest Rate *	8.53%	8.53%	8.53%	8.53%	8.53%
11						
12	Present Value: Income **	NA	NA	NA	$364.97	$364.32
13	Taxes & Property Taxes per				(PV of $31.40 per year	(PV of $31.60 per year
14	$1,000 of Investment				for 58 years at 8.53%)	for 50 years at 8.53%)
15						
16	Removal Cost Per $1,000 Investment				$204.38	$463.24
17						
18	Present Value: Removal Cost				$1.77	$7.74
19	at End of Useful Life				(PV of $204.38 in	(PV of $463.24 in
20					58 years at 8.53%)	50 years at 8.53%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,366.74	$1,372.06
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.019100	0.040968
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$26.10	$56.21
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,392.84	$1,428.27
30						
31	EOY Annual Charge ***	$84.97	$130.41	$225.78	$86.80	$90.61
32						
33	Annual Economic Carrying	8.50%	13.04%	22.58%	8.68%	9.06%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	1.71%	1.71%
35						
36	Annual Econ Carrying + A&G Loading	8.50%	13.04%	22.58%	10.39%	10.77%

Footnotes:
From Financial Analysis -
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]   31.40*(1/0.0853-(1/0.0853)/(1+0.0853)^58)
31.60*(1/0.0853-(1/0.0853)/(1+0.0853)^50)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula: AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate = 1.9%
a = expected investment life
r = nominal interest rate

PacifiCorp
Oregon Marginal Cost Study
Financial Inputs to the Economic Carrying Charge Calculation

	(A)	(B)	(C)	(D)
	Financial Inputs		Levelized	
1	Weighted Cost of Capital	8.53%	Income Taxes	
2	Borrowing Rate	8.53%	Transmission	2.02%
3	Inflation	1.95%	Distribution	2.04%
4			Property Taxes	
5	Real Cost of Capital		Transmission	1.12%
6	(1+0.0853)/(1+0.0195)-1 =	$\boxed{6.46\%}$	Distribution	1.12%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: Financial Analysis, Use of Facilities Charges 12/31/07 Basis (prepared 8/19/08)
Inflation Rate 2007-2026, 2004 IRP, Appendix C, Table C.1

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life

Real Cost of Capital = 6.46%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0646 ^Year	(C) / (D)	(B)	1.0646 ^58	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000145	1.59%	0.0159	1.064581	0.014900	0.0159	37.702878	0.000421	0.014479	99.9841
2	0.000416	3.17%	0.0317	1.133334	0.027992	0.0317	37.702878	0.000841	0.027150	99.9524
3	0.000671	3.17%	0.0317	1.206526	0.026294	0.0317	37.702878	0.000841	0.025452	99.9207
4	0.000978	4.08%	0.0408	1.284445	0.031786	0.0408	37.702878	0.001083	0.030703	99.8799
5	0.001308	4.69%	0.0469	1.367396	0.034296	0.0469	37.702878	0.001244	0.033052	99.8330
6	0.001618	4.69%	0.0469	1.455705	0.032216	0.0469	37.702878	0.001244	0.030972	99.7861
7	0.001999	6.16%	0.0616	1.549716	0.039763	0.0616	37.702878	0.001634	0.038128	99.7244
8	0.002393	6.79%	0.0679	1.649799	0.041175	0.0679	37.702878	0.001802	0.039374	99.6565
9	0.002762	6.79%	0.0679	1.756345	0.038677	0.0679	37.702878	0.001802	0.036876	99.5886
10	0.003218	8.97%	0.0897	1.869772	0.047987	0.0897	37.702878	0.002380	0.045607	99.4989
11	0.003671	9.52%	0.0952	1.990525	0.047813	0.0952	37.702878	0.002524	0.045288	99.4037
12	0.004095	9.52%	0.0952	2.119076	0.044912	0.0952	37.702878	0.002524	0.042388	99.3085
13	0.004623	12.68%	0.1268	2.255928	0.056220	0.1268	37.702878	0.003364	0.052856	99.1817
14	0.005131	13.03%	0.1303	2.401619	0.054274	0.1303	37.702878	0.003457	0.050817	99.0513
15	0.005607	13.03%	0.1303	2.556719	0.050981	0.1303	37.702878	0.003457	0.047524	98.9210
16	0.006201	17.45%	0.1745	2.721836	0.064105	0.1745	37.702878	0.004628	0.059477	98.7465
17	0.006757	17.45%	0.1745	2.897616	0.060216	0.1745	37.702878	0.004628	0.055588	98.5720
18	0.007293	17.99%	0.1799	3.084748	0.058329	0.1799	37.702878	0.004772	0.053557	98.3921
19	0.007929	22.90%	0.2290	3.283965	0.069722	0.2290	37.702878	0.006073	0.063649	98.1631
20	0.008524	22.90%	0.2290	3.496048	0.065493	0.2290	37.702878	0.006073	0.059420	97.9342
21	0.009110	24.21%	0.2421	3.721828	0.065059	0.2421	37.702878	0.006422	0.058637	97.6920
22	0.009776	29.48%	0.2948	3.962189	0.074410	0.2948	37.702878	0.007820	0.066591	97.3972
23	0.010397	29.48%	0.2948	4.218072	0.069896	0.2948	37.702878	0.007820	0.062077	97.1024
24	0.011021	31.83%	0.3183	4.490481	0.070886	0.3183	37.702878	0.008443	0.062443	96.7841
25	0.011703	37.31%	0.3731	4.780483	0.078047	0.3731	37.702878	0.009896	0.068151	96.4110
26	0.012337	37.31%	0.3731	5.089213	0.073313	0.3731	37.702878	0.009896	0.063417	96.0379
27	0.012984	40.98%	0.4098	5.417882	0.075637	0.4098	37.702878	0.010869	0.064768	95.6281
28	0.013667	46.48%	0.4648	5.767776	0.080590	0.4648	37.702878	0.012329	0.068262	95.1632
29	0.014301	46.48%	0.4648	6.140267	0.075702	0.4648	37.702878	0.012329	0.063373	94.6984
30	0.014956	51.79%	0.5179	6.536814	0.079233	0.5179	37.702878	0.013737	0.065496	94.1805
31	0.015625	57.10%	0.5710	6.958970	0.082057	0.5710	37.702878	0.015146	0.066912	93.6094
32	0.016244	57.10%	0.5710	7.408390	0.077079	0.5710	37.702878	0.015146	0.061934	93.0384
33	0.016890	64.45%	0.6445	7.886835	0.081716	0.6445	37.702878	0.017094	0.064623	92.3939
34	0.017532	69.34%	0.6934	8.396177	0.082591	0.6934	37.702878	0.018392	0.064199	91.7005
35	0.018124	69.34%	0.6934	8.938414	0.077581	0.6934	37.702878	0.018392	0.059188	91.0070
36	0.018746	79.17%	0.7917	9.515669	0.083199	0.7917	37.702878	0.020998	0.062200	90.2153
37	0.019348	83.38%	0.8338	10.130205	0.082308	0.8338	37.702878	0.022115	0.060193	89.3816
38	0.019900	83.38%	0.8338	10.784427	0.077315	0.8338	37.702878	0.022115	0.055200	88.5478
39	0.020484	96.34%	0.9634	11.480901	0.083917	0.9634	37.702878	0.025554	0.058364	87.5843
40	0.021034	99.59%	0.9959	12.222353	0.081479	0.9959	37.702878	0.026413	0.055065	86.5884
41	0.021536	99.59%	0.9959	13.011690	0.076536	0.9959	37.702878	0.026413	0.050123	85.5926
42	0.022067	116.28%	1.1628	13.852003	0.083947	1.1628	37.702878	0.030842	0.053105	84.4298
43	0.022555	118.14%	1.1814	14.746584	0.080112	1.1814	37.702878	0.031334	0.048778	83.2484
44	0.022994	118.14%	1.1814	15.698939	0.075252	1.1814	37.702878	0.031334	0.043918	82.0670
45	0.023458	139.28%	1.3928	16.712799	0.083335	1.3928	37.702878	0.036940	0.046394	80.6742
46	0.023871	139.28%	1.3928	17.792135	0.078279	1.3928	37.702878	0.036940	0.041339	79.2815
47	0.024243	141.63%	1.4163	18.941175	0.074776	1.4163	37.702878	0.037566	0.037210	77.8651
48	0.024619	162.86%	1.6286	20.164423	0.080767	1.6286	37.702878	0.043196	0.037571	76.2365
49	0.024946	162.86%	1.6286	21.466669	0.075867	1.6286	37.702878	0.043196	0.032671	74.6079
50	0.025235	167.95%	1.6795	22.853017	0.073492	1.6795	37.702878	0.044546	0.028946	72.9284
51	0.025510	188.31%	1.8831	24.328896	0.077402	1.8831	37.702878	0.049946	0.027456	71.0453
52	0.025737	188.31%	1.8831	25.900090	0.072706	1.8831	37.702878	0.049946	0.022761	69.1622
53	0.025928	196.04%	1.9604	27.572754	0.071098	1.9604	37.702878	0.051995	0.019103	67.2018
54	0.026090	214.07%	2.1407	29.353441	0.072928	2.1407	37.702878	0.056778	0.016150	65.0611
55	0.026207	214.07%	2.1407	31.249127	0.068504	2.1407	37.702878	0.056778	0.011726	62.9204
56	0.026286	223.53%	2.2353	33.267239	0.067193	2.2353	37.702878	0.059288	0.007905	60.6851
57	0.026327	237.72%	2.3772	35.415684	0.067124	2.3772	37.702878	0.063052	0.004072	58.3079
58	0.026327	237.72%	2.3772	37.702878	0.063052	2.3772	37.702878	0.063052	0.000000	55.9306
59	0.026287	246.88%	2.4688	40.137782	0.061508	2.4688	37.702878	0.065480	-0.003972	53.4618
60	0.026207	256.03%	2.5603	42.729936	0.059919	2.5603	37.702878	0.067908	-0.007989	50.9015

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0646 ^Year	(C) / (D)	(B)	1.0646 ^58	(F) / (G)	(E) - (H)	(Given)
61	0.026091	256.03%	2.5603	45.489495	0.056284	2.5603	37.702878	0.067908	-0.011624	48.3411
62	0.025937	261.70%	2.6170	48.427270	0.054041	2.6170	37.702878	0.069412	-0.015372	45.7241
63	0.025748	265.48%	2.6548	51.554771	0.051495	2.6548	37.702878	0.070414	-0.018919	43.0693
64	0.025528	265.48%	2.6548	54.884249	0.048371	2.6548	37.702878	0.070414	-0.022043	40.4144
65	0.025279	263.96%	2.6396	58.428751	0.045177	2.6396	37.702878	0.070011	-0.024834	37.7748
66	0.025004	263.31%	2.6331	62.202161	0.042331	2.6331	37.702878	0.069838	-0.027507	35.1417
67	0.024703	263.31%	2.6331	66.219263	0.039763	2.6331	37.702878	0.069838	-0.030075	32.5086
68	0.024393	251.34%	2.5134	70.495795	0.035653	2.5134	37.702878	0.066663	-0.031010	29.9952
69	0.024066	248.34%	2.4834	75.048511	0.033091	2.4834	37.702878	0.065869	-0.032778	27.5118
70	0.023718	248.34%	2.4834	79.895249	0.031084	2.4834	37.702878	0.065869	-0.034785	25.0283
71	0.023386	224.39%	2.2439	85.054995	0.026381	2.2439	37.702878	0.059514	-0.033133	22.7845
72	0.023043	221.72%	2.2172	90.547965	0.024487	2.2172	37.702878	0.058808	-0.034321	20.5672
73	0.022685	221.72%	2.2172	96.395679	0.023001	2.2172	37.702878	0.058808	-0.035807	18.3500
74	0.022371	187.10%	1.8710	102.621046	0.018232	1.8710	37.702878	0.049626	-0.031393	16.4790
75	0.022046	187.10%	1.8710	109.248456	0.017126	1.8710	37.702878	0.049626	-0.032499	14.6079
76	0.021718	183.31%	1.8331	116.303873	0.015761	1.8331	37.702878	0.048620	-0.032858	12.7748
77	0.021442	149.17%	1.4917	123.814939	0.012048	1.4917	37.702878	0.039565	-0.027517	11.2831
78	0.021160	149.17%	1.4917	131.811080	0.011317	1.4917	37.702878	0.039565	-0.028248	9.7914
79	0.020885	141.86%	1.4186	140.323623	0.010109	1.4186	37.702878	0.037624	-0.027515	8.3728
80	0.020661	112.59%	1.1259	149.385918	0.007537	1.1259	37.702878	0.029861	-0.022325	7.2470
81	0.020434	112.59%	1.1259	159.033469	0.007079	1.1259	37.702878	0.029861	-0.022782	6.1211
82	0.020222	102.87%	1.0287	169.304072	0.006076	1.0287	37.702878	0.027285	-0.021209	5.0924
83	0.020053	80.21%	0.8021	180.237964	0.004450	0.8021	37.702878	0.021273	-0.016823	4.2903
84	0.019882	80.21%	0.8021	191.877983	0.004180	0.8021	37.702878	0.021273	-0.017093	3.4882
85	0.019732	69.35%	0.6935	204.269730	0.003395	0.6935	37.702878	0.018394	-0.014999	2.7947
86	0.019616	53.07%	0.5307	217.461754	0.002440	0.5307	37.702878	0.014076	-0.011635	2.2640
87	0.019498	53.07%	0.5307	231.505736	0.002292	0.5307	37.702878	0.014076	-0.011783	1.7333
88	0.019404	42.14%	0.4214	246.456699	0.001710	0.4214	37.702878	0.011176	-0.009467	1.3120
89	0.019333	31.21%	0.3121	262.373216	0.001189	0.3121	37.702878	0.008277	-0.007088	0.9999
90	0.019261	31.21%	0.3121	279.317643	0.001117	0.3121	37.702878	0.008277	-0.007160	0.6878
91	0.019212	21.32%	0.2132	297.356365	0.000717	0.2132	37.702878	0.005654	-0.004937	0.4747
92	0.019177	14.72%	0.1472	316.560053	0.000465	0.1472	37.702878	0.003905	-0.003440	0.3274
93	0.019143	14.72%	0.1472	337.003942	0.000437	0.1472	37.702878	0.003905	-0.003468	0.1802
94	0.019125	7.46%	0.0746	358.768126	0.000208	0.0746	37.702878	0.001978	-0.001770	0.1056
95	0.019115	4.34%	0.0434	381.937871	0.000114	0.0434	37.702878	0.001152	-0.001039	0.0621
96	0.019104	4.34%	0.0434	406.603950	0.000107	0.0434	37.702878	0.001152	-0.001046	0.0187
97	0.019101	1.14%	0.0114	432.862999	0.000026	0.0114	37.702878	0.000304	-0.000277	0.0072
98	0.019100	0.34%	0.0034	460.817894	0.000007	0.0034	37.702878	0.000091	-0.000084	0.0038
99	0.019100	0.34%	0.0034	490.578155	0.000007	0.0034	37.702878	0.000091	-0.000084	0.0003
100	0.019100	0.03%	0.0003	522.260375	0.000001	0.0003	37.702878	0.000009	-0.000008	0.0000
101	0.019100	0.00%	0.0000	555.988677	0.000000	0.0000	37.702878	0.000000	0.000000	0.0000
102	0.019100	0.00%	0.0000	591.895200	0.000000	0.0000	37.702878	0.000000	0.000000	0.0000
103	0.019100	0.00%	0.0000	630.120616	0.000000	0.0000	37.702878	0.000000	0.000000	0.0000
104	0.019100	0.00%	0.0000	670.814682	0.000000	0.0000	37.702878	0.000000	0.000000	0.0000
		100.0000	100.0000							

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.0 & 50 Year Average Life

Real Cost of Capital = 6.46%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0646 ^Year	(C) / (D)	(B)	1.0646 ^50	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000910	10.16%	0.1016	1.064581	0.095437	0.1016	22.853017	0.004446	0.090991	99.8984
2	0.002614	20.32%	0.2032	1.133334	0.179294	0.2032	22.853017	0.008892	0.170402	99.6952
3	0.004209	20.32%	0.2032	1.206526	0.168417	0.2032	22.853017	0.008892	0.159526	99.4920
4	0.005967	23.92%	0.2392	1.284445	0.186228	0.2392	22.853017	0.010467	0.175761	99.2528
5	0.007611	23.92%	0.2392	1.367396	0.174931	0.2392	22.853017	0.010467	0.164464	99.0136
6	0.009284	26.00%	0.2600	1.455705	0.178608	0.2600	22.853017	0.011377	0.167231	98.7536
7	0.010973	28.08%	0.2808	1.549716	0.181194	0.2808	22.853017	0.012287	0.168907	98.4728
8	0.012552	28.08%	0.2808	1.649799	0.170203	0.2808	22.853017	0.012287	0.157915	98.1920
9	0.014272	32.72%	0.3272	1.756345	0.186296	0.3272	22.853017	0.014318	0.171978	97.8648
10	0.015879	32.72%	0.3272	1.869772	0.174995	0.3272	22.853017	0.014318	0.160677	97.5376
11	0.017499	35.34%	0.3534	1.990525	0.177541	0.3534	22.853017	0.015464	0.162077	97.1842
12	0.019125	37.96%	0.3796	2.119076	0.179135	0.3796	22.853017	0.016610	0.162524	96.8046
13	0.020641	37.96%	0.3796	2.255928	0.168268	0.3796	22.853017	0.016610	0.151657	96.4250
14	0.022275	43.84%	0.4384	2.401619	0.182543	0.4384	22.853017	0.019183	0.163360	95.9866
15	0.023798	43.84%	0.4384	2.556719	0.171470	0.4384	22.853017	0.019183	0.152286	95.5482
16	0.025321	47.08%	0.4708	2.721836	0.172971	0.4708	22.853017	0.020601	0.152370	95.0774
17	0.026838	50.32%	0.5032	2.897616	0.173660	0.5032	22.853017	0.022019	0.151641	94.5742
18	0.028249	50.32%	0.5032	3.084748	0.163125	0.5032	22.853017	0.022019	0.141106	94.0710
19	0.029751	57.60%	0.5760	3.283965	0.175398	0.5760	22.853017	0.025205	0.150193	93.4950
20	0.031146	57.60%	0.5760	3.496048	0.164757	0.5760	22.853017	0.025205	0.139553	92.9190
21	0.032532	61.62%	0.6162	3.721828	0.165564	0.6162	22.853017	0.026964	0.138600	92.3028
22	0.033902	65.64%	0.6564	3.962189	0.165666	0.6564	22.853017	0.028723	0.136943	91.6464
23	0.035171	65.64%	0.6564	4.218072	0.155616	0.6564	22.853017	0.028723	0.126893	90.9900
24	0.036504	74.52%	0.7452	4.490481	0.165951	0.7452	22.853017	0.032608	0.133343	90.2448
25	0.037737	74.52%	0.7452	4.780483	0.155884	0.7452	22.853017	0.032608	0.123275	89.4996
26	0.038949	79.40%	0.7940	5.089213	0.156016	0.7940	22.853017	0.034744	0.121272	88.7056
27	0.040136	84.28%	0.8428	5.417882	0.155559	0.8428	22.853017	0.036879	0.118680	87.8628
28	0.041229	84.28%	0.8428	5.767776	0.146122	0.8428	22.853017	0.036879	0.109243	87.0200
29	0.042359	94.92%	0.9492	6.140267	0.154586	0.9492	22.853017	0.041535	0.113051	86.0708
30	0.043396	94.92%	0.9492	6.536814	0.145208	0.9492	22.853017	0.041535	0.103673	85.1216
31	0.044402	100.70%	1.0070	6.958970	0.144705	1.0070	22.853017	0.044064	0.100641	84.1146
32	0.045374	106.48%	1.0648	7.408390	0.143729	1.0648	22.853017	0.046593	0.097136	83.0498
33	0.046258	106.48%	1.0648	7.886835	0.135010	1.0648	22.853017	0.046593	0.088416	81.9850
34	0.047154	118.96%	1.1896	8.396177	0.141684	1.1896	22.853017	0.052054	0.089629	80.7954
35	0.047965	118.96%	1.1896	8.938414	0.133088	1.1896	22.853017	0.052054	0.081034	79.6058
36	0.048735	125.56%	1.2556	9.515669	0.131951	1.2556	22.853017	0.054942	0.077008	78.3502
37	0.049461	132.16%	1.3216	10.130205	0.130461	1.3216	22.853017	0.057830	0.072631	77.0286
38	0.050108	132.16%	1.3216	10.784427	0.122547	1.3216	22.853017	0.057830	0.064717	75.7070
39	0.050741	146.00%	1.4600	11.480901	0.127168	1.4600	22.853017	0.063887	0.063281	74.2470
40	0.051297	146.00%	1.4600	12.222353	0.119453	1.4600	22.853017	0.063887	0.055567	72.7870
41	0.051803	153.06%	1.5306	13.011690	0.117633	1.5306	22.853017	0.066976	0.050657	71.2564
42	0.052258	160.12%	1.6012	13.852003	0.115593	1.6012	22.853017	0.070065	0.045528	69.6552
43	0.052644	160.12%	1.6012	14.746584	0.108581	1.6012	22.853017	0.070065	0.038516	68.0540
44	0.052991	174.16%	1.7416	15.698939	0.110937	1.7416	22.853017	0.076209	0.034729	66.3124
45	0.053271	174.16%	1.7416	16.712799	0.104208	1.7416	22.853017	0.076209	0.027999	64.5708
46	0.053496	180.84%	1.8084	17.792135	0.101640	1.8084	22.853017	0.079132	0.022509	62.7624
47	0.053665	187.52%	1.8752	18.941175	0.099001	1.8752	22.853017	0.082055	0.016946	60.8872
48	0.053775	187.52%	1.8752	20.164423	0.092995	1.8752	22.853017	0.082055	0.010941	59.0120
49	0.053831	199.48%	1.9948	21.466669	0.092925	1.9948	22.853017	0.087288	0.005637	57.0172
50	0.053831	199.48%	1.9948	22.853017	0.087288	1.9948	22.853017	0.087288	0.000000	55.0224
51	0.053777	204.36%	2.0436	24.328896	0.083999	2.0436	22.853017	0.089424	-0.005425	52.9788
52	0.053669	209.24%	2.0924	25.900090	0.080787	2.0924	22.853017	0.091559	-0.010772	50.8864
53	0.053512	209.24%	2.0924	27.572754	0.075887	2.0924	22.853017	0.091559	-0.015673	48.7940
54	0.053303	215.92%	2.1592	29.353441	0.073559	2.1592	22.853017	0.094482	-0.020923	46.6348
55	0.053049	215.92%	2.1592	31.249127	0.069096	2.1592	22.853017	0.094482	-0.025386	44.4756

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.0 & 50 Year Average Life

Real Cost of Capital = 6.46%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0646 ^Year	(C) / (D)	(B)	1.0646 ^50	(F) / (G)	(E) - (H)	(Given)
56	0.052752	217.28%	2.1728	33.267239	0.065314	2.1728	22.853017	0.095077	-0.029764	42.3028
57	0.052412	218.64%	2.1864	35.415684	0.061735	2.1864	22.853017	0.095672	-0.033937	40.1164
58	0.052036	218.64%	2.1864	37.702878	0.057990	2.1864	22.853017	0.095672	-0.037682	37.9300
59	0.051627	216.76%	2.1676	40.137782	0.054004	2.1676	22.853017	0.094850	-0.040846	35.7624
60	0.051186	216.76%	2.1676	42.729936	0.050728	2.1676	22.853017	0.094850	-0.044122	33.5948
61	0.050721	213.28%	2.1328	45.489495	0.046886	2.1328	22.853017	0.093327	-0.046441	31.4620
62	0.050237	209.80%	2.0980	48.427270	0.043323	2.0980	22.853017	0.091804	-0.048481	29.3640
63	0.049726	209.80%	2.0980	51.554771	0.040695	2.0980	22.853017	0.091804	-0.051109	27.2660
64	0.049220	197.88%	1.9788	54.884249	0.036054	1.9788	22.853017	0.086588	-0.050534	25.2872
65	0.048693	197.88%	1.9788	58.428751	0.033867	1.9788	22.853017	0.086588	-0.052721	23.3084
66	0.048168	189.68%	1.8968	62.202161	0.030494	1.8968	22.853017	0.083000	-0.052506	21.4116
67	0.047648	181.48%	1.8148	66.219263	0.027406	1.8148	22.853017	0.079412	-0.052006	19.5968
68	0.047111	181.48%	1.8148	70.495795	0.025743	1.8148	22.853017	0.079412	-0.053668	17.7820
69	0.046619	161.60%	1.6160	75.048511	0.021533	1.6160	22.853017	0.070713	-0.049180	16.1660
70	0.046115	161.60%	1.6160	79.895249	0.020226	1.6160	22.853017	0.070713	-0.050486	14.5500
71	0.045633	150.60%	1.5060	85.054995	0.017706	1.5060	22.853017	0.065899	-0.048193	13.0440
72	0.045176	139.60%	1.3960	90.547965	0.015417	1.3960	22.853017	0.061086	-0.045669	11.6480
73	0.044710	139.60%	1.3960	96.395679	0.014482	1.3960	22.853017	0.061086	-0.046604	10.2520
74	0.044312	116.92%	1.1692	102.621046	0.011393	1.1692	22.853017	0.051162	-0.039768	9.0828
75	0.043908	116.92%	1.1692	109.248456	0.010702	1.1692	22.853017	0.051162	-0.040460	7.9136
76	0.043536	105.82%	1.0582	116.303873	0.009099	1.0582	22.853017	0.046305	-0.037206	6.8554
77	0.043198	94.72%	0.9472	123.814939	0.007650	0.9472	22.853017	0.041447	-0.033797	5.9082
78	0.042855	94.72%	0.9472	131.811080	0.007186	0.9472	22.853017	0.041447	-0.034261	4.9610
79	0.042584	73.88%	0.7388	140.323623	0.005265	0.7388	22.853017	0.032328	-0.027063	4.2222
80	0.042311	73.88%	0.7388	149.385918	0.004946	0.7388	22.853017	0.032328	-0.027383	3.4834
81	0.042070	64.24%	0.6424	159.033469	0.004039	0.6424	22.853017	0.028110	-0.024071	2.8410
82	0.041863	54.60%	0.5460	169.304072	0.003225	0.5460	22.853017	0.023892	-0.020667	2.2950
83	0.041655	54.60%	0.5460	180.237964	0.003029	0.5460	22.853017	0.023892	-0.020862	1.7490
84	0.041512	37.08%	0.3708	191.877983	0.001932	0.3708	22.853017	0.016225	-0.014293	1.3782
85	0.041367	37.08%	0.3708	204.269730	0.001815	0.3708	22.853017	0.016225	-0.014410	1.0074
86	0.041252	29.38%	0.2938	217.461754	0.001351	0.2938	22.853017	0.012856	-0.011505	0.7136
87	0.041167	21.68%	0.2168	231.505736	0.000936	0.2168	22.853017	0.009487	-0.008550	0.4968
88	0.041081	21.68%	0.2168	246.456699	0.000880	0.2168	22.853017	0.009487	-0.008607	0.2800
89	0.041043	9.36%	0.0936	262.373216	0.000357	0.0936	22.853017	0.004096	-0.003739	0.1864
90	0.041006	9.36%	0.0936	279.317643	0.000335	0.0936	22.853017	0.004096	-0.003761	0.0928
91	0.040983	5.60%	0.0560	297.356365	0.000188	0.0560	22.853017	0.002450	-0.002262	0.0368
92	0.040976	1.84%	0.0184	316.560053	0.000058	0.0184	22.853017	0.000805	-0.000747	0.0184
93	0.040968	1.84%	0.0184	337.003942	0.000055	0.0184	22.853017	0.000805	-0.000751	0.0000
94	0.040968	0.00%	0.0000	358.768126	0.000000	0.0000	22.853017	0.000000	0.000000	0.0000
			99.9816	50.9667						

CHARGE 6

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 12/31/2006 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	TRANSMISSION PLANT						
350.20	Land Rights	61,181,203	R5	70.00	0.00%	-	
352.00	Structures & Improvements	55,260,234	S1	75.00	-1.00%	(552,602)	
353.00	Station Equipment	907,682,638	R1.5	58.00	-4.00%	(36,307,306)	
353.70	Supervisory Equipment	55,509,184	R2	25.00	0.00%	-	
354.00	Towers & Fixtures	380,678,705	R5	65.00	-7.00%	(26,647,509)	
355.00	Poles & Fixtures	508,938,637	R2.5	52.00	-42.00%	(213,754,228)	
356.00	OH Conductors & Devices	630,352,557	R4	60.00	-42.00%	(264,748,074)	
356.20	Clearing	30,355,853	S6	65.00	0.00%	-	
357.00	UG Conduit	3,277,188	R2	60.00	0.00%	-	
358.00	UG Conductors & Devices	7,274,658	R2	60.00	0.00%	-	
359.00	Roads & Trails	11,494,522	R5	70.00	0.00%	-	
	Total Transmission Plant	2,652,005,379		58.41	-20.44%	(542,009,719)	
				Use 58 Years			58

[1] Account Number	[2] Description	[3] 12/31/2006 Balance				
	TRANSMISSION PLANT excludes land accounts					
352.00	Structures & Improvements	55,260,234	-	2.13%	-	
353.00	Station Equipment	907,682,638	1.50	35.03%	0.5255	
353.70	Supervisory Equipment	55,509,184	2.00	2.14%	0.0429	
354.00	Towers & Fixtures	380,678,705	5.00	14.69%	0.7347	
355.00	Poles & Fixtures	508,938,637	2.50	19.64%	0.4911	
356.00	OH Conductors & Devices	630,352,557	4.00	24.33%	0.9732	
356.20	Clearing	30,355,853	-	1.17%	-	
357.00	UG Conduit	3,277,188	2.00	0.13%	0.0025	
358.00	UG Conductors & Devices	7,274,658	2.00	0.28%	0.0056	
359.00	Roads & Trails	11,494,522	5.00	0.44%	0.0222	
	Total Transmission Plant	2,590,824,176		100.00%	2.7977	**Use R 3**

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 12/31/2006 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	DISTRIBUTION PLANT (OREGON)						
360.20	Land Rights	3,556,253	R4	53.00	0.00%	-	
361.00	Structures & Improvements	12,345,312	R1.5	65.00	-5.00%	(617,266)	
362.00	Station Equipment	160,587,683	R1	52.00	-10.00%	(16,058,768)	
362.70	Supervisory & Alarm Equipment	2,779,659	R2.5	23.00	0.00%	-	
364.00	Poles, Towers & Fixtures	282,793,465	R2	49.00	-100.00%	(282,793,465)	
365.00	OH Conductors & Devices	210,301,551	R1.5	58.00	-80.00%	(168,241,241)	
366.00	UG Conduit	75,474,348	R2.5	60.00	-60.00%	(45,284,609)	
367.00	UG Conductors & Devices	133,175,353	R2.5	58.00	-45.00%	(59,928,909)	
368.00	Line Transformers	340,095,762	R1.5	40.00	-20.00%	(68,019,152)	
369.10	Overhead Services	60,741,141	R2	65.00	-25.00%	(15,185,285)	
369.20	Underground Services	122,060,821	R4	55.00	-20.00%	(24,412,164)	
370.00	Meters	58,792,161	R2.5	26.00	-2.00%	(1,175,843)	
371.00	I.O.C.P.	2,433,995	S1	25.00	-40.00%	(973,598)	
373.00	Street Lighting & Signal Systems	19,600,663	R1	40.00	-26.00%	(5,096,172)	
	Total OREGON Distribution Plant	1,484,738,167		50.08	-46.32%	(687,786,473)	
				Use 50 years			50

	DISTRIBUTION PLANT excludes land accounts (OREGON)						
361.00	Structures & Improvements	12,345,312	1.5	0.83%	0.01		Curves:
362.00	Station Equipment	160,587,683	1	10.84%	0.11		R=positive
362.70	Supervisory & Alarm Equipment	2,779,659	2.5	0.19%	0.00		L=negative
364.00	Poles, Towers & Fixtures	282,793,465	2	19.09%	0.38		S=0
365.00	OH Conductors & Devices	210,301,551	1.5	14.20%	0.21		
366.00	UG Conduit	75,474,348	2.5	5.10%	0.13		R means right of the standard
367.00	UG Conductors & Devices	133,175,353	2.5	8.99%	0.22		L means left of the standard
368.00	Line Transformers	340,095,762	1.5	22.96%	0.34		S is at the standard
369.10	Overhead Services	60,741,141	2	4.10%	0.08		
369.20	Underground Services	122,060,821	4	8.24%	0.33		
370.00	Meters	58,792,161	2.5	3.97%	0.10		
371.00	I.O.C.P.	2,433,995	0	0.16%	0.00		
373.00	Street Lighting & Signal Systems	19,600,663	1	1.32%	0.01		
	Total OREGON Distribution Plant	1,481,181,914		100.00%	1.94	**Use R 2**	

Exhibit PPL/919

15. Losses

PacifiCorp
Oregon Marginal Cost Study
Energy Loss Factors

Line	(A) Voltage Level	(B) Energy Factor	(C) Energy Loss Percent	(D) Demand Factor	(E) Demand Loss Percent
1	Transmission Line	1.03605	3.60%	1.04975	4.98%
2	(>= 69 kV)				
3					
4					
5					
6	Primary Line	1.05771	5.77%	1.08191	8.19%
7	(2.4 kV thru 34.5 kV)				
8					
9					
10					
11	Secondary Distribution	1.09180	9.18%	1.11306	11.31%
12	(<= 600 Volts)				

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended June 30, 2008 - Actual

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class
1	Res - Schedule 4	(sec)	469,380	100.0%	5,546,125	100.0%	3,585,565	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	65,352	87.3%	660,613	57.5%	301,351	68.1%
5	15+ kW	(sec)	9,474	12.7%	487,926	42.5%	141,484	31.9%
6	Sec Subtotal		74,826	100.0%	1,148,539	100.0%	442,835	100.0%
7	Primary	(pri)	34		1,278		399	
8	Total		74,860		1,149,817		443,234	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,459	44.7%	441,213	21.3%	108,871	5.2%
12	51-100 kW	(sec)	3,500	35.1%	686,792	33.2%	158,141	7.6%
13	> 101kW	(sec)	2,020	20.2%	942,085	45.5%	199,971	9.6%
14	Sec Subtotal		9,979	100.0%	2,070,090	100.0%	2,080,071	22.5%
15	Primary	(pri)	50		18,798		3,848	
16	Total		10,029		2,088,888		2,083,919	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	240	28.7%	210,232	16.1%	41,138	17.5%
20	301+ kW	(sec)	597	71.3%	1,099,384	83.9%	193,793	82.5%
21	Sec Subtotal		837	100.0%	1,309,615	100.0%	234,931	100.0%
22	Primary	(pri)	55		96,013		16,855	
23	Total		892		1,405,628		251,786	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	123	98.4%	649,403	91.6%	143,412	88.9%
27	> 4 MW	(sec)	2	1.6%	59,339	8.4%	17,994	11.1%
28	Sec Subtotal		125	100.0%	708,743	100.0%	161,406	100.0%
29	1 - 4 MW	(pri)	57	62.6%	459,309	26.1%	91,794	28.0%
30	> 4 MW	(pri)	34	37.4%	1,301,457	73.9%	236,113	72.0%
31	Pri Subtotal		91	100.0%	1,760,766	100.0%	327,907	100.0%
32	Trans	(trn)	2		454,296		68,934	
33	Total		218		2,923,804		558,246	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	2,850	100.0%	130,845	100.0%	97,809	100.0%
36	Irrigation - Schedule 33* (Average)	(sec)	802	100.0%	104,533	100.0%	78,140	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	6,142					
38	Irrigation - Schedule 33* (Annual)	(sec)	2,187					

Source: Pricing Dept.
Columns B & D - PacifiCorp, Pricing Department

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended December 2010 - Normalized

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class
1	Res - Schedule 4	(sec)	478,485	100.0%	5,435,846	100.0%	3,585,565	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	64,649	87.3%	582,532	57.5%	301,351	68.1%
5	15+ kW	(sec)	9,372	12.7%	430,256	42.5%	141,484	31.9%
6	Sec Subtotal		74,021	100.0%	1,012,789	100.0%	442,835	100.0%
7	Primary	(pri)	34		1,152		399	
8	Total		74,055		1,013,940		443,234	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,491	44.7%	431,990	21.3%	108,871	5.2%
12	51-100 kW	(sec)	3,525	35.1%	672,435	33.2%	158,141	7.6%
13	> 101kW	(sec)	2,034	20.2%	922,391	45.5%	199,971	9.6%
14	Sec Subtotal		10,050	100.0%	2,026,816	100.0%	2,036,868	22.5%
15	Primary	(pri)	50		18,249		3,848	
16	Total		10,100		2,045,065		2,040,716	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	230	28.7%	206,234	16.1%	41,138	17.5%
20	301+ kW	(sec)	572	71.3%	1,078,480	83.9%	193,793	82.5%
21	Sec Subtotal		802	100.0%	1,284,715	100.0%	234,931	100.0%
22	Primary	(pri)	52		93,931		16,855	
23	Total		854		1,378,646		251,786	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	121	98.4%	594,746	91.6%	143,412	88.9%
27	> 4 MW	(sec)	2	1.6%	54,345	8.4%	17,994	11.1%
28	Sec Subtotal		123	100.0%	649,091	100.0%	161,406	100.0%
29	1 - 4 MW	(pri)	56	62.6%	414,743	26.1%	91,794	28.0%
30	> 4 MW	(pri)	34	37.4%	1,175,179	73.9%	236,113	72.0%
31	Pri Subtotal		90	100.0%	1,589,921	100.0%	327,907	100.0%
32	Trans	(trn)	2		404,889		68,934	
33	Total		215		2,643,901		558,246	
34								
35								
36	Irrigation - Schedule 41 (Average)	(sec)	2,834	100.0%	136,792	100.0%	97,809	100.0%
37	Irrigation - Schedule 33* (Average)	(sec)	756	100.0%	118,046	100.0%	78,140	100.0%
37								
38								
39	Irrigation - Schedule 41 (Annual)	(sec)	6,108	100.0%	136,792	100.0%	97,809	100.0%
40	Irrigation - Schedule 33* (Annual)	(sec)	2,062	100.0%	118,046	100.0%	78,140	100.0%

Source:
Columns B & D - PacifiCorp, Pricing Department

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Customer Class Split between
Three Phase / Single Phase

Line	Customer Class		(A) Voltage Level	(B) Three Phase	(C) Total Customers	(D) Three Phase % of Customers	(E) Single Phase % of Customers
						(A) / (B)	100% - (C)
1	Res - Schedule 4		(sec)	-	469,380	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	10,847	65,352	16.5978%	83.4022%
5	15+ kW		(sec)	5,439	9,474	57.4098%	42.5902%
6		Sec Subtotal		16,286	74,826		
7	Primary		(pri)	34	34	100.0000%	0.0000%
8		Total		16,320	74,860	21.8007%	78.1993%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	3,161	4,459	70.8903%	29.1097%
12	51-100 kW		(sec)	3,030	3,500	86.5714%	13.4286%
13	> 101kW		(sec)	1,966	2,020	97.3267%	2.6733%
14		Sec Subtotal		8,157	9,979		
15	Primary		(pri)	50	50	100.0000%	0.0000%
16		Total		8,207	10,029	81.8327%	18.1673%
17							
18	GS - Schedule 30						
19	0-300 kW			239	240	99.5833%	0.4167%
20	301+ kW			596	597	99.8325%	0.1675%
21		Sec Subtotal		835	837		
22	Primary			55	55	100.0000%	0.0000%
23		Total		890	892	99.7758%	0.2242%
24							
25	LPS - Schedule 48T						
26	1 - 4 MW		(sec)	123	123	100.0000%	0.0000%
27	1 - 4 MW		(pri)	57	57	100.0000%	0.0000%
28	> 4 MW		(sec)	2	2	100.0000%	0.0000%
29	> 4 MW		(pri)	34	34	100.0000%	0.0000%
30	Trans		(trn)	2	2	100.0000%	0.0000%
31	Total			218	218	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	4,935	6,143	80.3353%	19.6647%
34							
35	Irrigation - Schedule 33* (Annual)		(sec)	2,205	2,276	96.8805%	3.1195%
35							
36							
37	TOTAL			32,775	563,798	5.8133%	94.1867%

**Source: Meters worksheet
* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Customer Loads
12 Months Ended December 2010

	(A)	(B)	(C)	(D)	(E)
			12 Month Average Peak Loads @ Sales		
Line	Description	Del. Volt	System	Feeder	Transformer
1	Res - Schedule 4	(sec)	886	1,084	2,402
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	79	76	271
5	15+ kW	(sec)	72	67	109
6	Primary	(pri)	0	0	0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	71	67	109
10	51-100 kW	(sec)	116	110	158
11	> 101kW	(sec)	145	143	200
12	Primary	(pri)	3	3	4
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	31	31	41
16	301+ kW	(sec)	163	162	194
17	Primary	(pri)	14	14	17
18					
19	LPS - Schedule 48T				
20	1 - 4 MW	(sec)	90	89	143
21	1 - 4 MW	(pri)	60	58	92
22	> 4 MW	(sec)	7	6	18
23	> 4 MW	(pri)	156	154	236
24	Trans	(trn)	46	0	69
25					
26	Irrigation - Sch 41	(sec)	21	16	98

Source:
Columns C, D & E - PacifiCorp, Load Research Dept.

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2010

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Revenues 2008		Percent of Total Revenues		Allocated Net Uncollectible		
Line	Description	Del. Volt	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Total
1	Res - Schedule 4	(sec)	0	0	0.00%	0.00%	-	-	1,372,331
2									
3	GS - Schedule 23								
4		(sec)	98,906,325	2,060,822	30.30%	1.62%	56,303	878	57,181
5		(pri)	94,057	14,785	0.03%	0.01%	54	6	60
6	Total		$99,000,382	$2,075,607	30.32%	1.63%	56,356	885	57,241
7									
8	GS - Schedule 28								
9		(sec)	119,734,513	7,231,431	36.68%	5.68%	68,159	3,082	71,241
10		(pri)	883,991	272,491	0.27%	0.21%	503	116	619
11	Total		$120,618,504	$7,503,922	36.95%	5.89%	68,662	3,198	71,861
12									
13	GS - Schedule 30								
14		(sec)	60,378,532	14,427,862	18.49%	11.33%	34,371	6,149	40,520
15		(pri)	4,790,442	645,423	1.47%	0.51%	2,727	275	3,002
16	Total		$65,168,974	$15,073,285	19.96%	11.84%	37,098	6,425	43,522
17									
18	LPS - Schedule 48T								
19		(sec)	20,145,149	19,064,942	6.17%	14.97%	11,468	8,126	19,594
20		(pri)	21,535,569	64,113,448	6.60%	50.34%	12,259	27,326	39,586
21		(trn)	0	19,524,413	0.00%	15.33%	-	8,322	8,322
22	Total		$41,680,718	$102,702,803	12.77%	80.64%	23,727	43,774	67,501
23									
24	Irrigation - Schedule 41 (Average)	(sec)	-	$13,718,053	0.00%	100.00%	-	9,875	9,875
25	Irrigation - Schedule 33* (Average)	(sec)	-	$3,422,637	0.00%	19.97%	-	1,972	1,972
25			$0	$13,718,053	0.00%	100.00%	-	9,875	9,875
26									
27	Total		$326,468,578	$141,073,670			185,843	64,157	1,622,330

* Schedule 33 Cost of Service results are provided for informational purposes only.

Docket No. UE-210
Exhibit PPL/920
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Oregon Line Losses

August 2009

PACIFICORP OREGON 2007 LOSS ANALYSIS

PACIFICORP OREGON REVISED

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		2,598	MW
GENERATION & PURCHASES-INPUT		15,300,810	MWH
ANNUAL SALES	-OUTPUT	14,120,569	MWH
SYSTEM LOSSES	INPUT	1,180,240	or 7.71%
	OUTPUT		or 8.36%
SYSTEM LOAD FACTOR		67.2%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	123.1		49.92%	532,420		45.11%
			4.74%			3.48%	
PRIMARY	69,34,12,1	70.2		28.48%	288,840		24.47%
			2.70%			1.89%	
SECONDARY		53.3		21.61%	358,980		30.42%
			2.05%			2.35%	
TOTAL		246.7		100.00%	1,180,240		100.00%
			9.50%			7.71%	

SUMMARY OF LOSS FACTORS

		CUMMULATIVE SALES EXPANSION FACTORS			
SERVICE	KV	DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08191	0.92430	1.05771	0.94544
SECONDARY		1.11306	0.89842	1.09180	0.91592

PACIFICORP OREGON 2007 LOSS ANALYSIS

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION			CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	345 KV	OR GREATER								
TIE LINES			0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT			0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	115 KV	TO	345.00 KV							
TIE LINES			0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	115 KV		0.0	0.00%	0.000	0.000	0.000	0	1	1
SUBTOT			0.0		0.000	0.000	0.000	0	1	1
--- SUBTRANS ------	35 KV	TO	115 KV							
TIE LINES			0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	69 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	46 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	35 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT			0.0		0.000	0.000	0.000	0	0	0
PRIMARY LINES			18,455		54.106	5.806	59.912	168,409	52,900	221,309
SECONDARY LINES			5,782		3.504	0.000	3.504	16,994	0	16,994
SERVICES			12,570		12.635	1.598	14.234	61,720	14,000	75,721
TOTAL			36,807		70.245	7.404	77.649	247,123	66,901	314,024

SUMMARY OF TRANSFORMER INFORMATION

EXHIBIT 3

DESCRIPTION		KV CAPACITY VOLTAGE	MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0	0.000	0.000	0	0	0
BULK - TRANS1		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
DISTRIBUTION SUBSTATIONS													
TRANS1 -	161	34	70.0	3	23.3	42.00%	29	0.047	0.079	0.126	196	692	889
TRANS1 -	161	12	85.0	3	28.3	55.14%	47	0.103	0.099	0.202	433	865	1,298
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	865	865
TRANS2 -	115	34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	2,362.2	116	20.4	55.14%	1,303	2.828	2.777	5.605	11,886	24,328	36,215
TRANS2 -	115	1	7.7	2	3.8	55.14%	4	0.013	0.015	0.028	56	129	185
SUBTRAN1-	69	34	4.7	1	4.7	42.00%	2	0.006	0.010	0.016	23	92	115
SUBTRAN1-	69	12	1,750.1	186	9.4	55.14%	965	2.443	2.464	4.907	10,267	21,587	31,854
SUBTRAN1-	69	1	10.9	4	2.7	55.14%	6	0.018	0.020	0.038	77	173	250
SUBTRAN2-	46	34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	46	12	36.8	2	18.4	55.14%	20	0.045	0.045	0.090	190	396	585
SUBTRAN2-	46	1	47.2	5	9.4	55.14%	26	0.067	0.069	0.136	280	608	889
SUBTRAN3-	35	34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			115.0	39	2.9	55.14%	63	0.209	0.229	0.438	878	2,004	2,882
LINE TRANSFRMR			7,815.8	201,430	38.8	26.52%	2,073	6.995	29.523	36.518	14,580	258,619	273,199
			===========	===========	===========	===========		===========	===========	===========	===========	==========	===========
TOTAL			12,305	201,791				12.774	35.330	48.104	38,867	310,358	349,226

Exhibit PPL/920
Paice/3

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 2598.116154 MW

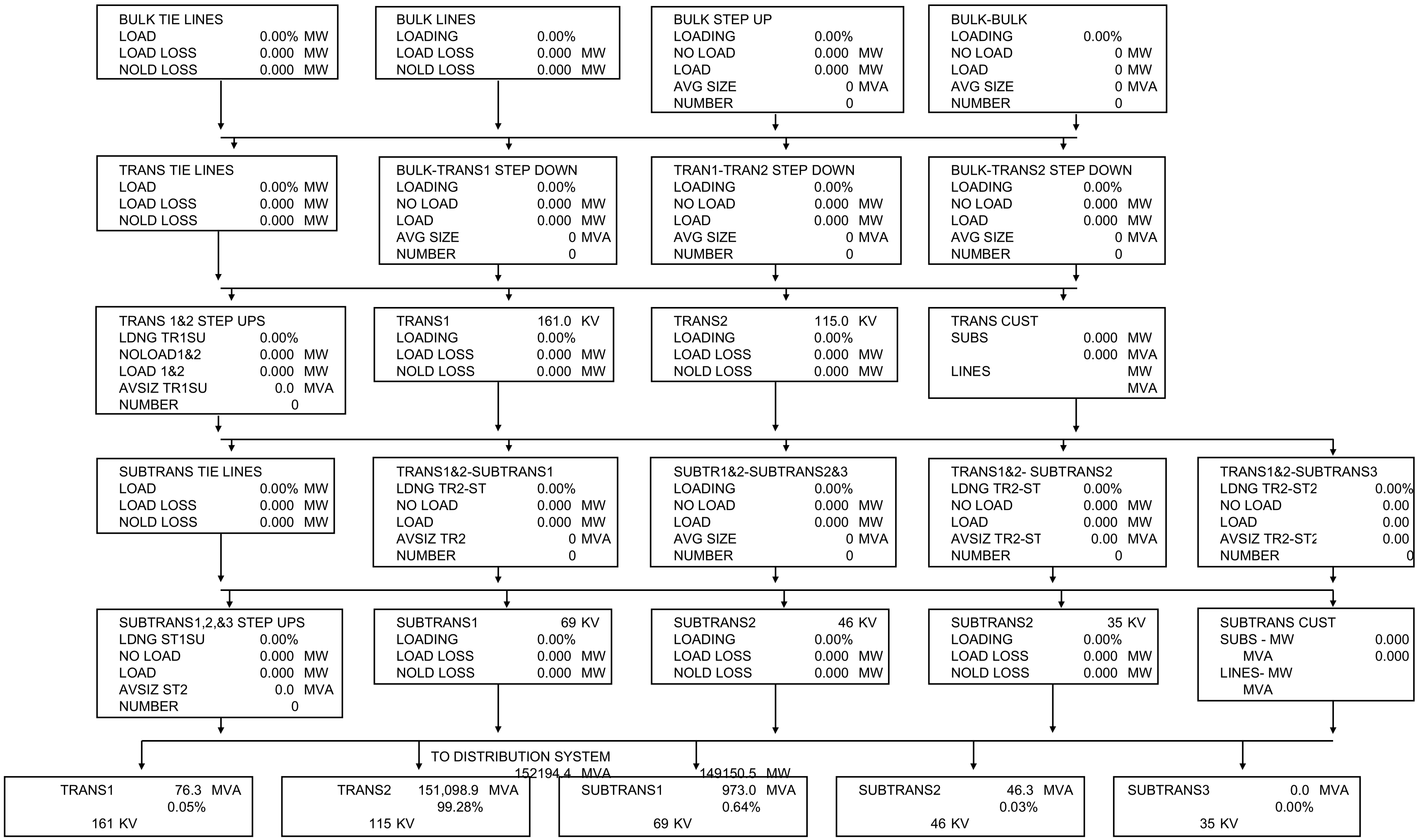

Exhibit PPL/920
Paice/4

FROM HIGH VOLTAGE SYSTEM

TOTAL 152,194 MVA 149,151 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
76.3 MVA	151,098.9 MVA	973.0 MVA	46.3 MVA	0.0 MVA
0.05%	99.28%	0.64%	0.03%	0.00%
161 KV	115 KV	69 KV	46 KV	35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	34	12	1	34	12	1	34	12	1	34	12	1	34	12	1
LOAD MVA	29	47	0	0	151,095	4	2	965	6	0	20	26	0	0	0
% SYS TOT	0.02%	0.03%	0.00%	0.00%	99.28%	0.00%	0.00%	0.63%	0.00%	0.00%	0.01%	0.02%	0.00%	0.00%	0.00%
NOLD LOSS	0.079	0.099	0.000	0.000	2.777	0.015	0.010	2.464	0.020	0.000	0.045	0.069	0.000	0.000	0.000
LOAD LOSS	0.047	0.103	0.000	0.000	2.828	0.013	0.006	2.443	0.018	0.000	0.045	0.067	0.000	0.000	0.000
AVG SIZE	23.3	28.3	0.0	0.0	20.4	3.8	4.7	9.4	2.7	0.0	18.4	9.4	0.0	0.0	0.0
NUMBER	3	3	0	0	116	2	1	186	4	0	2	5	0	0	0
DIVERSITY RATIO	1.000	1.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	0.000	0.000	0.000

PRIMARY LINES
LOADING 2354.997 MW
@ SYS PF 2403.058 MVA
LOAD LOSS 54.106 MW
NOLD LOSS 5.806 MW
TOT LOSS 59.912 MW

PRIM/PRIM TRANSF
LOADING 63.431 MW
NOLD LOSS 0.229 MW
LOAD LOSS 0.209 MW
AVG SIZE 2.95
NUMBER 39

PRIM CUST LOADS
NO LINES 0.000 MW
CUST SUB 0.000 MVA
NO LINES 0.000 MW
CO. SUB 0.000 MVA
PRIM WITH 389.361 MW
LINES 409.854 MVA

LINE TRANSFORMERS
LOADING 1905.287 MW MVA 2109.359
NOLD LOSS 29.523 MW
LOAD LOSS 6.995 MW
AVG SIZE 38.8 KVA
NUMBER 201430

SECONDARY LINES
LOAD 690.552 MW
LOAD LOSS 3.504 MW
NOLD LOSS 0.000 MW
TOT LOSS 3.504 MW

NO SECONDARY LINES
LOAD 1178.217 MW

SERVICES
LOAD 1865.266 MW
LOAD LOSS 12.635 MW
NOLD LOSS 1.598 MW
TOT LOSS 14.234 MW

CUSTOMER SECONDARY LOAD
1851.032 MW

Exhibit PPL/920
Paice/5

PACIFICORP OREGON 2007 LOSS ANALYSIS

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	1	0	1	0.0000000	0.0000000
TOTAL TRAN	0.0	0.00	0.00	0.00	0.000000	0.000000	0	1	0	1	0.0000000	0.0000000
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000		0	0	0	0	0.0000000	
22 TRANSMSN LOSS FAC	2,598.1	24.53	98.61	123.14	1.049754	1.049754	15,300,810	208,601	323,819	532,420	1.0360513	1.0360513
DISTRIBUTION SUBST												
TRANS1	74.7	0.18	0.15	0.33	1.004402	0.000000	443,072	2,422	630	3,052	1.0069356	0.0000000
TRANS2	1,276.5	2.79	2.84	5.63	1.004433	0.000000	7,591,451	24,457	11,942	36,400	1.0048179	0.0000000
SUBTR1	953.5	2.49	2.47	4.96	1.005230	0.000000	5,652,241	21,852	10,368	32,220	1.0057330	0.0000000
SUBTR2	45.4	0.11	0.11	0.23	1.005016	0.000000	268,969	1,004	470	1,474	1.0055104	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	2,350.1	5.6	5.6	11.15	1.004766	1.054758	13,955,733	49,735	23,410	73,145	1.0052688	1.0415101
PRIMARY INTRCHNGE	16.0				1.000000		163,558				1.0000000	
PRIMARY LINES	2,355.0	6.03	54.31	60.35	1.026300	1.082498	14,046,057	52,866	168,409	221,275	1.0160057	1.0581802
LINE TRANSF	1,905.3	29.52	7.00	36.52	1.019541	1.103651	11,504,234	258,619	14,580	273,199	1.0243254	1.0839208
SECONDARY	1,868.8	0.00	3.50	3.50	1.001878	1.105724	11,231,034	0	16,994	16,994	1.0015155	1.0855634
SERVICES	1,865.3	1.60	12.64	14.23	1.007689	1.114226	11,214,040	14,000	61,720	75,721	1.0067982	1.0929433
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		67.27	181.63	248.89				583,822	608,933	1,192,755		

PACIFICORP OREGON 2007 LOSS ANALYSIS

EXHIBIT 6

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	111.0	5.5	116.5	1.04975	0.95260
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS LINES	0.0	0.0	0.0	0.00000	0.00000
PRIM SUBS	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	389.4	32.1	421.5	1.08250	0.92379
SECONDARY	1,851.0	211.4	2,062.5	1.11423	0.89748
TOTALS	2,351.4	249.1	2,600.5		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	661,701	23,855	685,556	1.03605	0.96520
SUBTRANS SUBS	0	0	0	0.00000	0.00000
SUBTRANS LINES	0	0	0	0.00000	0.00000
PRIM SUBS	0	0	0	0.00000	0.00000
PRIM LINES	2,320,549	135,010	2,455,559	1.05818	0.94502
SECONDARY	11,138,319	1,035,232	12,173,552	1.09294	0.91496
TOTALS	14,120,569	1,194,098	15,314,667		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	116.55	685,556
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	0.00	0
PRIM SUBS	0.00	0
PRIM LINES	421.48	2,455,559
SECONDARY	2,062.47	12,173,552
SUBTOTAL	2,600.50	15,314,667
ACTUAL ENERGY LESS THI	2,598.12	15,300,810
MISMATCH	2.38	13,857
% MISMATCH	0.09%	0.09%

DEVELOPMENT of LOSS FACTORS
ADJUSTED
DEMAND

EXHIBIT 7

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM EXPANSION FACTORS	
	a	b	c	d	e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	111.0	0.0	5.5	116.5	1.04975	0.95260
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	389.4	0.0	31.9	421.3	1.08191	0.92430
SECONDARY	1,851.0	0.0	209.3	2,060.3	1.11306	0.89842
TOTALS	2,351.4	0.0	246.7	2,598.1		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES ADJUST	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM EXPANSION FACTORS	
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	661,701	0	23,855	685,556	1.03605	0.96520
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
SUBTRANS LINES	0	0	0	0	0.00000	0.00000
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	2,320,549	0	133,915	2,454,464	1.05771	0.94544
SECONDARY	11,138,319	0	1,022,470	12,160,789	1.09180	0.91592
TOTALS	14,120,569	0	1,180,240	15,300,810		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	116.55	685,556
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	0.00	0
PRIM SUBS	0.00	0
PRIM LINES	421.25	2,454,464
SECONDARY	2,060.31	12,160,789
	2,598.12	15,300,810
ACTUAL ENERGY LESS THIR	2,598.12	15,300,810
MISMATCH	0.00	0
% MISMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facitliy

Unadjusted Losses by Segment

	MW	MWH
Service Drop Losses	14.25	75,875
Secondary Losses	3.51	17,029
Line Transformer Losses	36.57	273,755
Primary Line Losses	60.44	221,725
Distribution Substation Losses	11.17	73,294
Transmission System Losses	123.14	532,420
Total	249.08	1,194,098

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	0.27	1,589
Secondary Losses	0.07	357
Line Transformer Losses	0.69	5,733
Primary Line Losses	1.14	4,644
Distribution Substation Losses	0.21	1,535
Transmission System Losses	0.00	0
Total	2.38	13,857

Adjusted Losses by Segment

	MW	MWH
Service Drop Losses	13.98502	74,286
Secondary Losses	3.44255	16,672
Line Transformer Losses	35.88024	268,022
Primary Line Losses	59.29569	217,081
Distribution Substation Losses	10.95389	71,759
Transmission System Losses	123.14001	532,420
Total	246.69739	1,180,240

Loss Factors by Segment

Retail Sales from Service Drops	1851.03	11,138,319
Adjusted Service Drop Losses	13.99	74,286
Input to Service Drops	1865.02	11,212,605
Service Drop Loss Factor	**1.00756**	**1.00667**
Output from Secondary	1865.02	11,212,605
Adjusted Secondary Losses	3.44	16,672
Input to Secondary	1868.46	11,229,277
Secondary Loss Factor	**1.00185**	**1.00149**
Output from Line Transformers	1868.46	11,229,277
Adjusted Line Transformer Losses	35.88	268,022
Input to Line Transformers	1904.34	11,497,299
Line Transformer Loss Factor	**1.01920**	**1.02387**
Retail Sales from Primary	389.36	2,320,549
Req. Whls Sales from Primary	0.00	0
Input to Line Transformers	1904.34	11,497,299
Output from Primary Lines	2293.70	13,817,848
Adjusted Primary Line Losses	59.30	217,081
Input to Primary Lines	2353.00	14,034,930
Primary Line Loss Factor	**1.02585**	**1.01571**
Output from Distribution Substations	2353.00	14,034,930
Adjusted Distribution Substation Losses	10.95389	71,759
Input to Distribution Substations	2363.95	14,106,689
Distribution Substation Loss Factor	**1.00466**	**1.00511**
Retail Sales at from Transmission	111.026	661,701
Req. Whls Sales from Transmission	0.00	0
Non-Req. Whls Sales from Transmission	0.000	0
Third Party Wheeling Losses	0.000	0
Input to Distribution Substations	2363.95	14,106,689
Output from Transmission	2,474.976	14,768,390
Adjusted Transmission System Losses	123.14001	532,420
Input to Transmission	2,598.116	15,300,810
Transmission System Loss Factor	**1.04975**	**1.03605**

DEMAND MW **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		1,851.0		1,851.0				
3	LOSSES			14.0	14.0				
4	INPUT				1,865.0				
5	**EXPANSION FACTOR**	**1.00756**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			3.4	3.4				
9	INPUT				1,868.5				
10	**EXPANSION FACTOR**	**1.00185**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			35.9	35.9				
14	INPUT				1,904.3				
15	**EXPANSION FACTOR**	**1.01920**							
16	**PRIMARY**								
17	SECONDARY				1,904.3				
18	SALES		389.4			389.4			
19	LOSSES			59.3	49.2	10.1			
20	INPUT								
21	**EXPANSION FACTOR**	**1.02585**							
22	**SUBSTATION**								
23	PRIMARY				1,953.6	399.4			
24	SALES		0.0				0.0		
25	LOSSES			11.0	9.1	1.9	0.0		
26	INPUT				1,962.7	401.3	0.0		
27	**EXPANSION FACTOR**	**1.00466**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				1,962.7	401.3	0.0		
37	SALES		111.0						111.0
38	LOSSES			123.1	97.7	20.0	0.0		5.5
39	INPUT				2,060.3	421.3	0.0		116.5
40	**EXPANSION FACTOR**	**1.04975**							
41	**TOTALS** LOSSES			246.7	209.3	31.9	0.0		5.5
42	% OF TOTAL			100%	84.83%	12.93%	0.00%		2.24%
43	SALES		2,351.4		1,851.0	389.4	0.0		111.0
44	% OF TOTAL		100.00%		78.72%	16.56%	0.00%		4.72%
45	INPUT		2,598.1		2,060.3	421.3	0.0		116.5
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.11306**	**1.08191**	**NA**		**1.04975**

ENERGY MWH **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

	SERVICE LEVEL		SALES	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		11,138,319		11,138,319				
3	LOSSES			74,286	74,286				
4	INPUT				11,212,605				
5	**EXPANSION FACTOR**	**1.00667**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			16,672	16,672				
9	INPUT				11,229,277				
10	**EXPANSION FACTOR**	**1.00149**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			268,022	268,022				
14	INPUT				11,497,299				
15	**EXPANSION FACTOR**	**1.02387**							
16	**PRIMARY**								
17	SECONDARY				11,497,299				
18	SALES		2,320,549.000			2,320,549			
19	LOSSES			217,081	180,625	36,456			
20	INPUT								
21	**EXPANSION FACTOR**	**1.01571**							
22	**SUBSTATION**								
23	PRIMARY				11,677,924	2,357,005			
24	SALES		0				0		
25	LOSSES			71,759	59,708	12,051	0		
26	INPUT				11,737,632	2,369,056	0		
27	**EXPANSION FACTOR**	**1.00511**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				11,737,632	2,369,056	0		
37	SALES		661,701						661,701
38	LOSSES			532,420	423,157	85,408	0		23,855
39	INPUT				12,160,789	2,454,464	0		685,556
40	**EXPANSION FACTOR**	**1.03605**							
41	**TOTALS** LOSSES			1,180,240	1,022,470	133,915	0		23,855
42	% OF TOTAL			100%	86.63%	11.35%	0.00%		2.02%
43	SALES		14,120,569		11,138,319	2,320,549	0		661,701
44	% OF TOTAL		100.00%		78.88%	16.43%	0.00%		4.69%
45	INPUT		15,300,810		12,160,789	2,454,464	0		685,556
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.09180**	**1.05771**	**NA**		**1.03605**

C. Craig Paice
Exhibit PPL/921

Docket No. UE-210
Exhibit PPL/921
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

OPUC Staff Data Request Response

August 2009

August 7, 2009

TO: Katherine McDowell
Counsel for PacifiCorp

FROM: Judy Johnson
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 210
PacifiCorp's Second Set of Data Requests to OPUC
Due August 7, 2009
Data Request 2.15

Request:

2.15 See Staff/1100, Compton/3, lines 19 and 20. Please provide the basis for the statement that "something closer [i.e., than the Company's $8 figure] to the $5/MMBTU seems to be the current long-run projection" for natural gas prices. Include all files relied upon in electronic format with all formulae intact.

Response:

As a subscriber to the *Wall Street Journal* I'm regularly exposed to articles referring to the natural gas industry, but wouldn't be able to tell you the precise source of the above statement. However, the following citation from the Googled reference, "Natural Gas" by Tom Whipple in the journal of the *Association for the Study of Peak Oil and Gas*, June 22, 2009, should be sufficient for the limited purpose of my testimony (see the response to DR 2.17): "The US's supply of natural gas has been much in the news lately as prices have fallen to $4 /mbtu [sic] and a steady stream of announcements and articles have touted the potential of shale gas…A report issued by the non-profit Potential Gas Committee last week concludes that due to the discovery of immense new shale gas fields in Texas, Louisiana and Appalachians, the US now has 2,074 trillion cubic feet of gas in the ground or nearly 100 years worth 'at current rates of production'…"

C. Craig Paice
Exhibit PPL/922

Docket No. UE-210
Exhibit PPL/922
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Oregon Substation Peaks

August 2009

Oregon Distribution Substations
Monthly Peaks for July 2007 to June 2008

Substation	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Peak Month	Peak	Column
Agness Avenue	17465	19342	17138	15748	16713	17764	18531	17559	17206	17072	17033	17644	Aug-07	19,342.0	2
Alderwood	19801	19171	18535	16076	16886	16746	16944	16275	15880	15788	18700	19052	Jul-07	19,801.0	1
Applegate	10353	9246	8350	10300	10995	11403	13561	12496	12226	11396	9499	8641	Jan-08	13,561.0	7
Arlington	1240	1000		1300	1700	1800	2300	2300	1700		960	1400	Jan-08	2,300.0	7
Ashland	17013	15354	12997	12460	14516	15626	16161	15398	14273	13871	15087	15097	Jul-07	17,013.0	1
Athena	3120	3120	3250	3650	3650	3650	4300	4500	2500	3120	2400	3100	Feb-08	4,500.0	8
Bandon	1284	1088	976	1066	1242	1774	1564	1442	1732	1436	1902	1244	May-08	1,902.0	11
Beacon	8200	8790	7600	7600	7600	6650	7020	6440	6090		7030	5740	Aug-07	8,790.0	2
Beall Lane	17350	16362	14737	13472	15554	15648	16618	15651	15486	14916	15025	15326	Jul-07	17,350.0	1
Beatty	2419	2754	2027	2027	826	968	1105	880	842	1944	2610	2676	Aug-07	2,754.0	2
Belknap		33000		24700	24700	24000	24700	23300	21600	19800			Aug-07	33,000.0	2
Bend Plant	17146	15905	12925	12476	15447	17712	17552	15456	13719	13390	12905	15269	Dec-07	17,712.0	6
Blalock	1	287		287	287	287	287	287	61	290	296	272	May-08	296.0	11
Bond Street	13789	12747	10589	10170	12241	14068	14777	12804	11868	11634	10937	12389	Jan-08	14,777.0	7
Brookhurst	37298	33714	29079	24564	26677	28401	30014	28940	27795	25758	29959	30772	Jul-07	37,298.0	1
Bryant	22489	23350	19599	20642	24578	27437	27707	25833	23818	22507	20493	20516	Jan-08	27,707.0	7
Buchanan	26271	25096	24211	23660	27050	27348	29518	25911	26542	25083	23664	21982	Jan-08	29,518.0	7
Buckaroo	21918	20687	16639	18107	18326	19335	22933	18657	17501	17866	18724	22325	Jan-08	22,933.0	7
Campbell	15200	16000	14700	13200	18106	15738	16367	18317	17494	17121	20213	20084	May-08	20,213.0	11
Cannon Beach		5500	550	6000	12200	8500	8500	65000	8000	6850	6850	6500	Feb-08	65,000.0	8
Carnes	3200	3100	3100	3400	3400	3500	3750	3400	2000	2800	2800		Jan-08	3,750.0	7
Cave Junction	10036	9395	9396	11229	13527	14483	15692	13720	13967	13523	11976	8609	Jan-08	15,692.0	7
Caveman	23529	20999	17592	14559	16567	17748	18320	17113	16879	16234	18765	17841	Jul-07	23,529.0	1
Cherry Lane	7467	7391	7327	7340	7209	7355	7359	7241	7327	7060	6979	6846	Jul-07	7,467.0	1
Chiloquin Market	4953	4655	4522	5492				4886	5241	5241	4116		Jun-08	5,492.0	12
China Hat	16278	14815	17355	18451	20395	16198	27256	22696	22172	21987	18728	15451	Jan-08	27,256.0	7
Circle Blvd	19192	18959	18889	17448	17352	16953	17234	17256	17358	17320	19324	18354	May-08	19,324.0	11
Cleveland Ave.	26625	25548	22685	23364	27478	27674	31648	27532	26122	25784	23197	24832	Jan-08	31,648.0	7
Cloak	17209	15317	13756	12090	13871	14952	17612	14416	14614	13946	16049	15053	Jan-08	17,612.0	7
Coburg	2323	2176	2011	1957	2157	2393	2593	2213	2224	2144	1951	1938	Jan-08	2,593.0	7
Columbia	31587	29716	30662	32867	28571	28933	30960	29129	28151	30502	27394	26853	Oct-07	32,867.0	4
Coquille	10657	10772	12879	16156	16787	17517	18495	17152	10358	13980	15191	12674	Jan-08	18,495.0	7
Crooked River	7061	6804	7612	7612	9258	13854	9591	9846	11003	6429	5774	6392	Dec-07	13,854.0	6
Crowfoot	8840	9534	9315	9908	11354	12156	13829	11859	10959	11220	9550	10235	Jan-08	13,829.0	7
Cully	14886	13964	13863	12883	17875	16318	16310	15020	14070	20795	13505	18707	Apr-08	20,795.0	10
Culver	8723	7591	6113	5983	6318	7136	8416	6465	6640	7220	7912	7863	Jul-07	8,723.0	1
Dairy	11284	9519	6355	1944	2072	2401	2719	2322	2243	2297	8495	8783	Jul-07	11,284.0	1
Dallas	14075	12757	12665	14906	17816	18111	19557	18285	16904	17203	14731	12840	Jan-08	19,557.0	7
Dalreed	35					5					4391		May-08	4,391.3	11
Dalreed	43198	38706	36249	26651	16026	5373	5305	12548	13743	23865	35498	42459	Jul-07	43,198.0	1
Deschutes	6387	6020	7012	8093	9886	11617	14165	10798	10615	10432	8507	6473	Jan-08	14,165.0	7
Devils Lake	21378	21906	24320	27229	33210	36346	36742	32898	34455	31333	26141	24149	Jan-08	36,742.0	7
Dixon	3998	3833	3624	2662	3010	3088	3103	2886	2775	2651	3626	3351	Jul-07	3,998.0	1
Dodge Bridge	10180	12266	8045	9228	10472	11996	12792	11772	11147	10675	9760	9126	Jan-08	12,792.0	7
Easy Valley	24101	22216	18309	18247	21732	21379	25177	23280	22146	21522	20697	21741	Jan-08	25,177.0	7
Empire	9444	9383	12618	15086	18948	20160	21355	20028	19540	19299	15938	12090	Jan-08	21,355.0	7
Enterprise	13500	12700	9700	14400		16600		16000	12500	15100	10300	12000	Dec-07	16,600.0	6
Fern Hill	2258	2457	2588	1994	2185	2220	2428	2257	2103	2169	1824	2104	Sep-07	2,588.0	3
Fielder Creek	7108	7424	5867	7344	8952	8687	9716	9255	9000	8599	7025	6236	Jan-08	9,716.0	7
Foothills Rd	18215	17026	14100	9360	10576	11211	11661	11337	10927	10550	13315	13375	Jul-07	18,215.0	1
Fraley	4280	3960	3400	3400	4200		4840	4800	4440	3480	3480		Jan-08	4,840.0	7
Garden Valley	14454	13746	10398	7707	9344	13762	15015	12931	13111	12748	13746	13657	Jan-08	15,015.0	7
Gazley	4550	4270	3960	4110	4340	4810	4520	4230	4020	3970	4340	4610	Dec-07	4,810.0	6
Glendale	12633	11618	13028	12123	14844	14734	16038	15059	14068	15247	13554	11784	Jan-08	16,038.0	7
Glide	7700	7620	7860	9150	10230	10740		12590	10950	11030	9550	6800	Feb-08	12,590.0	8
Gold Hill	7041	6426	5497	6608	7555	7649	8369	8075	7834	7580	5887	6184	Jan-08	8,369.0	7
Goshen	5594	5612	5370	7057	7489	7920	9504	8058	7855	8058	6560	4463	Jan-08	9,504.0	7
Grant	24587	26455	22585	25002	31582	30630	33686	30230	28705	26862	24415	23178	Jan-08	33,686.0	7
Grass Valley		907	907	400	1132	1129	1212	1212	1212	1122	10004	941	May-08	10,004.0	11
Green	13248	12089	11503	11875	12808	13718	15960	13303	13874	13678	11574	11163	Jan-08	15,960.0	7
Hamaker		536	488	532	616	616	748	704	632	560	484	532	Jan-08	748.0	7
Harrisburg	7028	7065	6384	7608	8216	8589	9926	8296	8217	8171	7158	6368	Jan-08	9,926.0	7
Hazelwood	9000	8000	8000	8000	8200	9400	10000	8800	8800	8000	7800		Jan-08	10,000.0	7
Henley			4600	1373	1589	1771	1790	1680	1574	2846	3466	4080	Sep-07	4,600.0	3
Hermiston	5500	5500			5000		6200	6200	4500	4500	4800	5000	Jan-08	6,200.0	7
Hillview	28370	27429	27075	26465	29271	28652	31042	28423	27191	26553	27620	24027	Jan-08	31,042.0	7
Hinkle	4000	4000			4000	4000	4000	500	3600	3900	3600	3500	Jul-07	4,000.0	1
Holladay	35284	35316	34426	27791	27543	27258	29805	27353	26347	26084	33331	31856	Aug-07	35,316.0	2
Hollywood	25429	23163	27909	20797	25213	26198	27073	24480	22917	21806	22712	23017	Sep-07	27,909.0	3
Hood River	25857	23629	19189	21167	25282	26589	29955	23940	22879	23217	19957	22989	Jan-08	29,955.0	7
Hornet	17185	16478	14390	14412	17295	18666	20227	18692	17774	16597	15346	16405	Jan-08	20,227.0	7
Independence	16491	15625	14735	15112	17683	17397	19183	16509	16704	16573	14668	15347	Jan-08	19,183.0	7
Jacksonville	16318	14613	11764	11912	13587	15518	15899	15369	14680	14025	13509	14782	Jul-07	16,318.0	1
Jefferson	9747	9130	8383	8717	11153	11442	11861	10445	10505	10247	8416	10036	Jan-08	11,861.0	7
Jerome Prairie	16800	15000	12750	15900	19500	21600	21600	22950	21000	20250	19500	10800	Feb-08	22,950.0	8
Jordan Point	2000	2000	2000	2000	2300	2000		2300	2300	2400			Apr-08	2,400.0	10
Junction City	8561	8152	8106	8743	10130	10691	11611	9793	9748	9568	8045	7541	Jan-08	11,611.0	7
Killingsworth	40806	38485	36719	36439	37545	40922	43752	39336	37293	38017	29812	30865	Jan-08	43,752.0	7
Knappa Svensen	2741	2945	3481	4471	5197	4950	5367	4935	4703	5003	3930	3429	Jan-08	5,367.0	7
Knott	17000	19400	20400	28400		38500	25000	39000	22100	21800	21800	21800	Feb-08	39,000.0	8
Lakeport	18615	19037	21538	18967	18390	19142	20290	18043	18113	17922	16475	17398	Sep-07	21,538.0	3
Lakeview		2250	2550	2850	3600		3900	4050	4050	3600	3150	2100	Feb-08	4,050.0	8
Lancaster	3700	4000	3700	4400	5400	5500	5700	5000	5000	5000	4600	3700	Jan-08	5,700.0	7
Lebanon	32577	24428	23147	24415	26727	27936	30949	26310	25683	24127	23029	24063	Jul-07	32,577.0	1
Lemolo 1	867	951	916	1364	1374		1905	1662	1530	942	749	954	Jan-08	1,905.0	7
Lincoln	46051	43277	42091	37291	41081	40728	53810	40033	39259	40128	47168	42853	Jan-08	53,810.0	7
Lockhart	15607	15868	16519	21776	26036	25384	29220	27616	26750	24797	22986	18699	Jan-08	29,220.0	7
Lyons	15551	15202	16473	17741	19338	20028	20795	19513	19674	20030	17639	16952	Jan-08	20,795.0	7
Madras	16013	14499	13123	16078	17527	18905	22976	18286	17918	18040	14599	15155	Jan-08	22,976.0	7
Mallory	12760	11811	11706	11233	12137	12803	13033	12037	11049	10619	8972	9138	Jan-08	13,033.0	7
Marys River				16929	17355	17939	19446	17647	17287	15308	14733	14645	Jan-08	19,446.0	7
Medco	11600	12000	12000	12000	12400	12200	12500	12200	12100	12200			Jan-08	12,500.0	7
Medford	11760	11136	9600	7680	9120	10080	9648	9120	9120	7392			Jul-07	11,760.0	1
Medford	29623	28437	25693	18264	23167	22266	22990	21741	20021	19130	26771	25823	Jul-07	29,623.0	1
Merlin	21901	19867	16955	22584	26889	27786	32952	29259	29412	28328	22865	19563	Jan-08	32,952.0	7
Merrill	10119	10575	7639	4080	4280	4897	5139	4705	4343	5234	9706	10348	Aug-07	10,575.0	2

Oregon Distribution Substations
Monthly Peaks for July 2007 to June 2008

Substation	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Peak Month	Peak	Column
Mile High	6853	7086	7177	8051	9483	9507	10430	9892	9916	9681	8414	9761	Jan-08	10,430.0	7
Minam	42	42	42	12		42	42	42	42		30		Jul-07	42.0	1
Modoc	2250	2200	3100	3363	3974	4277	4683	4179	4106	4106	3549	3008	Jan-08	4,683.0	7
Moro		480	400	350	600	400		510	500	500	450		Nov-07	600.0	5
Murder Creek	52044	55367	51545	52649	55284	56182	58376	55120	54429	52552	51127	51856	Jan-08	58,376.0	7
Myrtle Creek	11500	10500	9600	10000	11500	17600	16000	11800	12000	12000	10000		Dec-07	17,600.0	6
Myrtle Point	6000	5500	6750	8250	9500	9750		9200	9500	8600	7400	6500	Dec-07	9,750.0	6
Oak Knoll	17475	15869	14026	14519	17798	18568	19466	18682	18223	17021	15257	14971	Jan-08	19,466.0	7
Oakland	6040	5620	5240	5960	6550	6880	10740	7200	6790	6160	6160	5310	Jan-08	10,740.0	7
O'Brien	2846	2815	2974	2898	3140	3517	3527	3429	3329	3619	3088	3189	Apr-08	3,619.0	10
Oremet	36194	38390	36858	34116	33314	34913	33372	35065	35986	37519	33962	32850	Aug-07	38,390.0	2
Overpass	35302	33472	29855	31696	35368	36774	42600	35937	33178	34196	30433	30585	Jan-08	42,600.0	7
Pallette	370	352			711								Nov-07	711.0	5
Park Street	34725	31677	26949	25386	27712	28947	31685	30167	29189	27556	28885	29498	Jul-07	34,725.0	1
Parkrose	25689	23276	22560	23326	28134	29349	29699	26827	24917	26480	26390	23950	Jan-08	29,699.0	7
Pendleton	29200	27520			22650	24700	27500	27470	23100	2650	24000	26950	Jul-07	29,200.0	1
Pilot Butte	13095	12091	10577	11053	13638	15220	17697	13926	13336	13010	11348	11982	Jan-08	17,697.0	7
Pilot Rock	8600	9200			8200	8200	9100	7700	6000	8100	8500	9600	Jun-08	9,600.0	12
Powell Butte	2966	2966	2952	2952	2882		4151	2974	3182	2962	3173	2734	Jan-08	4,151.0	7
Prineville	40367	38344	35334	36904	41785	46655	48304	41808	39476	38851	38126	36802	Jan-08	48,304.0	7
Provolt	4064	3580	3593	4161	4125	5357	6008	5738	5738	5285	4228	3130	Jan-08	6,008.0	7
Queen Ave	32410	17328	11913	37339	32591	34837	34566	31606	29924	27993	29861	29869	Oct-07	37,339.0	4
Red Blanket	1100	1050	1100	1200	1260	1490	1850	1940	1400		1280		Feb-08	1,940.0	8
Redmond	43896	41597	35169	40608	45804	49594	58916	46965	45223	45167	40247	40173	Jan-08	58,916.0	7
Riddle	11000	10750	10000	11600	12000	14500	15300	13500	13500	12000	10000		Jan-08	15,300.0	7
Riddle Veneer	14020	13820	14140	14800	14800	14950	14750	14810	14680	14680	14260		Dec-07	14,950.0	6
Rogue River	12050	10950	11200	11000	12800	13200	14400	13850	13500		11250	9200	Jan-08	14,400.0	7
Roseburg	20678	20430	18801	17829	20136	21706	25851	21498	33574	21175	19229	17979	Mar-08	33,574.0	9
Ross Ave	6080	4600	3880	4120	5320	5400	5400	4800	4600	4600	3960	4480	Jul-07	6,080.0	1
Roxy Ann	8037	7583	6435	6657	8398	9838	7507	7107	6800	6328	10560	10695	Jun-08	10,695.0	12
Ruch	7400	6600	6100	7200	7400	9200		9700		9300	8200	6500	Feb-08	9,700.0	8
Running Y	3050	2806	2581	2536	2372	2830	3922	3368	1370	1263	2605	2822	Jan-08	3,922.0	7
Russelville	26017	26643	25487	23851	30601	32179	33945	30087	26925	26756	25176	25916	Jan-08	33,945.0	7
Sage Road	31600	31900	32300	26000	34000	28000		28200	25900	25700	27600	31700	Nov-07	34,000.0	5
Scenic	25648	24206	20172	17244	19631	20959	24451	20583	19593	19237	22434	23460	Jul-07	25,648.0	1
Scio	4890	4417	4197	4813	5950	6224	6835	5614	5622	5707	4465	4530	Jan-08	6,835.0	7
Seaside	15124	14606	15746	16990	23988	22650	21366	20670	20810	18596	18518	15410	Nov-07	23,988.0	5
Selma	2980	2590	2630	2910	4200	4150	4180	3710	3720	3900	3360	2370	Nov-07	4,200.0	5
Shevlin Park	17590	15763	13212	12959	15256	16650	16496	15109	13662	13582	14443	16089	Jul-07	17,590.0	1
South Dunes	4400	4000	3800	3800	4000	4000	4000	4100		3700	4300	3400	Jul-07	4,400.0	1
Southgate	12426	12099	10104	10705	11861	12698	14026	12925	11835	12275	11260	9659	Jan-08	14,026.0	7
Sprague River	937	1129	999	423	553	610	684	547	651	949	0	1142	Jun-08	1,142.0	12
State Street	22447	21944	24357	30158	36276	38447	42624	38811	38066	38340	32343	25637	Jan-08	42,624.0	7
Stayton	39716	37489	34248	32656	38800	38321	43247	33981	34833	34184	30112	31379	Jan-08	43,247.0	7
Steamboat	91	112	137	116	116	96	100	99	99	118	112	92	Sep-07	137.4	3
Stevens Road	18994	18286	16103	12201	15900	17483	17085	16330	16163	14879	17540	19330	Jun-08	19,330.0	12
Sutherlin	8674	8251	7488	8594	9675	10290	13301	11771	12146	6168	9495	8296	Jan-08	13,301.0	7
Sweet Home	20212	19698	20685	22386	23362	26215	30943	25869	24075	27123	18481	16050	Jan-08	30,943.0	7
Takelma	8918	7925	6704	8628	9895	11575	12245	11109	10843	10166	8378	7702	Jan-08	12,245.0	7
Talent	23871	21994	19094	20731	23547	26317	27204	25802	24355	23526	20563	20462	Jan-08	27,204.0	7
Texum	14,700	10,500	14,400	13,200	13,000	44,000	29,200	31,000	27,700	28,400	28,200	28,400	Dec-07	44,000.0	6
Tiller	770	940	900	1000	1050	1060	1540	1080	1120	1030	870	720	Jan-08	1,540.0	7
Tolo	7000	6200	6200	6500	6500	7000	7000	6600	7100	7000		6200	Mar-08	7,100.0	9
Turkey Hill	9778	9792	6242	6242					10288	10288	8496	9994	Mar-08	10,288.0	9
Umapine	12000	11400	11400							7200	9600	11400	Jul-07	12,000.0	1
Umatilla	13735	12517	10552	11051	9540	10230	11976	9629	8335	8039	9439	12400	Jul-07	13,735.0	1
Vernon	28497	27168	27725	25804	31549	33036	33980	31488	29182	30958	27917	28782	Jan-08	33,980.0	7
Vilas Road	20922	20743	18441	13978	14952	15782	16253	15373	14837	14573	18920	18577	Jul-07	20,922.0	1
Village Green	11805	13950	12639	12628	13791	14126	16757	13933	13613	13932	11475	10665	Jan-08	16,757.0	7
Vine Street	17744	16359	15201	12198	15750	16476	15866	14591	13454	13135	15677	16257	Jul-07	17,744.0	1
Wallowa	3900	2000	2000	2400	2800	3800	3800	3600	2450	2400	2200	1900	Jul-07	3,900.0	1
Warm Springs	701	686	823	823	945	882	1006	888	982	949	782	834	Jan-08	1,006.0	7
Warrenton	15432	14795	14792	16223	16773	17452	19029	17671	17201	17513	14768	14966	Jan-08	19,029.0	7
Wasco	772	744	644	664	992	908	1188	1188	1188	908	796	604	Jan-08	1,188.0	7
Western Kraft	10740	34988	217	32755	34347	8806	35586	21243	48170	9198	17490	42241	Mar-08	48,170.5	9
Weston	11190	10924	11071	9916	8281	3890	4047	3681	3618	3666	4620	11977	Jun-08	11,977.0	12
Westside	14634	14395	12351	12885	14453	15573	17007	15931	14707	14071	13351	12627	Jan-08	17,007.0	7
Weyerhauser	10000	10000	9500	9500	10000	10000	10500	10500	10500	9500	10000	10000	Jan-08	10,500.0	7
White City	44421	42941	39985	39026	40285	40199	41250	40843	39193	38854	36429	36694	Jul-07	44,421.0	1
Winchester	27249	26652	25024	25062	27606	25081	28507	23464	25582	24074	25029	23513	Jan-08	28,507.0	7
Winston	7310	6980	5090	6480	7380	7610	12240	7690	7500	6870	6920		Jan-08	12,240.0	7
Youngs Bay	51000	11500	12500		56500	16000	54500	54500	60000	0	52000	12500	Mar-08	60,000.0	9
Total by Month	29	7	5	2	5	8	84	8	5	3	6	6			

C. Craig Paice
Exhibit PPL/923

Docket No. UE-210
Exhibit PPL/923
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

ICNU Data Request Response

August 2009

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UE 210

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 1.2

Data Request No. 1.2:

See ICNU/200, Schoenbeck/6, lines 14 and 15, please provide the basis for the assumption that "any customer with a demand greater than 2,000 KW was served from a dedicated customer substation."

Response to Data Request No. 1.2:

There were two reasons for selecting 2,000 kW as the break point for a dedicated substation. First, and most important, it resulted in average class loss factors reflective of Mr. Schoenbeck's judgment for Schedule 48T customers. For example, for primary customers, the demand value is almost 2.3% lower than the comparable PacifiCorp value (1.05801 versus 1.08095). In Mr. Schoenbeck's view, this is a reasonable result given the average primary line losses are 2.5%. Similarly, for secondary customers the demand value difference is 1.2% (1.09902 versus 1.11114). It is Mr. Schoenbeck's opinion that this is a reasonable differential given the fact that these customers are served from transformers with lower losses and no secondary and service drop losses are incurred. The second reason was the recognition that service at and beyond this level could not be readily accommodated from a typical primary feeder.

C. Craig Paice
Exhibit PPL/924

Docket No. UE-210
Exhibit PPL/924
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of C. Craig Paice

Schedule 48 Distance Data

August 2009

Exhibit 1012 - Schedule 48 Customer Distance from Substation

NAME	DISTANCE (FEET)	HIGHEST KW READ IN BASE PERIOD (07-01-2007 to 06-30-2008)
Customer 1	4,993	2,276
Customer 2	15,785	4,522
Customer 3	24,861	1,107
Customer 4	19,047	1,376
Customer 5	7,834	2,616
Customer 6	4,791	1,386
Customer 7	13,903	1,274
Customer 8	4,014	1,295
Customer 9	7,834	1,120
Customer 10	3,665	1,722
Customer 11	7,684	11,880
Customer 12	2,689	4,298
Customer 13	3,058	1,188
Customer 14	5,612	1,211
Customer 15	11,259	1,030
Customer 16	2,762	1,644
Customer 17	35,354	1,234
Customer 18	1,525	4,145
Customer 19	6,934	1,304
Customer 20	7,191	953
Customer 21	5,384	1,286
Customer 22	9,393	4,075
Customer 23	1,175	5,117
Customer 24	7,639	1,258
Customer 25	6,474	1,320
Customer 26	11,276	4,628
Customer 27	511	1,677
Customer 28	4,172	1,246
Customer 29	10,080	1,507
Customer 30	1,399	2,059
Customer 31	9,473	1,199
Customer 32	12,090	1,052
Customer 33	2,268	3,640
Customer 34	7,653	1,928
Customer 35	14,831	1,112
Customer 36	10,267	1,517
Customer 37	6,202	1,781
Customer 38	9,768	999
Customer 39	5,429	1,155
Customer 40	818	2,047
Customer 41	9,024	1,150
Customer 42	26,479	1,030
Customer 43	5,928	3,092
Customer 44	12,708	1,726
Customer 45	4,368	1,307
Customer 46	563	9,252
Customer 47	1,780	1,232
Customer 48	24,235	321
Customer 49	6,820	3,480
Customer 50	12,277	1,252
Customer 51	17,529	4,536
Customer 52	22,594	1,165
Customer 53	16,864	4,784
Customer 54	6,086	1,674
Customer 55	9,185	1,398
Customer 56	8,459	1,044
Customer 57	1,443	1,088
Customer 58	9,587	1,660
Customer 59	4,684	1,362
Customer 60	2,790	1,041
Customer 61	9,345	1,405
Customer 62	5,061	7,452
Customer 63	4,552	1,356
Customer 64	10,764	1,180
Customer 65	5,671	867
Customer 66	1,787	16,008
Customer 67	2,102	1,150
Customer 68	8,485	2,285
Customer 69	30,103	1,322
Customer 70	10,021	10,280
Customer 71	5,041	1,541
Customer 72	7,792	926

NAME	DISTANCE (FEET)	HIGHEST KW READ IN BASE PERIOD (07-01-2007 to 06-30-2008)
Customer 73	6,472	1,351
Customer 74	5,182	1,072
Customer 75	4,063	1,108
Customer 76	9,767	1,441
Customer 77	9,981	1,034
Customer 78	14,614	956
Customer 79	7,907	935
Customer 80	23,232	1,211
Customer 81	7,927	980
Customer 82	8,905	1,584
Customer 83	14,404	4,817
Customer 84	4,903	1,542
Customer 85	2,400	983
Customer 86	5,350	1,149
Customer 87	4,014	3,528
Customer 88	2,468	1,165
Customer 89	10,553	11,034
Customer 90	6,983	211
Customer 91	12,296	1,456
Customer 92	34,195	3,102
Customer 93	31,497	3,220
Customer 94	8,164	9,468
Customer 95	13,326	1,650
Customer 96	1,023	1,601
Customer 97	3,749	1,453
Customer 98	7,024	244
Customer 99	10,502	920
Customer 100	1,380	3,572
Customer 101	3,749	1,119
Customer 102	20,820	1,371
Customer 103	4,176	1,666
Customer 104	9,973	1,400
Customer 105	8,593	1,778
Customer 106	2,562	5,457
Customer 107	10,155	1,472
Customer 108	2,662	1,960
Customer 109	9,457	1,053
Customer 110	1,670	1,430
Customer 111	1,267	3,704
Customer 112	10,435	9,232
Customer 113	9,030	1,137
Customer 114	5,666	1,236
Customer 115	3,944	1,498
Customer 116	37,796	1,140
Customer 117	3,492	8,446
Customer 118	10,577	1,580
Customer 119	21,203	1,367
Customer 120	15,509	1,493
Customer 121	248	3,370
Customer 122	8,426	1,678
Customer 123	9,556	1,029
Customer 124	4,253	1,115
Customer 125	2,976	1,010
Customer 126	12,881	1,476
Customer 127	5,811	1,565
Customer 128	8,938	1,166
Customer 129	2,930	1,261
Customer 130	3,948	1,115
Customer 131	5,680	2,619
Customer 132	19,170	1,757
Customer 133	18,954	5,166
Customer 134	13,763	2,357
Customer 135	26,237	1,764
Customer 136	9,704	4,170
Customer 137	6,459	1,152
Customer 138	10,039	3,074
Customer 139	17,569	1,751
Customer 140	9,991	1,707
Customer 141	5,566	1,518
Customer 142	15,708	1,026
Customer 143	5,026	2,140
Customer 144	10,206	3,300
Customer 145	4,526	2,818
Customer 146	19,520	2,470
Customer 147	4,202	1,598
Customer 148	11,531	1,676

NAME	DISTANCE (FEET)	HIGHEST KW READ IN BASE PERIOD (07-01-2007 to 06-30-2008)
Customer 149	6,563	2,126
Customer 150	6,681	1,166
Customer 151	2,249	1,116
Customer 152	4,461	1,058
Customer 153	4,915	1,219
Customer 154	5,340	1,282
Customer 155	11,457	1,005
Customer 156	10,945	1,392
Customer 157	4,478	1,434
Customer 158	6,171	1,400
Customer 159	3,431	4,284
Customer 160	2,513	8,964
Customer 161	10,764	1,018
Customer 162	15,212	1,469
Customer 163	5,101	4,219
Customer 164	5,364	4,536
Customer 165	24,510	2,576
Customer 166	10,431	1,588
Customer 167	8,210	1,330
Customer 168	1,787	4,776
Customer 169	15,509	1,824
Customer 170	7,228	1,360
Customer 171	9,373	1,750
Customer 172	3,894	6,594
Customer 173	9,806	274
Customer 174	7,827	15,720
Customer 175	9,528	1,351
Customer 176	1,865	2,106
Customer 177	17,728	9,504
Customer 178	15,686	5,752
Customer 179	2,357	1,879
Customer 180	5,444	3,516
Customer 181	6,423	2,603
Customer 182	7,617	1,415
Customer 183	4,463	1,103
Customer 184	5,033	2,275
Customer 185	6,052	5,634
Customer 186	2,853	1,635
Customer 187	1,390	2,518
Customer 188	1,618	1,628
Customer 189	5,938	2,248
Customer 190	9,512	12,120
Customer 191	9,024	3,751
Customer 192	31,620	1,240
Customer 193	2,068	5,081
Customer 194	15,687	1,041
Customer 195	1,872	5,190
Customer 196	1,389	27,456
Customer 197	4,567	2,088
Customer 198	7,916	3,112
Customer 199	7,862	2,006
Customer 200	12,112	2,409
Customer 201	7,943	4,459
Customer 202	9,512	2,165
Customer 203	9,084	5,677

Statistics

Customers with 2 MW or more	72
Customers with 2 MW or more and greater than 0.5 mile from the substation.	54
% of total 2 MW or more	75.0%
Average Miles from Substation for Customers with 2MW or more	1.50

Docket No. UE-210
Exhibit PPL/1010
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of William R. Griffith

August 2009

Q. Are you the same William R. Griffith who previously provided testimony in this docket?

A. Yes, as Exhibit PPL/1000.

Purpose and Summary

Q. Please explain the purpose of your reply testimony.

A. The purpose of my reply testimony is to present the Company's proposed rate spread and rate design reflecting the Company's reply revenue requirement and updated cost of service study. In addition, I will respond to the rate spread and rate design issues raised in the opening testimonies of Staff of the Oregon Public Utility Commission ("Staff") witness Dr. George Compton, Fred Meyer Stores witness Mr. Kevin Higgins, and Klamath Water Users Association ("KWUA") witness Mr. Gary Saleba.

Q. Please summarize your testimony.

A. My testimony includes the following:

- I present the proposed reply rate spread and rate design. The Company proposes to cap the rate increase to all rate schedules at 1.5 times the overall net rate increase. The Company's proposed rate spread reduces cross subsidization of customer classes through the Rate Mitigation Adjustment while minimizing overall customer impacts.
- I present the proposed rates for the new tariff riders described by Company witness Mr. R. Bryce Dalley. These tariff riders are proposed to recover the costs associated with the regulatory assets proposed for separate amortization by Staff witness Mr. Dustin Ball in his opening testimony.

- In response to issues raised by Dr. Compton, I explain the direct relationship between unbundled costs shown in the cost of service study and the Company' s unbundled retail rates. I provide further discussion on transmission and ancillary service costs and rates.
- I state concerns with Dr. Compton' s suggestions to implement additional seasonal and time-of-use rates for residential and large industrial customers. The Company' s current tariffs include options for these types of pricing mechanisms.
- I respond to Dr. Compton' s proposal concerning the residential basic charge. The Company' s proposed residential basic charge is reasonable and compares favorably with the residential basic charges of other electric utilities in Oregon.
- I respond to Mr. Higgins' proposal to include a demand component in Schedule 200, which the Company believes could be viewed as a barrier to direct access for low-load-factor customers.
- I respond to Mr. Saleba' s claim that the Company may set irrigation rates to less than 100 percent cost of service and explain the revised proposed net rate increase for irrigation customers which caps the increase for these customers at 1.5 times the overall average percentage increase.

Reply Exhibits

Q. Have you prepared exhibits showing the Company' s revised rate spread and rate design based on the updates made in this reply filing?

A. Yes. Exhibit PPL/1011 shows the impact of the Company' s updated filing, including monthly billing comparisons for customers at various usage levels. This exhibit is an update to my direct Exhibit PPL/1002.

Exhibit PPL/1012 shows the revised rates. This exhibit is an update to my direct Exhibit PPL/1003, however Exhibit PPL/1012 includes greater detail as discussed later in my testimony.

Q. What are the Company's rate spread proposals in this reply filing?

A. As a result of the revised revenue requirement and cost of service ("COS") results, the Company proposes to cap the net rate increase to all rate schedules at 1.5 times the proposed overall percentage increase in this case. The Company's proposed rate spread reduces cross subsidization of customer classes by minimizing the Rate Mitigation Adjustment where possible while minimizing overall customer impacts. The Company believes that this will appropriately reflect marginal cost of service results while mitigating rate impacts on customers.

Q. Have you prepared rates for the new tariff riders described in the reply testimony of Company witness Mr. R. Bryce Dalley?

A. Yes. Rates for proposed Schedules 193, 194 and 195 are shown in my Exhibit PPL/1011, Griffith/3 in columns 8, 9 and 10. Schedule 193 is proposed to implement the surcharge for the tariff rider to recover the balance associated with the Transition Plan – Oregon regulatory asset. Schedule 194 is proposed to implement the surcharge for the tariff rider to recover the balance associated with the MidAmerican Energy Holdings Company ("MEHC") Change-in-Control Severance regulatory asset. Schedule 195 is proposed to implement the surcharge for the tariff rider to recover the balance associated with the Grid West regulatory asset.

Rates for each of these new tariff riders are proposed to be applied on an equal cents per kilowatt-hour basis. The surcharges are designed to recover the associated balancing accounts with interest over the remaining life of each regulatory asset, with the exception of Schedule 193 which is designed to recover the Transition Plan-Oregon balance over one year, rather than the asset' s remaining life of six months. At the conclusion of this docket, the Company proposes that tariffs for each these riders would be filed and adopted by the Commission in the tariff compliance filing for this docket.

Q. Please summarize the estimated effect of the proposed price change on net rates.

A. The net rate increase for all customer classes has decreased or remained the same as the net rate increases proposed in the Company' s initial filing. Consistent with the results of the updated cost of service study presented by Company witness Mr. C. Craig Paice, the net increase for lighting and irrigation customers have decreased significantly from the initial filing.

Response to Staff witness Dr. George R. Compton

Q. Please discuss the issues raised by Dr. Compton regarding the connection between functionalized costs and functionalized revenues.

A. Dr. Compton indicates that there is not a clear connection between functionalized costs and functionalized revenues in the Company' s rate design exhibits. He states that " Based upon cursory comparisons of PacifiCorp' s rate design worksheets and COS results, the [functionalized revenue] targets have not always been closely achieved." Staff 1100/Compton 32. In particular, he focuses on the Transmission & Ancillary Services Charge revenues.

Q. Do you agree with Dr. Compton's assertions?

A. No. The method of rate design in the Company's filed case is correct and is consistent with the rate design methodology utilized by the Company since the implementation of direct access in 2001. This method complies with the Commission's rules to functionalize and unbundle rates and is appropriate. The updated rate design in Exhibit PPL/1012 follows the same methodology.

Q. Please explain the difference between the revenues collected through the Transmission & Ancillary Services Charge as shown in the rate design exhibit and the total transmission and ancillary services target revenues as shown in the cost of service exhibit.

A. The Transmission & Ancillary Service Charge rate in the Company's Oregon retail tariffs is not presently designed to collect the total transmission costs shown in the cost of service Unbundled Revenue Requirement Allocation by Rate Schedule exhibit (Exhibit PPL/917 in this reply filing). As indicated in my direct testimony PPL/1000, Griffith 5, lines 21-23, only the Federal Energy Regulatory Commission ("FERC")-related transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services Charge rate. Non-FERC transmission costs are not collected through this charge but are collected through the Company's distribution charges.

Q. Why are Non-FERC transmission services collected though the distribution charges rather than through the Transmission & Ancillary Services Charge?

A. The Transmission & Ancillary Services Charge is designed to recover only those transmission and ancillary services that customers can avoid if they elect to take direct access service. Those services are FERC-related transmission and ancillary services costs. Non-FERC transmission costs cannot be avoided by customers choosing direct access and, therefore, they are not included in the Transmission & Ancillary Services Charge. Instead, they are included in the distribution charges which are paid by all of the Company' s customers.

Q. Is this calculation a departure from the way rates have been calculated in the past?

A. No. Non-FERC transmission costs have been collected through the distribution charges since rates were unbundled in UE 116 with the implementation of direct access.

Q. Are you sponsoring an exhibit that shows the breakout of transmission costs into FERC and non-FERC transmission costs?

A. Yes. Exhibit PPL/1013 is a worksheet from the reply cost of service model prepared by Company witness Mr. Paice. It shows the breakout into FERC and non-FERC transmission costs of total transmission costs as identified on line 28 of page 1 in the reply cost of service Exhibit PPL/917 sponsored by Mr. Paice. This transmission cost breakout worksheet was included as part of the cost of service model provided at the time of the initial filing as well as part of the rate design model provided at the time of the initial filing. The worksheet was not included as a printed exhibit for simplicity sake.

Q. Do the revenues from the proposed Transmission & Ancillary Services Charge tie to the cost of FERC transmission plus the cost of ancillary Services?

A. Yes. Looking specifically at Schedule 23, Secondary in my billing determinants Exhibit PPL/1012, column 6, the proposed revenues for Transmission & Ancillary Services is $3.788 million. This is approximately equal to the total costs for FERC transmission plus ancillary services for this class of $3.783 million. The small difference is due to rounding. This target Transmission & Ancillary Services revenue of $3.783 million is the sum of the following: the Schedule 23 Secondary FERC transmission target revenues from Exhibit PPL/1013, row 5, columns B and C totaling $2.924 million and the Schedule 23 Secondary ancillary services target revenues from Exhibit PPL/917 row 30, column B totaling $0.859 million.

Q. Can the total target revenues to be collected through the Transmission & Ancillary Services Charge be seen in your exhibits?

A. Yes. My reply billing determinants Exhibit PPL/1012 show the direct relationship between unbundled costs and unbundled rates. In addition to reflecting the Company' s revised revenue requirement and cost of service study, this exhibit shows the target unbundled revenue requirement for each class in column 8.

Q. Was this level of detail available in the initial filing?

A. Yes. A detailed billing determinant worksheet was included in the rate design model, containing all formulas, and was provided to all parties at the time of the initial filing. My direct testimony included Exhibit PPL/1003 which displayed the present rates and revenues in comparison to proposed rates and revenues in an easier to view format for comparison purposes. Previously, detailed background information and calculation formulas were available only in the electronic rate design model. In the future, although the Company did not encounter this issue in past general rate cases, in addition to the information previously provided in the electronic exhibit, the Company is willing to provide a more detailed exhibit in printed format similar to Exhibit PPL/1012 if parties believe it will facilitate understanding of the proposed rate design.

Q. Dr. Compton suggests that elevating the residential tail-block rate in the summer would be one way to better capture cost causation in the Company' s rates; however, he does not suggest changing the rate design at this time. Do you have any comment on this general proposal?

A. Yes. The Company does not support increasing the tail-block rate for Oregon residential customers in the summer. The current level of inverted blocks in residential rates provides a clear price signal to larger users throughout the year without creating excessive revenue volatility. The main purpose of the inverted residential rate structure is to send price signals to all customers about the higher cost of increasing usage. Given the presence of a year round inverted rate in Oregon, the summer inverted residential rate that the Company has implemented in Utah, and that Dr. Compton appears to suggest here for Oregon, is not necessary in Oregon. Moreover, the Company agrees with CUB witness Mr. Bob

Jenks, who indicates that “ CUB urges the Commission to adopt the rate design proposed by the Company.” CUB/100, Jenks/26.

Q. Dr. Compton also suggests a super-peak time-of-use rate for large industrial customers. In this case, he appears to recommend the adoption of some form of this rate design in this case. What is the Company’ s perspective on this proposal?

A. The Company does not support the adoption of a super-peak time-of-use rate for large industrial customers at this time. The Company believes that the current options available to large industrial customers are sufficient, and we do not believe that it is appropriate to single out large general service customers with this proposal. In addition, in view of the current economy, we believe that it is not a good time to implement a super-peak pricing mechanism for our commercial and industrial customers given that it is difficult to predict the potential implication of such a change on customers.

Q. Are seasonal rates and time-of-use options available for residential and large industrial customers today?

A. Yes. Residential customers along with small general service and small irrigation customers have seasonal, time-of-use rates available under the Portfolio Time-of-Use Supply Service option Schedule 210. In addition, all non-residential customers, including large general service customers, have the option of choosing market-based Standard Offer Supply Service Schedule 220, which includes a time of use structure, or choosing direct access supply from an electricity service supplier (“ ESS”).

Q. What has Dr. Compton proposed regarding the residential basic charge?

A. Dr. Compton proposes a residential basic charge of at most $8.00. He indicates that if the Company's final revenue requirement is "appreciably less" than the filed amount, the basic charge should remain at its current level of $7.50.

Q. Does the Company agree with Dr. Compton's proposal?

A. No. The Company believes that its filed residential basic charge of $8.50 is reasonable. As indicated in my direct testimony, the Company's proposed basic charge would result in a basic charge that is ranked in the bottom half of basic charges for 23 electric utilities surveyed by the Company in Oregon.

Response to Fred Meyer Stores Witness Mr. Kevin C. Higgins

Q. Please summarize Mr. Higgins' proposal regarding Schedule 200, Schedule 201 and the direct access transition adjustments.

A. Mr. Higgins recommends incorporating a demand component into the new Schedule 200 rate for customers who are demand billed, and he proposes charging Schedule 200 rates to direct access customers rather than subtracting those rates from the transition adjustments in Schedules 294 and 295 as occurs at present. He proposes that Schedule 201 rates for net power costs be subtracted from the transition adjustment rates and that direct access customers not pay the Schedule 201 rates, consistent with the Company's proposal.

Q. Does the Company agree with Mr. Higgins' proposal to incorporate a demand component into the Schedule 200 rate?

A. At first glance, Mr. Higgins' Schedule 200 demand/energy charge structure proposal seems plausible. However, on closer examination, the proposal to include a demand component in Schedule 200 would mean that high-load-factor customers would get more benefit by electing direct access than would low-load-factor customers. The Company does not believe that a proposal which provides greater benefits to high-load-factor customers who choose direct access is consistent with the intent of Senate Bill 1149 to provide fair access to electricity markets for all consumers. Such a proposal could be viewed as a barrier to direct access for low-load-factor customers that does not exist today.

Response to KWUA Witness Mr. Gary Saleba

Q. Please summarize the testimony of KWUA witness Mr. Saleba.

A. Mr. Saleba is concerned with the magnitude of the proposed increase to Schedule 41 irrigation rates, and he suggests that it is standard practice for utilities to set rates for irrigation below 100 percent of cost of service.

Q. Do you agree with Mr. Saleba' s claim that it is standard practice for utilities to set rates for irrigation customers at levels below 100 percent cost of service?

A. No. It is not standard practice in Oregon. Base rates in Oregon must be set to reflect the unbundled cost of serving that customer class. These requirements are clearly specified in Oregon rule OAR 860, Division 38, which requires the Company to charge rates for each customer class to recover the costs to serve that customer class. As a result, the base rates for all customers, including irrigation customers, must be set at 100 percent of the cost to serve that class.

Q. Has the Company revised the proposed rate increase to Schedule 41 in this reply filing?

A. Yes. As a result of the updated cost of service results and in an effort to reduce the subsidization of irrigation customers through the current Rate Mitigation Adjustment, the Company has proposed to cap the overall increase to Schedule 41 at 1.5 times the overall average. This results in a proposed net rate increase for Schedule 41 that has been significantly reduced from the increase filed in the Company's direct case.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/1011
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of William R. Griffith

Estimated Effects of the Proposed Rates

August 2009

Table 1011-1

**PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010**

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates[1]	Adders[2]	Net Rates	Base Rates	Adders[2]	Net Rates	($000)	%[3]	($000)	%[3]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	478,485	5,435,846	$480,018	$18,970	$498,988	$511,386	$18,807	$530,193	$31,368	6.5%	$31,205	6.3%	1
2	**Total Residential**			478,485	5,435,846	$480,018	$18,970	$498,988	$511,386	$18,807	$530,193	$31,368	6.5%	$31,205	6.3%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,055	1,013,941	$92,485	($2,688)	$89,797	$99,316	$2,038	$101,354	$6,831	7.4%	$11,557	12.9%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,101	2,045,065	$128,645	$14,255	$142,900	$143,019	$13,068	$156,087	$14,374	11.2%	$13,187	9.2%	4
5	Gen. Svc. 201 - 999 kW	30	30	853	1,378,646	$80,753	$6,369	$87,122	$89,575	$5,597	$95,172	$8,822	10.9%	$8,050	9.2%	5
6	Large General Service >= 1,000 kW	48	48	215	2,643,901	$134,416	$3,542	$137,958	$151,046	$4,602	$155,648	$16,630	12.5%	$17,690	12.9%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	571,965	$26,499	$767	$27,266	$29,935	$996	$30,931	$3,436	12.5%	$3,665	12.9%	7
8	Agricultural Pumping Service	41	41	6,108	136,792	$14,533	($3,071)	$11,462	$15,579	($2,637)	$12,942	$1,046	7.2%	$1,480	12.9%	8
9	Agricultural Pumping - Other	33	33	2,062	118,046	$3,839	$344	$4,183	$3,665	$385	$4,050	($174)	-4.5%	($133)	-3.2%	9
10	**Total Commercial & Industrial**			93,401	7,908,356	$481,170	$19,518	$500,688	$532,135	$24,049	$556,184	$50,965	10.6%	$55,496	11.1%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,404	10,466	$1,321	$132	$1,453	$1,453	$134	$1,587	$132	10.0%	$134	9.2%	11
12	Street Lighting Service	50	50	287	10,738	$1,179	$124	$1,303	$1,253	$128	$1,381	$74	6.3%	$78	6.0%	12
13	Street Lighting Service HPS	51	51	686	16,085	$2,847	$270	$3,117	$3,029	$275	$3,304	$182	6.4%	$187	6.0%	13
14	Street Lighting Service	52	52	79	1,186	$135	$14	$149	$144	$14	$158	$9	6.7%	$9	6.0%	14
15	Street Lighting Service	53	53	250	9,316	$593	$75	$668	$632	$70	$702	$39	6.6%	$34	5.1%	15
16	Recreational Field Lighting	54	54	105	816	$71	$6	$77	$75	$6	$81	$4	5.6%	$4	5.2%	16
17	**Total Public Street Lighting**			8,811	48,607	$6,146	$621	$6,767	$6,586	$627	$7,213	$440	7.2%	$446	6.6%	17
18	**Total Sales to Ultimate Consumers**			580,697	13,392,809	$967,334	$39,109	$1,006,443	$1,050,107	$43,483	$1,093,590	$82,773	8.6%	$87,147	8.7%	18
19	**Employee Discount**				18,481	($403)	($16)	($419)	($430)	($16)	($446)	($27)		($27)		19
20	**Total Sales with Employee Discount**			580,697	13,392,809	$966,931	$39,093	$1,006,024	$1,049,677	$43,467	$1,093,144	$82,746	8.6%	$87,120	8.7%	20
21	AGA Revenue					$2,380		$2,380	$2,380		$2,380	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			580,697	13,392,809	$969,311	$39,093	$1,008,404	$1,052,057	$43,467	$1,095,524	$82,746	8.5%	$87,120	8.6%	22

[1] Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.
[2] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[3] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Table 1011-2
PACIFIC POWER & LIGHT COMPANY
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 (000)	Prop. Sales 96 (000)	Interv. Fndg. 97 (000)	Tax Adj 102 (000)	OR Trns Plan 193 (000)	MEHC Sev 194 (000)	Grid West 195 (000)	RAC Defer. 203 (000)	Shop. Inctv. 296 (000)	RMA 299 (000)	RMA 299 (000)	Total (000)	Total (000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								PRO	PRO	PRO			PRE	PRO	PRE	PRO
	Residential															
1	Residential	4	4	$381	($544)	$0	$10,817	$815	$870	$163	$5,218	$0	$3,098	$1,087	$18,970	$18,807
2	**Total Residential**															
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	$71	($101)	$0	$2,017	$152	$163	$31	$993	$0	($5,668)	($1,288)	($2,688)	$2,038
4	Gen. Svc. 31 - 200 kW	28	28	$144	($205)	$0	$4,070	$307	$327	$61	$1,963	$82	$8,201	$6,319	$14,255	$13,068
5	Gen. Svc. 201 - 999 kW	30	30	$96	($138)	$0	$2,744	$207	$221	$41	$1,296	$55	$2,316	$1,075	$6,369	$5,597
6	Large General Service >= 1,000 kW	48	48	$185	($264)	$0	$5,261	$397	$424	$80	$2,300	$0	($3,940)	($3,781)	$3,542	$4,602
7	Partial Req. Svc. >= 1,000 kW	47	47	$40	($57)	$0	$1,138	$86	$92	$17	$498	$0	($852)	($818)	$767	$996
8	Agricultural Pumping Service	41	41	$10	($14)	$0	$272	$21	$22	$4	$131	$3	($3,473)	($3,086)	($3,071)	($2,637)
9	Agricultural Pumping - Other	33	33	$8	($12)	$0	$235	$18	$19	$4	$113	$0	$0	$0	$344	$385
10	**Total Commercial & Industrial**			$554	($791)	$0	$15,737	$1,188	$1,268	$238	$7,294	$140	($3,416)	($1,579)	$19,518	$24,049
	Lighting															
11	Outdoor Area Lighting Service	15	15	$1	($1)	$0	$22	$1	$1	$0	$5	$0	$105	$105	$132	$134
12	Street Lighting Service	50	50	$1	($1)	$0	$21	$2	$2	$0	$5	$0	$98	$98	$124	$128
13	Street Lighting Service HPS	51	51	$1	($2)	$0	$32	$2	$3	$0	$11	$0	$228	$228	$270	$275
14	Street Lighting Service	52	52	$0	$0	$0	$2	$0	$0	$0	$1	$0	$11	$11	$14	$14
15	Street Lighting Service	53	53	$1	($1)	$0	$19	$1	$1	$0	$2	$0	$54	$47	$75	$70
16	Recreational Field Lighting	54	54	$0	$0	$0	$2	$0	$0	$0	$0	$0	$4	$4	$6	$6
17	**Total Public Street Lighting**			$4	($5)	$0	$98	$6	$7	$0	$24	$0	$500	$493	$621	$627
18	**Total**			$939	($1,340)	$0	$26,652	$2,009	$2,145	$401	$12,536	$140	$182	$1	$39,109	$43,483
19	**Employee Discount**			$0	$0	$0	($9)	($1)	($1)	$0	($4)	$0	($3)	($1)	($16)	($16)
20	**Total Sales with Employee Discount**			$939	($1,340)	$0	$26,643	$2,008	$2,144	$401	$12,532	$140	$179	$0	$39,093	$43,467

Table 1011-3
PACIFIC POWER & LIGHT COMPANY
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 ¢/kWh	Prop. Sales 96 ¢/kWh	Interv. Fndg. 97 ¢/kWh	Tax Adj 102 ¢/kWh	OR Trns Plan 193 ¢/kWh	MEHC Sev 194 ¢/kWh	Grid West 195 ¢/kWh	RAC Defer. 203 ¢/kWh	Shop. Inctv. 296 ¢/kWh	RMA 299 ¢/kWh	RMA 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								PRO	PRO	PRO			PRE	PRO
	Residential													
1	Residential	4	4	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.000	0.057	0.020
	Commercial & Industrial													
2	Gen. Svc. < 31 kW	23	23	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.098	0.000	(0.559)	(0.127)
3	Gen. Svc. 31 - 200 kW	28	28	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.004	0.401	0.309
4	Gen. Svc. 201 - 999 kW	30	30	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.094	0.004	0.168	0.078
5	Large General Service >= 1,000 kW	48	48	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.087	0.000	(0.149)	(0.143)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.087	0.000	(0.149)	(0.143)
7	Agricultural Pumping Service	41	41	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.004	(2.539)	(2.256)
8	Agricultural Pumping - Other	33	33	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.096	0.000	0.000	0.000
	Lighting													
9	Outdoor Area Lighting Service	15	15	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.053	0.000	1.002	1.002
10	Street Lighting Service	50	50	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.044	0.000	0.908	0.908
11	Street Lighting Service HPS	51	51	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.069	0.000	1.416	1.416
12	Street Lighting Service	52	52	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.053	0.000	0.920	0.920
13	Street Lighting Service	53	53	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.023	0.000	0.580	0.508
14	Recreational Field Lighting	54	54	0.007	(0.010)	0.000	0.199	0.015	0.016	0.003	0.039	0.000	0.539	0.539

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price**	GRC Proposed Price	Difference	Difference
100	$15.93	$17.33	$1.40	8.79%
200	$23.62	$25.39	$1.77	7.49%
300	$31.32	$33.47	$2.15	6.86%
400	$39.02	$41.55	$2.53	6.48%
500	$46.72	$49.61	$2.89	6.19%
600	$55.08	$58.46	$3.38	6.14%
700	$63.45	$67.31	$3.86	6.08%
800	$71.82	$76.17	$4.35	6.06%
900	$80.18	$85.01	$4.83	6.02%
950	**$84.37**	**$89.45**	**$5.08**	**6.02%**
1,000	$88.55	$93.87	$5.32	6.01%
1,100	$97.94	$103.90	$5.96	6.09%
1,200	$107.30	$113.91	$6.61	6.16%
1,300	$116.68	$123.94	$7.26	6.22%
1,400	$126.06	$133.96	$7.90	6.27%
1,500	$135.43	$143.98	$8.55	6.31%
1,600	$144.79	$153.99	$9.20	6.35%
2,000	$182.29	$194.08	$11.79	6.47%
3,000	$276.03	$294.29	$18.26	6.62%
4,000	$369.77	$394.49	$24.72	6.69%
5,000	$463.51	$494.70	$31.19	6.73%

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

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
kW		Present Price**		GRC Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$55	$63	$62	$72	12.97%	13.27%
	750	$74	$82	$84	$93	12.77%	13.01%
	1,000	$93	$101	$105	$115	12.65%	12.85%
	1,500	$132	$140	$148	$158	12.51%	12.66%
10	1,000	$93	$101	$105	$115	12.65%	12.85%
	2,000	$170	$178	$191	$201	12.44%	12.56%
	3,000	$247	$255	$277	$287	12.35%	12.44%
	4,000	$311	$320	$350	$359	12.30%	12.37%
20	4,000	$336	$345	$378	$388	12.47%	12.53%
	6,000	$466	$474	$523	$533	12.36%	12.41%
	8,000	$595	$604	$669	$678	12.31%	12.34%
	10,000	$725	$733	$814	$823	12.27%	12.30%
30	9,000	$710	$718	$799	$808	12.45%	12.48%
	12,000	$904	$913	$1,016	$1,026	12.37%	12.40%
	15,000	$1,099	$1,107	$1,234	$1,243	12.32%	12.34%
	18,000	$1,293	$1,301	$1,452	$1,461	12.29%	12.31%
31	9,300	$735	$743	$826	$836	12.45%	12.48%
	12,400	$935	$944	$1,051	$1,060	12.38%	12.40%
	15,500	$1,136	$1,144	$1,276	$1,285	12.33%	12.35%
	18,600	$1,337	$1,345	$1,501	$1,510	12.29%	12.31%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price**		GRC Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$54	$62	$61	$70	12.67%	12.98%
	750	$73	$81	$82	$91	12.40%	12.68%
	1,000	$91	$100	$103	$112	12.26%	12.49%
	1,500	$129	$137	$144	$154	12.09%	12.27%
10	1,000	$91	$100	$103	$112	12.26%	12.49%
	2,000	$166	$174	$186	$195	12.00%	12.14%
	3,000	$241	$249	$269	$279	11.90%	12.00%
	4,000	$304	$312	$340	$349	11.83%	11.92%
20	4,000	$328	$337	$368	$377	12.03%	12.10%
	6,000	$455	$463	$509	$518	11.90%	11.96%
	8,000	$581	$589	$649	$659	11.83%	11.88%
	10,000	$707	$715	$790	$800	11.79%	11.82%
30	9,000	$693	$701	$776	$786	12.00%	12.03%
	12,000	$882	$890	$987	$997	11.91%	11.93%
	15,000	$1,071	$1,080	$1,198	$1,208	11.85%	11.87%
	18,000	$1,261	$1,269	$1,410	$1,419	11.81%	11.83%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
15	4,500	$338	$370	9.49%
	7,500	$511	$554	8.42%
	10,500	$685	$739	7.89%
31	9,300	$685	$748	9.20%
	15,500	$1,043	$1,129	8.21%
	21,700	$1,400	$1,508	7.71%
40	12,000	$880	$960	9.13%
	20,000	$1,343	$1,452	8.16%
	28,000	$1,796	$1,933	7.64%
60	18,000	$1,315	$1,434	9.05%
	30,000	$1,997	$2,158	8.06%
	42,000	$2,677	$2,880	7.56%
80	24,000	$1,741	$1,897	8.95%
	40,000	$2,648	$2,859	7.98%
	56,000	$3,554	$3,821	7.50%
100	30,000	$2,164	$2,357	8.88%
	50,000	$3,298	$3,559	7.93%
	70,000	$4,431	$4,762	7.46%
200	60,000	$4,262	$4,636	8.76%
	100,000	$6,529	$7,041	7.84%
	140,000	$8,796	$9,447	7.39%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
15	4,500	$340	$364	6.87%
	7,500	$505	$536	6.10%
	10,500	$669	$708	5.72%
31	9,300	$686	$731	6.56%
	15,500	$1,026	$1,086	5.89%
	21,700	$1,364	$1,439	5.54%
40	12,000	$880	$938	6.50%
	20,000	$1,319	$1,396	5.84%
	28,000	$1,748	$1,844	5.46%
60	18,000	$1,315	$1,402	6.56%
	30,000	$1,962	$2,076	5.83%
	42,000	$2,606	$2,748	5.45%
80	24,000	$1,740	$1,852	6.47%
	40,000	$2,599	$2,748	5.75%
	56,000	$3,458	$3,644	5.39%
100	30,000	$2,162	$2,300	6.41%
	50,000	$3,236	$3,420	5.71%
	70,000	$4,309	$4,540	5.36%
200	60,000	$4,239	$4,493	6.00%
	100,000	$6,387	$6,733	5.43%
	140,000	$8,534	$8,973	5.14%

* Net rate including Schedules 91, 290 and 297.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

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

kW Load Size	kWh	Monthly Billing* Present Price**	GRC Proposed Price	Percent Difference
100	30,000	$2,358	$2,609	10.67%
	50,000	$3,361	$3,678	9.43%
	70,000	$4,365	$4,748	8.76%
200	60,000	$4,262	$4,678	9.75%
	100,000	$6,269	$6,816	8.72%
	140,000	$8,277	$8,955	8.19%
300	90,000	$6,279	$6,885	9.64%
	150,000	$9,291	$10,093	8.63%
	210,000	$12,302	$13,301	8.12%
400	120,000	$8,234	$9,028	9.64%
	200,000	$12,249	$13,305	8.62%
	280,000	$16,264	$17,582	8.10%
500	150,000	$10,195	$11,168	9.55%
	250,000	$15,214	$16,515	8.55%
	350,000	$20,233	$21,861	8.05%
600	180,000	$12,156	$13,309	9.48%
	300,000	$18,179	$19,725	8.50%
	420,000	$24,202	$26,140	8.01%
800	240,000	$16,078	$17,590	9.40%
	400,000	$24,108	$26,144	8.45%
	560,000	$32,139	$34,699	7.97%
1000	300,000	$20,000	$21,871	9.36%
	500,000	$30,038	$32,564	8.41%
	700,000	$40,076	$43,257	7.94%

* Net rate including Schedules 91, 290 and 297.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
100	30,000	$2,311	$2,480	7.30%
	50,000	$3,296	$3,521	6.82%
	70,000	$4,281	$4,563	6.57%
200	60,000	$4,178	$4,466	6.89%
	100,000	$6,149	$6,549	6.51%
	140,000	$8,119	$8,632	6.32%
300	90,000	$6,154	$6,576	6.87%
	150,000	$9,109	$9,701	6.49%
	210,000	$12,065	$12,825	6.30%
400	120,000	$8,088	$8,650	6.96%
	200,000	$12,029	$12,816	6.55%
	280,000	$15,970	$16,982	6.34%
500	150,000	$10,012	$10,704	6.92%
	250,000	$14,938	$15,911	6.52%
	350,000	$19,864	$21,119	6.32%
600	180,000	$11,935	$12,758	6.89%
	300,000	$17,847	$19,006	6.50%
	420,000	$23,758	$25,255	6.30%
800	240,000	$15,783	$16,865	6.85%
	400,000	$23,665	$25,197	6.47%
	560,000	$31,547	$33,528	6.28%
1000	300,000	$19,631	$20,972	6.83%
	500,000	$29,483	$31,387	6.46%
	700,000	$39,336	$41,801	6.27%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			GRC Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill**	December-March Monthly Bill**	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$201	$221	$185	$230	$253	$206	14.01%	14.18%	11.11%
	5,000	$336	$355	$185	$383	$406	$206	14.01%	14.11%	11.11%
	7,000	$470	$490	$185	$536	$559	$206	14.01%	14.08%	11.11%
Three Phase										
20	6,000	$403	$442	$371	$459	$505	$412	14.01%	14.17%	11.11%
	10,000	$671	$711	$371	$765	$811	$412	14.01%	14.11%	11.11%
	14,000	$940	$979	$371	$1,072	$1,117	$412	14.01%	14.08%	11.11%
100	30,000	$2,014	$2,213	$1,504	$2,296	$2,527	$1,638	14.01%	14.17%	8.90%
	50,000	$3,357	$3,557	$1,504	$3,827	$4,058	$1,638	14.01%	14.10%	8.90%
	70,000	$4,699	$4,900	$1,504	$5,357	$5,590	$1,638	14.01%	14.07%	8.90%
300	90,000	$6,042	$6,640	$3,770	$6,888	$7,580	$4,110	14.01%	14.17%	9.02%
	150,000	$10,070	$10,670	$3,770	$11,480	$12,175	$4,110	14.01%	14.10%	9.02%
	210,000	$14,098	$14,701	$3,770	$16,072	$16,770	$4,110	14.01%	14.07%	9.02%

* Net rate including Schedules 91, 98, 290 and 297.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			GRC Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill**	December-March Monthly Bill**	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$194	$214	$185	$220	$243	$196	13.41%	13.59%	5.56%
	5,000	$324	$343	$185	$367	$389	$196	13.41%	13.52%	5.56%
	7,000	$453	$473	$185	$514	$536	$196	13.41%	13.49%	5.56%
Three Phase										
20	6,000	$389	$427	$371	$441	$485	$391	13.41%	13.59%	5.56%
	10,000	$648	$686	$371	$734	$779	$391	13.41%	13.52%	5.56%
	14,000	$907	$945	$371	$1,028	$1,073	$391	13.41%	13.49%	5.56%
100	30,000	$1,943	$2,137	$1,494	$2,203	$2,427	$1,627	13.41%	13.58%	8.97%
	50,000	$3,238	$3,433	$1,494	$3,672	$3,897	$1,627	13.41%	13.51%	8.97%
	70,000	$4,533	$4,729	$1,494	$5,141	$5,366	$1,627	13.41%	13.48%	8.97%
300	90,000	$5,829	$6,410	$3,760	$6,610	$7,281	$4,099	13.41%	13.58%	9.04%
	150,000	$9,714	$10,298	$3,760	$11,017	$11,690	$4,099	13.41%	13.51%	9.04%
	210,000	$13,600	$14,187	$3,760	$15,424	$16,099	$4,099	13.41%	13.48%	9.04%

* Net rate including Schedules 91, 98, 290 and 297.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
1,000	300,000	$18,959	$21,127	11.44%
	500,000	$28,247	$31,538	11.65%
	700,000	$37,536	$41,949	11.76%
2,000	600,000	$37,599	$41,904	11.45%
	1,000,000	$55,615	$62,166	11.78%
	1,400,000	$73,768	$82,564	11.92%
4,000	1,200,000	$74,106	$82,686	11.58%
	2,000,000	$110,411	$123,482	11.84%
	2,800,000	$146,717	$164,279	11.97%
6,000	1,800,000	$110,100	$123,295	11.98%
	3,000,000	$164,559	$184,489	12.11%
	4,200,000	$219,017	$245,684	12.18%

Notes:

On-Peak kWh	64.01%
Off-Peak kWh	35.99%

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

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
1,000	300,000	$17,633	$20,127	14.14%
	500,000	$26,545	$30,083	13.33%
	700,000	$35,458	$40,040	12.92%
2,000	600,000	$34,988	$39,882	13.99%
	1,000,000	$52,253	$59,236	13.36%
	1,400,000	$69,654	$78,726	13.02%
4,000	1,200,000	$68,925	$78,622	14.07%
	2,000,000	$103,727	$117,601	13.38%
	2,800,000	$138,529	$156,581	13.03%
6,000	1,800,000	$102,906	$117,477	14.16%
	3,000,000	$155,109	$175,946	13.43%
	4,200,000	$207,312	$234,415	13.07%

Notes:

On-Peak kWh	60.53%
Off-Peak kWh	39.47%

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

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price**	Monthly Billing: GRC Proposed Price	Percent Difference
1,000	300,000	$16,372	$19,161	17.04%
	500,000	$24,931	$28,680	15.04%
	700,000	$33,490	$38,199	14.06%
2,000	600,000	$32,476	$37,827	16.48%
	1,000,000	$49,034	$56,306	14.83%
	1,400,000	$65,728	$74,920	13.98%
4,000	1,200,000	$63,911	$74,389	16.39%
	2,000,000	$97,300	$111,617	14.71%
	2,800,000	$130,689	$148,846	13.89%
6,000	1,800,000	$95,710	$111,508	16.51%
	3,000,000	$145,793	$167,351	14.79%
	4,200,000	$195,876	$223,194	13.95%

Notes:

On-Peak kWh	56.04%
Off-Peak kWh	43.96%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010.

Docket No. UE-210
Exhibit PPL/1012
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of William R. Griffith

Billing Determinants

August 2009

Exhibit PPL/1012
Griffith/1

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 4									
Residential Service									
Transmission & Ancillary Services Charge								Proposed	%
per kWh	5,435,845,633	kWh	0.394 ¢	$21,417,232	0.386 ¢	$20,982,364	Total	511,369,471	108.4%
Distribution Charge							T Rev	20,965,344	97.9%
Basic Charge, per month	5,741,820	bill	$7.50	$43,063,650	$8.50	$48,805,470	D Rev	226,976,602	107.3%
Three Phase Demand Charge, per kW demand	17,328	kW	$2.20	$38,122	$2.20	$38,122	E Rev	263,427,525	110.3%
Three Phase Minimum Demand Charge, per month	1,556	bill	$3.80	$5,913	$3.80	$5,913	NPC Rev	113,641,512	
Distribution Energy Charge, per kWh	5,435,845,633	kWh	3.115 ¢	$169,326,591	3.277 ¢	$178,132,661			
Energy Charge									
Schedule 200									
First Block kWh	2,374,190,522	kWh	3.521 ¢	$83,595,248	2.327 ¢	$55,247,413			
Second Block kWh	1,499,989,488	kWh	4.173 ¢	$62,594,561	2.758 ¢	$41,369,710			
Third Block kWh	1,561,665,624	kWh	5.149 ¢	$80,410,163	3.403 ¢	$53,143,481			
Schedule 201									
First Block kWh	2,374,190,522	kWh			1.766 ¢	$41,928,205			
Second Block kWh	1,499,989,488	kWh			2.093 ¢	$31,394,780			
Third Block kWh	1,561,665,624	kWh			2.583 ¢	$40,337,823			
Subtotal				$460,451,480		$511,385,942			
Renewable Adjustment Clause, per kWh	5,435,845,633	kWh	0.223 ¢	$12,121,936	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	5,435,845,633	kWh	(0.018) ¢	($978,452)	0.000 ¢	$0			
Total	5,435,845,633	kWh		$471,594,964		$511,385,942			
					Change	$39,790,978			
Schedule No. 4 - Employee Discount									
Residential Service									
Transmission & Ancillary Services Charge									
per kWh	18,481,059	kWh	0.394 ¢	$72,815	0.386 ¢	$71,337			
Distribution Charge									
Basic Charge, per month	14,361	bill	$7.50	$107,708	$8.50	$122,069			
Three Phase Demand Charge, per kW demand	82	kW	$2.20	$180	$2.20	$180			
Three Phase Minimum Demand Charge, per month	12	bill	$3.80	$46	$3.80	$46			
Distribution Energy Charge, per kWh	18,481,059	kWh	3.115 ¢	$575,685	3.277 ¢	$605,624			
Energy Charge									
Schedule 200									
First Block kWh	6,715,105	kWh	3.521 ¢	$236,439	2.327 ¢	$156,260			
Second Block kWh	5,192,652	kWh	4.173 ¢	$216,689	2.758 ¢	$143,213			
Third Block kWh	6,573,302	kWh	5.149 ¢	$338,459	3.403 ¢	$223,689			
Schedule 201									
First Block kWh	6,715,105	kWh			1.766 ¢	$118,589			
Second Block kWh	5,192,652	kWh			2.093 ¢	$108,682			
Third Block kWh	6,573,302	kWh			2.583 ¢	$169,788			
Subtotal				$1,548,021		$1,719,477			
Renewable Adjustment Clause, per kWh	18,481,059	kWh	0.223 ¢	$41,213	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	18,481,059	kWh	(0.018) ¢	($3,327)	0.000 ¢	$0			
Total	18,481,059	kWh		$1,585,907		$1,719,477			
Total Employee Discount				($396,477)		($429,869)			

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)		(4)	(5)		(6)	(7)	(8)	(9)
Schedule No. 23/723											
General Service (Secondary)											
Transmission & Ancillary Services Charge										Proposed	%
per kWh	1,012,788,782	kWh	0.455	¢	$4,608,189	0.374	¢	$3,787,830	Total	99,191,050	109.3%
Distribution Charge									T Rev	3,783,269	82.1%
Basic Charge									D Rev	47,114,947	115.0%
Single Phase, per month	695,056	bill	$16.15		$11,225,154	$18.55		$12,893,289	E Rev	48,292,834	106.8%
Three Phase, per month	193,187	bill	$24.10		$4,655,807	$27.70		$5,351,280	NPC Rev	20,833,323	
Load Size Charge											
≤ 15 kW		kW	No Charge			No Charge					
per kW for all kW in excess of 15 kW	767,514	kW	$1.10		$844,265	$1.25		$959,393			
Demand Charge, the first 15 kW of demand		kW	No Charge			No Charge					
Demand Charge, per kW for all kW in excess of 15 kW	419,716	kW	$3.77		$1,582,329	$4.33		$1,817,370			
Reactive Power Charge, per kvar	54,155	kvar	65.00	¢	$35,201	65.00	¢	$35,201			
Distribution Energy Charge, per kWh	1,012,788,782	kWh	2.252	¢	$22,808,003	2.574	¢	$26,069,183			
Energy Charge											
Schedule 200											
1st 3,000 kWh, per kWh	778,802,018	kWh	4.502	¢	$35,061,667	2.883	¢	$22,452,862			
All additional kWh, per kWh	233,986,764	kWh	3.343	¢	$7,822,178	2.141	¢	$5,009,657			
Schedule 201											
1st 3,000 kWh, per kWh	778,802,018	kWh				2.187	¢	$17,032,400			
All additional kWh, per kWh	233,986,764	kWh				1.624	¢	$3,799,945			
Subtotal					$88,642,793			$99,208,410			
Renewable Adjustment Clause, per kWh	1,012,788,782	kWh	0.229	¢	$2,319,286	0.000	¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	1,012,788,782	kWh	(0.017)	¢	($172,174)	0.000	¢	$0			
Total	1,012,788,782	kWh			$90,789,905			$99,208,410			
						Change		$8,418,505			

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
Schedule No. 23/723											
General Service (Primary)											
Transmission & Ancillary Services Charge										Proposed	%
per kWh	1,151,715	kWh	0.442	¢	$5,091	0.362	¢	$4,169	Total	140,052	141.2%
Distribution Charge									T Rev	4,445	87.3%
Basic Charge									D Rev	81,581	170.5%
Single Phase, per month	228	bill	$16.15		$3,682	$18.55		$4,229	E Rev	54,025	116.9%
Three Phase, per month	190	bill	$24.10		$4,579	$27.70		$5,263	NPC Rev	23,306	
Load Size Charge											
≤ 15 kW		kW	No Charge			No Charge					
per kW for all kW in excess of 15 kW	2,989	kW	$1.10		$3,288	$1.25		$3,736			
Demand Charge, the first 15 kW of demand		kW	No Charge			No Charge					
Demand Charge, per kW for all kW in excess of 15 kW	2,440	kW	$3.67		$8,955	$4.21		$10,272			
Reactive Power Charge, per kvar	3,872	kvar	60.00	¢	$2,323	60.00	¢	$2,323			
Distribution Energy Charge, per kWh	1,151,715	kWh	2.190	¢	$25,223	2.494	¢	$28,724			
Energy Charge											
Schedule 200											
1st 3,000 kWh, per kWh	535,677	kWh	4.386	¢	$23,495	2.793	¢	$14,961			
All additional kWh, per kWh	616,038	kWh	3.259	¢	$20,077	2.074	¢	$12,777			
Schedule 201											
1st 3,000 kWh, per kWh	535,677	kWh				2.119	¢	$11,351			
All additional kWh, per kWh	616,038	kWh				1.573	¢	$9,690			
Subtotal					$96,713			$107,495			
Renewable Adjustment Clause, per kWh	1,151,715	kWh	0.229	¢	$2,637	0.000	¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	1,151,715	kWh	(0.017)	¢	($196)	0.000	¢	$0			
Total	1,151,715	kWh			$99,154			$107,495			
						Change		$8,341			

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 28/728									
Large General Service - (Secondary)									
Transmission & Ancillary Services Charge								Proposed	%
per kW	6,689,074	kW	$1.25	$8,361,343	$1.23	$8,227,561	Total	141,772,578	114.0%
Distribution Charge							T Rev	8,250,834	98.7%
Basic Charge							D Rev	35,186,616	128.5%
Load Size ≤ 50 kW, per month	55,594	bill	$12.00	$667,128	$15.00	$833,910	E Rev	98,335,128	110.9%
Load Size 51-100 kW, per month	41,613	bill	$22.00	$915,486	$28.00	$1,165,164	NPC Rev	42,421,355	
Load Size 101-300 kW, per month	22,978	bill	$52.00	$1,194,856	$67.00	$1,539,526			
Load Size > 300 kW, per month	422	bill	$75.00	$31,650	$96.00	$40,512			
Load Size Charge									
≤ 50 kW	2,060,865	kW	$0.75	$1,545,649	$0.95	$1,957,822			
51-100 kW, per kW	2,821,071	kW	$0.60	$1,692,643	$0.75	$2,115,803			
101-300 kW, per kW	3,340,661	kW	$0.35	$1,169,231	$0.45	$1,503,297			
>300 kW, per kW	183,259	kW	$0.25	$45,815	$0.30	$54,978			
Demand Charge, per kW	6,689,074	kW	$2.21	$14,782,854	$2.84	$18,996,970			
Reactive Power Charge, per kvar	562,858	kvar	65.00 ¢	$365,858	65.00 ¢	$365,858			
Distribution Energy Charge, per kWh	2,026,816,182	kWh	0.259 ¢	$5,249,454	0.327 ¢	$6,627,689			
Energy Charge									
Schedule 200									
1st 20,000 kWh, per kWh	1,433,359,115	kWh	4.182 ¢	$59,943,078	2.781 ¢	$39,861,717			
All additional kWh, per kWh	593,457,067	kWh	4.069 ¢	$24,147,768	2.706 ¢	$16,058,948			
Schedule 201									
1st 20,000 kWh, per kWh	1,433,359,115	kWh			2.110 ¢	$30,243,877			
All additional kWh, per kWh	593,457,067	kWh			2.053 ¢	$12,183,674			
Subtotal				$120,112,813		$141,777,306			
Renewable Adjustment Clause, per kWh	2,026,816,182	kWh	0.224 ¢	$4,540,068	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	2,026,816,182	kWh	(0.014) ¢	($283,754)	0.000 ¢	$0			
Total	2,026,816,182	kWh		$124,369,127		$141,777,306			
					Change	$17,408,179			

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
Schedule No. 28/728									
Large General Service - (Primary)									
Transmission & Ancillary Services Charge								Proposed	%
per kW	60,958	kW	$1.23	$74,978	$1.18	$71,930	Total	1,241,970	110.6%
Distribution Charge							T Rev	71,809	95.8%
Basic Charge							D Rev	313,905	117.0%
Load Size ≤ 50 kW, per month	59	bill	$16.00	$944	$19.00	$1,121	E Rev	856,256	109.8%
Load Size 51-100 kW, per month	174	bill	$28.00	$4,872	$33.00	$5,742	NPC Rev	369,385	
Load Size 101-300 kW, per month	356	bill	$66.00	$23,496	$77.00	$27,412			
Load Size > 300 kW, per month	14	bill	$94.00	$1,316	$110.00	$1,540			
Load Size Charge									
≤ 50 kW	2,153	kW	$0.90	$1,938	$1.05	$2,261			
51-100 kW, per kW	12,408	kW	$0.75	$9,306	$0.90	$11,167			
101-300 kW, per kW	58,741	kW	$0.40	$23,496	$0.45	$26,433			
>300 kW, per kW	6,724	kW	$0.25	$1,681	$0.30	$2,017			
Demand Charge, per kW	60,958	kW	$2.87	$174,949	$3.36	$204,819			
Reactive Power Charge, per kvar	34,625	kvar	60.00 ¢	$20,775	60.00 ¢	$20,775			
Distribution Energy Charge, per kWh	18,249,203	kWh	0.044 ¢	$8,030	0.057 ¢	$10,402			
Energy Charge									
Schedule 200									
1st 20,000 kWh, per kWh	9,486,985	kWh	4.104 ¢	$389,346	2.703 ¢	$256,433			
All additional kWh, per kWh	8,762,218	kWh	3.994 ¢	$349,963	2.631 ¢	$230,534			
Schedule 201									
1st 20,000 kWh, per kWh	9,486,985	kWh			2.051 ¢	$194,578			
All additional kWh, per kWh	8,762,218	kWh			1.996 ¢	$174,894			
Subtotal				$1,085,090		$1,242,058			
Renewable Adjustment Clause, per kWh	18,249,203	kWh	0.224 ¢	$40,878	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	18,249,203	kWh	(0.014) ¢	($2,555)	0.000 ¢	$0			
Total	18,249,203	kWh		$1,123,413		$1,242,058			
					Change	$118,645			

Exhibit PPL/1012
Griffith/4

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 30/730									
Large General Service - (Secondary)									
Transmission & Ancillary Services Charge								Proposed	%
per kW	3,534,295	kW	$1.38	$4,877,327	$1.42	$5,018,699	Total	83,654,318	114.0%
Distribution Charge							T Rev	5,030,259	103.1%
Basic Charge							D Rev	17,170,097	124.2%
Load Size ≤ 200 kW, per month	155	bill	$319.00	$49,342	$393.00	$60,788	E Rev	61,453,962	112.4%
Load Size 201-300 kW, per month	2,716	bill	$99.00	$268,849	$123.00	$334,024	NPC Rev	26,510,977	
Load Size > 300 kW, per month	6,740	bill	$258.00	$1,738,822	$320.00	$2,156,679			
Load Size Charge									
≤ 200 kW	14,627	kW	No Charge		No Charge				
201-300 kW, per kW	714,392	kW	$1.10	$785,831	$1.35	$964,429			
>300 kW, per kW	3,411,992	kW	$0.55	$1,876,596	$0.70	$2,388,394			
Demand Charge, per kW	3,534,295	kW	$2.49	$8,800,395	$3.09	$10,920,972			
Reactive Power Charge, per kvar	713,631	kvar	65.00 ¢	$463,860	65.00 ¢	$463,860			
Energy Charge									
Schedule 200									
1st 20,000 kWh, per kWh	190,869,386	kWh	4.552 ¢	$8,688,374	3.009 ¢	$5,743,260			
All additional kWh, per kWh	1,093,845,348	kWh	3.947 ¢	$43,174,076	2.659 ¢	$29,085,348			
Schedule 201									
1st 20,000 kWh, per kWh	190,869,386	kWh			2.327 ¢	$4,441,531			
All additional kWh, per kWh	1,093,845,348	kWh			2.018 ¢	$22,073,799			
Subtotal				$70,723,472		$83,651,783			
Renewable Adjustment Clause, per kWh	1,284,714,734	kWh	0.218 ¢	$2,800,678	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	1,284,714,734	kWh	(0.012) ¢	($154,166)	0.000 ¢	$0			
Total	1,284,714,734	kWh		$73,369,984		$83,651,783			
					Change	$10,281,799			
Schedule No. 30/730									
Large General Service - (Primary)									
Transmission & Ancillary Services Charge								Proposed	%
per kW	279,833	kW	$1.32	$369,380	$1.27	$355,388	Total	5,923,010	111.4%
Distribution Charge							T Rev	356,039	96.4%
Basic Charge							D Rev	1,211,862	115.9%
Load Size ≤ 200 kW, per month	0	bill	$310.00	$0	$356.00	$0.00	E Rev	4,355,109	111.6%
Load Size 201-300 kW, per month	106	bill	$100.00	$10,597	$116.00	$12,293.00	NPC Rev	1,878,776	
Load Size > 300 kW, per month	520	bill	$260.00	$135,223	$301.00	$156,546.00			
Load Size Charge									
≤ 200 kW	0	kW	No Charge		No Charge				
201-300 kW, per kW	27,640	kW	$1.05	$29,022	$1.20	$33,168			
>300 kW, per kW	314,299	kW	$0.55	$172,864	$0.65	$204,294			
Demand Charge, per kW	279,833	kW	$2.46	$688,389	$2.85	$797,524			
Reactive Power Charge, per kvar	35,084	kvar	60.00 ¢	$21,050	60.00 ¢	$21,050			
Energy Charge									
Schedule 200									
1st 20,000 kWh, per kWh	12,465,248	kWh	4.461 ¢	$556,075	2.889 ¢	$360,121			
All additional kWh, per kWh	81,466,178	kWh	3.857 ¢	$3,142,150	2.583 ¢	$2,104,271			
Schedule 201									
1st 20,000 kWh, per kWh	12,465,248	kWh			2.266 ¢	$282,463			
All additional kWh, per kWh	81,466,178	kWh			1.959 ¢	$1,595,922			
Subtotal				$5,124,750		$5,923,040			
Renewable Adjustment Clause, per kWh	93,931,426	kWh	0.218 ¢	$204,771	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	93,931,426	kWh	(0.012) ¢	($11,272)	0.000 ¢	$0			
Total	93,931,426	kWh		$5,318,249		$5,923,040			
					Change	$604,791			

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)		(4)	(5)		(6)	(7)	(8)	(9)
Schedule No. 33											
Klamath Irrigation and Drainage Pumping											
Total Customers	2,062										
Charges											
Off-Project (Rate Code 35)	52,080,607	kWh	3.016	¢	$1,570,751	3.097	¢	$1,612,936			
On-Project (Rate Code 40)	62,373,687	kWh	2.757	¢	$1,719,643	2.832	¢	$1,766,423			
U.S. Government (Rate Code 33TX)	3,592,093	kWh									
U.S. Gov - On Peak	1,437,815	kWh	2.560	¢	$36,808	2.630	¢	$37,815			
U.S. Gov - Off Peak	2,154,278	kWh	2.037	¢	$43,883	2.037	¢	$43,883			
Minimum Charges Off-Project					$6,529			$6,529			
Minimum Charges On-Project					$197,821			$197,821			
Subtotal	118,046,387	kWh			$3,575,435			$3,665,407			
Renewable Adjustment Clause, per kWh	118,046,387	kWh	0.223	¢	$263,243	0.000	¢	$0			
Total	118,046,387	kWh			$3,838,678			$3,665,407			
Note: Rates reflect estimated rate changes through 2010.						Change		($173,271)			

PACIFIC POWER & LIGHT COMPANY
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Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 41/741									
Agricultural Pumping Service (Secondary)									
Transmission & Ancillary Services Charge									
per kWh	134,221,373	kWh	0.427 ¢	$573,125	0.437 ¢	$586,547		Proposed	%
Distribution Charge							Total	15,580,004	108.8%
Basic Charge							T Rev	596,811	102.2%
Load Size ≤ 50 kW, or Single Phase Any Size	5,637	bill	No Charge		No Charge		D Rev	8,439,193	108.4%
Three Phase Load Size 51 - 300 kW, per month	453	bill	$360.00	$163,080	$390.00	$176,670	E Rev	6,544,000	109.9%
Three Phase Load Size > 300 kW, per month	13	bill	$1,420.00	$18,460	$1,540.00	$20,020	NPC Rev	2,823,054	
Total Customers	6,103	bill							
Load Size Charge									
Single Phase Any Size, Three Phase≤ 50 kW	74,733	kW	$18.00	$1,345,194	$20.00	$1,494,660			
Three Phase 51-300 kW, per kW	39,848	kW	$11.00	$438,328	$12.00	$478,176			
Three Phase > 300 kW, kW	6,641	kW	$7.00	$46,487	$8.00	$53,128			
Single Phase, Minimum Charge	838	bill	$60.00	$50,280	$65.00	$54,470			
Three Phase, Minimum Charge	1,139	bill	$105.00	$119,595	$115.00	$130,985			
Distribution Energy Charge, per kWh	134,221,373	kWh	4.088 ¢	$5,486,970	4.381 ¢	$5,880,238			
Reactive Power Charge, per kvar	27,433	kvar	65.00 ¢	$17,831	65.00 ¢	$17,831			
Energy Charge									
Schedule 200									
Winter, 1st 100 kWh/kW, per kWh	1,363,670	kWh	6.035 ¢	$82,297	3.976 ¢	$54,220			
Winter, All additional kWh, per kWh	1,466,167	kWh	4.112 ¢	$60,289	2.709 ¢	$39,718			
Summer, All kWh, per kWh	131,391,536	kWh	4.112 ¢	$5,402,820	2.709 ¢	$3,559,397			
Schedule 201									
Winter, 1st 100 kWh/kW, per kWh	1,363,670	kWh			3.016 ¢	$41,128			
Winter, All additional kWh, per kWh	1,466,167	kWh			2.055 ¢	$30,130			
Summer, All kWh, per kWh	131,391,536	kWh			2.055 ¢	$2,700,096			
Subtotal				$13,804,756		$15,317,414			
Renewable Adjustment Clause, per kWh	134,221,373	kWh	0.223 ¢	$299,314	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	134,221,373	kWh	(0.017) ¢	($22,818)	0.000 ¢	$0			
Total	134,221,373	kWh		$14,081,252		$15,317,414			
					Change	$1,236,162			
Schedule No. 41/741									
Agricultural Pumping Service (Primary)									
Transmission & Ancillary Services Charge									
per kWh	2,570,507	kWh	0.415 ¢	$10,668	0.423 ¢	$10,873			
Distribution Charge									
Basic Charge									
Load Size ≤ 50 kW, or Single Phase Any Size	3	bill	No Charge		No Charge				
Three Phase Load Size 51 - 300 kW, per month	0	bill	$350.00	$0	$380.00	$0			
Three Phase Load Size > 300 kW, per month	2	bill	$1,380.00	$2,760	$1,500.00	$3,000			
Total Customers	5	bill							
Load Size Charge									
Single Phase Any Size, Three Phase≤ 50 kW	46	kW	$18.00	$828	$19.00	$874			
Three Phase 51-300 kW, per kW	0	kW	$11.00	$0	$12.00	$0			
Three Phase > 300 kW, kW	2,169	kW	$7.00	$15,183	$8.00	$17,352			
Single Phase, Minimum Charge	0	bill	$60.00	$0	$65.00	$0			
Three Phase, Minimum Charge	1	bill	$100.00	$100	$110.00	$110			
Distribution Energy Charge, per kWh	2,570,507	kWh	3.975 ¢	$102,178	4.244 ¢	$109,092			
Reactive Power Charge, per kvar	3,066	kvar	60.00 ¢	$1,840	60.00 ¢	$1,840			
Energy Charge									
Schedule 200									
Winter, 1st 100 kWh/kW, per kWh	10,613	kWh	5.877 ¢	$624	3.852 ¢	$409			
Winter, All additional kWh, per kWh	61,869	kWh	4.007 ¢	$2,479	2.624 ¢	$1,623			
Summer, All kWh, per kWh	2,498,025	kWh	4.007 ¢	$100,096	2.624 ¢	$65,548			
Schedule 201									
Winter, 1st 100 kWh/kW, per kWh	10,613	kWh			2.922 ¢	$310			
Winter, All additional kWh, per kWh	61,869	kWh			1.991 ¢	$1,232			
Summer, All kWh, per kWh	2,498,025	kWh			1.991 ¢	$49,736			
Subtotal				$236,756		$261,999			
Renewable Adjustment Clause, per kWh	2,570,507	kWh	0.223 ¢	$5,732	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	2,570,507	kWh	(0.017) ¢	($437)	0.000 ¢	$0			
Total	2,570,507	kWh		$242,051		$261,999			
					Change	$19,948			

PACIFIC POWER & LIGHT COMPANY
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Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units	Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 47/747								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	629,550 kW	$1.05	$661,028	$1.06	$667,323			
credit per kW of on-peak demand	0 kW	($1.05)	$0	($1.06)	$0			
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	0 bill	$270.00	$0	$360.00	$0			
Load Size > 4,000 kW, per month	36 bill	$480.00	$17,280	$640.00	$23,040			
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	0 kW	$0.85	$0	$0.75	$0			
Load Size > 4,000 kW, per kW	655,984 kW	$0.80	$524,787	$0.70	$459,189			
Demand Charge, per kW of on-peak demand	629,550 kW	$1.43	$900,257	$2.33	$1,466,852			
Reactive Power Charge, per kvar	22,941 kvar	60.00 ¢	$13,765	60.00 ¢	$13,765			
Reactive Hours, per kvarh	4,083,071 kvarh	0.080 ¢	$3,266	0.080 ¢	$3,266			
Reserves Charges								
Spinning Reserves, per kW of Facility	655,984 kW	$0.27	$177,116	$0.27	$177,116			
Supplemental Reserves, per kW of Facility	655,984 kW	$0.27	$177,116	$0.27	$177,116			
Spinning Reserves Credit, per kW of Facility	520,704 kW	($0.27)	($140,590)	($0.27)	($140,590)			
Supplemental Reserves Credit, per kW of Facility	520,704 kW	($0.27)	($140,590)	($0.27)	($140,590)			
Energy Charge								
Schedule 200								
On-Peak, per on-peak kWh	232,517,250 kWh	3.797 ¢	$8,828,680	2.610 ¢	$6,068,700			
Off-Peak, per off-peak kWh	179,422,218 kWh	3.697 ¢	$6,633,239	2.560 ¢	$4,593,209			
Schedule 201								
On-Peak, per on-peak kWh	232,517,250 kWh			1.986 ¢	$4,617,793			
Off-Peak, per off-peak kWh	179,422,218 kWh			1.936 ¢	$3,473,614			
Unscheduled Energy, per kWh	832,620 kWh	*5.970 ¢*	$49,709	*5.970 ¢*	$49,709			
Subtotal			$17,705,063		$21,509,512			
Renewable Adjustment Clause, per kWh	412,772,088 kWh	0.203 ¢	$837,927	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	412,772,088 kWh	(0.011) ¢	($45,405)	0.000 ¢	$0			
Total	412,772,088 kWh		$18,497,585		$21,509,512			
				Change	$3,011,927			
Schedule No. 47/747								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	291,068 kW	$1.40	$407,495	$1.43	$416,227			
credit per kW of on-peak demand	0 kW	($1.40)	$0	($1.43)	$0			
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	24 bill	$260.00	$6,240	$480.00	$11,520			
Load Size > 4,000 kW, per month	24 bill	$480.00	$11,520	$890.00	$21,360			
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	35,910 kW	$0.45	$16,160	$0.65	$23,342			
Load Size > 4,000 kW, per kW	330,471 kW	$0.45	$148,712	$0.65	$214,806			
Demand Charge, per kW of on-peak demand	291,068 kW	$0.78	$227,033	$1.64	$477,352			
Reactive Power Charge, per kvar	43,402 kvar	55.00 ¢	$23,871	55.00 ¢	$23,871			
Reactive Hours, per kvarh	977,033 kvarh	0.08 ¢	$782	0.08 ¢	$782			
Reserves Charges								
Spinning Reserves, per kW of Facility	366,381 kW	$0.27	$98,923	$0.27	$98,923			
Supplemental Reserves, per kW of Facility	366,381 kW	$0.27	$98,923	$0.27	$98,923			
Spinning Reserves Credit, per kW of Facility	0 kW	($0.27)	$0	($0.27)	$0			
Supplemental Reserves Credit, per kW of Facility	0 kW	($0.27)	$0	($0.27)	$0			
Energy Charge								
Schedule 200								
On-Peak, per on-peak kWh	88,587,292 kWh	3.630 ¢	$3,215,719	2.492 ¢	$2,207,595			
Off-Peak, per off-peak kWh	64,575,860 kWh	3.530 ¢	$2,279,528	2.442 ¢	$1,576,943			
Schedule 201								
On-Peak, per on-peak kWh	88,587,292 kWh			1.896 ¢	$1,679,615			
Off-Peak, per off-peak kWh	64,575,860 kWh			1.846 ¢	$1,192,070			
Unscheduled Energy, per kWh	6,030,044 kWh	*6.347 ¢*	$382,701	*6.347 ¢*	$382,701			
Subtotal			$6,917,607		$8,426,030			
Renewable Adjustment Clause, per kWh	159,193,196 kWh	0.203 ¢	$323,162	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	159,193,196 kWh	(0.011) ¢	($17,511)	0.000 ¢	$0			
Total	159,193,196 kWh		$7,223,258		$8,426,030			
				Change	$1,202,772			

Exhibit PPL/1012
Griffith/8

PACIFIC POWER & LIGHT COMPANY
State of Oregon
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Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

	Forecast 1/10 - 12/10		Present Rates Effective 3/31/09		Proposed		Cost of Service Based Unbundled Target Revenues		
Schedule	Units		Price	Dollars	Price	Dollars			
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 76R/776R									
Large General Service/Partial Requirements Service - Economic Replacement Power Rider									
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand									
Secondary	0	kW	$0.038	$0	$0.038	$0			
Primary	0	kW	$0.041	$0	$0.041	$0			
Transmission	0	kW	$0.055	$0	$0.056	$0			
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand									
Secondary	0	kW	$0.051	$0	$0.084	$0			
Primary	0	kW	$0.056	$0	$0.091	$0			
Transmission	0	kW	$0.030	$0	$0.064	$0			
Schedule No. 48/748									
Large General Service (Secondary)									
Transmission & Ancillary Services Charge									
per kW of on-peak demand	1,680,446	kW	$1.51	$2,537,473	$1.51	$2,537,473		Proposed	%
Distribution Charge							Total Rev	40,759,959	113.5%
Basic Charge							T Rev	2,533,707	99.9%
Load Size ≤ 4,000 kW, per month	1,466	bill	$310.00	$454,460	$340.00	$498,440	D Rev	7,224,741	111.2%
Load Size > 4,000 kW, per month	12	bill	$580.00	$6,960	$640.00	$7,680	E Rev	31,001,511	115.3%
Load Size/Facility Charge							NPC Rev	13,373,920	
Load Size ≤ 4,000 kW, per kW	1,931,585	kW	$1.75	$3,380,274	$1.35	$2,607,640			
Load Size > 4,000 kW, per kW	130,868	kW	$1.60	$209,389	$1.25	$163,585			
Demand Charge, per kW of on-peak demand	1,680,446	kW	$1.31	$2,201,384	$2.15	$3,612,959			
Reactive Power Charge, per kvar	486,931	kvar	65.00 ¢	$316,505	65.00 ¢	$316,505			
Energy Charge									
Schedule 200									
On-Peak, per on-peak kWh	415,357,613	kWh	3.976 ¢	$16,514,619	2.735 ¢	$11,360,031			
Off-Peak, per off-peak kWh	233,733,537	kWh	3.876 ¢	$9,059,512	2.685 ¢	$6,275,745			
Schedule 201									
On-Peak, per on-peak kWh	415,357,613	kWh			2.078 ¢	$8,631,131			
Off-Peak, per off-peak kWh	233,733,537	kWh			2.028 ¢	$4,740,116			
Subtotal				$34,680,576		$40,751,305			
Renewable Adjustment Clause, per kWh	649,091,150	kWh	0.203 ¢	$1,317,655	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	649,091,150	kWh	-0.011 ¢	($71,400)	0.000 ¢	$0			
Total	649,091,150	kWh		$35,926,831		$40,751,305			
					Change	$4,824,474			
Schedule No. 48/748									
Large General Service (Primary)									
Transmission & Ancillary Services Charge									
per kW of on-peak demand	3,454,326	kW	$1.59	$5,492,378	$1.60	$5,526,922		Proposed	%
Distribution Charge							Total Rev	89,885,740	116.2%
Basic Charge							T Rev	5,519,735	100.5%
Load Size ≤ 4,000 kW, per month	673	bill	$270.00	$181,710	$360.00	$242,280	D Rev	11,913,009	133.6%
Load Size > 4,000 kW, per month	400	bill	$480.00	$192,000	$640.00	$256,000	E Rev	72,452,996	115.1%
Load Size/Facility Charge							NPC Rev	31,255,914	
Load Size ≤ 4,000 kW, per kW	1,185,743	kW	$0.85	$1,007,882	$0.75	$889,307			
Load Size > 4,000 kW, per kW	2,859,392	kW	$0.80	$2,287,514	$0.70	$2,001,574			
Demand Charge, per kW of on-peak demand	3,454,326	kW	$1.43	$4,939,686	$2.33	$8,048,580			
Reactive Power Charge, per kvar	800,170	kvar	60.00 ¢	$480,102	60.00 ¢	$480,102			
Energy Charge									
Schedule 200									
On-Peak, per on-peak kWh	962,377,337	kWh	3.797 ¢	$36,541,467	2.610 ¢	$25,118,048			
Off-Peak, per off-peak kWh	627,543,923	kWh	3.697 ¢	$23,200,299	2.560 ¢	$16,065,124			
Schedule 201									
On-Peak, per on-peak kWh	962,377,337	kWh			1.986 ¢	$19,112,814			
Off-Peak, per off-peak kWh	627,543,923	kWh			1.936 ¢	$12,149,250			
Subtotal				$74,323,038		$89,890,001			
Renewable Adjustment Clause, per kWh	1,589,921,260	kWh	0.203 ¢	$3,227,540	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	1,589,921,260	kWh	-0.011 ¢	($174,891)	0.000 ¢	$0			
Total	1,589,921,260	kWh		$77,375,687		$89,890,001			
					Change	$12,514,314			

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 48/748									
Large General Service (Transmission)									
Transmission & Ancillary Services Charge									
per kW of on-peak demand	619,494	kW	$1.94	$1,201,818	$1.97	$1,220,403		Proposed	%
Distribution Charge							Total Rev	20,404,496	117.3%
Basic Charge							T Rev	1,223,310	101.8%
Load Size ≤ 4,000 kW, per month	0	bill	$260.00	$0	$480.00	$0	D Rev	1,588,061	185.0%
Load Size > 4,000 kW, per month	23	bill	$480.00	$11,040	$890.00	$20,470	E Rev	17,593,125	114.7%
Load Size/Facility Charge							NPC Rev	7,589,599	
Load Size ≤ 4,000 kW, per kW	0	kW	$0.45	$0	$0.65	$0			
Load Size > 4,000 kW, per kW	753,152	kW	$0.45	$338,918	$0.65	$489,549			
Demand Charge, per kW of on-peak demand	619,494	kW	$0.78	$483,205	$1.64	$1,015,970			
Reactive Power Charge, per kvar	127,183	kvar	55.00 ¢	$69,951	55.00 ¢	$69,951			
Energy Charge									
Schedule 200									
On-Peak, per on-peak kWh	226,903,748	kWh	3.630 ¢	$8,236,606	2.492 ¢	$5,654,441			
Off-Peak, per off-peak kWh	177,985,113	kWh	3.530 ¢	$6,282,874	2.442 ¢	$4,346,396			
Schedule 201									
On-Peak, per on-peak kWh	226,903,748	kWh			1.896 ¢	$4,302,095			
Off-Peak, per off-peak kWh	177,985,113	kWh			1.846 ¢	$3,285,605			
Subtotal				$16,624,412		$20,404,880			
Renewable Adjustment Clause, per kWh	404,888,861	kWh	0.203 ¢	$821,924	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	404,888,861	kWh	-0.011 ¢	($44,538)	0.000 ¢	$0			
Total	404,888,861	kWh		$17,401,798		$20,404,880			
					Change	$3,003,082			
Schedule No. 15									
Outdoor Area Lighting Service									
No. of Customers	7,404								
Transmission & Ancillary Services Charge									
per kWh	10,467,219	kWh	0.015 ¢	$1,570	0.017 ¢	$1,779			
Distribution Charge								Proposed	
Distribution Charge, per kWh	10,467,219	kWh	10.129 ¢	$1,062,234	11.345 ¢	$1,187,484	Total Rev	1,453,676	10.8%
Energy Charge							Change	141,694	10.8%
Sch 200, per kWh	10,467,219	kWh	2.276 ¢	$238,234	1.375 ¢	$143,924			
Sch 201 TAM, per kWh	10,467,219	kWh			1.147 ¢	$120,059	Energy Rev	278,229	
Subtotal				$1,302,038		$1,453,247	NPC Rev	120,027	
Renewable Adjustment Clause, per kWh	10,467,219	kWh	0.123 ¢	$12,875	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	10,467,219	kWh	-0.028 ¢	($2,931)	0.000 ¢	$0			
Total	10,467,219	kWh		$1,311,982		$1,453,247			
					Change	$141,265			
Schedule No. 50									
Mercury Vapor Street Lighting Service									
No. of Customers	287								
Transmission & Ancillary Services Charge									
per kWh	10,738,031	kWh	0.013 ¢	$1,396	0.014 ¢	$1,503			
Distribution Charge									
Distribution Charge, per kWh	10,738,031	kWh	8.919 ¢	$957,702	10.443 ¢	$1,022,512	Total Rev	1,253,363	
Energy Charge							Change	82,726	7.1%
Sch 200, per kWh	10,738,031	kWh	1.893 ¢	$203,271	1.215 ¢	$130,467			
Sch 201 TAM, per kWh	10,738,031	kWh			0.921 ¢	$98,897	Energy Rev	229,363	
Subtotal				$1,162,369		$1,253,380	NPC Rev	98,946	
Renewable Adjustment Clause, per kWh	10,738,031	kWh	0.102 ¢	$10,953	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	10,738,031	kWh	-0.025 ¢	($2,685)	0.000 ¢	$0			
Total	10,738,031	kWh		$1,170,637		$1,253,380			
					Change	$82,743			

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars	Cost of Service Based Unbundled Target Revenues		
(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
Schedule No. 51/751									
High Pressure Sodium Vapor Street Lighting Service									
No. of Customers	686								
Transmission & Ancillary Services Charge									
per kWh	16,084,697	kWh	0.019 ¢	$3,056	0.020 ¢	$3,217			
Distribution Charge									
Distribution Charge, per kWh	16,084,697	kWh	14.457 ¢	$2,325,307	16.893 ¢	$2,483,346	Total Rev	3,028,660	
Energy Charge							Change	199,901	7.1%
Sch 200, per kWh	16,084,697	kWh	2.988 ¢	$480,611	1.918 ¢	$308,505			
Sch 201 TAM, per kWh	16,084,697	kWh			1.454 ¢	$233,872	Energy Rev	542,301	
Subtotal				$2,808,974		$3,028,939	NPC Rev	233,946	
Renewable Adjustment Clause, per kWh	16,084,697	kWh	0.161 ¢	$25,896	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	16,084,697	kWh	-0.038 ¢	($6,112)	0.000 ¢	$0			
Total	16,084,697	kWh		$2,828,758		$3,028,939			
					Change	$200,180			
Schedule No. 52/752									
Company-Owned Street Lighting Service									
No. of Customers	79								
Transmission & Ancillary Services Charge									
per kWh	1,185,726	kWh	0.015 ¢	$178	0.016 ¢	$190			
Distribution Charge									
Distribution Charge, per kWh	1,185,726	kWh	8.913 ¢	$105,671	10.627 ¢	$112,785	Total Rev	143,619	
Energy Charge							Change	9,479	7.1%
Sch 200, per kWh	1,185,726	kWh	2.289 ¢	$27,141	1.469 ¢	$17,418			
Sch 201 TAM, per kWh	1,185,726	kWh			1.115 ¢	$13,221	Energy Rev	30,633	
Subtotal				$132,990		$143,614	NPC Rev	13,215	
Renewable Adjustment Clause, per kWh	1,185,726	kWh	0.124 ¢	$1,470	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	1,185,726	kWh	-0.027 ¢	($320)	0.000 ¢	$0			
Total	1,185,726	kWh		$134,140		$143,614			
					Change	$9,474			
Schedule No. 53/753									
Customer-Owned Street Lighting Service									
No. of Customers	250								
Transmission & Ancillary Services Charge									
per kWh	9,316,113	kWh	0.005 ¢	$466	0.005 ¢	$466			
Distribution Charge									
Distribution Charge, per kWh	9,316,113	kWh	5.355 ¢	$495,092	6.150 ¢	$528,630	Total Rev	631,919	
Energy Charge							Change	41,709	7.1%
Sch 200, per kWh	9,316,113	kWh	0.978 ¢	$91,112	0.628 ¢	$58,505			
Sch 201 TAM, per kWh	9,316,113	kWh			0.476 ¢	$44,345	Energy Rev	102,838	
Subtotal				$586,670		$631,946	NPC Rev	44,364	
Renewable Adjustment Clause, per kWh	9,316,113	kWh	0.053 ¢	$4,938	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	9,316,113	kWh	-0.015 ¢	($1,397)	0.000 ¢	$0			
Total	9,316,113	kWh		$590,211		$631,946			
					Change	$41,735			
Schedule No. 54/754									
Recreational Field Lighting									
Transmission & Ancillary Services Charge									
per kWh	815,719	kWh	0.011 ¢	$90	0.012 ¢	$98			
Distribution Charge									
Basic Charge, Single Phase, per month	865	bill	$6.00	$5,190	$6.00	$5,190			
Basic Charge, Three Phase, per month	397	bill	$9.00	$3,573	$9.00	$3,573	Total Rev	74,736	
Distribution Energy Charge, per kWh	815,719	kWh	5.716 ¢	$46,626	6.177 ¢	$50,387	Change	4,933	7.1%
Energy Charge									
Sch 200, per kWh	815,719	kWh	1.683 ¢	$13,729	1.080 ¢	$8,810			
Sch 201 TAM, per kWh	815,719	kWh			0.819 ¢	$6,681	Energy Rev	15,494	
Subtotal				$69,208		$74,739	NPC Rev	6,684	
Renewable Adjustment Clause, per kWh	815,719	kWh	0.091 ¢	$742	0.000 ¢	$0			
Klamath Rate Reconciliation Surcharge, per kWh	815,719	kWh	-0.018 ¢	($147)	0.000 ¢	$0			
Total	815,719	kWh		$69,803		$74,739			
					Change	$4,936			
TOTAL OREGON	13,392,810,002			$947,357,466		$1,050,108,446			
Employee Discount				($396,477)		($429,869)			
TOTAL OREGON				$946,960,989		$1,049,678,577			

Docket No. UE-210
Exhibit PPL/1013
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of William R. Griffith

FERC/Non-FERC Transmission Cost Breakout

August 2009

PacifiCorp
State of Oregon
December 31, 2010 Unbundled Revenue Requirement Allocation by Load Size
FERC Transmission Revenue
-

	Description	Total	(A) Residential	(B) General Service Schedule 23	(C)	(D)	(E) General Service Schedule 28	(F)	(G)	(H)	(I) General Service Schedule 30	(J)	(K)	(L) Large Power Service Schedule 48T	(M)	(N)	(O)	(P)	(Q) Schedule 41	(R) Street Lgt
			(sec)	0-15 kW (sec)	>15 kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 (sec)	>100 kW (sec)	Primary (pri)	0-300 kW (sec)	>300 (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 M (pri)	> 4 MW (sec)	> 4 M (pri)	Trans (trn)	Irrigation	(sec)
1	Total Transmission Revenue Requirement	$79,096	$35,458	$3,302	$2,857	$7	$2,837	$4,593	$5,855	$115	$1,278	$6,645	$562	$3,682	$2,404	$294	$6,399	$1,924	$844	$40
2	FERC Transmission																			
3	Peak Mw @ Generator	1,990	862	82	73	0	69	122	153	3	34	175	15	98	61	7	163	48	25	0
4	% of Total	100.00%	43.31%	4.13%	3.65%	0.01%	3.49%	6.12%	7.69%	0.15%	1.69%	8.78%	0.74%	4.91%	3.07%	0.37%	8.18%	2.42%	1.28%	0.00%
5	FERC Transmission Revenues	$37,588	$16,281	$1,554	$1,370	$3	$1,312	$2,301	$2,890	$57	$636	$3,301	$279	$1,844	$1,155	$138	$3,076	$910	$480	$0
6	Other Transmission Revenue Requirement	$41,508	$19,177	$1,748	$1,487	$4	$1,525	$2,292	$2,965	$58	$641	$3,345	$284	$1,838	$1,249	$156	$3,323	$1,013	$363	$40