PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

RE: Advice No. 12-003, Docket UE 246
In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon

Enclosed for filing by PacifiCorp dba Pacific Power are an original and 30 copies of the following proposed tariff pages associated with the Company's Tariff P.U.C. OR No. 36 applicable to electric service in the State of Oregon, together with the Executive Summary, and supporting direct testimony and exhibits. The tariffs reflect an effective date of March 31, 2012. Provided on the enclosed CDs (3) are electronic versions of the testimony, exhibits and workpapers, in their original format when available.

Third Revision of Sheet No. INDEX-3		Tariff Index Sheet
First Revision of Sheet No.4	Schedule 4	Residential Service Delivery Service
Second Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service No New Service Delivery Service
First Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
First Revision of Sheet No. 23-2	Schedule 23	General Service – Small Nonresidential Delivery Service
First Revision of Sheet No. 28-1	Schedule 28	General Service – Large Nonresidential – 31 kW to 200 kW Delivery Service
First Revision of Sheet No. 28-2	Schedule 28	General Service – Large Nonresidential – 31 kW to 200 kW Delivery Service
First Revision of Sheet No. 30-1	Schedule 30	General Service-Large Nonresidential 201 KW to 999 KW Delivery Service
First Revision of Sheet No. 30-2	Schedule 30	General Service-Large Nonresidential 201 KW to 999 KW Delivery Service
First Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service
First Revision of Sheet No. 41-2	Schedule 41	Agricultural Pumping Service Delivery Service

First Revision of Sheet No. 47-1	Schedule 47	Large General Service/Partial Requirements Service – 1,000 kW and Over Delivery Service
First Revision of Sheet No. 47-2	Schedule 47	Large General Service/Partial Requirements Service – 1,000 kW and Over Delivery Service
First Revision of Sheet No. 48-1	Schedule 48	Large General Service - 1,000 kW and Over Delivery Service
First Revision of Sheet No. 48-2	Schedule 48	Large General Service - 1,000 kW and Over Delivery Service
First Revision of Sheet No. 50-1	Schedule 50	Mercury Vapor Street Lighting Service No New Service Delivery Service
First Revision of Sheet No. 51-1	Schedule 51	Street Lighting Service Company-Owned System Delivery Service
Second Revision of Sheet No. 52-1	Schedule 52	Street Lighting Service Company-Owned System No New Service Delivery Service
First Revision of Sheet No. 53-1	Schedule 53	Street Lighting Service Consumer-Owned System Delivery Service
Second Revision of Sheet No. 54-1	Schedule 54	Recreational Field Lighting Restricted Delivery Service
First Revision of Sheet No. 55-1	Schedule 55	LED Pilot Street Lighting Service Company-Owned System Delivery Service
First Revision of Sheet No. 76R-1	Schedule 76R	Large General Service/Partial Requirements Service – Economic Replacement Power Rider Delivery Service
CANCELING Original Sheet No. 80	Schedule 80	Populus to Ben Lomond Cost Recovery Charge
Third Revision of Sheet No. 90	Schedule 90	Summary of Effective Rate Adjustments
First Revision of Sheet No. 200-1	Schedule 200	Base Supply Service
First Revision of Sheet No. 200-2	Schedule 200	Base Supply Service
First Revision of Sheet No. 200-3	Schedule 200	Base Supply Service
First Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
First Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
First Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues
Original Sheet No. 206	Schedule 206	Power Cost Adjustment Mechanism-Adjustment
First Revision of Sheet No. 230	Schedule 230	Emergency Supply Service
First Revision of Sheet No. 247-2	Schedule 247	Partial Requirements Supply Service
First Revision of Sheet No. 276R-4	Schedule 276R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Supply Service

First Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
First Revision of Sheet No. 723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
First Revision of Sheet No. 723-2	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
First Revision of Sheet No. 728-1	Schedule 728	General Service – Large Nonresidential 31kW to 200kW Direct Access Delivery Service
First Revision of Sheet No. 728-2	Schedule 728	General Service – Large Nonresidential 31kW to 200kW Direct Access Delivery Service
First Revision of Sheet No. 730-1	Schedule 730	General Service – Large Nonresidential 201kW to 999kW Direct Access Delivery Service
First Revision of Sheet No. 730-2	Schedule 730	General Service – Large Nonresidential 201kW to 999kW Direct Access Delivery Service
First Revision of Sheet No. 741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
First Revision of Sheet No. 741-2	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
First Revision of Sheet No. 747-1	Schedule 747	Large General Service Partial Requirements Service – 1,000 kW and Over Direct Access Delivery Service
First Revision of Sheet No. 747-2	Schedule 747	Large General Service Partial Requirements Service – 1,000 kW and Over Direct Access Delivery Service
First Revision of Sheet No. 748-1	Schedule 748	Large General Service 1,000 kW and Over Direct Access Delivery Service
First Revision of Sheet No. 748-2	Schedule 748	Large General Service 1,000 kW and Over Direct Access Delivery Service
First Revision of Sheet No. 751-1	Schedule 751	Street Lighting Service - Company-Owned System Direct Access Delivery Service
First Revision of Sheet No. 752	Schedule 752	Street Lighting Service Company Owned System No New Service Direct Access Delivery Service
First Revision of Sheet No. 753-1	Schedule 753	Street Lighting Service Consumer Owned System Direct Access Delivery service
First Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting Restricted Direct Access Delivery Service
First Revision of Sheet No. 776R-1	Schedule 776R	Large General Service/Partial

Requirements Service – Economic Replacement Service Rider Direct Access Delivery Service

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

Copies of the Company's responses to the Standard Data Requests are provided under separate cover.

A copy of this filing has been served on all parties to PacifiCorp's last general rate case proceeding, UE 217, as indicated on the attached certificate of service.

Very truly yours,

William Griffith/jfs

William R. Griffith
Vice President, Regulation

Enclosure

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 217, on the date indicated below by email, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: March 1, 2012

Carrie Meyer
Coordinator, Regulatory Operations

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of PACIFICORP d/b/a PACIFIC POWER's Request for a General Rate Revision.	**PACIFICORP'S EXECUTIVE SUMMARY**

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power ("PacifiCorp" or "Company") is filing this request for a general rate revision under ORS 757.205 and ORS 757.220 to revise its schedules of rates and charges for electric service in Oregon, effective March 31, 2012. The revised rates reflect an Oregon-allocated revenue requirement increase of $38.4 million, or 3.2 percent. As a result of resetting Schedule 299, the Rate Mitigation Adjustment, to reflect forecast customer loads by rate schedule, the increase to net rates is $41.2 million, or 3.5 percent. The revised rates produce revenues necessary to sustain a stable, reliable, and low-cost power supply, while preserving the Company's ability to attract capital for future investments. The Company has also included in this filing the analysis and evidence that demonstrates that the Mona-to-Oquirrh transmission line is a prudent investment that will be used and useful during calendar year 2013, which is the test period for these proceedings. Because the transmission line is not projected to be in service until the second quarter of 2013, the Company is proposing to delay implementation of the revenue requirement increase related to the Mona-to-Oquirrh transmission line, $13.1 million or 1.1 percent on an overall basis, until it has closed to plant in service. The Company files this executive summary and the attached Exhibit A in compliance with OAR 860-022-0019.

PacifiCorp is an electric company and public utility in the state of Oregon within the meaning of ORS 757.005. The Public Utility Commission of Oregon ("Commission") has jurisdiction over the prices and terms of PacifiCorp's electric service to its Oregon retail customers. The Company provides electric service to approximately 580,000 retail customers in Oregon and approximately 1.7 million total retail customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon.

The Company requests that communications regarding this filing be addressed to:

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

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

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
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Please direct informal correspondence and questions regarding this filing to Bryce Dalley at (503) 813-6389.

II. CASE SUMMARY

This case is based upon a historical base period of 12 months ending June 2011, with normalizing and pro forma adjustments to calculate a calendar year 2013 future test period. The new rates will become effective no later than January 1, 2013, assuming application of the full

nine-month statutory suspension period to the 30-day effective date now contained in the tariffs. Thus, the rate effective period closely aligns with the test period in this case.

A. Return on Equity

PacifiCorp is currently forecast to earn a return on equity ("ROE") in Oregon of 8.5 percent for the test period. In this case, the Company seeks a return on equity of 10.2 percent. This ROE is necessary to maintain the financial integrity of the Company, while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impacts. This filing supports an overall price increase of $38.4 million, or 3.2 percent, required to produce the requested 10.2 percent ROE. As a result of resetting the Rate Mitigation Adjustment to reflect forecast customer loads by rate schedule, the increase to net rates is $41.2 million, or 3.5 percent. Notwithstanding the increase, PacifiCorp's Oregon customers continue to benefit from some of the lowest electricity rates in the country.

B. Cost Drivers

1. New System Investments

The Company's need for this rate increase is driven by on going new investments in the system required to provide safe, adequate, and reliable service to customers and to comply with regulatory mandates. This case includes investments in all facets of the system—including transmission, generation, and distribution—to bolster reliability and improve power delivery. This filing includes an increase in Oregon-allocated net electric plant in service of more than $225 million over what was included in the Company's last request for a general rate revision in 2010 (Docket UE 217).

This filing includes investments for environmental improvements at several of the Company's thermal generation plants (Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3). These investments are necessary to comply with environmental regulations, will result in reduced emissions, and are similar to the pollution

control investments in Dave Johnston Unit 3 included in Docket UE 217. Upgrades at the Company's hydro generation plants also represent major investments included in this filing. The upgrades include improvements to the Lewis River and North Umpqua hydro systems to comply with the licenses issued by the Federal Energy Regulatory Commission for those systems.

In addition to these major plant improvements, this filing includes a new two megawatt solar photovoltaic project that the Company is acquiring to help meet PacifiCorp's portion of the Solar Energy Capacity Standard in ORS 757.370, as well as on going investments in the distribution system.

2. Retirement of the Carbon Thermal Generation Plant

The Company expects to retire its Carbon thermal generation plant in early 2015 to comply with the Environmental Protection Agency's recently finalized Mercury and Air Toxins Standards. The Company has therefore included accelerated depreciation for the Carbon plant in this filing.

C. Mitigating Factors

In light of the current economic climate, PacifiCorp is keenly aware of the financial pressures faced by its customers. The Company has therefore taken several steps to mitigate the rate increase request.

First, the Company is proposing an overall cost of capital of 7.92 percent, which is lower than the 8.08 percent in the stipulation adopted in UE 217. This lower cost of capital is a result of the Company's success in securing low interest rates in recent debt issuances. In fact, the rates are among the lowest ever achieved by borrowers. The lower debt rates directly benefit customers by reducing the Company's cost of long-term debt in the capital structure, which translates to a $9.2 million reduction in the revenue requirement increase requested in this case.

Second, the Company has prudently controlled increases in labor costs, particularly benefit costs. The total labor and benefit costs in this filing are nearly two percent less than the

level filed in UE 217.

Third, the Company continues to aggressively and proactively control operations and maintenance ("O&M") and administrative and general ("A&G") expenses (collectively "OMAG"). As a result of these efforts, the Oregon-allocated OMAG expense in this case is only $2.2 million higher than the level filed for two years ago in UE 217. This equates to an increase of 0.7 percent in OMAG over this two-year period. Contributing to this on going low level of OMAG expense is a reduction in full-time equivalent employees of 194 from the level in UE 217.

Finally, using the 2010 Protocol adopted by the Commission for inter-jurisdictional cost allocations, Oregon's share of system costs is lower than in the last general rate case, which translates to a decrease in the allocation factors for Oregon. This decrease is consistent with Oregon's slower growth rates compared to the other states in which the Company serves customers. The Company's requested increase is $9.5 million lower than if the allocation factors from UE 217 had been used.

D. Mona-to-Oquirrh Transmission Line

To mitigate the rate impacts on customers, and to minimize controversy in this case, the Company included plant in service through December 31, 2012, rather than through the end of the test period (December 31, 2013). The one exception is the Mona-to-Oquirrh transmission project. The Mona-to-Oquirrh transmission project is currently expected to go into service in May 2013, which is during the test period. The project consists of a single-circuit 500 kV transmission line originating from the Clover substation (being constructed near Mona, Utah), extending north about 70 miles to the future Limber substation (to be located in Tooele County, Utah), and continuing as a double-circuit 345 kV line for approximately 30 miles to the existing Oquirrh substation in South Jordan, Utah. To begin recovery of the investment concurrent with the provision of service to customers, the Company is requesting approval to make an advice

filing for a separate tariff rider to recover the investment when it goes into service in the test period. The Oregon-allocated revenue requirement associated with this project is approximately $13.1 million.

E. Power Cost Adjustment Mechanism

The Company is proposing a power cost adjustment mechanism ("PCAM") to operate in conjunction with the Company's Transition Adjustment Mechanism ("TAM"). The proposed PCAM is a rate mechanism designed to allow the Company to collect or credit the differences between actual net power costs and the forecasted net power costs approved in the TAM. With the addition of significant intermittent renewable energy resources to the Company's system, the Company needs the PCAM to recover its prudently incurred costs.

III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 13 witnesses:

Richard Patrick "Pat" Reiten, President, Pacific Power, provides the Company's policy testimony.

Dr. Samuel C. Hadaway, Principal, FINANCO, Inc., testifies concerning the Company's cost of equity. He recommends that the appropriate allowed ROE for PacifiCorp be set at 10.2 percent.

Bruce N. Williams, Vice President and Treasurer, describes the calculation of PacifiCorp's capital structure, cost of debt and preferred stock, and presents the Company's recommended overall rate of return of 7.92 percent .

Mark R. Tallman, Vice President, Renewable Resource Development, demonstrates the prudence of two additions to hydro generation plant and increases in costs related to non-labor-related O&M activities for the Company's wind and hydro generation resources.

Chad A. Teply, Vice President, Resource Development and Construction, describes the environmental improvements in thermal generation plants and explains the anticipated closure of the Carbon plant in early 2015.

Dana M. Ralston, Vice President, Generation, explains the O&M cost increases for the thermal generation fleet.

Darrell T. Gerrard, Vice President, Transmission System Planning, provides additional details and technical information on the Mona-to-Oquirrh project.

Bruce W. Griswold, Director, Short-Term Origination and QF Contracts, demonstrates the prudence of the Black Cap Solar, LLC, asset purchase and sale agreement.

Gregory N. Duvall, Director, Net Power Costs, describes the proposed PCAM. He also presents the Company's load and sales forecasts for 2013 and describes how these forecasts were developed.

Erich D. Wilson, Director, Human Resources, presents an overview of the Company's compensation and benefit plans and supports the costs related to these plans included in the test period.

R. Bryce Dalley, Director, Regulatory Affairs and Revenue Requirement, presents the Company's overall revenue requirement based on the test period using the 2010 Protocol allocation methodology.

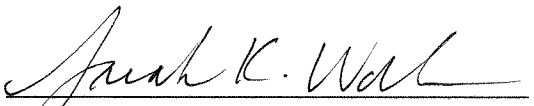
C. Craig Paice, Regulatory Consultant, Cost of Service, presents the Company's marginal cost of service study.

William R. Griffith, Vice President, Regulation, presents the Company's proposed rate spread, rate design, and tariffs.

IV. CONCLUSION

The Company respectfully requests that the Commission issue an order approving the proposed rate changes and tariffs described above.

DATED: March 1, 2012



Sarah K. Wallace
Senior Counsel
PacifiCorp d/b/a Pacific Power

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed March 1, 2012

(A)	Total Revenues collected under proposed rates:		$876,299,254
(B)	Revenue change requested:		
	Total:		$38,356,265
	Net of credits from federal agencies:		$38,356,265
(C)	Percentage change in revenues requested:		
	Total %:		3.2%
	Net of credits from federal agencies:		3.2%
(D)	Test period:		Calendar year 2013
(E)	Requested return on capital:		7.92%
	Requested return on equity:		10.2%
(F)	Rate base proposed in filing:		$3,253,958,859
(G)	Results of operation:		
	Utility operating income, before proposed change:		$234,825,114
	Utility operating income, after proposed change:		$257,757,438
(H)	Effect of rate change on each customer class:	Base Change	Net Change[1]
	• Residential:	4.0%	3.5%
	• Small General Service (Schedule 23):	-2.6%	2.0%
	• General Service 31-200 kW (Schedule 28):	5.4%	3.5%
	• General Service 201-999 kW (Schedule 30):	3.9%	3.5%
	• Large General Service >= 1,000 kW (Schedule 48):	4.2%	4.4%
	• Agriculture Pumping Service (Schedule 41):	-8.5%	3.5%
	• Street lighting:	0.5%	2.0%
(I)	Information Required by Utility Staff General Rate Case Data Request Form A:	Provided under separate cover	

[1] The net change reflects resetting Schedule 299, the Rate Mitigation Adjustment, for changes in forecast customer loads by rate schedule, resulting in an increase to net rates of $41.2 million, or 3.5 percent.

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

A. My name is Richard Patrick "Pat" Reiten. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am President of Pacific Power.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a bachelor's degree in political science with an emphasis in economics from the University of Washington and completed executive training at the Wharton School of Business, University of Pennsylvania. Prior to joining PacifiCorp in September 2006, I was president and chief executive officer of PNGC Power, an energy cooperative located in Portland, Oregon, that provides power management services to electric distribution utilities serving parts of seven Western states. I was appointed to that position in May 2002. I joined PNGC Power in 1993, advancing through positions of increasing responsibility. Prior to PNGC Power, I served as an aide to U.S. Sen. Mark O. Hatfield, handling issues associated with the U.S. Senate Energy and Natural Resources Committee. I also was an official in several different capacities at the U.S. Department of Interior, including acting as deputy director of the U.S. Bureau of Land Management.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony provides an overview of the Company's request for an increase in its base electric rates, describes the major factors driving the need for the rate

increase, and discusses actions taken by the Company to mitigate the rate increase. My testimony also introduces the other witnesses providing testimony on behalf of PacifiCorp.

Q. For background, please provide a brief introduction of the Company.

A. PacifiCorp is a regulated electric utility company comprised of three business units: Pacific Power, Rocky Mountain Power, and PacifiCorp Energy. Pacific Power, headquartered in Portland, Oregon, serves customers in Oregon, Washington, and California. Rocky Mountain Power, headquartered in Salt Lake City, Utah, serves customers in Utah, Wyoming, and Idaho. PacifiCorp Energy, containing the electric generation, commercial, energy trading and coal mining operations of the Company, is also headquartered in Salt Lake City.

In 2006, PacifiCorp was acquired by MidAmerican Energy Holdings Company. Today, PacifiCorp serves more than 1.7 million customers across 136,000 square miles of service territory in six states. See Exhibit PAC/101 for a map of the Company's service territories.

Summary of PacifiCorp's Rate Increase Request

Q. Please summarize PacifiCorp's rate increase request.

A. PacifiCorp is requesting an increase to its base electric rates in Oregon. Based on the evidence provided in the direct testimony of Company witness Mr. R. Bryce Dalley, PacifiCorp is currently forecast to earn a return on equity ("ROE") in Oregon of 8.5 percent for the test period. This filing supports a revenue

requirement increase of $38.4 million, or 3.2 percent overall,[1] requested to go into effect on March 31, 2012. This revenue requirement is required to produce the 10.2 percent ROE supported by Company witness Dr. Samuel C. Hadaway in his direct testimony, which is necessary to maintain the financial integrity of the Company.

The Company has also included in this filing the analysis and evidence that demonstrates that the Mona-to-Oquirrh transmission line is a prudent investment that will be used and useful during calendar year 2013, which is the test period for this proceeding. Because the transmission line is not projected to be in service until the second quarter of 2013, the Company is proposing to delay implementation of the revenue requirement increase related to the Mona-to-Oquirrh transmission line, $13.1 million or 1.1 percent on an overall basis, until it has closed to plant in service. The testimony of Company witness Mr. Griffith describes and provides an illustrative tariff that would be used to implement the tariff rider to recover the investment.

Q. Upon what test year is the rate increase request based?

A. As described in the testimony of Mr. Dalley, the test year for this filing is the 12 months ending December 31, 2013.

Q. What is the primary factor driving the need for an overall rate increase?

A. As a regulated utility, PacifiCorp has a duty and an obligation to provide safe, adequate and reliable service to customers in its Oregon service territory while balancing cost, risk and state and federal energy policy objectives. The

[1] As discussed in Mr. William R. Griffith's testimony, the increase to net rates is $41.2 million, or 3.5 percent, as a result of resetting the Rate Mitigation Adjustment to reflect forecast customer loads by rate schedule.

Company's need for this rate increase is driven by on-going new investments in the system, many of which are necessary to meet state or federal regulatory mandates.

As described in the testimony of Mr. Dalley, the Company continues to make significant investments to serve its customers. This filing includes an increase in Oregon-allocated net electric plant in service of more than $225 million over what was included in the Company's last general rate case filing two years ago in 2010, Docket UE 217.

Q. What major new investments are included in this filing?

A. This case includes investments in all facets of the system, including transmission, generation and distribution investment, which will help to bolster reliability, improve power delivery and comply with regulatory mandates.

This filing includes generation investments for environmental improvements at several of the Company's thermal generation plants, specifically, Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3. The investments are necessary to comply with environmental regulations and will result in reductions to emissions from those plants. These investments are similar to the pollution control investments in the Dave Johnston Unit 3 power plant included in Docket UE 217. Company witness Mr. Chad A. Teply explains the nature of the investments and the environmental regulations governing the investment decision.

Upgrades at the Company's hydro generation plants also represent major investments included in this filing. The upgrades include improvements for the

Lewis River and North Umpqua hydro systems required to comply with the licenses issued by the Federal Energy Regulatory Commission for those systems. The projects are described in the direct testimony of Company witness Mr. Mark R. Tallman.

In addition to the major plant additions, the filing includes a new two megawatt solar photovoltaic project the Company is acquiring to meet Oregon's Solar Energy Capacity Standard in Oregon Revised Statute 757.370, which is discussed in the direct testimony of Company witness Mr. Bruce W. Griswold, as well as on-going investment in the Oregon distribution system.

Q. In addition to these capital investments, is there another driver of the requested increase?

A. Yes. As explained in Mr. Teply's testimony, the Company anticipates retiring the Carbon thermal generation plant in early 2015 in order to comply with the Environmental Protection Agency's recently finalized Mercury and Air Toxins Standards. As a result, the Company has included accelerated depreciation of the Carbon plant in this filing. The proposed treatment of depreciation is discussed in Mr. Dalley's testimony.

Q. Are increases associated with net power costs part of the increase requested in this case?

A. No. The Company filed a separate Transition Adjustment Mechanism ("TAM") to recover increases in net power costs on February 29, 2012. The TAM rate changes related to 2013 net power costs will have an effective date of January 1, 2013.

Q. Does this case include a proposal for a power cost adjustment mechanism ("PCAM")?

A. Yes. The Company is requesting approval of a PCAM that will operate with the TAM. The PCAM is a rate mechanism designed to allow the Company to collect or credit the differences between actual net power costs and the forecasted net power costs approved in the TAM. As discussed in detail in the direct testimony of Company witness Mr. Gregory N. Duvall, with the addition of significant intermittent renewable energy resources to the Company's system, the Company needs a PCAM in order to recover its prudent costs. Mr. Duvall's testimony explains the design and operation of the proposed PCAM.

Q. Are the cost increases facing the Company unique in the industry?

A. No. Other utilities are facing the same types of cost pressures. But even with the increase proposed in this case, PacifiCorp's prices will remain competitive.

Q. Has the Company taken any actions to mitigate the rate increase requested in this case?

A. Yes. The Company has taken several steps to mitigate the rate increase request. First, the Company is proposing an overall cost of capital of 7.92 percent, which is lower than the 8.08 percent adopted in the UE 217 stipulation. This lower cost of capital was made possible by the Company's success in securing low interest rates in recent debt issuances. In fact, the rates are among the lowest ever achieved by U.S. borrowers. This is discussed in the direct testimony of Company witness Mr. Bruce N. Williams. The lower debt rates directly benefit

customers by reducing the Company's cost of long-term debt in the capital structure, which translates to a $9.2 million reduction in the revenue requirement increase requested in this case. This helps keep rates reasonable for customers.

Second, the Company has prudently controlled increases in labor costs since the last rate case and, in particular, has kept increases in benefit costs at a competitive level. In fact, the current total labor and benefit costs are expected to decline by nearly two percent from the level filed in UE 217 for calendar year 2011 when compared to the current filing for calendar year 2013. Company witness Mr. Erich D. Wilson discusses these costs in his direct testimony.

The Company also continues to proactively and aggressively control operations and maintenance ("O&M") and administrative and general ("A&G") expenses, collectively ("OMAG"). As a result of the Company's cost-control efforts, the Oregon-allocated OMAG in this case is only $2.2 million higher than the level filed for two years ago in UE 217. This equates to a 0.7 percent increase in Oregon-allocated OMAG over this two-year period (calendar year 2011 to calendar year 2013), which is significantly less than Global Insight's inflation increase of 4.4 percent over the same period. The Company has been able to keep overall expenses low by aggressively pursuing efficiency gains that have allowed the Company to largely offset the increases in O&M expense for generation.

Contributing to this on-going low level of OMAG expense is a decrease in the Company's number of full-time equivalent employees ("FTEs") since UE 217. The current filing has 194 less FTEs than the level included in UE 217.

Q. Are there other factors that help mitigate the increase requested in this case?

A. Yes. Using the 2010 Protocol adopted by the Commission for inter-jurisdictional cost allocations, Oregon's share of system costs is lower than in the last rate case, which translates to a decrease in the allocation factors for Oregon. The decrease in Oregon's allocation factors is commensurate with Oregon's slower growth rates compared to the other states in which the Company serves customers. As a result, the Company's requested increase is $9.5 million lower than if the allocation factors from the last rate case had been used.

Q. Has the Company taken any actions to address issues contested by Commission Staff and other parties in past cases, in order to further mitigate impacts on customers?

A. Yes. One of the most significant areas of controversy in recent past rate cases, notably Docket UE 210, was the removal of Oregon-allocated capital additions forecast to be completed during the future test year. Commission Staff removed capital additions during the test year arguing that these projects were not used and useful under Oregon Revised Statute 757.355. The Company disagrees with this interpretation of the statute and believes it is inconsistent with Commission precedent. For purposes of minimizing controversy in this case and mitigating impacts to customers, however, with one exception for the Mona-to-Oquirrh transmission line, the Company has included plant in service through only December 31, 2012, rather than through the end of the test period, December 31, 2013. Mr. Dalley discusses this in more detail in his testimony.

Q. Please explain the Mona-to-Oquirrh transmission line and the Company's proposal for its cost recovery in this filing.

A. The Mona-to-Oquirrh transmission line is expected to be in service by May 2013, which is during the test period. Specifically, the line consists of a single-circuit 500 kV transmission line originating from the Clover substation (being constructed near Mona, Utah), extending northward about 70 miles to the future Limber substation (to be located in Tooele County, Utah), and continuing as a double-circuit 345 kV line for approximately 30 miles to the existing Oquirrh substation in South Jordan, Utah. The Mona-to-Oquirrh line's detailed description, justification and projected costs are described in the direct testimony of Company witness Mr. Darrell T. Gerrard.

In order to begin recovery of the investment concurrent with the provision of service to customers, the Company is requesting approval to make an advice filing for a separate tariff rider to recover the investment when it goes into service in the test period. Accordingly, the Company has separated the revenue requirement associated with this project, which is $13.1 million, as discussed in Mr. Dalley's testimony. This separate tariff rider will ensure that costs are properly reflected in rates in a timely manner, while allowing the prudence of the project to be reviewed in this general rate case. As indicated earlier, the proposed tariff rider to recover the costs for the Mona-to-Oquirrh line is described in the testimony of Mr. Griffith.

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 cost of equity. He recommends that the appropriate allowed ROE for PacifiCorp be set at 10.2 percent.

Bruce N. Williams, Vice President and Treasurer, describes the calculation of PacifiCorp's capital structure, cost of debt and preferred stock, and presents the Company's recommended overall rate of return of 7.92 percent.

Mark R. Tallman, Vice President, Renewable Resource Development, demonstrates the prudence of two additions to hydro generation plant and increases in costs related to non-labor-related O&M activities for the Company's wind and hydro generation resources.

Chad A. Teply, Vice President, Resource Development and Construction, provides the justification and description of the environmental improvements in thermal generation plants and explains the anticipated closure of the Carbon plant in early 2015.

Dana M. Ralston, Vice President, Generation, explains the O&M cost increases for the thermal generation fleet.

Darrell T. Gerrard, Vice President, Transmission System Planning, provides additional details and technical information on the Mona-to-Oquirrh transmission line.

Bruce W. Griswold, Director, Short-Term Origination and QF Contracts,

demonstrates the prudence of the Black Cap Solar, LLC, asset purchase and sale agreement.

Gregory N. Duvall, Director, Net Power Costs, describes the proposed PCAM. He also presents the Company's load and sales forecasts for 2013 and describes how these forecasts were developed.

Erich D. Wilson, Director, Human Resources, presents an overview of the Company's compensation and benefit plans and supports the costs related to these plans included in the test period.

R. Bryce Dalley, Director, Regulatory Affairs and Revenue Requirement, presents the Company's overall revenue requirement based on the test period using the 2010 Protocol allocation methodology.

C. Craig Paice, Regulatory Consultant, Cost of Service, presents the Company's marginal cost of service study.

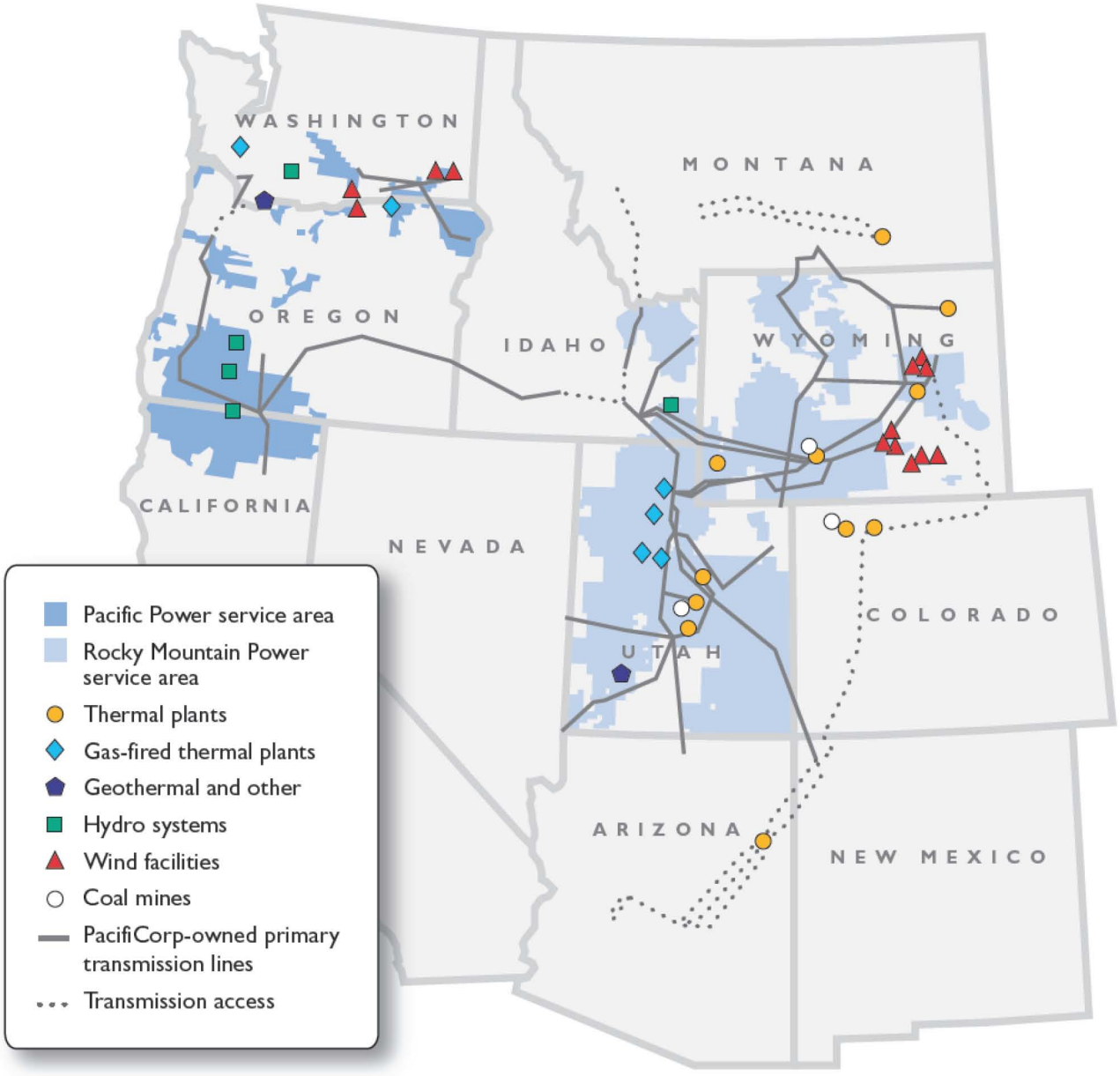
William R. Griffith, Vice President, Regulation, presents the Company's proposed rate spread, rate design, and tariffs.

Q. Does this conclude your direct testimony?

A. Yes.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

PacifiCorp Service Territories



DIRECT TESTIMONY OF SAMUEL C. HADAWAY

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ATTACHED EXHIBITS

Introduction and Purpose of Testimony

Q. Please state your name, occupation, and business address.

A. My name is Samuel C. Hadaway. I am a Principal in FINANCO, Inc., Financial Analysis Consultants, 3520 Executive Center Drive, Austin, Texas 78731.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of PacifiCorp ("Company").

Q. Please describe your educational background and professional experience.

A. My educational background and professional experience is summarized in my resume, which is included as Exhibit PAC/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to estimate PacifiCorp's cost of equity capital.

Q. Please define the term "cost of equity capital" ("COE").

A. The COE is the rate of return that equity investors require or expect to receive from their investment in common stocks. Conceptually, COE is no different than the interest rate on debt or the cost of preferred stock. Equity investors expect a return on their capital commensurate with the risks they take and consistent with returns that might be available from other similar investments.

Summary of Recommendations

Q. Have you determined the COE for utilities comparable to the Company?

A. Yes. I applied the discounted cash flow ("DCF") model to estimate the COE for utilities comparable to PacifiCorp. The results of that analysis indicate that the comparable group's COE is in the range of 9.6 percent to 10.2 percent. I also performed an equity risk premium analysis. That analysis indicates a COE in the

range of 9.55 percent to 9.70 percent. As I will explain later in this testimony, I discount the current equity risk premium results because they are unduly affected by the artificially low interest rates caused by the Federal Government's ongoing expansionary monetary policy.

Q. Based on these quantitative results and other economic data discussed in this testimony, have you determined the appropriate allowed return on equity ("ROE") for PacifiCorp?

A. Yes. I recommend that the appropriate allowed ROE for PacifiCorp be set at 10.2 percent. This is a reasonable ROE for establishing the Company's rates at this time and should be authorized by the Commission.

Q. How is your analysis structured?

A. In my DCF analysis, I apply a comparable company approach. PacifiCorp's COE cannot be estimated directly from its own market data because the Company is a wholly-owned subsidiary of MidAmerican Energy Holdings Company. As such, PacifiCorp does not have publicly traded common stock or other independent market data that would be required to estimate its DCF cost directly. Therefore, I begin my comparable company review with all the vertically-integrated electric utilities that are included in the Value Line Investment Survey ("Value Line"). Value Line is a widely-followed, reputable source of financial data that is often used by professional regulatory economists. To improve the group's comparability with PacifiCorp, which has a senior secured bond rating of A from Standard & Poor's ("S&P") and A2 from Moody's Investors Service ("Moody's"), I restricted the group to integrated electric utilities with senior

secured bond ratings of at least A- by S&P or A3 by Moody's. I also required the companies to derive at least 70 percent of their revenues from regulated utility sales, to have consistent financial records not affected by recent mergers or restructuring, and to have a consistent dividend record with no dividend cuts or resumptions during the past two years. I also excluded delivery-only companies from the group. The fundamental characteristics and bond ratings of the 14 companies in my comparable group are presented in Exhibit PAC/202, page 1.

In my risk premium analysis, I present estimates from both current and projected single-A utility bond yields for 2012. These rates are consistent with the Company's single-A bond ratings and reflect both the current Government-influenced interest rate environment and the rate levels that are expected during the coming year. As I will discuss later in this testimony, these risk premium estimates continue to be depressed by the Federal Government's stated intentions to keep interest rates artificially low. For these reasons, the risk premium results are not reasonable estimates of the Company's market-required COE. The data sources and the details of my COE studies are contained in Exhibits PAC/202 through PAC/207.

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is divided into three sections. In this first section, I review general capital market costs and conditions and discuss recent developments in the electric utility industry that may affect the cost of equity. In the second section, I review various methods for estimating the COE. I discuss comparable earnings methods, equity risk premium methods, and the discounted

cash flow model. In the third section, I apply the DCF and risk premium models to estimate PacifiCorp's COE, I discuss the details of my COE studies, and I summarize my ROE recommendations.

Fundamental Factors That Affect the Cost of Equity

Q. What is the current outlook for the U.S. economy?

A. Growth for the U.S. economy is expected to remain slow in the near term. While most economists expect real growth to remain positive (in the 1.5 percent range), unemployment is also expected to remain stubbornly high in the 8 percent to 9 percent range. Forecasts for 2012 indicate continuing but slow recovery, with new job creation a fundamental concern. Based on these conditions, the Federal Reserve System has announced its intention to keep interest rates at their current, historically low levels through 2014.[1] Equity markets, however, have continued to be extremely volatile and utility stocks have only recently had favorable performance relative to the general market recovery. As I will explain later in this testimony, the recent positive utility stock performance is not necessarily a reflection of improving economic conditions. Rather it very likely reflects a search for yield by investors discouraged by the persistent intervention in the fixed income market and the Federal Government's stated intention of maintaining low bond yields. On top of these market dislocations, investors are also concerned about the European sovereign debt crisis. All of these factors

[1] In the policy statement following its January 24-25, 2012 meeting, the Federal Reserve System Board of Governors provided the following comments: "To support a stronger economic recovery and to help ensure that inflation, over time, is at levels consistent with the dual mandate [of maximum employment and stable inflation], the Committee expects to maintain a highly accommodative stance for monetary policy. In particular, the Committee decided today to keep the target range for the federal funds rate at 0 to 1/4 percent and currently anticipates that economic conditions—including low rates of resource utilization and a subdued outlook for inflation over the medium run—are likely to warrant exceptionally low levels for the federal funds rate at least through late 2014."

point to elevated risk aversion, a fundamental lack of equilibrium conditions in the financial markets, and a continuing relatively high cost for equity capital.

Q. What has been the experience in the U.S. capital markets for the past several years?

A. In Exhibit PAC/203, page 1, I provide a 10-year review of annual interest rates and rates of inflation. During this time period, interest rates and inflation generally have been lower than in the previous decade. Inflation in this period, as measured by the Consumer Price Index ("CPI"), fluctuated between a low of zero percent (in 2008) and 4.1 percent (caused by the spike in energy costs that occurred in 2007). The decade's average annual inflation rate (2.4 percent) was approximately 100 basis points lower than the longer-term average rate of the past 60 years (see Exhibit PAC/205). Interest rates declined steadily over most of the period, with the 2010 average utility rate at its lowest level in more than 30 years (see Exhibit PAC/207, page 1).

Q. What has been the more recent monthly trend in long-term interest rates?

A. The month-by-month interest rate data for the period from January 2009 to December 2011are presented in Exhibit PAC/203, page 2, and summarized below:

Table 1

Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
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
Aug-09	5.71	4.37	1.34
Sep-09	5.53	4.19	1.34
Oct-09	5.55	4.19	1.36
Nov-09	5.64	4.31	1.33
Dec-09	5.79	4.49	1.30
Jan-10	5.77	4.60	1.17
Feb-10	5.87	4.62	1.25
Mar-10	5.84	4.64	1.20
Apr-10	5.81	4.69	1.12
May-10	5.50	4.29	1.21
Jun-10	5.46	4.13	1.33
Jul-10	5.26	3.99	1.27
Aug-10	5.01	3.80	1.21
Sep-10	5.01	3.77	1.24
Oct-10	5.10	3.87	1.23
Nov-10	5.37	4.19	1.18
Dec-10	5.56	4.42	1.14
Jan-11	5.57	4.52	1.05
Feb-11	5.68	4.65	1.03
Mar-11	5.56	4.51	1.05
Apr-11	5.55	4.50	1.05
May-11	5.32	4.29	1.03
Jun-11	5.26	4.23	1.03
Jul-11	5.27	4.27	1.00
Aug-11	4.69	3.65	1.04
Sep-11	4.48	3.18	1.30
Oct-11	4.52	3.13	1.39
Nov-11	4.25	3.02	1.23
Dec-11	4.33	2.98	1.35
3-Mo Avg	**4.37**	**3.04**	**1.32**
12-Mo Avg	**5.04**	**3.91**	**1.13**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury rates). Three month average is for October 2011-December 2011. Twelve month average is for January 2011-December 2011.

The data in Table 1 track the steady decline in corporate interest rates that has occurred since early 2009 and the market turmoil that has existed during this time period. The Federal Reserve's continuing intervention in the financial markets, and its efforts to keep short-term rates near zero and rates on longer-term U.S. Treasury bonds at historically low levels, are affecting yields on high quality corporate debt as well. While the effects of these monetary policy efforts are not easily captured in financial models for estimating COE (models that assume market equilibrium exists), equity market turbulence and the resulting elevated level of risk aversion indicate that any decline in COE has not been nearly as large as the decline in borrowing costs.

Q. Has PacifiCorp recently issued low cost debt?

A. Yes. Earlier this year, the Company issued $350 million of debt with a 10-year maturity and a coupon interest rate of 2.95 percent, and $300 million with a 30-year maturity and a coupon rate of 4.10 percent. As discussed in the testimony of Company Vice President and Treasurer Mr. Bruce N. Williams, these rates are among the lowest ever achieved by borrowers. The coupon rate on the 10-year maturity is tied for the lowest utility rate on record (for any ratings level) and the sixth lowest coupon rate for any industry and any credit rating. The 30-year coupon rate of 4.10 percent is the third lowest coupon achieved by any issuer in any industry and credit rating. While the beneficial effects of these low-cost bonds are flowed directly to Oregon customers in this case, the historically low debt costs are a concrete example of the impact of the Government's monetary policy.

Q. Do the smaller spreads between yields on single-A utility bonds and U.S. Treasury bonds mean that the markets have fully recovered from the economic turmoil that resulted from the financial crisis?

A. No. While markets have stabilized considerably from the conditions that existed in early 2009, investors remain concerned about high unemployment, large federal deficits, the Mideast turmoil, and European and domestic economic issues. These factors combined with sluggish growth in gross domestic product ("GDP") continue to raise substantial equity market concerns and contribute to heightened investor risk aversion.

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

A. Interest rates are expected to rise somewhat from currently low levels. In Exhibit PAC/203, page 3, I provide S&P's most recent interest rate forecast from its *Trends & Projection*s publication for November 2011. Table 2 summarizes the interest rate forecasts:

Table 2
Interest Rate Forecasts

	Dec. 2011 Average	Average 2012 Est.
Treasury Bills	0.1%	0.0%
10-Yr. T-Bonds	2.0%	2.3%
30-Yr. T-Bonds	3.0%	3.3%
Aaa Corporate Bonds	3.9%	4.2%

Sources: www.federalreserve.gov, (Current Rates). Standard & Poor's *Trends & Projections*, November 2011, page 8 (Projected Rates).

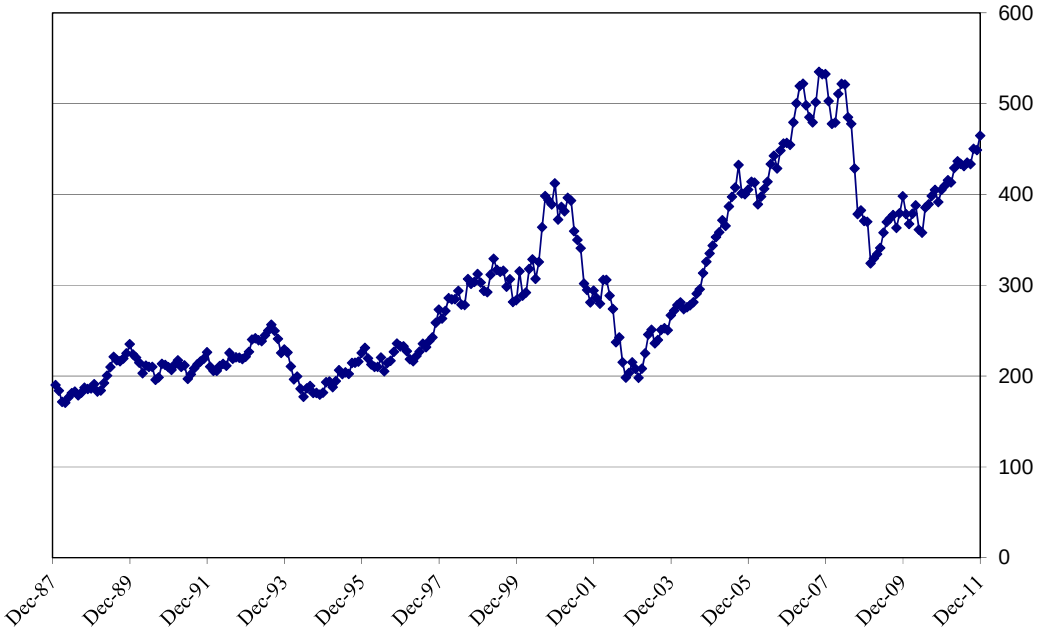
These data show that, during 2012, average long-term Treasury interest rates are expected to increase by 30 basis points relative to the low levels in December 2011. Yields on the other bonds shown in the table are also expected to increase

slightly. The small interest rate increases projected by S&P are consistent with a sluggishly improving economy and the Government's announced intention to maintain low interest rates.

Q. How have utility stocks performed during the past several years?

A. Utility stock prices have been more volatile in recent years as compared to their traditional performance. The wider fluctuations in more recent years are vividly illustrated in the following Graph 1, which depicts Dow Jones Utility Average ("DJUA") prices over the past 25 years:

Graph 1
Dow Jones Utility Average
1987-2011



Until the late 1990s, utility stocks were viewed as relatively stable investments. Over the past decade, however, utility stock prices have fluctuated much more widely. In this environment, investors' return expectations and requirements for

providing capital to the utility industry remain high relative to the longer-term, traditional view of the utility industry.

Q. How have utility stocks performed since the market low point reached in March 2009?

A. Before May 2011, utility stock prices had lagged well behind the general market recovery. Since May, however, fears of potential sovereign defaults and domestic financial problems have increased equity market risk aversion. This situation has made dividend-oriented stocks, like utility stocks, relatively more attractive for all income-oriented investors. For the May-December time period, the DJUA rose over 6 percent (6.5 percent), while the S&P 500 dropped by over 7 percent (-7.5 percent). The relatively better performance for utilities has produced lower dividend yields in the DCF model; *i.e.*, the DCF model results, with respect to dividend yields, do not reflect the overall market's volatility and heightened risk aversion. This anomaly makes it more difficult to interpret current DCF cost of equity estimates for utility companies.

Furthermore, as noted previously, any decline in the COE has not been nearly as large as the recent decline in borrowing costs. By the same token, any rise in the COE would not be as large as an increase in borrowing costs. From a regulatory policy point of view, incremental changes in the embedded cost of debt are gradually applied to the rate base as new debt issues are added to the balance sheet and retiring debt issues are removed from the balance sheet. But incremental changes in common equity costs, either up or down, are applied to the rate base without moderation. This could have a material effect on the utility's

funds from operations. Thus, tempering incremental changes in common equity costs, either up or down, would be consistent with the way incremental debt cost changes are handled and would be consistent with maintaining the utility's credit quality, financial integrity, and access to capital markets.

Q. How has the "flight to quality" in the traditional fixed income markets (bond markets) affected dividend-oriented stocks?

A. As bond yields have fallen (as a result of the Government's ongoing policies in the financial markets), investors have looked for income from dividend paying stocks. Consequently, utility stocks have experienced some price support as investors in search of yield have substituted utility common stocks for low-yielding fixed income securities.

Q. Does this imply that the cost of equity capital for utilities has declined as much as the drop in interest rates?

A. No. Equity market risk aversion has increased, not decreased. The domestic economy faces severe challenges—growth in GDP has slowed; unemployment remains stubbornly high; job creation is weak. The Federal Government is responding to this economic distress by artificially depressing interest rates through its ongoing purchases of Treasury bonds and other securities. While this Government policy pumps liquidity into the financial markets, it also removes yield opportunities for investors in traditionally lower risk fixed income investments. Thus, investors are trying to react rationally to a market environment that has many risks but few income opportunities. These

circumstances raise significant questions about the ability of traditional rate of return estimation methods to function reasonably.

Q. Has equity market volatility been recognized as a cause for reduced equity capital availability in the U.S.?

A. Yes. Many Wall Street analysts have commented on the recent equity market volatility and its effects:

> In market-speak, it's called volatility: Large jumps followed by deep dives, within the course of a week or sometimes the same day. The surge in volatility since early August has been blamed for preventing companies from going public and scaring people out of stocks. Some think that even if Europe resolves its debt crisis, large price swings are here to stay.
>
> The long-term trend is toward more volatility. Judging by the number of times in a year the S&P 500 swung 2 percent or more in a single day, markets are much more likely to have large leaps up or dives down, according to S&P's equity research group. Swings of 2 percent occurred an average of five times a year from 1950 to 1999. It's already happened 20 times this year, with three months left to go. (Matthew Craft, Associated Press/Yahoo Finance, October 2, 2011.)

Q. What is the industry's current fundamental position?

A. The industry has seen significant volatility both in terms of fundamental operating characteristics and the effects of the economy. Slow economic growth has reduced sales volumes. These reduced volumes and uncertain environmental rules have both increased the difficulty of planning for future load requirements. In the equity markets, ongoing turmoil has increased investors' preferences for safer, dividend paying companies. Value Line discusses this phenomenon and provides a warning of possible overvaluation in its recent Electric Utility update:

Value Line Investor Survey

> With most of 2011 completed, it seems almost certain that electric utility stocks will have outperformed the broader market averages when the year is over. As of mid-December, the Value Line Utility Average is up slightly, while the Value Line Geometric Average is down about 14 percent. Electric utility stocks have long been viewed as a safe haven in volatile markets, due in large part to their generous dividend yields. However, many of these issues are now trading within their 2014-2016 Target Price Ranges. This is often an indication that they have become expensively priced. (*Value Line Investor Survey*, December 23, 2011, p. 901).

In the summary in its recent assessment of the Electric Utility Industry, S&P provides perspective for investors' concerns for 2012:

Standard & Poor's

> Regulated U.S. electric utility companies will begin implementing Environmental Protection Agency (EPA) rules concerning carbon and other pollutants in 2012. Other challenges included the continued need for substantial capital spending, the potential for rate pressure in a slow growth period, and the changing global capital markets. ("The Top 10 Investor Questions For U.S. Regulated Electric Utilities In 2012," Standard & Poor's RatingsDirect, January 3, 2012, p. 2).

Credit market gyrations and the volatility of utility shares demonstrate the increased uncertainties that utility investors face. These uncertainties translate into a higher cost of equity capital.

Q. How do capital market concerns and financial risk perceptions affect the cost of equity capital?

A. As I discussed previously, equity investors respond to changing assessments of risk and financial prospects by changing the price they are willing to pay for a given security. When the risk perceptions increase or financial prospects decline, investors refuse to pay the previously existing market price for a company's securities, and market supply and demand forces then establish a new lower price.

The lower market price typically translates into a higher cost of capital through a higher dividend yield requirement, as well as the potential for increased capital gains if prospects improve. In addition to market losses for prior shareholders, the higher cost of capital is transmitted directly to the company by the need to earn a higher cost of capital on existing and new investments just to maintain the stock's new lower price level and the reality that the firm must issue more shares to raise any given amount of capital for future investment. The additional shares also impose additional future dividend requirements and may reduce future earnings per share growth prospects if the proceeds of the share issuance are unable to earn their expected rate of return.

Q. How have regulatory commissions responded to these changing market and industry conditions?

A. Over the past five years, quarterly allowed ROEs for all types of electric utilities have averaged about 10.4 percent. For integrated electric utilities, like PacifiCorp, the average allowed rate for 2010 was 10.38 percent and for 2011, it was 10.24 percent.[2] Table 3 summarizes the data for all types of electric utilities:

[2] See Exhibit PAC/202, page 2.

Table 3
Authorized Electric Utility Equity Returns

	2007	2008	2009	2010	2011
1st Quarter	10.27%	10.45%	10.29%	10.66%	10.32%
2nd Quarter	10.27%	10.57%	10.55%	10.08%	10.12%
3rd Quarter	10.02%	10.47%	10.46%	10.27%	10.00%
4th Quarter	10.56%	10.33%	10.54%	10.30%	10.34%
Full Year Average	10.36%	10.46%	10.48%t	10.34%	10.22%
Average Utility Debt Cost	6.11%	6.65%	6.28%	5.55%	5.17%
Indicated Average Risk Premium	4.25%	3.81%	4.20%	4.79%	5.05%

Source: Regulatory Focus, Regulatory Research Associates, Inc., Major Rate Case Decisions, January 10, 2012. Utility debt costs are the "average" public utility bond yields as reported by Moody's.

Based on these data, the allowed equity risk premium for electric utilities over the past five years has ranged between 3.81 percent and 5.05 percent. In most utility jurisdictions, allowed ROEs for vertically integrated utilities have remained above 10 percent.

Estimating the Cost of Equity Capital

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to compare the strengths and weaknesses of several of the most widely used methods for estimating the COE. Estimating the COE is fundamentally a matter of informed judgment. The various models provide a concrete link to actual capital market data and assist with defining the various relationships that underlie the COE estimation process. See Exhibit PAC/204 for further technical discussion of the DCF and risk premium models.

Q. How is the fair rate of return in the regulatory process related to the estimated cost of equity capital?

A. The regulatory process is guided by fair rate of return principles established in the

U.S. Supreme Court cases *Bluefield Water Works* and *Hope Natural Gas*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. (*Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-693 (1923)).

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (*Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944)).

Based on these principles, the fair rate of return should closely parallel investor opportunity costs as discussed above. If a utility earns its market COE, neither its stockholders nor its customers should be disadvantaged.

Q. Please provide an overview of the cost of equity capital estimation process.

A. The COE is the rate of return that common stockholders expect, just as interest on bonds and dividends on preferred stock are the returns that investors in those securities expect. Unlike returns from debt and preferred stocks, however, the equity return is not directly observable in advance, and it must, therefore, be estimated or inferred from capital market data and trading activity.

An example helps to illustrate the COE concept. Assume that an investor buys a share of common stock for $20 per share. If the stock's expected dividend is $1.00, the expected dividend yield is 5.0 percent ($1.00 / $20.00 = 5.0 percent).

If the stock price is also expected to increase to $21.20 after one year, this $1.20 expected gain adds an additional 6.0 percent to the expected total rate of return ($1.20 / $20.00 = 6.0 percent). Therefore, buying the stock at $20.00 per share, the investor expects a total return of 11.0 percent: 5.0 percent dividend yield, plus 6.0 percent price appreciation. In this example, the total expected rate of return of 11.0 percent is the appropriate measure of the cost of equity capital, because it is this rate of return that caused the investor to commit the $20 of equity capital in the first place. If the stock were riskier, or if expected returns from other investments were higher, investors would have required a higher rate of return from the stock, which would have resulted in a lower initial purchase price in market trading.

Each day market rates of return and prices change to reflect new investor expectations and requirements. For example, when interest rates on bonds and savings accounts rise, utility stock prices usually fall. This is true, at least in part, because higher interest rates on these alternative investments make utility stocks relatively less attractive, which causes utility stock prices to decline in market trading. This competitive market adjustment process is quick and continuous, so that market prices generally reflect investor expectations and the relative attractiveness of one investment versus another. The data presented previously in Tables 1 and 2 illustrate this fundamental financial principle. Therefore, to estimate the COE one must apply informed judgment about the relative risk of the company in question as well as knowledge about the risk and expected rate of return characteristics of other available investments.

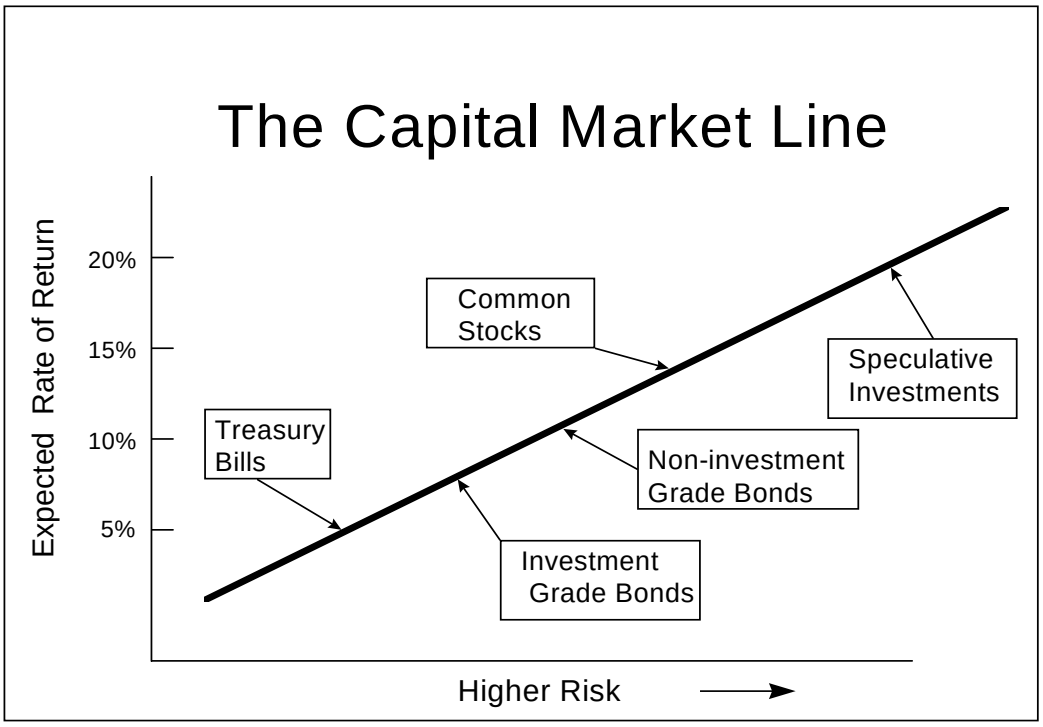
Q. How does the market account for risk differences among the various investments?

A. Risk-return tradeoffs among capital market investments have been the subject of extensive financial research. Literally dozens of textbooks and hundreds of academic articles have addressed the issue. Generally, that research confirms the common sense conclusion that investors will take additional risks only if they expect to receive a higher rate of return. Empirical tests consistently show that: returns from low risk securities, such as U.S. Treasury bills, are the lowest; returns from longer-term Treasury bonds and corporate bonds are increasingly higher as risks increase; and generally returns from common stocks and other more risky investments are even higher. These observations provide a sound theoretical foundation for both the DCF and risk premium methods for estimating the cost of equity capital. These methods attempt to capture the well-founded risk-return principle and explicitly measure investors' rate of return requirements.

Q. Can you illustrate the capital market risk-return principle that you just described?

A. Yes. The following graph depicts the risk-return relationship that has become widely known as the Capital Market Line ("CML"). The CML offers a graphical representation of the capital market risk-return principle. The graph is not meant to illustrate the actual expected rate of return for any particular investment, but merely to illustrate in a general way the risk-return relationship.

Risk-Return Tradeoffs



As a continuum, the CML can be viewed as an available opportunity set for investors. Those investors with low risk tolerance or investment objectives that mandate a low risk profile should invest in assets depicted in the lower left-hand portion of the graph. Investments in this area, such as Treasury bills and short-maturity, high quality corporate commercial paper, offer a high degree of investor certainty. Before considering the potential effects of inflation, such assets are virtually risk-free.

Investment risks increase as one moves up and to the right along the CML. A higher degree of uncertainty exists about the level of investment value at any point in time and about the level of income payments that may be received. Among these investments, long-term bonds and preferred stocks, which offer

priority claims to assets and income payments, are relatively low risk, but they are not risk-free. The market value of long-term bonds, even those issued by the U.S. Treasury, often fluctuates widely when Government policies or other factors cause interest rates to change.

Farther up the CML continuum, common stocks are exposed to even more risk, depending on the nature of the underlying business and the financial strength of the issuing corporation. Common stock risks include market-wide factors, such as general changes in capital costs, as well as industry and company specific elements that may further add to the volatility of a given company's performance. As I will illustrate in my risk premium analysis, common stocks typically are more volatile (have higher risk) than high-quality bond investments and, they therefore reside above and to the right of bonds on the CML graph. Other more speculative investments, such as stock options and commodity futures contracts, offer even higher risks (and higher potential returns). The CML's depiction of the risk-return tradeoffs available in the capital markets provides a useful perspective for estimating investors' required rates of return.

Q. What specific methods and capital market data are used to evaluate the COE?

A. Techniques for estimating the COE normally fall into three groups: (1) comparable earnings methods; (2) risk premium methods; and (3) DCF methods.

The first set of estimation techniques based on comparable earnings has evolved over time. The original comparable earnings methods were based on book accounting returns. This approach developed ROE estimates by reviewing

accounting returns for unregulated companies thought to have risks similar to those of the regulated company in question. These methods have generally been rejected because they assume that the unregulated group is earning its actual cost of capital and that its equity book value is the same as its market value. In most situations these assumptions are not valid, and thus accounting-based methods do not generally provide reliable COE estimates.

More recent comparable earnings methods are based on historical stock market returns rather than book accounting returns. While this approach has some merit, it too has been criticized because there can be no assurance that historical returns actually reflect current or future market requirements. Also, in practical application, earned market returns tend to fluctuate widely from year to year. For these reasons, a current COE estimate (based on the DCF model or a risk premium analysis) is usually required.

The second set of estimation techniques is grouped under the heading of risk premium methods. These methods begin with currently observable market returns, such as yields on Government or corporate bonds, and add an increment to account for the additional equity risk. The capital asset pricing model ("CAPM") and arbitrage pricing theory ("APT") model are more sophisticated risk premium approaches. The CAPM and APT methods estimate the COE directly by combining the "risk free" Government bond rate with explicit risk measures to determine the risk premium required by the market. Although these more sophisticated methods are widely used in academic cost of capital research, their additional data requirements and their potentially questionable underlying

assumptions have detracted from their use in most regulatory jurisdictions. On the other hand, the basic risk premium methods generally provide a useful parallel approach with the DCF model and assure consistency with other capital market data in the equity cost estimation process.

The third set of estimation techniques, based on the DCF model, is the most widely used regulatory COE estimation method. Like the risk premium approach, the DCF model has a sound basis in theory, and many argue that it has the additional advantage of simplicity. I will describe the DCF model in detail below, but in essence its estimate of COE is simply the sum of the expected dividend yield and the expected long-term dividend, earnings, or price growth rate (all of which are assumed to grow at the same rate). While dividend yields are easy to obtain, estimating long-term growth is more difficult. Because the constant growth DCF model also requires very long-term growth estimates (technically to infinity), some argue that its application is too speculative to provide reliable results, resulting in the preference for the multistage growth DCF analysis.

Q. Of the three estimation methods, which do you believe provides the most reliable results?

A. From my experience, in periods of reasonable capital market equilibrium, a combination of DCF and the basic risk premium methods usually provide the most reliable approach. While the caveat about estimating long-term growth must be observed, the DCF model's other inputs are readily obtainable, and the model's results typically are consistent with equilibrium capital market behavior. The

basic risk premium methods provide a good parallel approach to the DCF model and further ensure that current market conditions are accurately reflected in the COE estimate. However, due to ongoing market turmoil and current Government monetary policy, which I previously discussed in this testimony, COE estimates obtained from all of these methods, especially the equity risk premium methodology, should be discounted.

Q. Please explain why you have not provided COE estimates based on the CAPM.

A. I have not included a CAPM estimate in his case because, under current market conditions, the CAPM does not provide reliable estimates of the cost of equity. This situation is caused by the U.S. Government's intervention in the credit markets and the resulting artificially low U.S. Treasury bond interest rates that have resulted, as well as the recent market turmoil's effects on the CAPM's other required inputs.

The CAPM is based on three principal inputs:

1) the risk-free interest rate (R_f);

2) the expected market risk premium for stocks relative to the risk-free rate $E(R_m) – R_f$; and

3) a measure of market-related, or nondiversifiable, risk (β or beta).

The CAPM estimate of COE is then calculated as:

$$ROE = R_f + \beta[E(R_m) – R_f]$$

The market data discussed previously in this testimony show that, under present market conditions, potentially all three of the CAPM's principal inputs tend to

understate COE. The risk-free rate, R_f, is understated because, due to Governmental credit market policies and investors' increased risk aversion, the U.S. Treasury rates used for R_f are artificially low. The second input, the expected market risk premium [$E(R_m) - R_f$], when based on historical data, may also be understated because such data cannot reflect the heighted investor risk aversion that has resulted from the financial crisis. Finally, utility beta coefficients have declined because until recently utility stocks had far underperformed relative to the broader market index during the recent stock market recovery. All these factors indicate that CAPM estimates of COE for utilities are currently understated. For this reason, in the present case, I rely on the DCF and other risk premium models to estimate the COE for PacifiCorp.

Q. Did the Commission rely upon the CAPM in setting PacifiCorp's most recently litigated ROE?

A. No. In Order No. 01-787, the Commission gave no weight to CAPM results in determining PacifiCorp's ROE.

Cost of Equity Capital for PacifiCorp

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present my quantitative studies of the cost of equity capital for PacifiCorp and to discuss the details and results of my analysis.

Q. How are your studies organized?

A. In the first part of my analysis, I apply three versions of the DCF model to a 14-company group of electric utilities based on the selection criteria discussed previously. In the second part of my analysis, I apply basic equity risk premium

models and review projected economic conditions and projected capital costs for the coming year.

My DCF analysis is based on three versions of the DCF model. In the first version of the DCF model, I use the constant growth format with long-term expected growth based on analysts' estimates of five-year utility earnings growth. While I continue to endorse a longer-term growth estimation approach based on growth in overall gross domestic product, I show the analyst growth rate DCF results because this is the approach that has traditionally been used by many regulators. In the second version of the DCF model, for the estimated growth rate, I use only the long-term estimated GDP growth rate. Finally, in the third version of the DCF model, I use a two-stage growth approach, with stage one growth based on Value Line's three-to-five-year dividend projections and stage two growth based on long-term projected GDP growth. The dividend yields in all three of the models are from Value Line's projections of dividends for the coming year and stock prices are from the three-month average for the months that correspond to the Value Line editions from which the underlying financial data are taken.

Q. Why do you believe the long-term GDP growth rate should be used to estimate long-term growth expectations in the DCF model?

A. Growth in nominal GDP (real GDP plus inflation) is the most general measure of economic growth in the U.S. economy. For long time periods, such as those used in the Morningstar/Ibbotson Associates rate of return data, nominal GDP growth has averaged between 5 percent and 8 percent per year. From this observation,

Professors Brigham and Houston offer the following observation concerning the appropriate long-term growth rate in the DCF Model:

> Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation). On this basis, one might expect the dividend of an average, or "normal," company to grow at a rate of 5 to 8 percent a year. (Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, 11th Ed. 2007, page 298).

Other academic research on corporate growth rates offers similar conclusions about GDP growth as well as concerns about the long-term adequacy of analysts' forecasts:

> Our estimated median growth rate is reasonable when compared to the overall economy's growth rate. On average over the sample period, the median growth rate over 10 years for income before extraordinary items is about 10 percent for all firms. ... After deducting the dividend yield (the median yield is 2.5 percent per year), as well as inflation (which averages 4 percent per year over the sample period), the growth in real income before extraordinary items is roughly 3.5 percent per year. This is consistent with the historical growth rate in real gross domestic product, which has averaged about 3.4 percent per year over the period 1950-1998. (Louis K. C. Chan, Jason Karceski, and Josef Lakonishok, "The Level and Persistence of Growth Rates," The Journal of Finance, April 2003, p. 649).

> IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic. … On the whole, the absence of predictability in growth fits in with the economic intuition that competitive pressures ultimately work to correct excessively high or excessively low profitability growth. (Ibid, page 683).

These findings support the notion that long-term growth expectations are more closely predicted by broader measures of economic growth than by near-term analysts' estimates. The growth in nominal GDP should be considered an

important input, especially for the very long-term growth rate requirements of the DCF model.

Q. How did you estimate the expected long-run GDP growth rate?

A. I developed my long-term GDP growth forecast from nominal GDP data contained in the St. Louis Federal Reserve Bank database. That data for the period 1950 through 2010 are summarized in my Exhibit PAC/205. As shown at the bottom of that exhibit, the overall average for the period was 6.7 percent. The data also show, however, that after the early 1980s, lower inflation has resulted in lower nominal GDP growth. For this reason, I gave more weight to the more recent years in my GDP forecast. Based on this approach, my overall forecast for long-term GDP growth at 5.8 percent is almost 100 basis points lower than the long-term average GDP growth rate.

Q. Why do you believe your forecast of GDP growth based on long-term historical data is appropriate in the DCF model?

A. There are at least three reasons. First, most econometric forecasts are derived from the trending of historical data or the use of weighted averages. This is the approach I have taken in Exhibit PAC/205. The long-run historical average GDP growth rate is 6.7 percent, but my estimate of long-term expected growth is lower at 5.8 percent. My forecast is lower because my forecasting method gives much more weight to the more recent 10- and 20-year periods.

Second, some currently lower GDP growth forecasts likely understate very long growth rate expectations that are required in the DCF model. Many of those forecasts are currently low because they are based on the assumption of

permanently low inflation rates, in the range of 2 percent. As shown in my Exhibit PAC/205, the average long-term inflation rate measured by CPI has been over 3 percent in all but the most recent 10- and 20- year periods. Also, as shown in Exhibit PAC/203, page 1, from December 2008 to December 2009, even with the continuing effects of the economic recession, the CPI increased by 2.8 percent and in 2007 the CPI increased by over 4 percent. Use of long-term inflation rates of two percent or less to estimate long-term nominal growth in the DCF model is not consistent with reasonable long-term expectations for the U.S. economy or investors' long-term experience.

Finally, the current economic turmoil makes it even more important to consider longer-term economic data in the growth rate estimate. As discussed in the previous section, current near-term forecasts for both real GDP and inflation are severely depressed. The longer-term forecasts of professional economists are also depressed. Under these circumstances, a longer-term balance is even more important. For all these reasons, while I am also presenting other growth rate approaches based on analysts' estimates in this testimony, I believe it is appropriate also to consider long-term GDP growth in estimating the DCF growth rate.

Q. Please summarize the results of your DCF analyses.

A. The DCF results for my comparable company group are presented in Exhibit PAC/206. As shown in the first column of page 1 of that exhibit, the traditional constant growth model indicates a COE range of 9.6 percent to 10.0 percent. In the second column of page 1, I recalculate the constant growth results with the

growth rate based on long-term forecasted growth in GDP. With the GDP growth rate, the constant growth model indicates a cost of common equity range of 10.1 percent to 10.2 percent. Finally, in the third column of page 1, I present the results from the multistage DCF model. The multistage model indicates a cost of common equity of 9.9 percent to 10.0 percent. The results from the DCF model, therefore, indicate a cost of common equity range of 9.6 percent to 10.2 percent.

Q. What are the results of your basic equity risk premium studies?

A. The details and results of my basic equity risk premium studies are shown in my Exhibit PAC/207. These studies indicate a cost of common equity range of 9.55 percent to 9.70 percent. As noted previously, I discount these risk premium estimates because they are directly affected by the Government's ongoing efforts to keep interest rates artificially low.

Q. How are your basic equity risk premium studies structured?

A. My basic equity risk premium studies are divided into two parts. First, I compare electric utility authorized ROEs for the period 1980-2011 to contemporaneous long-term utility interest rates. The differences between the average authorized ROEs and the average interest rate for each year is the indicated equity risk premium. I then add the indicated equity risk premium to the forecasted and current single-A utility bond interest rate to estimate the cost of common equity. Because there is a strong inverse relationship between equity risk premiums and interest rates (when interest rates are high, risk premiums are low, and vice versa), further analysis is required to estimate the current equity risk premium level.

The inverse relationship between equity risk premiums and interest rate

levels is well documented in numerous, well-respected academic studies. These studies typically use regression analysis or other statistical methods to predict or measure the equity risk premium relationship under varying interest rate conditions. On page 3 of Exhibit PAC/207, I provide a regression analysis of the allowed annual equity risk premiums relative to interest rate levels. The negative and statistically significant regression coefficients confirm the inverse relationship between equity risk premiums and interest rates. This means that when interest rates rise by one percentage point, the COE increases, but by a smaller amount. Similarly, when interest rates decline by one percentage point, the COE will also decline but by less than one percentage point. I use this negative interest rate change coefficient in conjunction with current and forecasted interest rates to estimate the appropriate cost of common equity.

Q. Can you illustrate the inverse relationship between equity risk premiums and interest rates without using the statistical analysis described above?

A. Yes. Statistical analysis is often used, especially in academic research, to substantiate certain economic and financial relationships. For equity risk premium analysis, however, the fundamental issue can be observed by simply averaging the data for various time periods without further statistical analysis. The data in Table 4 show average utility bond yields and equity risk premiums for each non-overlapping, five-year period between 1980 and 2010:

Table 4
Average Five-Year Utility Bond Yields and Equity Risk Premiums
(1980-2011)

Period	Average Utility Bond Interest Rate	Average Equity Risk Premium
1980-1986	13.31%	1.69%
1987-1991	9.81%	2.99%
1992-1996	8.02%	3.54%
1997-2001	7.61%	3.66%
2002-2006	6.42%	4.34%
2007-2011	5.95%	4.42%

Source: Exhibit PAC/207, page 1.

These data show that equity risk premiums have consistently increased as interest rates have declined, and that they were lower when interest rates were high. This result is a market-based reflection, which shows that required rates of return in the stock market do not move in lockstep with changes in interest rates. Because utilities must compete with other types of equity investments for capital, the COE for utilities does not change by as much as the observed changes in interest rates. Arguments that unadjusted, long-term average risk premiums can be used with current, historically low interest rates to estimate COE are mistaken. That approach to equity risk premium analysis will consistently understate the required rate of return.

Q. Please summarize the results of your COE analysis.

A. Table 5 below summarizes my results:

Table 5
Summary of Cost of Equity Estimates

DCF Analysis	Indicated Cost
Constant Growth (Analysts' Growth)	9.6%-10.0%
Constant Growth (GDP Growth)	10.1%-10.2%
Multistage Growth Model	9.9%-10.0%
Indicated DCF Range	9.6%-10.2%
Equity Risk Premium Analysis	**Indicated Cost**
Forecast Utility Debt Yield+ Equity Risk Premium	
Equity Risk Premium ROE (4.62% + 5.08%)	9.70%
Current Utility Debt + Equity Risk Premium	
Equity Risk Premium ROE (4.37% + 5.08%)	9.55%
PacifiCorp Cost of Equity	10.20%

Q. How should these results be interpreted to determine a reasonable ROE upon which to base rates for PacifiCorp?

A. The fair and reasonable ROE for PacifiCorp is 10.2 percent. This requested ROE, at the top of my DCF range, is appropriate given the ongoing effects of U.S. and global economic turmoil on the equity market for utility shares. Recent market turmoil and the continuing effects on capital markets make it difficult to strictly interpret quantitative model estimates for the cost of equity. While corporate interest rates have dropped to record low levels and the DCF results have declined as utility dividend yields have dropped, equity market volatility remains high. Under these conditions, use of a lower DCF range or equity risk premium estimates based strictly on historical risk premium relationships will understate the market cost of equity. Based on all these factors, an ROE of 10.2 percent is a reasonable rate of return to be used for setting rates in this case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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SUMMARY OF QUALIFICATIONS

- Principal, Financial Analysis Consultants (FINANCO, Inc.).
- Ph.D. in Finance and Economics.
- Extensive expert witness testimony in court and before regulatory agencies.
- Management of professional research staff in academic and regulatory organizations.
- Professional presentations before executive development groups, the National Rate of Return Analysts' Forum, and the New York Society of Security Analysts.
- Financial Management Association, previously Vice President for Practitioner Services.

EDUCATION

The University of Texas at Austin **Ph.D., Finance and Econometrics** **January 1975**	Dissertation: *An Evaluation of the Original and Recent Variants of the Capital Asset Pricing Model.*
The University of Texas at Austin **MBA, Finance** **June 1973**	Thesis: *The Pricing of Risk on the New York Stock Exchange.*
Southern Methodist University **BA, Economics** **June 1969**	Honors program. Departmental distinction.

OTHER EXPERIENCE

University of Texas at Austin **Adjunct Associate Professor** **1985-1988, 2004-Present**	Corporate Financial Management, Investments, and Integrative Finance Cases.
Texas State University San Marcos **Associate Professor of Finance** **1983-1984, 2003-2004**	Graduate and undergraduate courses in Financial Management, Managerial Economics, and Investment Analysis.
Public Utility Commission of Texas **Chief Economist and Director of Economic Research Division** **August 1980-August 1983**	Lead financial witness. Supervised Commission staff in research and testimony on rate of return, financial condition, and economic analysis.
Assistant Professor of Finance **Texas Tech University** **July 1978-July 1980** **University of Alabama** **January 1975-June 1978**	Member of graduate faculty. Conducted Ph.D. seminars and directed doctoral dissertations in capital market theory**.** Served as consultant to industry, church and governmental organizations.

FINANCIAL AND ECONOMIC TESTIMONY IN REGULATORY PROCEEDINGS (Client in parenthesis)

Cost of Money Testimony

- Texas Public Utility Commission, Docket No. 40094, February 1, 2012, (El Paso Electric Company).
- Oregon Public Utility Commission, Docket No. UG 221, December 30, 2011 (NW Natural Gas Company).
- Wyoming Public Service Commission, Docket No. 20000-405-ER-11, December 9, 2011 (Rocky Mountain Power dba/PacifiCorp).
- Texas Public Utility Commission, Docket No. 39896, November 28, 2011, (Entergy Texas, Inc.)
- Idaho Public Utilities Commission, Case No. PAC-E-111-12, May 27, 2011 (Rocky Mountain Power/PacifiCorp).
- Maine Public Utilities Commission, Docket No. 2011-92, May 5, 2011 (Northern Utilities, Inc.)
- New Hampshire Public Utilities Commission, Docket No. DG 11-069, May 4, 2011(Northern Utilities, Inc.)
- Arizona Corporation Commission, Docket No. G-04204A-11-0158, April 8, 2011 (UNS Gas, Inc.)
- Utah Public Service Commission, Docket No. 10-035-124, January 24, 2011 (Rocky Mountain Power/PacifiCorp).
- Massachusetts Department of Public Utilities, D.P.U. 11.01 (Electric) and D.P.U. 11.02 (Gas), January 14, 2011, (Fitchburg Gas and Electric Light Company d/b/a/ Unitil)
- Wyoming Public Service Commission, Docket No. 20000-384-ER-10, November 22, 2010 (Rocky Mountain Power dba/PacifiCorp).
- Illinois Commerce Commission, Docket No. 10-0467, July 28, 2010 (Commonwealth Edison Company).
- Missouri Public Service Commission, Case No. ER-2010-0355, June 4, 2010 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2010-0356, June 4, 2010 (KCP&L Greater Missouri Operations Company).
- Idaho Public Utilities Commission, Case No. PAC-E-10-07, May 28, 2010 (Rocky Mountain Power/PacifiCorp).
- Washington Utilities and Transportation Commission, Docket UE-100749, May 4, 2010 (PacifiCorp).
- New Hampshire Public Utilities Commission, Docket No. DE 10-055, April 15, 2010 (Unitil Energy Systems)
- Oregon Public Utility Commission, Docket No. UE-217, March 1, 2010 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 37744, December 30, 2009,(Entergy Texas, Inc.)
- Kansas Corporation Commission, Docket No. 10-KCPE-415-RTS, December 17, 2009 (Kansas City Power & Light Company).
- Texas Public Utility Commission, Docket No. 37690, December 9, 2009,(El Paso Electric Company).
- California Public Utilities Commission, Application No. 09-11-015, November 20, 2009 (PacifiCorp).
- Federal Energy Regulatory Commission, Docket No. ER10-230-000, November 6, 2009 (Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company).
- Wyoming Public Service Commission, Docket No. 20000-352-ER-09, October 2, 2009 (Rocky Mountain Power dba/PacifiCorp).
- Arkansas Public Service Commission, Docket No. 09-084-U, September 4, 2009, (Entergy-Arkansas)
- Texas Public Utility Commission, Docket No. 37364, August 28, 2009,(American Electric Power-SWEPCO)
- Utah Public Service Commission, Docket No. 09-035-23, June 23, 2009 (Rocky Mountain Power/PacifiCorp).

- New Mexico Public Regulation Commission, Case No. 09-00171-UT, May 2009, (El Paso Electric Company).
- Oregon Public Utility Commission, Docket No. UE-207, April 2, 2009 (PacifiCorp).
- Arkansas Public Service Commission, Docket No. 09-008-U, February 19, 2009 (American Electric Power-SWEPCO).
- Washington Utilities and Transportation Commission, Docket UE-090205, February 9, 2009 (PacifiCorp).
- Idaho Public Utilities Commission, Case No. PAC-E-08-07, September 19, 2008 (Rocky Mountain Power/PacifiCorp).
- Missouri Public Service Commission, Case No. ER-2009-089, September 5, 2008 (Kansas City Power & Light Company).
- Kansas Corporation Commission, Docket No. 09-KCPE-246-RTS, September 5, 2008 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2009-090, September 5, 2008 (Aquila, Inc. dba/KCP&L Greater Missouri Operations Company).
- Utah Public Service Commission, Docket No. 08-035-38, July 17, 2008 (Rocky Mountain Power/PacifiCorp).
- Wyoming Public Service Commission, Docket No. 20000-333-ER-08, July 2008 (Rocky Mountain Power dba/PacifiCorp).
- Texas Public Utility Commission, Docket No. 35717, June 27, 2008, (Oncor Electric Delivery Company LLC).
- Washington Utilities and Transportation Commission, Docket UG-080546, March 28, 2008 (NW Natural).
- Washington Utilities and Transportation Commission, Docket UE-080220, February 6, 2008 (PacifiCorp).
- Utah Public Service Commission, Docket No. 07-035-93, December 17, 2007 (PacifiCorp).
- Illinois Commerce Commission, Docket No. 07-0566, October 17, 2007 (Commonwealth Edison Company).
- Texas Public Utility Commission, Docket No. 34800, September 26, 2007, (Entergy Gulf States, Inc.)
- Texas Public Utility Commission, Docket No. 34040, August 28, 2007, (Oncor/TXU Electric Delivery Company)
- Massachusetts Department of Public Utilities, D.P.U. 07-71, August 17, 2007, (Fitchburg Gas and Electric Light Company d/b/a/ Unitil)
- Arizona Corporation Commission, Docket No. E-01933A-07-0402, July 2, 2007, (Tucson Electric Power Company).
- Wyoming Public Service Commission, Docket No. 20000-277-ER-07, June 29, 2007 (Rocky Mountain Power dba/PacifiCorp).
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, June 8, 2007 (Rocky Mountain Power dba/PacifiCorp).
- Kansas Corporation Commission, Docket No. 07-KCPE-905-RTS, March 1, 2007 (Kansas City Power & Light Company).
- New Mexico Public Regulation Commission, Case No. 07-00077-UT, February 21, 2007, (Public Service Company of New Mexico).
- Missouri Public Service Commission, Case No. ER-2006-0291, February 1, 2007 (Kansas City Power & Light Company).
- Texas PUC Docket Nos. 33734, January 22, 2007 (Electric Transmission Texas, LLC).
- Texas PUC Docket Nos. 33309 and 33310, November 2006, (AEP Texas Central Company and AEP Texas North Company).
- Louisiana Public Service Commission, Docket No. U-23327, October 2006 and January 2005 (Southwestern Electric Power Company, American Electric Power Company)
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- Texas PUC Docket No. 20125, November 1999 (Entergy Gulf States, Inc.)
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- Texas PUC Docket No. 20292, May 1999 (Central Power and Light Co.)
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- Analysis of Electric Power Transmission Costs in Purchased Power Dispute, 1995, (City of College Station, Texas).

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- Analysis of Lost Profits due to Equipment Failure in Cogeneration Facility (WF Energy/Travelers Insurance Company).
- Analysis of Economic Damages due to Grain Elevator Explosion (Degesch Chemical Company).
- Analysis of Economic Damages due to failure of Plastic Pipe Water Lines (Western Plastics, Inc.)
- Analysis of Rail Car Repair and Maintenance Costs in Product Warranty Dispute (Youngstown Steel Door Company).
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PacifiCorp Oregon
Comparable Company Fundamental Characteristics

		(1)	(2)		(3)		
					Capital Structure (2010)		
		% Regulated	Credit Rating		Common Eq	L-T Debt	Pfd Stock
No.	Company	Revenue	S&P	Moody's	Ratio	Ratio	Ratio
1	ALLETE	92.1%	A-	Baa1	55.8%	44.2%	0.0%
2	Alliant Energy Co.	92.4%	A-/BBB+	A2/A3	49.5%	46.3%	4.2%
3	Avista Corp.	91.0%	A-	Baa1	48.4%	51.6%	0.0%
4	Black Hills Corp	85.7%	BBB+	A3	48.1%	51.9%	0.0%
5	DTE Energy Co.	77.6%	A	A2	48.7%	51.3%	0.0%
6	Edison Internat.	80.4%	BBB+	A1	44.3%	51.8%	3.9%
7	IDACORP	84.0%	A-	A2	50.7%	49.3%	0.0%
8	Portland General	100.0%	A-	A3	47.0%	53.0%	0.0%
9	SCANA Corp.	72.9%	A-	A3	47.1%	52.9%	0.0%
10	Sempra Energy	75.7%	A+	Aa3	49.6%	49.4%	1.0%
11	Southern Co.	84.7%	A	A2/A3	45.7%	51.2%	3.1%
12	Vectren Corp.	73.4%	A-	A2	50.1%	49.9%	0.0%
13	Wisconsin Energy	99.1%	A-	A1	49.0%	50.6%	0.4%
14	Xcel Energy Inc.	99.3%	A	A3	46.3%	53.1%	0.6%
	Average	86.3%	A-	A2/A3	48.6%	50.5%	0.9%

Column Sources:

(1) Most recent company 10-Ks.

(2) AUS Utility Reports, Jan 2012.

(3) Value Line Investment Survey, Electric Utility (East), Nov 25, 2011; (Central), Dec 23, 2011; (West), Nov 4, 2011.

Exhibit PAC/202
Hadaway/1

PacifiCorp Oregon
Authorized Electric Utility Equity Returns

Average Authorized ROE	2007	No.	2008	No.	2009	No.	2010	No.	2011	No.
All Electric Utilities	10.36%	39	10.46%	37	10.48%	39	10.34%	59	10.22%	41
Vertically-Integrated Utilities	10.56%	28	10.45%	25	10.63%	27	10.38%	42	10.24%	27
Delivery-Only Utilities	9.86%	11	9.78%	7	10.15%	10	9.98%	15	9.85%	12
Power Plant Only Cases	NA	0	11.44%	5	10.18%	2	12.30%	2	12.30%	2

Data Source:
Regulatory Focus , "Major Rate Case Decisions," Regulatory Research Associates, Jan 10, 2012; January 7, 2011; January 8, 2010; and January 12, 2009.

Exhibit PAC/202
Hadaway/2

PacifiCorp Oregon
Historical Capital Market Costs

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011*
Prime Rate	4.7%	4.1%	4.3%	6.2%	8.0%	8.1%	5.1%	3.3%	3.3%	3.3%
Consumer Price Index	2.5%	2.0%	3.3%	3.3%	2.5%	4.1%	0.0%	2.8%	1.4%	3.0%
Long-Term Treasuries	5.4%	5.0%	5.1%	4.7%	5.0%	4.8%	4.3%	4.1%	4.3%	3.9%
Moody's Avg Utility Debt	7.5%	6.6%	6.2%	5.7%	6.1%	6.1%	6.7%	6.3%	5.6%	5.2%
Moody's A Utility Debt	7.4%	6.6%	6.2%	5.7%	6.1%	6.1%	6.5%	6.0%	5.5%	5.0%

SOURCES:
Prime Interest Rate - Federal Reserve Bank of St. Louis website
Consumer Price Index For All Urban Consumers: All Items (Seasonally Adjusted, December to December) - Federal Reserve Bank of St. Louis website
Long-Term Treasuries - Federal Reserve Bank of St. Louis website; 30-year Treasury bonds 2001 and 2007-2011; 20-year Treasury bonds 2002-2006
Moody's Average Utility Debt - Moody's (Mergent) Bond Record
Moody's A Utility Debt - Moody's (Mergent) Bond Record
*Consumer Price Index for 2011 is through November 2011

Exhibit PAC/203
Hadaway/1

PacifiCorp Oregon
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
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
Aug-09	5.71	4.37	1.34
Sep-09	5.53	4.19	1.34
Oct-09	5.55	4.19	1.36
Nov-09	5.64	4.31	1.33
Dec-09	5.79	4.49	1.30
Jan-10	5.77	4.60	1.17
Feb-10	5.87	4.62	1.25
Mar-10	5.84	4.64	1.20
Apr-10	5.81	4.69	1.12
May-10	5.50	4.29	1.21
Jun-10	5.46	4.13	1.33
Jul-10	5.26	3.99	1.27
Aug-10	5.01	3.80	1.21
Sep-10	5.01	3.77	1.24
Oct-10	5.10	3.87	1.23
Nov-10	5.37	4.19	1.18
Dec-10	5.56	4.42	1.14
Jan-11	5.57	4.52	1.05
Feb-11	5.68	4.65	1.03
Mar-11	5.56	4.51	1.05
Apr-11	5.55	4.50	1.05
May-11	5.32	4.29	1.03
Jun-11	5.26	4.23	1.03
Jul-11	5.27	4.27	1.00
Aug-11	4.69	3.65	1.04
Sep-11	4.48	3.18	1.30
Oct-11	4.52	3.13	1.39
Nov-11	4.25	3.02	1.23
Dec-11	4.33	2.98	1.35
3-Mo Avg	**4.37**	**3.04**	**1.32**
12-Mo Avg	**5.04**	**3.91**	**1.13**

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

Three month average is for October 2011-December 2011.

Twelve month average is for January 2011-December 2011.

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

			----- Annual % Change -----				---------- 2011 ----------				---------- E2012 ----------			
2010	E2011	E2012	2010	E2011	E2012		Q1	Q2	AQ3	EQ4	Q1	Q2	Q3	Q4
						Gross Domestic Product								
$14,526.6	$15,100.1	$15,565.8	4.2	3.9	3.1	GDP (current dollars)	$14,867.8	$15,012.8	$15,198.6	$15,321.3	$15,441.6	$15,514.1	$15,598.6	$15,708.8
4.2	3.9	3.1	-	-	-	Annual rate of increase (%)	3.1	4.0	5.0	3.3	3.2	1.9	2.2	2.9
3.0	1.8	1.7	-	-	-	Annual rate of increase–real GDP (%)	0.4	1.3	2.5	2.4	1.5	1.1	1.4	2.0
1.2	2.1	1.4	-	-	-	Annual rate of increase–GDP deflator (%)	2.5	2.5	2.5	1.0	1.7	0.8	0.8	0.8
						***Components of Real GDP**								
$9,220.9	$9,432.2	$9,636.6	2.0	2.3	2.2	Personal consumption expenditures	$9,376.7	$9,392.7	$9,449.5	$9,509.7	$9,559.7	$9,613.4	$9,662.2	$9,711.3
2.0	2.3	2.2	-	-	-	% change	2.1	0.7	2.4	2.6	2.1	2.3	2.0	2.0
1,188.3	1,281.1	1,352.7	7.2	7.8	5.6	Durable goods	1,277.4	1,260.2	1,273.0	1,313.7	1,324.5	1,341.4	1,363.4	1,381.5
2,041.3	2,078.9	2,117.0	2.9	1.8	1.8	Nondurable goods	2,075.4	2,076.6	2,077.7	2,085.8	2,101.4	2,113.5	2,122.5	2,130.9
5,991.8	6,087.0	6,192.5	0.9	1.6	1.7	Services	6,039.1	6,067.0	6,111.4	6,130.3	6,155.0	6,182.0	6,203.8	6,229.3
1,319.2	1,438.5	1,516.8	4.4	9.0	5.4	Nonresidental fixed investment	1,378.9	1,413.2	1,467.5	1,494.4	1,503.1	1,512.7	1,516.7	1,534.5
4.4	9.0	5.4	-	-	-	% change	2.1	10.3	16.3	7.5	2.4	2.6	1.1	4.8
1,019.4	1,127.5	1,205.5	14.6	10.6	6.9	Producers durable equipment	1,086.9	1,103.5	1,148.7	1,170.8	1,179.8	1,195.6	1,211.4	1,235.3
321.5	314.1	323.6	(4.6)	(2.3)	3.0	Residental fixed investment	311.5	314.8	316.7	313.3	314.4	318.5	327.2	334.4
(4.6)	(2.3)	3.0	-	-	-	% change	(2.6)	4.2	2.5	(4.2)	1.4	5.3	11.4	9.0
58.8	26.9	35.9	-	-	-	Net change in business inventories	49.1	39.1	5.4	14.0	33.0	37.1	37.0	36.4
2,556.8	2,504.5	2,437.6	0.7	(2.0)	(2.7)	Gov't purchases of goods & services	2,513.9	2,508.2	2,508.2	2,487.7	2,465.9	2,444.0	2,427.8	2,412.5
1,075.9	1,057.6	1,027.1	4.5	(1.7)	(2.9)	Federal	1,053.3	1,058.3	1,063.5	1,055.2	1,043.4	1,031.8	1,021.6	1,011.6
1,487.0	1,453.2	1,416.4	(1.8)	(2.3)	(2.5)	State & local	1,466.4	1,456.1	1,451.2	1,438.9	1,428.8	1,418.3	1,412.0	1,406.6
(421.8)	(413.0)	(411.9)	-	-	-	Net exports	(424.4)	(416.4)	(409.4)	(401.9)	(409.2)	(420.0)	(415.7)	(402.8)
1,663.2	1,772.9	1,833.4	11.3	6.6	3.4	Exports	1,749.6	1,765.0	1,782.4	1,794.7	1,806.4	1,817.9	1,839.3	1,870.2
2,085.0	2,185.9	2,245.3	12.5	4.8	2.7	Imports	2,173.9	2,181.4	2,191.8	2,196.6	2,215.6	2,237.9	2,255.0	2,273.0
						****Income & Profits**								
$12,373.5	$12,989.6	$13,401.5	3.7	5.0	3.2	Personal income	$12,846.9	$12,992.6	$13,022.1	$13,096.8	$13,235.2	$13,347.6	$13,455.6	$13,567.4
11,179.7	11,590.3	11,895.8	3.6	3.7	2.6	Disposable personal income	11,481.0	11,591.5	11,608.5	11,680.3	11,781.6	11,868.5	11,932.8	12,000.2
5.3	4.5	3.7	-	-	-	Savings rate (%)	5.0	5.1	4.1	3.9	4.0	3.9	3.6	3.4
1,819.5	1,930.6	2,046.9	25.0	6.1	6.0	Corporate profits before taxes	1,877.1	1,890.6	1,992.8	1,961.8	2,061.6	2,034.2	2,030.6	2,061.3
1,408.4	1,504.2	1,573.5	19.0	6.8	4.6	Corporate profits after taxes	1,454.8	1,470.1	1,558.0	1,534.0	1,580.3	1,561.5	1,562.1	1,590.0
77.35	90.18	98.14	51.2	16.6	8.8	‡Earnings per share (S&P 500)	81.31	83.87	87.85	90.18	93.39	95.37	96.80	98.14
						†Prices & Interest Rates								
1.6	3.2	1.5	-	-	-	Consumer price index	5.2	4.1	3.1	1.1	0.9	0.9	1.4	1.2
0.1	0.1	0.0	-	-	-	Treasury bills	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0
3.2	2.8	2.3	-	-	-	10-yr notes	3.5	3.2	2.4	2.0	2.1	2.3	2.4	2.5
4.3	3.9	3.3	-	-	-	30-yr bonds	4.6	4.3	3.7	3.0	3.1	3.2	3.3	3.4
4.9	4.6	4.2	-	-	-	New issue rate–corporate bonds	5.1	5.0	4.5	3.9	4.0	4.2	4.3	4.3
						Other Key Indicators								
584.9	596.8	664.7	5.6	2.0	11.4	Housing starts (1,000 units SAAR)	582.3	572.3	615.0	617.7	623.8	643.3	678.5	713.1
11.6	12.7	13.4	11.1	9.8	5.6	Auto & truck sales (1,000,000 units)	13.0	12.1	12.4	13.2	13.1	13.3	13.4	13.8
9.6	9.1	9.2	-	-	-	Unemployment rate (%)	8.9	9.1	9.1	9.2	9.2	9.2	9.2	9.2
(3.0)	(6.1)	3.7	-	-	-	§U.S. dollar	(5.7)	(12.2)	1.0	12.0	8.2	4.6	(3.2)	(3.2)

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.
*2005 Chain-weighted dollars. **Current dollars. ‡Trailing 4 quarters. †Average for period. §Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.

Technical Discussion of Discounted Cash Flow And Risk Premium Models

General Stock Price DCF Model

The DCF model is predicated on the concept that stock prices are the present value or discounted value of all future dividends that investors expect to receive. In the most general form, the DCF model is expressed in the following formula:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + ... + D_\infty/(1+k)^\infty \qquad (1)$$

where P_0 is today's stock price; D_1, D_2, etc. are all future dividends and k is the discount rate, or the investor's required rate of return on equity. Equation (1) is a routine present value calculation based on the assumption that the stock's price is the present value of all dividends expected to be paid in the future.

Constant Growth DCF Model

Under the additional assumption that dividends are expected to grow at a constant rate "g" and that k is strictly greater than g, equation (1) can be solved for k and rearranged into the simple form:

$$k = D_1/P_0 + g \qquad (2)$$

Equation (2) is the familiar constant growth DCF model for cost of equity estimation, where D_1/P_0 is the expected dividend yield and g is the long-term expected dividend growth rate.

Multi-stage DCF Models

Under circumstances when growth rates are expected to fluctuate or when future growth rates are highly uncertain, the constant growth model may not give reliable results. Although the DCF model itself is still valid (equation 1 is mathematically correct), under such circumstances the simplified form of the model must be modified to capture market

expectations accurately.

Over the past several years, events in the electric utility industry have challenged the constant growth assumption of the traditional DCF model. Since the mid-1980s, dividend growth expectations for many electric utilities have fluctuated widely. In fact, over one-third of the electric utilities in the U.S. reduced or eliminated their common dividends during this time period. Some of these companies have reestablished their dividends, producing exceptionally high growth rates. Under these circumstances, long-term growth rate estimates may be highly uncertain, and estimating a reliable "constant" growth rate for many companies is often difficult.

When growth expectations are uncertain, the more general version of the model represented in equation (1) should be solved explicitly over a finite "transition" period while uncertainty prevails. The constant growth version of the model can then be applied after the transition period, under the assumption that more stable conditions will prevail in the future. There are two alternatives for dealing with the nonconstant growth transition period.

Terminal Price Multi-stage DCF Model

Under the "terminal price" multi-stage growth approach, equation (1) is written in a slightly different form:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + ... + P_T/(1+k)^T \qquad (3)$$

where the variables are the same as in equation (1) except that P_T is the estimated stock price at the end of the transition period T. Under the assumption that normal growth resumes after the transition period, the price P_T is then expected to be based on constant growth assumptions. With the terminal price approach, the estimated cost of equity, k, is

just the rate of return that investors would expect to earn if they bought the stock at today's market price, held it and received dividends through the transition period (until period T), and then sold it for price P_T. In this approach, the analyst's task is to estimate the rate of return that investors expect to receive given the current level of market prices they are willing to pay.

Generalized Multi-stage DCF Model

Under the general "multistage" growth approach, equation (1) is simply expanded to incorporate two or more growth rate periods, with the assumption that a permanent constant growth rate can be estimated for some point in the future:

$$P_0 = D_0(1+g_1)/(1+k) + ... + D_2(1+g_2)^n/(1+k)^n + ... + [D_T(1+g_T)^{(T+1)}/(k-g_T)]/(1+k)^T \quad (4)$$

where the variables are the same as in equation (1), but g_1 represents the growth rate for the first period; D_2 is the dividend at the beginning of the second period and g_2 is the growth rate for the second period; and D_T is the dividend at the beginning of the third period and g_T for the period from year T (the end of the transition period) to infinity. The difficult task for analysts in the multistage approach is determining the various growth rates for each period.

Although less convenient for exposition purposes, the multi-stage models are based on the same valid capital market assumptions as the constant growth version. This approach simply requires more explicit data inputs and more work to solve for the discount rate, k. Fortunately, the required data are available from investment and economic forecasting services, and computer algorithms can easily produce the required solutions.

Equity Risk Premium Models

Equity risk premium models are based on the assumption that equity securities are riskier than debt and, therefore, that equity investors require a higher rate of return. This basic premise is well supported by legal and economic distinctions between debt and equity securities, and it is widely accepted as a fundamental capital market principle. For example, debt holders' claims to the earnings and assets of the borrower have priority over all claims of equity investors. The contractual interest on mortgage debt must be paid in full before any dividends can be paid to shareholders, and secured mortgage claims must be fully satisfied before any assets can be distributed to shareholders in bankruptcy. Also, the fixed-income nature of interest payments makes year-to-year returns from bonds typically more stable than capital gains and dividend payments on stocks. All these factors demonstrate the more risky position of stockholders and support the equity risk premium concept.

The risk premium approach is useful because it is founded on current market interest rates, which are directly observable. This feature assures that risk premium estimates of the cost of equity begin with a sound basis, which is tied directly to current market interest rates. However, in regulatory practice there is often considerable debate about how risk premium data should be used and interpreted. Since the basic task is to gauge investors' required returns on long-term investments, some argue that the estimated equity risk premiums should cover the longest possible time period. Others argue that market relationships between debt and equity from several decades ago are irrelevant and that only recent debt-equity return observations should be used in estimating investor requirements. There is no consensus on this issue. Since analysts cannot observe or measure investors' expectations directly, it is not possible to know

exactly how such expectations are formed or, therefore, to know exactly what time period is most appropriate in a risk premium analysis.

The important point in the equity risk premium analysis is to answer the following question: "What rate of return should equity investors reasonably expect relative to returns that are currently available from long-term bonds?"

Summary of DCF and Equity Risk Premium Approaches

The DCF and equity risk premium models have become the most widely accepted in regulatory practice. The DCF model and a review of equity risk premium data generally provide a reasonable estimate of the cost of equity. While estimating the DCF growth rate is controversial, the dividend yield is straightforward, and the model's results generally comport with capital market behavior. The equity risk premium approach provides further confirmation. While its inputs and the interpretation of its results require informed judgment, under normal market conditions the risk premium approach is a useful addition to the overall analysis.

PacifiCorp Oregon
GDP Growth Rate Forecast

	Nominal GDP	% Change	GDP Price Deflator	% Change	CPI	% Change
1950	313.3		15.0		25.0	
1951	347.9	11.0%	15.9	5.6%	26.5	6.0%
1952	371.4	6.8%	16.1	1.5%	26.7	0.9%
1953	375.9	1.2%	16.2	0.8%	26.9	0.6%
1954	389.4	3.6%	16.4	0.8%	26.8	-0.4%
1955	426.0	9.4%	16.8	2.6%	26.9	0.4%
1956	448.1	5.2%	17.3	3.3%	27.6	2.8%
1957	461.5	3.0%	17.8	2.7%	28.5	3.0%
1958	485.0	5.1%	18.3	2.5%	29.0	1.8%
1959	513.2	5.8%	18.4	0.9%	29.4	1.5%
1960	523.7	2.0%	18.7	1.4%	29.8	1.4%
1961	562.6	7.4%	18.9	1.1%	30.0	0.7%
1962	593.3	5.5%	19.1	1.3%	30.4	1.2%
1963	633.5	6.8%	19.4	1.4%	30.9	1.6%
1964	675.6	6.6%	19.7	1.5%	31.3	1.2%
1965	747.5	10.6%	20.1	2.0%	31.9	1.9%
1966	806.9	7.9%	20.8	3.5%	32.9	3.4%
1967	852.7	5.7%	21.4	3.1%	34.0	3.3%
1968	936.2	9.8%	22.4	4.6%	35.6	4.7%
1969	1004.5	7.3%	23.6	5.2%	37.7	5.9%
1970	1052.7	4.8%	24.7	5.0%	39.8	5.6%
1971	1151.4	9.4%	25.9	4.7%	41.1	3.3%
1972	1286.6	11.7%	27.1	4.5%	42.5	3.4%
1973	1431.8	11.3%	28.9	6.8%	46.3	8.9%
1974	1552.8	8.5%	32.0	10.7%	51.9	12.1%
1975	1713.9	10.4%	34.4	7.6%	55.6	7.1%
1976	1884.5	10.0%	36.3	5.4%	58.4	5.0%
1977	2110.8	12.0%	38.7	6.7%	62.3	6.7%
1978	2416.0	14.5%	41.5	7.3%	67.9	9.0%
1979	2659.4	10.1%	45.2	8.7%	76.9	13.3%
1980	2915.3	9.6%	49.6	9.7%	86.4	12.4%
1981	3194.7	9.6%	53.6	8.3%	94.1	8.9%
1982	3312.5	3.7%	56.4	5.2%	97.7	3.8%
1983	3688.1	11.3%	58.3	3.3%	101.4	3.8%
1984	4034.0	9.4%	60.4	3.6%	105.5	4.0%
1985	4318.7	7.1%	62.1	2.8%	109.5	3.8%
1986	4543.3	5.2%	63.5	2.3%	110.8	1.2%
1987	4883.1	7.5%	65.5	3.1%	115.6	4.3%
1988	5251.0	7.5%	67.9	3.7%	120.7	4.4%
1989	5581.7	6.3%	70.3	3.5%	126.3	4.6%
1990	5846.0	4.7%	73.2	4.2%	134.2	6.3%
1991	6092.5	4.2%	75.5	3.2%	138.2	3.0%
1992	6493.6	6.6%	77.1	2.2%	142.3	3.0%
1993	6813.8	4.9%	78.8	2.2%	146.3	2.8%
1994	7248.2	6.4%	80.5	2.1%	150.1	2.6%
1995	7542.5	4.1%	82.1	2.0%	153.9	2.5%
1996	8023.0	6.4%	83.6	1.8%	159.1	3.4%
1997	8505.7	6.0%	85.0	1.6%	161.8	1.7%
1998	9027.5	6.1%	85.9	1.1%	164.4	1.6%
1999	9607.7	6.4%	87.2	1.5%	168.8	2.7%
2000	10129.8	5.4%	89.4	2.5%	174.6	3.4%
2001	10373.1	2.4%	91.2	2.0%	177.4	1.6%
2002	10766.9	3.8%	92.8	1.8%	181.8	2.5%
2003	11416.5	6.0%	94.8	2.1%	185.5	2.0%
2004	12144.9	6.4%	97.9	3.2%	191.7	3.3%
2005	12915.6	6.3%	101.3	3.5%	198.1	3.3%
2006	13611.5	5.4%	104.2	2.9%	203.1	2.5%
2007	14291.3	5.0%	106.9	2.6%	211.4	4.1%
2008	14191.2	-0.7%	109.2	2.1%	211.3	0.0%
2009	14277.3	0.6%	109.7	0.4%	217.2	2.8%
2010	14861.0	4.1%	111.2	1.4%	220.2	1.4%
10-Year Average		3.9%		2.2%		2.4%
20-Year Average		4.8%		2.1%		2.5%
30-Year Average		5.6%		2.7%		3.2%
40-Year Average		6.9%		3.9%		4.4%
50-Year Average		7.0%		3.7%		4.1%
60-Year Average		6.7%		3.4%		3.7%
Average of Periods		5.8%		3.0%		3.4%

Source: St. Louis Federal Reserve Bank, www.research.stlouisfed.org

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	10.4%	10.4%	10.0%
2	Alliant Energy Co.	10.2%	10.2%	10.1%
3	Avista Corp.	9.3%	10.5%	10.5%
4	Black Hills Corp	11.1%	10.4%	9.9%
5	DTE Energy Co.	8.9%	10.5%	10.3%
6	Edison Internat.	7.4%	9.1%	8.8%
7	IDACORP	7.4%	8.8%	8.9%
8	Portland General	10.6%	10.2%	10.0%
9	SCANA Corp.	8.6%	10.5%	10.0%
10	Sempra Energy	9.9%	9.8%	9.8%
11	Southern Co.	10.1%	10.3%	10.1%
12	Vectren Corp.	10.1%	10.8%	10.6%
13	Wisconsin Energy	11.2%	9.5%	10.0%
14	Xcel Energy Inc.	9.2%	9.9%	9.6%
	GROUP AVERAGE	9.6%	10.1%	9.9%
	GROUP MEDIAN	10.0%	10.2%	10.0%

Sources: Value Line Investment Survey, Electric Utility (East), Nov 25, 2011; (Central), Dec 23, 2011; (West), Nov 4, 2011.

Exhibit PAC/206
Hadaway/1

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	39.13	1.80	4.60%	6.00%	5.00%	6.50%	5.83%	10.4%
2 Alliant Energy Co.	41.06	1.80	4.38%	6.50%	6.00%	4.90%	5.80%	10.2%
3 Avista Corp.	24.90	1.18	4.74%	4.50%	4.70%	4.50%	4.57%	9.3%
4 Black Hills Corp	32.25	1.48	4.59%	8.50%	5.00%	6.00%	6.50%	11.1%
5 DTE Energy Co.	51.36	2.42	4.71%	4.50%	4.20%	3.75%	4.15%	8.9%
6 Edison Internat.	39.32	1.31	3.33%	NA	5.00%	3.18%	4.09%	7.4%
7 IDACORP	40.27	1.20	2.98%	4.00%	4.70%	4.50%	4.40%	7.4%
8 Portland General	24.35	1.08	4.43%	7.50%	5.00%	5.88%	6.13%	10.6%
9 SCANA Corp.	42.26	1.98	4.69%	3.00%	4.20%	4.48%	3.89%	8.6%
10 Sempra Energy	52.63	2.08	3.95%	3.50%	7.00%	7.33%	5.94%	9.9%
11 Southern Co.	43.58	1.94	4.45%	6.00%	5.10%	5.92%	5.67%	10.1%
12 Vectren Corp.	28.31	1.41	4.98%	5.50%	4.30%	5.50%	5.10%	10.1%
13 Wisconsin Energy	32.63	1.20	3.68%	8.50%	6.30%	7.80%	7.53%	11.2%
14 Xcel Energy Inc.	25.72	1.06	4.12%	5.00%	5.10%	5.13%	5.08%	9.2%
GROUP AVERAGE	36.98	1.57	4.26%	5.62%	5.11%	5.38%	5.33%	9.6%
GROUP MEDIAN			4.44%					10.0%

Sources: Value Line Investment Survey, Electric Utility (East), Nov 25, 2011; (Central), Dec 23, 2011; (West), Nov 4, 2011.

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)
			Next			**ROE**
		Recent	Year's	Dividend	GDP	K=Div Yld+G
	Company	Price(P0)	Div(D1)	Yield	Growth	*(Cols 12+13)*
1	ALLETE	39.13	1.80	4.60%	5.80%	10.4%
2	Alliant Energy Co.	41.06	1.80	4.38%	5.80%	10.2%
3	Avista Corp.	24.90	1.18	4.74%	5.80%	10.5%
4	Black Hills Corp	32.25	1.48	4.59%	5.80%	10.4%
5	DTE Energy Co.	51.36	2.42	4.71%	5.80%	10.5%
6	Edison Internat.	39.32	1.31	3.33%	5.80%	9.1%
7	IDACORP	40.27	1.20	2.98%	5.80%	8.8%
8	Portland General	24.35	1.08	4.43%	5.80%	10.2%
9	SCANA Corp.	42.26	1.98	4.69%	5.80%	10.5%
10	Sempra Energy	52.63	2.08	3.95%	5.80%	9.8%
11	Southern Co.	43.58	1.94	4.45%	5.80%	10.3%
12	Vectren Corp.	28.31	1.41	4.98%	5.80%	10.8%
13	Wisconsin Energy	32.63	1.20	3.68%	5.80%	9.5%
14	Xcel Energy Inc.	25.72	1.06	4.12%	5.80%	9.9%
	GROUP AVERAGE	36.98	1.57	4.26%	5.80%	10.1%
	GROUP MEDIAN			4.44%		10.2%

Sources: Value Line Investment Survey, Electric Utility (East), Nov 25, 2011; (Central), Dec 23, 2011; (West), Nov 4, 2011.

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)
			Annual	CASH FLOWS							ROE=Internal
	2012	2015	Change	Recent	Year 1	Year 2	Year 3	Year 4	Year 5	Year 5-150	Rate of Return
Company	Div	Div	to 2015	Price	Div	Div	Div	Div	Div	Div Growth	*(Yrs 0-150)*
1 ALLETE	1.80	1.95	0.05	-39.13	1.80	1.85	1.90	1.95	2.06	5.80%	10.0%
2 Alliant Energy Co.	1.80	2.10	0.10	-41.06	1.80	1.90	2.00	2.10	2.22	5.80%	10.1%
3 Avista Corp.	1.18	1.40	0.07	-24.90	1.18	1.25	1.33	1.40	1.48	5.80%	10.5%
4 Black Hills Corp	1.48	1.55	0.02	-32.25	1.48	1.50	1.53	1.55	1.64	5.80%	9.9%
5 DTE Energy Co.	2.42	2.70	0.09	-51.36	2.42	2.51	2.61	2.70	2.86	5.80%	10.3%
6 Edison Internat.	1.31	1.40	0.03	-39.32	1.31	1.34	1.37	1.40	1.48	5.80%	8.8%
7 IDACORP	1.20	1.50	0.10	-40.27	1.20	1.30	1.40	1.50	1.59	5.80%	8.9%
8 Portland General	1.08	1.20	0.04	-24.35	1.08	1.12	1.16	1.20	1.27	5.80%	10.0%
9 SCANA Corp.	1.98	2.10	0.04	-42.26	1.98	2.02	2.06	2.10	2.22	5.80%	10.0%
10 Sempra Energy	2.08	2.50	0.14	-52.63	2.08	2.22	2.36	2.50	2.65	5.80%	9.8%
11 Southern Co.	1.94	2.20	0.09	-43.58	1.94	2.03	2.11	2.20	2.33	5.80%	10.1%
12 Vectren Corp.	1.41	1.60	0.06	-28.31	1.41	1.47	1.54	1.60	1.69	5.80%	10.6%
13 Wisconsin Energy	1.20	1.65	0.15	-32.63	1.20	1.35	1.50	1.65	1.75	5.80%	10.0%
14 Xcel Energy Inc.	1.06	1.15	0.03	-25.72	1.06	1.09	1.12	1.15	1.22	5.80%	9.6%
GROUP AVERAGE											9.9%
GROUP MEDIAN											10.0%

Sources: Value Line Investment Survey, Electric Utility (East), Nov 25, 2011; (Central), Dec 23, 2011; (West), Nov 4, 2011.

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 (Oct 2011-Dec 2011)

Column 2: Estimated 2012 Div per Share from Value Line

Column 3: Column 2 Divided by Column 1

Column 4: "Est'd '08-'10 to '14-'16" 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: Estimated 2012 Div per Share from Value Line

Column 15: Estimated 2015 Div 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 16

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

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%
2009	6.28%	10.48%	4.20%
2010	5.55%	10.34%	4.79%
2011	5.17%	10.22%	5.05%
AVERAGE	8.82%	12.15%	3.33%

INDICATED COST OF EQUITY

PROJECTED SINGLE-A UTILITY BOND YIELD*	4.62%
MOODY'S AVG ANNUAL YIELD DURING STUDY	8.82%
INTEREST RATE DIFFERENCE	-4.20%
INTEREST RATE CHANGE COEFFICIENT	-41.62%
ADUSTMENT TO AVG RISK PREMIUM	1.75%
BASIC RISK PREMIUM	3.33%
INTEREST RATE ADJUSTMENT	1.75%
EQUITY RISK PREMIUM	5.08%
PROJECTED SINGLE-A UTILITY BOND YIELD*	4.62%
INDICATED EQUITY RETURN	**9.70%**

(1) Moody's Investors Service

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

*Projected single-A bond yield is 132 basis points over average 2012 projected long-term Treasury bond rate of 3.3% from Exhibit PAC/203, p. 3. The single-A spread is for 3 months ended December 2011 from Exhibit PAC/203, p. 2.

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%
2009	6.28%	10.48%	4.20%
2010	5.55%	10.34%	4.79%
2011	5.17%	10.22%	5.05%
AVERAGE	8.82%	12.15%	3.33%

INDICATED COST OF EQUITY

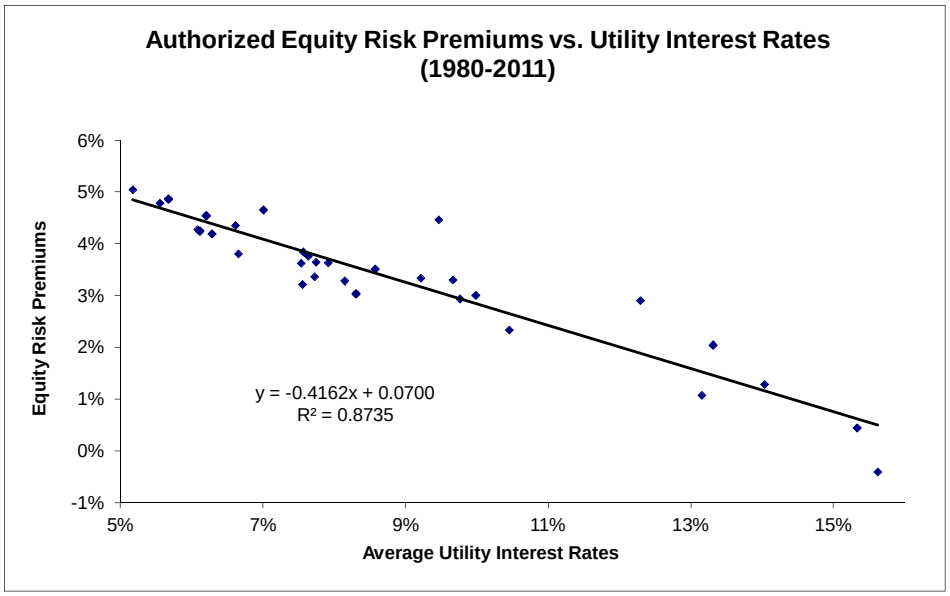
CURRENT SINGLE-A UTILITY BOND YIELD*	4.37%
MOODY'S AVG ANNUAL YIELD DURING STUDY	8.82%
INTEREST RATE DIFFERENCE	-4.45%
INTEREST RATE CHANGE COEFFICIENT	-41.62%
ADUSTMENT TO AVG RISK PREMIUM	1.85%
BASIC RISK PREMIUM	3.33%
INTEREST RATE ADJUSTMENT	1.85%
EQUITY RISK PREMIUM	5.18%
CURRENT SINGLE-A UTILITY BOND YIELD*	4.37%
INDICATED EQUITY RETURN	**9.55%**

(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 December 2011 from Exhibit PAC/203, p. 2.

PacifiCorp Oregon
Risk Premium Analysis
Regression Analysis & Interest Rate Change Coefficient



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.934607488
R Square	0.873491157
Adjusted R Square	0.869274196
Standard Error	0.004645908
Observations	32

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.004470953	0.004470953	207.1375734	5.236E-15
Residual	30	0.000647534	2.15845E-05		
Total	31	0.005118487			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.070011757	0.002679133	26.13224684	3.388E-22	0.064540238	0.075483276	0.064540238	0.075483276
X Variable 1	-0.41615627	0.028915253	-14.39227478	5.236E-15	-0.475209095	-0.357103445	-0.475209095	-0.357103445

DIRECT TESTIMONY OF BRUCE N. WILLIAMS

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ATTACHED EXHIBITS

Exhibit PAC/301 – Arizona Public Service Company Letter

Exhibit PAC/302 – Standard & Poor's Ratings Direct, October 3, 2011

Exhibit PAC/303 – Standard & Poor's Ratings Direct, July 29, 2011

Exhibit PAC/304 – Standard & Poor's Ratings Direct, April 28, 2011

Exhibit PAC/305 – Standard & Poor's Ratings Direct, October 7, 2010

Exhibit PAC/306 – Standard & Poor's Ratings Direct, April 30, 2010

Exhibit PAC/307 – Pro Forma Cost of Long-Term Debt Summary

Exhibit PAC/308 – Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' PPAs

Exhibit PAC/309 – Cost of Preferred Stock

Exhibit PAC/310 – Indicative Forward PCRB Variable Rates

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

A. My name is Bruce N. Williams. My business address is 825 NE Multnomah, Suite 1900, Portland, Oregon 97232. My present position is Vice President and Treasurer.

Qualifications

Q. Please describe your education and business experience.

A. I received a Bachelor of Science degree in Business Administration with a concentration in Finance from Oregon State University in 1980. I also received the Chartered Financial Analyst designation upon passing the examination in 1986. I have been employed by the Company for 26 years. My business experience has included financing of the Company's electric operations and non-utility activities, responsibility for the investment management of the Company's qualified and non-qualified retirement plan assets, and investor relations.

Q. Please describe your present duties.

A. I am responsible for the Company's treasury, credit risk management, and pension and other investment management activities. I am also responsible for the preparation of the Company's embedded cost of debt and preferred equity and any associated testimony related to capital structure for regulatory filings in all of PacifiCorp's state and federal jurisdictions.

Summary of Testimony

Q. Please provide a summary of your testimony.

A. My testimony discusses the Company's capital structure and costs of capital. It

supports the proposed common equity level of 52.8 percent and provides evidence of why that level is appropriate and benefits customers. Those benefits include maintaining the Company's current credit ratings, which will facilitate continued access to the capital markets for the Company, and providing a more competitive cost of debt and overall cost of capital over the long term. This capital structure is necessary to enable the Company to continue to invest in infrastructure in order to provide safe and reliable service to our customers at reasonable costs. I also support the Company's updated cost of long-term debt of 5.372 percent and cost of preferred stock of 5.427 percent.

Q. What is the overall cost of capital that you are proposing in this case?

A. PacifiCorp is proposing an overall cost of capital of 7.92 percent. This cost includes the return on equity recommendation of 10.20 percent from Dr. Samuel C. Hadaway and the following capital structure and costs:

Overall Cost of Capital

Component	Percent of Total	Cost	Weighted Average
Long Term Debt	46.9 %	5.372 %	2.519 %
Preferred Stock	0.3 %	5.427 %	0.016 %
Common Stock Equity	52.8 %	10.200 %	5.386 %
Total	100.0 %		7.921 %

The capital structure and costs of debt and preferred stock are measured on December 31, 2012, just prior to the effective date of the new rates, using the Company's actual costs adjusted for changes through December 31, 2012.

Q. How does the proposed overall cost of capital compare to the Company's current overall cost of capital?

A. The proposed overall cost of capital of 7.92 percent is lower than the 8.08 percent

now reflected in rates based on the UE 217 Stipulation. The reduction reflects the fact that the Company has been able to reduce the average cost of debt.

Financing Overview

Q. Please explain PacifiCorp's need for and sources of new capital.

A. PacifiCorp is in the process of adding significant new plant investments over multiple years. These investments include transmission facilities, hydro generation upgrades, required pollution control equipment and other capital investments to properly maintain the existing infrastructure. These investments help system reliability, improve power delivery, and help to ensure safe operations for the benefit of customers.

Q. How does the Company finance its electric utility operations?

A. Generally, the Company finances its regulated utility operations over the long term using approximately a 50/50 percent mix of debt and common equity capital. Immediately before and during periods of significant capital expenditures, the Company may allow the common equity component of the capital structure to increase. This provides more flexibility regarding the type and timing of debt financing, better access to the capital markets, a more competitive cost of debt, and more stable credit ratings over time—all of which assist in financing the capital expenditures. In addition, all else being equal, the Company will need to have a greater common equity component to offset various adjustments that rating agencies make to the debt component of the Company's published financial statements. I will discuss these adjustments in greater detail later in this testimony.

Q. In the past, the Company retained all of its earnings to help finance capital investments. Has the Company recently paid dividends to MidAmerican Energy Holdings Company ("MEHC")?

A. Yes. During 2011, the Company initiated the payment of dividends to MEHC as a result of the temporary cash benefits and boost to credit metrics from the passage of legislation enacting and extending bonus depreciation. The Company expects a similar but smaller benefit from bonus depreciation during 2012. This temporary improvement in credit metrics allowed PacifiCorp to moderate the level of equity that otherwise would have been necessary to sustain the Company's credit rating during these periods, and enabled dividends to be paid in 2011 and 2012. In addition, the temporary cash benefits from bonus depreciation have reduced, but not eliminated, the need for new borrowings. The proposed capital structure in this case includes the impact of additional dividends expected to be declared before December 31, 2012.

Q. Please explain why dividends were not paid to MEHC in the past.

A. Since the acquisition in 2006 by MEHC, the Company has managed the capital structure through the timing and amount of long-term debt issuances and capital contributions while forgoing any common dividend distributions for nearly five years. MEHC recognizes that the Company is in a period requiring significant capital investment that, until recently, has far exceeded the Company's ability to finance with internally generated funds. MEHC therefore allowed the Company to retain earnings totaling over $2 billion through 2010 and even increased its investment in the Company by more than $1 billion to enable the Company to

finance capital investment and help maintain its credit ratings during this period of capital spending. As I will discuss later, the maintenance of credit ratings has allowed the Company to access the capital markets when other utilities were denied access, provided a lower cost of debt, and provided a lower overall cost of capital.

Q. Does the additional cash flow generated by the tax law changes mitigate the need for a rate increase?

A. Yes, but only to a limited extent. Bonus depreciation provides a temporary cash flow benefit to the Company in the form of accelerated tax benefits, but this cash benefit does not translate one-for-one into a reduction in revenue requirement. Income tax expense, a component of revenue requirement, generally is unchanged as a result of bonus depreciation because the current income tax benefits received from bonus depreciation generally are fully offset by additional deferred income tax expenses. Customers receive benefits from bonus depreciation in the form of increased deferred income tax liabilities, which reduces rate base.

Credit Ratings

Q. What are the Company's current credit ratings?

A. The Company's current ratings are as follows:

	Fitch	Moody's	Standard & Poor's
Senior secured debt	A-	A2	A
Senior unsecured debt	BBB+	Baa1	A-
Outlook	Stable	Stable	Stable

Q. Why should this Commission be concerned about credit ratings and the views expressed by rating agencies?

A. Credit ratings and the views of rating agencies are important for several reasons. First, the credit rating of a utility has a direct impact on the price that a utility pays to attract the capital necessary to support its current and future operating needs. Many institutional investors have fiduciary responsibilities to their clients and are typically not permitted to purchase non investment grade (*i.e.*, rated below BBB-) securities or, in some cases, even securities rated below a single A.

Second, credit ratings are an estimate of the probability of default by the issuer on each rated security. Lower ratings equate to higher risks and higher costs of debt. But even investment grade rated borrowers have experienced recent problems accessing the capital markets or been shut out entirely. The financial crisis of 2008 and 2009 provided clear and compelling evidence of the benefits of the Company's credit rating as it was able to issue new long-term debt during the midst of the financial turmoil. Other lower-rated utilities were simply shut out of the market and could not obtain new capital regardless of how much they were willing to pay.

Further, the Company has a near constant need for short-term liquidity as well as periodic long-term debt issuances. On a daily basis, the Company pays significant amounts to suppliers to provide necessary goods and services such as fuel, spare parts, and inventory. Being unable to access funds can jeopardize the successful completion of necessary capital infrastructure projects and would increase the chance of outages and service failures over the long term.

Q. Please provide the Commission with examples where poor credit ratings hurt a utility's flexibility in the credit markets.

A. Arizona Public Service Company (rated at that time Baa2/BBB-) filed a letter with the Arizona Corporation Commission during October 2008 stating that the commercial paper market was completely closed to it and it likely could not successfully issue long-term debt. See Exhibit PAC/301.

Further, those issuers who could access the markets paid rates well above the levels that the Company was able to achieve. For example, Nevada Power (rated Baa3/BBB) issued new debt two days following PacifiCorp's January 2009 issuance and was required by investors to pay a coupon of 7.375 percent for a five-year maturity. Subsequently, Puget Sound Energy (rated Baa2/A-) issued new seven-year debt at a credit spread over Treasuries of 480.3 basis points resulting in a 6.75 percent coupon.

Q. How do these coupon rates compare to PacifiCorp's during that period?

A. In January 2009, the Company completed an offering of $350 million of first mortgage bonds with a 10-year maturity at a coupon rate of 5.50 percent and $650 million of 30-year first mortgage bonds with a coupon rate of 6.00 percent. The Company was able to achieve both a longer maturity and lower cost than either of the utilities discussed above.

Q. Please describe the Company's most recent debt issuance.

A. In January 2012, the Company completed an issuance of $650 million of first mortgage bonds. This offering consisted of $350 million with a 10-year maturity and a coupon interest rate of 2.95 percent and $300 million with a 30-year

maturity and a coupon rate of 4.10 percent. These rates, which average 3.56 percent, are among the lowest ever achieved by borrowers. The coupon rate on the 10-year maturity is tied for the lowest utility rate on record (for any ratings level) and the sixth lowest coupon rate for any industry and any credit rating. The 30-year coupon rate of 4.10 percent is the third lowest coupon achieved by any issuer in any industry and credit rating. These favorable debt rates are included in the cost of debt calculation in this case and help to keep rates reasonable for customers.

Q. Can regulatory actions or orders affect a company's credit rating?

A. Yes, in a very significant way. Regulated utilities are fairly unique since they cannot set their own prices for their services. The financial integrity of a regulated utility is largely a result of how the utility is treated on cost recovery issues and in the rates set by regulators. Rates are established by regulators to permit the utility to recover prudently incurred operating expenses and a reasonable opportunity to earn a fair return on the capital invested. Therefore, rate decisions by utility commissions have a direct and significant impact on the financial condition of utilities.

Rating agencies and investors have a keen understanding of the importance of regulatory outcomes. For example, Standard & Poor's ("S&P") writes:

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk.[1]

[1] Standard & Poor's Ratings Direct – Assessing U.S. Utility Regulation Environments (March 11, 2010).

Similarly, Moody's has stated:

> 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. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return.[2]

Q. How does maintaining the Company's current credit ratings benefit customers?

A. The Company is in the midst of a period of heavy capital spending and investing in infrastructure in order to provide for the needs of customers. If the Company does not have consistent access to the capital markets at reasonable costs, these borrowings and the resulting costs of building new facilities become more expensive than they otherwise would be. The inability to access financial markets can threaten the completion of these necessary projects, which will, in turn, affect system reliability and customer safety. All of the resulting higher costs are ultimately borne by the customers. Maintaining the current single-A credit rating makes it more likely the Company will have access to the capital markets at reasonable costs, even during periods of financial turmoil. This rating will allow the Company continued access to the capital markets that will enable it to fulfill its capital investments for the benefit of customers.

Q. Are there other identifiable advantages to a favorable rating?

A. Yes. Higher-rated companies have greater access to the long-term markets for power purchases and sales. Such access provides these companies with more

[2] Moody's Investors Service Regulated Electric and Gas Utilities (August 2009).

alternatives when attempting to meet the current and future load requirements of their customers. Additionally, a company with strong ratings will often avoid having to meet costly collateral requirements that are typically imposed on lower-rated companies when securing power in these markets.

In my opinion, maintaining the current single-A rating provides the best balance between costs and the continued access to the capital markets that is necessary to fund capital projects for the benefit of customers.

Q. Is the proposed capital structure consistent with the Company's current credit rating?

A. Yes. This capital structure is intended to enable the Company to deliver its required capital expenditures and achieve financial metrics that will meet rating agency expectations. S&P has stated very clearly its expectations for PacifiCorp:

> The stable outlook incorporates our anticipation that PacifiCorp will … [achieve] adjusted FFO to debt in the area of 20 percent, FFO interest coverage of at least 4.5x and adjusted debt to total capitalization of around 50 percent. We view these cash flow levels as merely adequate to maintain the ratings….[3]

Q. Do the Company's credit ratings benefit because of MEHC and its parent Berkshire Hathaway?

A. Yes. Although ring fenced, historically the Company's credit ratios have been weak for the ratings levels, and we have been able to sustain our ratings in part through MEHC and its parent, Berkshire Hathaway. S&P was very clear on this point in its recent assessment of PacifiCorp:

[3] Standard & Poor's Ratings Direct (October 3, 2011), attached as Exhibit PAC/302.

> MEHC has demonstrated a willingness to support the utility's capital program, providing PacifiCorp with $1.1 billion equity contribution since 2006. This has allowed the company to grow without straining borrowings.
>
> * * *
>
> [R]egulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. acquired the utility in 2006, cash flow metrics remain just adequate to support the rating[.][4]

Clearly, PacifiCorp and its customers have benefited from the higher ratings the Company would otherwise likely have been awarded on a stand-alone basis. Another important element supporting the Company's current ratings is the rating agencies' expectations that PacifiCorp will receive supportive regulatory treatment, including reasonable outcomes in rate proceedings and applications to recover the full cost of large scale capital projects. Absent ownership by MEHC and supportive regulatory treatment that permits a fair opportunity for the Company to recover its reasonable and prudent costs, including a return on its investment comparable to other similarly situated utilities, PacifiCorp's senior secured and corporate credit ratings would have likely suffered at least a one rating level downgrade.

Q. Do S&P's recent credit reports on PacifiCorp emphasize S&P's expectation that PacifiCorp improve its financial metrics in order to maintain its current credit rating?

A. Yes. S&P has been cautious about PacifiCorp's credit metrics and, as noted previously, views the Company's credit metrics on a stand-alone basis as just adequate to support the ratings. S&P has made several references to the need for

[4] Standard & Poor's Ratings Direct (July 29, 2011), attached as Exhibit PAC/303.

PacifiCorp to improve its stand-alone financial metrics, noting that PacifiCorp's financial risk profile reflects a large capital program and the need to shore up cash flow metrics. S&P also stated that, "[g]iven the recent turmoil in both the liquidity and capital markets, we have taken a firmer view on the need to link the PacifiCorp short-term ratings to its stand-alone quality, which supports an 'A-2' short-term rating." S&P also reiterated its credit view that, "supportive rate case outcomes remain key to maintaining and improving upon the company's financial performance."[5] See the S&P Ratings Direct publications in Exhibits PAC/302 from October 3, 2011, PAC/303 from July 29, 2011, PAC/304 from April 28, 2011, PAC/305 from October 7, 2010, and PAC/306 from April 30, 2010.

Q. Do other rating agencies share S&P's view concerning the need for supportive rate case outcomes?

A. Yes. Fitch stated: "The current ratings and Stable Outlook assume [PacifiCorp] continues to benefit from parent company support and reasonable outcomes in pending and future rate proceedings to recover anticipated, significant capital investment."[6] Further, Fitch stated:

> Given the size of its planned capital investment, timely recovery of capital and related operating and maintenance costs is crucial for PPW's creditworthiness. Therefore, currently unanticipated adverse developments in PPW's six regulatory jurisdictions, leading to greater regulatory lag or lower recoveries, and resulting weaker coverage ratios compared with Fitch's projections could lead to future deterioration in PPW's creditworthiness and lower credit ratings.[7]

[5] Standard & Poor's Ratings Direct (April 30, 2011).
[6] Fitch Ratings (September 29, 2011).
[7] Fitch Ratings (January 6, 2011).

Likewise, Moody's lists "Reasonably supportive regulatory environment" as one of the ratings drivers. Moody's also states:

> The stable outlook incorporates Moody's expectation that PacifiCorp will continue to receive reasonable regulatory treatment for the recovery of its higher capital expenditures….[8]

Discussing what could cause the rating to be lowered, Moody's writes:

> … if there were to be adverse regulatory rulings on current and future rate cases such that we would anticipate a sustained deterioration in financial metrics...[9]

Capital Structure

Q. How did the Company determine the capital structure and costs proposed in this case?

A. To appropriately match the Company's costs with customer prices, the capital structure and costs of debt and preferred stock in this case are measured on December 31, 2012, one day before the effective date of the new rates. The capital structure reflects scheduled maturities of debt issues that were outstanding at December 31, 2011, subsequent issuances of long-term debt, and any capital contributions received or dividends paid. The known and measurable changes represent actual and forecasted capital activity since December 31, 2011. Similarly, I determined the embedded cost of debt using the Company's actual costs adjusted for changes through December 31, 2012, as I detail in this testimony.

Q. What was the Company's actual capital structure as of December 31, 2011?

A. The Company's actual capital structure was comprised of 53.9 percent equity,

[8] Moody's Investor Service (May 9, 2011).
[9] Moody's Investor Service (May 9, 2011).

45.8 percent long-term debt and 0.3 percent preferred stock. The lower equity component in the proposed capital structure in this case reflects actual and projected debt issuances and dividend payments in 2012.

Q. How does the Company's proposed capital structure compare to the actual December 31, 2010 capital structure and to the stipulated capital structure from the Company's 2010 general rate case, UE 217?

A. The capital structures are compared in the table below.

PacifiCorp's Comparison of Capital Structures			
	2010 General Rate Case	**December 31, 2010 Actual**	**2012 General Rate Case**
Long-Term Debt	**48.7%**	**46.5%**	**46.9%**
Preferred Stock	**0.3%**	**0.3%**	**0.3%**
Common Equity	**51.0%**	**53.2%**	**52.8%**
Totals	**100.0%**	**100.0%**	**100.0%**

The proposed capital structure in the present case is in line with the Company's actual year-end capital structure in both 2010 and 2011. The equity component of the Company's capital structure reflected in the UE 217 stipulation is lower than the Company's actual capital structure in recent historical periods and its projected actual capital structure at year-end 2012.

Q. What type of debt and preferred equity securities does the Company employ in meeting its financing requirements?

A. The Company relies on a mix of first mortgage bonds, other secured debt, tax-exempt debt, and preferred stock to help meet its long-term financing requirements. These securities employ various maturities in order to provide flexibility and mitigate refinancing risks. The Company has completed the

majority of its long-term financing using secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit PAC/307 shows that on December 31, 2012, the Company is projected to have approximately $6.1 billion of first mortgage bonds outstanding, with an average cost of 5.73 percent. Presently, all outstanding first mortgage bonds bear interest at fixed rates. Proceeds from the issuance of the first mortgage bonds (and other financing instruments) are used to finance the combined utility operation.

Another important source of financing has been the tax-exempt financing associated with certain qualifying equipment at power generation plants. Under arrangements with local counties and other tax-exempt entities, these entities issue securities. The Company borrows the proceeds of these issuances from the respective entities and pledges its credit quality to repay the debt in order to take advantage of the tax-exempt status of the financings. These bonds are primarily in a variable rate mode and are remarketed, some as often as daily. In addition to tax-exempt status, these securities take advantage of current very low short-term interest rates. On the other hand, the variable rate structure of this type of financing exposes the Company to re-marketing and interest rate risks as well as dislocations in the short-term credit markets. Hence, the Company is careful about the total amount of this variable rate financing in its capital structure.

At December 31, 2012, PacifiCorp's tax-exempt portfolio, net of current maturities, is projected to be $698 million in principal amount with an average cost of 2.21 percent, which includes the cost of issuance and credit enhancement.

Q. How does the Company determine the amount of common equity, debt and preferred stock to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and an obligation to provide safe, adequate, and reliable service to its Oregon customers while prudently balancing cost and risk. To fulfill this obligation, the Company is making significant capital expenditures for new plant investment, including transmission, hydro generation upgrades, and environmental control investments on existing fossil-fired generation units. Each of these capital investments also have associated operating and maintenance costs. Through its planning process, the Company determined the amount of new financing necessary to support these activities and to provide financial results and credit ratings that balance the cost of capital with continued access to the financial markets.

Q. Please describe the changes to the amount and cost of outstanding long-term debt.

A. Approximately $17 million of long-term debt with an average cost of 9.02 percent will mature between December 31, 2011, and December 31, 2012. I have therefore removed this debt in the determination of the proposed capital structure and the cost of debt.

As I discussed earlier, the Company recently completed the issuance of new long-term debt in the amount of $650 million with an average cost of 3.56 percent. I included these issuances in the proposed capital structure and included the cost in the cost of debt calculation. The Company presently does not expect to issue further new long-term debt before December 31, 2012, although it continues

to assess the capital markets for refinancing opportunities. I then adjusted the interest rate on the $261 million of long-term debt that will mature during 2013 to reflect expected refinancing rates. This adjustment is consistent with the Commission practice set forth in Order No. 01-787[10] and with the Company's practice in cases since that order.

Purchase Power Agreements

Q. Is the Company subject to rating agency debt imputation associated with Purchase Power Agreements?

A. Yes. Rating agencies and financial analysts consider Purchase Power Agreements ("PPAs") to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P will adjust the Company's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. It does this to more accurately assess a company's financial commitments and fixed payments. Exhibit PAC/308 is a publication by S&P detailing its view of the debt aspects of PPAs.

Q. How does this affect the Company?

A. During a recent ratings review, S&P evaluated the Company's PPAs and other related long-term commitments. Approximately $355 million of additional debt and $21 million of related interest expense were added to the Company's debt and coverage tests solely as a result of PPAs. There were also other adjustments made by S&P that resulted in a total of approximately $897 million of debt and $75 million of interest being imputed into PacifiCorp's credit ratios.

[10] *In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 116, Order No. 01-787 (Sept. 7, 2001).

Q. How would the inclusion of this PPA related debt and these other adjustments affect the Company's capital structure as S&P reviews your credit metrics?

A. Negatively. By including the imputed debt resulting from PPAs and these other adjustments, the Company's capital structure has a lower equity component as a corollary to the higher debt component, lower coverage ratios, and reduced financial flexibility than what might otherwise appear to be the case from a review of the book value capital structure. For example, if one adds the approximately $900 million of debt adjustments that S&P makes to the Company's capital structure in this case, then the resulting common equity percentage would decline from 52.8 percent to 49.8 percent, as shown in the chart below. The 49.8 percent equity ratio falls below S&P's published expectations for PacifiCorp, heightening the risk of a downgrade.

	Book Values/Ratios	Rating Agency Adjustments	Adjusted Book Values/Ratios
Long-Term Debt	$6,804 / 46.9%	$897	$ 7,701 / 50.1%
Preferred Stock	$41 / 0.3%	($21)	$20 / 0.1%
Common Equity	$7,647 / 52.8%	0	$ 7,647 / 49.8%
Totals	$14,492 / 100.0%	$876	$ 15,368 / 100.0%

Financing Cost Calculations

Q. How did you calculate the Company's embedded costs of long-term debt and preferred stock?

A. I calculated the embedded costs of debt and preferred stock using the methodology relied upon in the Company's previous rate cases in Oregon and other jurisdictions.

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

A. The cost of long-term debt is 5.372 percent at December 31, 2012, as shown in Exhibit PAC/307.

Q. Please explain the cost of long-term debt calculation.

A. I calculated the cost of debt by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt. It should be noted that if a bond was issued to refinance a higher cost bond, then the pre-tax premium and unamortized costs, if any, associated with the refinancing were subtracted from the net proceeds of the bonds that were issued. Each bond yield was then multiplied by the principal amount outstanding of each debt issue, resulting in an annualized cost of each debt issue. Aggregating the annual cost of each debt issue produces the total annualized cost of debt. Dividing the total annualized cost of debt by the total principal amount of debt outstanding produces the weighted average cost for all debt issues. This is the Company's embedded cost of long-term debt.

Q. What is the Company's embedded cost of preferred stock?

A. Exhibit PAC/309 shows the embedded cost of preferred stock at December 31, 2012, to be 5.427 percent.

Q. How did you calculate the embedded cost of preferred stock?

A. The embedded cost of preferred stock was calculated by first determining the cost of money for each issue. I begin by dividing the annual dividend per share by the per share net proceeds for each series of preferred stock. The resulting cost rate associated with each series was then multiplied by the total par or stated value

outstanding for each issue to yield the annualized cost for each issue. The sum of annualized costs for each issue produces the total annual cost for the entire preferred stock portfolio. I then divided the total annual cost by the total amount of preferred stock outstanding to produce the weighted average cost for all issues. The result is the Company's embedded cost of preferred stock.

Q. A portion of the securities in the Company's debt portfolio bears variable rates. What is the basis for the projected interest rates used by the Company?

A. The Company's variable rate long-term debt in this case is in the form of tax-exempt debt. Exhibit PAC/310 shows that, on average, these securities had been trading at approximately 92 percent of the 30-day London Inter Bank Offer Rate ("LIBOR") for the period January 2000 through December 2011. Therefore, the Company has applied a factor of 92 percent to the forward 30-day LIBOR rates at each future quarter-end spanning the test period and then added the respective credit enhancement and remarketing fees for each floating rate tax-exempt bond. Credit enhancement and remarketing fees are included in the interest component because these are costs that contribute directly to the interest rate on the securities and are charged to interest expense. 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 the Company.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-246
Exhibit PAC/301
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Arizona Public Service Company Letter

March 2012

Exhibit PAC/301
Williams/1

PINNACLE WEST
CAPITAL CORPORATION

LAW DEPARTMENT

Thomas L. Mumaw
Senior Attorney
(602) 250-2052
Direct Line

October 17, 2008

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Docket No. E-01345A-08-0172 (Interim Rate Motion)

Dear Commissioner Mayes:

On October 8, 2008, you filed a letter in which you requested Arizona Public Service Company ("APS" or "Company") to respond to five specific issues covering a range of subjects. Because several of these issues are germane to the Company's pending Motion for Interim Rates, the Company has chosen to submit its response in the above docket. For the convenience of the parties to this proceeding, I have attached a copy of your October 8th letter as Appendix A.

APS Access to Commercial Paper Market and *Other Credit-Related Issues*

APS first began experiencing trouble accessing the commercial paper market in August of 2007 when the sub-prime credit issues began to impact the capital markets. Access has continued to be sporadic throughout 2008, with the amount of commercial paper APS can issue often being limited even when access to the market was possible. Beginning September 17, 2008, the commercial paper market has been completely closed to APS.

As discussed during the hearing, APS had total lines of credit of $900 million. The first line of $400 million expires at the end of 2010, with a second for $500 million expiring at the end of 2011. The purpose of these lines of credit is to provide the Company with liquidity and working capital when commercial paper cannot be utilized – not fund capital expenditures.[1] Indeed, Decision No. 69947 (October 30, 2007) specifically limited the use of the $500 million line of credit to fuel/purchased power requirements and thus cannot be used to fund the Company's capital requirements. As of September 30, 2008, approximately $270 million had to be drawn down due to the problems in the commercial paper market described above. Also, $34 million of the Company's credit line was with bankrupt Lehman Brothers and thus no longer

[1] *Borrowing on bank lines of credit is normally 25 to 50 basis points more expensive than commercial paper.*

exists. Another $36 million was with Wachovia, which is in the process of being acquired by Wells Fargo. Whether the new owner of Wachovia will assume the $36 million commitment is uncertain, to say the least. Accordingly, APS's previous $900 million lines of credit are now no more than $866 million, and may be as low as $830 million. Finally, as a result of recent write-downs of bank assets, there is $2 trillion less credit capacity in the U.S. banking system than there was before this global financial crisis began. As a result, APS will likely encounter difficulty in maintaining its remaining lines of credit in the future, and there is no doubt that these lines of credit would, in any case, be insufficient to meet APS's capital expenditure needs over the next few years.

Liquidity is absolutely vital to the financial integrity of an electric utility. APS itself was contacted by each of the three rating agencies after the Lehman Brothers bankruptcy and asked about the Company's exposure to Lehman, Morgan Stanley, Merrill Lynch and Goldman Sachs, as well as its ability to count on its lines of credit given the chaos in the short-term credit markets. A recent example of the critical importance of liquidity is Constellation Energy, the parent of Baltimore Gas & Electric Company, which began 2008 with a stock price of over $100 per share. After facing a liquidity crisis driven by threatened credit rating downgrades and the resultant cash collateral calls that nearly drove Constellation to the brink of bankruptcy, it was forced to sell itself to MidAmerican Energy (the same entity that bought out PacifiCorp) for $26.50 per share.

And the damage has not been limited to the short-term debt market. Despite massive efforts by our Federal government and governments in Europe and Asia to pump liquidity into the national and international credit markets, access to the corporate debt market is extremely strained, with only the most highly-rated corporations being successful in raising long-term debt capital. At present, APS likely could not successfully issue long-term debt. Whether this financial market environment will improve by the spring of next year, when APS likely will need to issue debt, is unknown.

Geo*Smart* Solar Financing Program

On Thursday, September 25, 2008 GE Money announced that it will no longer offer unsecured installment consumer financing for its energy efficiency and renewable energy programs after October 23, 2008 because of the current turmoil in the credit markets. The action specifically affected the Electric & Gas Industries Association's ("EGIA") GEO*Smart* Financing Program offered by APS because GE Money provided the financial support for the program. Although APS had no prior warning of GE Money's actions, APS remains committed to its partnership with EGIA. EGIA, as a non-profit entity implementing similar financing programs for utilities around the country, is situated to identify other suitable financial institutions to back the Geo*Smart* program. In recent conversations, EGIA informed APS that a number of financial institutions have been identified that **may** be able to provide funding for GEO*Smart*. APS remains hopeful but cannot offer any assurance that EGIA will secure other financial backing in the future.

Transactions with Investment Banks or Similar Financial Institutions

Attached as Appendix B is a list of the banks with which APS has existing lines of credit. As noted before, Lehman Brothers and Wachovia are in that group. APS has also submitted a $1.1 million claim against Lehman Brothers in bankruptcy over a hedging transaction. APS has conducted numerous transactions with Morgan Stanley and Goldman Sachs, who together are major players in the U.S energy markets. Although it would seriously reduce the overall liquidity of these energy markets should Morgan Stanley and/or Goldman Sachs bow out of the energy market, APS itself had controls in place well before all these problems began that limited its exposure to any single trading partner, including those discussed above. However, with chaotic and unprecedented market events such as we are presently experiencing, no amount of internal controls can provide complete protection against potential losses.[2] Finally, AIG is a carrier for APS property and casualty insurance. APS believes that these insurance policies will continue to be honored.

Auction Rate Securities

APS does not have any funds invested in auction rate securities ("ARS"). APS is an issuer of ARS, with $343 million outstanding and with maturities in 2029 and 2034. The average rate of interest paid on these securities has been 3.2%, thus providing very attractive financing for APS and its customers.

Palo Verde

Palo Verde Unit 3 experienced two relatively brief unplanned outages recently. The first was from September 16 to September 20 when a failed transmitter in the control circuitry for one of the two power supplies to the reactor control rods required the unit to be shut down. That was safely accomplished, and after the electronic card that included the failed component was replaced, the unit was returned to full power without incident. The second was from September 27 to 30 when high sulfate levels were detected in the secondary steam system (the system that connects the steam generators with the steam turbine). After operators had shut down the unit, the secondary system chemistry was returned to normal, the unit again returned to service without incident and has been operating at full power since then. APS estimates that the amount of additional fuel and purchased power costs deferred for recovery through the PSA to be approximately $3 million.[3]

Neither outage involved what could be characterized as an unusual event for a nuclear power plant and is the sort of occurrence anticipated in the budgeted effective forced outage rate ("EFOR") for Palo Verde. Palo Verde, like all generators, including all APS generators, has an

[2] Although such transactions are not directly with APS, the APS decommissioning trusts and the Pinnacle West retirement funds have relatively small investments in some of the troubled entities identified in your letter, as likely do most if not all large investment funds in this country.

[3] As the Commission is aware, APS absorbs 10% of higher fuel costs, and a portion of outage costs are embedded in the base fuel cost. In addition, a small amount is allocated to wholesale customers. Thus, the total cost of the outages was $4.4 million.

anticipated EFOR based primarily on past operations. This is merely an acknowledgement that all machines, no matter how well designed, constructed, operated, and maintained, will sometimes fail. Electric generators are no exception to that rule.

To date this year, the overall Palo Verde capacity factor has been 98% (excluding refueling outages). This past summer, Palo Verde set an all-time record for generation.

Throughout both outage events, Palo Verde staff demonstrated their safety-first focus by using effective problem identification and resolution behaviors, took proper action during troubleshooting (including developing contingency plans) and work planning. They executed all needed repairs with a focus on human performance. The NRC was kept fully informed throughout these outages and monitored Palo Verde's decision-making process and the actions taken. APS does not believe these outages have had any negative impact on APS's substantial progress in resolving the NRC's Confirmatory Action Letter.

Sincerely,

Thomas L. Mumaw

Thomas L. Mumaw

Attorney for Arizona Public Service Company

Attachments

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William A. Mundell
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Gary Pierce
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This 17th day of October 2008 to:

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Appendix A

ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Commissioner

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October 8, 2008

Mr. Don Brandt
President and CEO
Arizona Public Service
400 No. Fifth Street
M.S. 9042
Phoenix, AZ 85004

Re: Impact of recent financial crisis on APS' access to commercial paper markets and ability to finance capital projects; forced cancellation of GeoSmart Solar Loan Program; transactions with investment banks; exposure to auction rate securities; status of outages at Palo Verde Nuclear Generating Station's Unit 3.

Dear Mr. Brandt:

As you know, the recent upheaval in America's financial markets has had an unsettling effect on our national and local economies. It has also had serious consequences for individuals and companies who need to access financing, as credit tightens and capital markets become less fluid.

In recognition of the current environment, I write to request that you provide the Commission with information regarding whether the unfolding events on Wall Street have had an impact on Arizona Public Service Company ("APS"), with a particular focus on several areas.

First, please tell the Commission whether APS has experienced difficulty gaining access to short or long term debt markets. In particular, have you seen a decline in the Company's ability to issue commercial paper, a practice that has become common among large utilities seeking to make payments for short term capital expenditures and operating expenses. If so, please describe the ways in which you have responded to this deficiency in order to meet the Company's capital needs. Have you experienced additional expenses associated with accessing these markets? What is the short-term and long-term impact to APS' planned capital projects?

Second, APS recently reported to my office that it was forced to scuttle its GeoSmart Solar Financing Program – the program by which APS was offering loans to customers wishing to install solar panels who could not afford to do so solely using rebates – because General Electric pulled its funding due to the credit crisis. Please detail the circumstances surrounding this program suspension and whether you believe APS will be able to re-start the program in the future. Please also inform the Commission whether any other renewable energy or other capital expenditure programs have been threatened or come under pressure as a result of the tightened credit markets, and the Company's strategy for addressing these pressures.

Third, please tell the Commission whether APS engaged in any significant financial transactions with Lehman Brothers, American International Group, Bear Stearns, or any other investment firm that has been the subject of recent bankruptcies or governmental takeovers. If so, please detail those transactions, and to what extent they have impacted the Company.

Fourth, it is my understanding that APS has had some exposure to auction rate securities. As you know, the auction rate securities market recently collapsed. Please describe the Company's auction rate securities holdings, what worth those securities now have, and what the Company intends to do with those securities in order to minimize any losses associated with them.

Finally, as you know, Palo Verde Nuclear Generating Station's ("PVNGS") Unit Three was down from September 27th to October 1st – making for a second outage in less than a month. Please tell the Commission how these Unit Three outages will impact the Company's efforts to resolve PVNGS' Category Four status with the Nuclear Regulatory Commission, as well as the estimated replacement costs that have been passed through the Company's Purchased Power and Fuel Adjustment Clause as a result of these outages.

Thank you for your attention to these questions.

Sincerely,

Kris Mayes
Commissioner

Cc: Chairman Mike Gleason
Commissioner William A. Mundell
Commissioner Jeff Hatch-Miller
Commissioner Gary Pierce
Ernest Johnson
Janice Alward
Brian McNeil
Rebecca Wilder

Appendix B

Docket No. UE-246
Exhibit PAC/302
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct, October 3, 2011

March 2012

Exhibit PAC/302
Williams/1

October 3, 2011

PacifiCorp

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Table Of Contents

PacifiCorp

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Market and regulatory diversity is afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The recent approval of a fuel and purchased power adjuster in Utah is a positive development because the state is the company's largest market and will limit the amount that the utility will have to absorb if purchased fuel and power costs exceed levels authorized in electric rates;
- Dependence on purchased power has decreased; and
- A settlement reached in February 2010 regarding the contentious Klamath hydro relicensing case protects the company from any financial consequences if the project is decommissioned, which will not occur before 2020.

Weaknesses:

- Despite the company's practice of filing nearly annual rate cases, regulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and cash flow metrics remain just adequate to support the rating, although adjusted leverage has improved since MidAmerican Energy Holdings Co. acquired the utility in 2006;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's large capital investment program amid sluggish economic indicators; and
- Retail electric sales growth has stalled in the portions of the Pacific Northwest that PacifiCorp serves, which, if it becomes a medium- to long-term trend, could lower profitability and put additional pressure on retail electric rates.

Rationale

The 'A-' corporate credit rating (CCR) on PacifiCorp reflects what Standard & Poor's Ratings Services views as a significant financial profile and is supported by PacifiCorp's modest use of leverage to finance a large capital program and parent MidAmerican Energy Holdings Co.'s (MEHC; BBB+/Stable) willingness to deploy equity into PacifiCorp as needed to support the company's capital structure as it expands its rate base. Since acquiring the company in 2006, MEHC has provided $1.06 billion in equity support for the utility's capital needs.

PacifiCorp's excellent business profile benefits from the geographical, market, and regulatory diversity provided by its six-state service territory. PacifiCorp provides power to retail customers under the name Rocky Mountain Power in Utah, Wyoming, and Idaho, and as Pacific Power in Oregon, Washington, and California. Utah and Oregon are

the most important markets for the company, providing around 42% and 24% of annual retail sales, respectively, as of year-end 2010.

Since being acquired in 2006 by MEHC, the electric utility has made modest strides in improving key business and regulatory aspects of the utility that serves more than 1.7 million retail electric customers. Despite sluggish economic recovery in the company's Pacific Northwest territory, its western states, especially Utah, continue to exhibit some growth. PacifiCorp has been able to eke out rate increases that are in line with our expectations, and the utility was recently granted a fuel and purchased power adjuster in Utah. Despite its weak design (the utility may collect only 70% of any difference between actual and budgeted costs) and its pilot status (it will sunset in four years), we view the Utah adjuster as a step forward for credit quality because it mitigates a key business risk for electric utilities, the vast majority of which were afforded such mechanisms beginning shortly after the western energy crisis in 2001 and 2002. About 90% of PacifiCorp's retail electric sales are now covered by some type of fuel adjusters. (None exist in Washington state.) The company is building an additional baseload natural-gas–fired plant and in 2010 relied on natural gas for 12% of energy supplies.

The company's deferred tax balances are lifting cash flows due to an extension of bonus depreciation, and credit metrics this year are likely to exceed our expectations for this reason. For the 12 months ended June 30, adjusted funds from operations (FFO) to total debt and FFO interest coverage were 24.3% and 5.4x, respectively. Beneath this benefit, operating income and EBITDA in the first half of 2011 are approximately flat relative to the prior-year period, but a $117 million (7%) electric rate increase approved in Utah and a $62 million (11%) increase in Wyoming, both effective at the end of September, should nudge earnings metrics up in the fourth quarter. Adjusted debt to total capitalization was 52.4% as of June 30, an increase from 50.1% at year-end 2010. The leverage uptick is due to a $400 million May debt issuance and a common stock distribution of $550 million to its parent, which reduced shareholder equity.

The cash credit metrics we expect the company to achieve after this year are just adequate, in our view, to support the ratings, providing little cushion for the company to deviate. For 2012 we project adjusted FFO to total debt in the range of 20%, FFO interest coverage of 4.6x, and debt to total capitalization of around 51%. These expectations reflect our view that the company's earned return on equity (ROE) will be in line with past performance and that electric sales will grow 1.5% on average.

A key ongoing challenge for PacifiCorp is whether it will be able to achieve rate relief at levels necessary to sustain the company's capital investment program. The program has been at high levels throughout the recession and will remain so in the next few years, despite the dimming prospects for economic recovery. MEHC has been consistent in its investment thesis for the company, seeking to deploy capital in the electric utility in exchange for an opportunity to earn its authorized return, which varies by state but is in the area of 10%. Since acquisition, MEHC has spent an average of $1.7 billion per year on capital investment, providing equity investments in PacifiCorp totaling more than $1 billion to maintain a balanced capital structure. We expect PacifiCorp to spend $1.6 billion this year (it had spent $712 million as of June 30), and it is budgeting $1.8 billion for 2012 and $1.7 billion in 2013, according to its 10-K filing. This level of spending will continue to require regular retail electric rate increases in all of PacifiCorp's markets over the next three years. This begs the issue of whether rate case fatigue will set in, creating regulator or ratepayer resistance to further increases. Through the first half of this year, retail electric sales were up 2%, but this is largely a result of Rocky Mountain Power, which accounts for about two-thirds of PacifiCorp's total retail sales and includes Salt Lake City, Utah. Pacific Power, which accounts for the balance of utility electric sales, has seen load growth stagnate. Further weakening of the economy, which is increasingly appearing to be likely, could

increase revenue requirements as the company seeks to spread fixed costs over smaller sales volumes.

PacifiCorp's authorized ROE varies by state but is around 10%. (In its most recent rate case in Utah, its authorized ROE was lowered from 10.6% to 10.0%). Based on our calculations, PacifiCorp's actual ROE has been in the range of 8.1% to 8.5% since 2007. Achieving stronger ROE may prove difficult given the level of capital the company is deploying, because regulatory lag is inherent given its high spending.

Among the larger projects PacifiCorp is pursuing is the buildout of Lakeside 2, a 647-megawatt combined-cycle gas plant in Utah expected in service in 2014. Coal plant environmental upgrades are also planned, as is a major transmission investment, including the multi-segment transmission line, the Energy Gateway Transmission project (EGTE). The EGTE is a multiyear, $6 billion-plus transmission project that will add approximately 2,000 miles of new transmission line across the West. The project is being completed in phases, with the last phase expected to go into service in 2019. Construction of the first, 135-mile segment, running from the Populus substation in southern Idaho to the Terminal substation near Salt Lake City, was completed December 2010 at a cost of $830 million.

Some 89% of the total costs are being recovered in current rates in the various states. But in its December 2010 rate case, the Idaho Public Utilities Commission (IPUC) disallowed recovery in current rates of 27% of its 6% share of the investment (or about 1.62% or $13 million). In December 2010 the IPUC ordered the company to carry the asset as plant held for future use. The company has filed an appeal of the IPUC's order with the Idaho Supreme Court. The IPUC's ruling is an unfavorable precedent. Given that no transmission projects have received explicit pre-approval in any of the jurisdictions PacifiCorp serves, the onus is on the company to demonstrate the value of its transmission investment to regulators, largely on an ex post basis. The next segment to be completed is Mona-to-Oquirrh, a 100-mile segment within Utah expected in service summer 2013 at a cost of $440 million. Construction is underway.

PacifiCorp is wholly owned by MEHC and has put in ring-fencing provisions that allow us to rate PacifiCorp above the 'BBB+' CCR on MEHC, if its stand-alone credit metrics and business profile risks warrant. In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Negative/A-1+). PacifiCorp benefits from regulatory insulation from its parent. Our criteria provide that the PacifiCorp CCR can be no more than three notches above the MEHC consolidated credit rating. The parent and subsidiary are currently rated within one notch of one another.

Liquidity

On a stand-alone basis (i.e., unenhanced by the existing $2 billion contingent equity agreement available to MEHC to support any of its regulated subsidiaries, including PacifiCorp) we view PacifiCorp's liquidity as adequate under our corporate liquidity methodology. This methodology categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). Projected sources of liquidity, which consist of operating cash flow and available bank lines, exceed projected uses, including capital expenditures, debt maturities, and common dividends, by more than 1.2x. Under our criteria, we exclude as sources of liquidity any facilities expiring within one year of the liquidity assessment date.

The utility maintains unsecured credit facilities that totaled $1.395 billion as of June 30. Of this total, $304 million of liquidity is reserved for letters of credit to support tax exempt bond obligations, reducing available borrowings to $1.091 billion. (In July 2011, as scheduled, $40 million in bank commitments under one of its facilities expires; current credit lines total $1.355 billion.) There are no rating triggers on the credit lines. One facility, for $635 million, expires in October 2012. (We have included this facility as source of liquidity based on this assessment

completed in late September.) The other credit facility is sized at $720 million and will decline to $630 million in July 2012 and expire in 2013. Regulatory restrictions limit PacifiCorp's short-term debt to $1.5 billion.

PacifiCorp's liquidity is indirectly supported by Berkshire Hathaway, which has in place through February 2014 a $2 billion equity commitment agreement between itself and MEHC under which MEHC can unilaterally call upon Berkshire Hathaway to support either its parent debt repayment or the capital needs of its regulated subsidiaries, including MidAmerican Energy Co. Nevertheless, we assess PacifiCorp's liquidity on a stand-alone basis because the utility has no authority to cause MEHC to make an equity contribution from Berkshire Hathaway through an MEHC board request. Although MEHC would typically have strong incentives to support the utility by tapping the Berkshire Hathaway contingent equity, MEHC would be expected to do so only if doing so were in the parent's best economic interests. Because Berkshire has up to 180 days to fund an equity request, we also do not count on the agreement to provide PacifiCorp with immediate cash. For these reasons, we consider the equity agreement a qualitative enhancement to liquidity but continue to calculate the utility's liquidity metrics on a stand-alone basis.

Recovery analysis

We rate PacifiCorp's first mortgage bonds (FMB) 'A', a notch higher than the 'A-' issuer credit rating, and have assigned them a recovery rating of '1+'. We assign recovery ratings to FMBs issued by investment-grade U.S. utilities, and this can result in issue ratings that are higher than the utility CCR depending on the CCR category and the extent of the collateral coverage. We base our investment-grade FMB recovery methodology on the ample historical record of nearly 100% recovery for secured-bond holders in utility bankruptcies and on our view that the factors that supported those recoveries (the limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist. Under our notching criteria, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, and the regulatory limitations on bond issuance. FMB ratings can exceed a utility CCR by as many as one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories. (See "Changes To Collateral Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds," published Sept. 6, 2007, on RatingsDirect on the Global Credit Portal.)

PacifiCorp's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral, in combination with regulatory covenants that restrict borrowing that were entered into as a condition of MEHC's acquisition of PacifiCorp in 2006, provides coverage of more than 1.5x, supporting a recovery rating of '1+' and an issue rating one notch above the CCR.

Outlook

The stable outlook incorporates our anticipation that PacifiCorp will be able to perform to forecast, achieving adjusted FFO to debt in the area of 20%, FFO interest coverage of at least 4.5x and adjusted debt to total capitalization of around 50%. We view these cash flow levels as merely adequate to maintain the ratings, and could lower the ratings if FFO to total debt drops to less than 18% on a sustained basis, with FFO interest coverage or adjusted leverage creeping above 52% over our outlook horizon. We do not expect upward ratings momentum for the utility, given its heavy investment program.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of Sept. 22, 2010	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Watch Neg/A-2
	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,404.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
Funds from operations (FFO)	1,342.3	326.5	3,030.0
Capital expenditures	1,850.2	511.4	3,437.7
Cash and short-term investments	134.7	38.0	175.7
Debt	6,641.7	1,875.2	12,662.8
Preferred stock	34.2	0.0	258.0
Equity	5,926.2	1,404.3	10,032.3
Debt and equity	12,567.9	3,279.5	22,695.2
Adjusted ratios			
EBIT interest coverage (x)	2.8	2.2	2.9
FFO int. cov. (x)	4.3	3.5	4.1
FFO/debt (%)	20.2	17.4	23.9
Discretionary cash flow/debt (%)	(10.5)	(14.4)	(14.1)
Net cash flow/capital expenditure (%)	72.5	51.5	71.2
Total debt/debt plus equity (%)	52.8	57.2	55.8
Return on common equity (%)	7.2	6.3	11.1
Common dividend payout ratio (unadj.; %)	2.7	59.6	49.6

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Dec. 31--				
	2009	2008	2007	2006	2006
Rating history	A-/Stable/A-2	A-/Watch Neg/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,896.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
Capital expenditures	2,297.1	1,757.0	1,496.4	1,375.0	1,030.5
Cash and short-term investments	117.0	59.0	228.0	59.0	119.6
Debt	7,415.8	6,635.9	5,873.5	5,473.6	5,185.3
Preferred stock	20.5	41.0	41.0	41.3	41.3
Equity	6,711.5	5,987.0	5,080.0	4,426.8	3,750.7
Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8

Table 2.

PacifiCorp -- Financial Summary* (cont.)					
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)
Net cash flow/capital expenditure (%)	76.6	72.3	66.3	66.1	66.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.; %)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2009--									
PacifiCorp reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	6,416.0	6,732.0	1,609.0	1,609.0	1,060.0	359.0	1,500.0	1,500.0	2.0	2,328.0
Standard & Poor's adjustments										
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--	4.1
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--	(35.0)
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	78.2	43.1	260.1	(1.0)	(30.9)

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	7,415.8	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0	2,297.1

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of October 3, 2011)*

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (2 Issues)	BBB
Senior Secured (54 Issues)	A
Senior Unsecured (2 Issues)	A-
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (8 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2

Ratings Detail (As Of October 3, 2011)* **(cont.)**

MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (1 Issue)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (1 Issue)	BBB-/Stable
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (2 Issues)	A-
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Docket No. UE-246
Exhibit PAC/303
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct, July 29, 2011

March 2012

PacifiCorp

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PacifiCorp

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Market and regulatory diversity is afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The recent approval of a fuel and purchased power adjuster in Utah is a positive development because the state is the company's largest market and will limit the amount that the utility will have to absorb if purchased fuel and power costs exceed amounts reflected in rates; ;
- Dependence on purchased power has decreased; and
- A settlement reached in February 2010 regarding the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, which will not occur before 2020.

Weaknesses:

- Despite the company's practice of filing annual rate cases in the states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. acquired the utility in 2006, cash flow metrics remain just adequate to support the rating;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling-back of capital plans; and
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility, which the company is managing by seeking fuel and purchased power adjusters.

Rationale

The 'A-' corporate credit rating on PacifiCorp reflects what Standard & Poor's Ratings Services views as a "significant" financial profile and is supported by its modest use of leverage to finance a large capital program and MidAmerican Energy Holdings Co.'s (MEHC; BBB+/Stable) willingness to deploy equity into PacifiCorp as needed to support the company's capital structure as it expands its rate base. The electric utility's excellent business profile benefits from the geographical, market, and regulatory diversity provided by its six-state service territory. PacifiCorp provides power to retail customers under the name Rocky Mountain Power in Utah, Wyoming, and Idaho, and as Pacific Power in Oregon, Washington, and California. Utah and Oregon are the most important regions for the company, providing around 42% and 24% of annual retail sales, respectively, as of year-end 2010.

PacifiCorp's financial performance has held steady throughout the recession. The utility's credit metrics would have deteriorated slightly in 2010 but for the benefits of bonus depreciation, which added $700 million in deferred taxes to the company's $1.4 billion in cash flow. Beneath this benefit, authorized rate increases in Utah, Wyoming, and Idaho supported a 1% increase in gross margin, but operating revenues and operating income for the year were both down slightly, by 0.6% and 2.2%, respectively, largely due to lower wholesale volumes and margins and weaker growth in retail sales. In 2010, funds from operations (FFO) to total debt was 25%, FFO interest coverage was 5.4x, and leverage was 50%.

A key consideration in 2011 is whether a resurgence in sales will occur to rekindle modest growth. Although overall 2010 retail sales revenues increased by about 1%, this growth has been led by Rocky Mountain Power (which accounted for roughly two-thirds of retail sales). Utah's population and economic growth continue to outpace the nation's. Declines have been meaningful for Pacific Power, with retail sales falling a cumulative 4.4% over 2009 and 2010 on a weather-adjusted basis. Industrial load loss has been especially significant in Oregon, but may have bottomed.

Our expectation in 2011 is that the sales growth for Rocky Mountain Power market will continue to improve. A slower, more hesitant recovery appears likely for Pacific Power sales, and we expect retail sales through 2012 there to remain below levels seen when MEHC acquired PacifiCorp in March 2006. As a result, growth led by Rocky Mountain should produce financial metrics in line with past performance, with FFO to total debt in the high teens and FFO interest coverage of 4.0x to 4.5x. These expectations do not reflect any additional benefits for bonus depreciation, which would slightly improve results. Leverage is not forecast to change from its current level of 50% of total capitalization.

PacifiCorp is wholly owned by MEHC. In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+). MEHC's stated strategy when it acquired PacifiCorp was to invest significant capital to upgrade its infrastructure. Its largest project is Energy Gateway, a new, 2,000-mile high-voltage transmission line that is being constructed in segments. In the company's 2010 10-K filing, it disclosed that it expects to spend $6 billion for the project, with about $1 billion of that amount to be spent over the next three years. MEHC has demonstrated a willingness to support the utility's capital program, providing PacifiCorp with $1.1 billion equity contributions since 2006. This has allowed the company to grow without straining borrowings.

The company's consolidated earned return on equity, at 8.2%, is below authorized levels, which vary between states but are in the area of 10%. For the company's investment strategy to succeed, PacifiCorp's customers will be required to shoulder nearly annual increases in electric rates at a time when utility regulators around the U.S. are especially focused on holding down costs. A February 2011 ruling in Idaho, which is a small portion of PacifiCorp's franchise, reduced the company's request by $11 million to $13.8 million, noting that difficult economic conditions challenge customer ability to pay rate increases. Two large rate cases are in process in Utah and Wyoming. It has requested a $232 million increase in Utah effective September 2011 that would increase rates an average of 14% if approved as filed. Also pending is an $80 million rate case in Wyoming, with rates also requested to go into effect in September.

Liquidity

On a stand-alone basis (i.e., unenhanced by the existing contingent equity agreement available to MEHC to support any of its regulated subsidiaries, including PacifiCorp) we view the company's liquidity as "adequate" under our corporate liquidity methodology. This methodology categorizes liquidity in five standard descriptors (exceptional,

strong, adequate, less than adequate, and weak). Projected sources of liquidity, which consist of operating cash flow and available bank lines, exceed projected uses, the company's committed capital expenditures, debt maturities, and common dividends by more than 1.2x over the next 12 months. Under our criteria, we exclude as sources of liquidity any facilities expiring within one year of the liquidity assessment date. This assessment does not consider MEHC draws on its contingent equity that it could make to support PacifiCorp's projected capital requirements and debt maturities over the next two years.

As of March 31, 2011, cash and cash equivalents totaled $39 million. The utility maintains unsecured credit facilities totaling nearly $1.4 billion that mature 2012-2013. (A $760 million facility decreased to $720 million this month and is reflected in our liquidity calculations.) As of March 31, 2011, the company had additional borrowing capacity of $821 million, because of $270 million of borrowings under the facility and $304 million of liquidity reserved to support variable-rate tax-exempt bond obligations and letters of credit. There are no rating triggers on the credit lines. PacifiCorp's next substantial long-term debt maturities are $587 million due in 2011 and $261 million in 2013.

Recovery analysis

We rate PacifiCorp's first mortgage bonds (FMB) 'A', a notch higher than the 'A-' issuer credit rating, and assign them a recovery rating of '1+.' We assign recovery ratings to first mortgage bonds (FMBs) issued by investment-grade U.S. utilities, which can result in higher issue ratings than a utility's corporate credit rating (CCR) depending on the CCR category and the extent of the collateral coverage. We base our investment-grade FMB recovery methodology on the ample historical record of nearly 100% recovery for secured bondholders in utility bankruptcies and on our view that the factors that supported those recoveries (limited size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist in the future. Under our notching criteria, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, and the regulatory limitations on bond issuance. FMB ratings can exceed a utility's CCR by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories. (See "Changes To Collateral Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds," published Sept. 6, 2007, on RatingsDirect on the Global Credit Portal.)

PacifiCorp's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral, in combination with regulatory covenants that restrict borrowing that were entered into as a condition of MEHC's acquisition of PacifiCorp in 2006, provides coverage of more than 1.5x, supporting a recovery rating of '1+' and an issue rating one notch above the CCR.

Outlook

The stable outlook on the PacifiCorp ratings incorporates our expectation that MEHC will continue to support the utility by contributing sufficient equity to manage its debt levels to 50% of total capitalization on a fully adjusted basis. We expect FFO to total debt and FFO interest coverage will be in the high teens and the 4.0x-4.5x range, respectively. We view these cash flow levels as minimum levels to maintain the rating. As with 2010, credit metrics could exceed these levels this year, depending on whether the company is able to utilize bonus depreciation benefits. We do not expect upward ratings momentum for the utility, given its heavy investment program. PacifiCorp benefits from regulatory insulation from its parent. Our criteria provide that the PacifiCorp corporate credit rating can be no

more than three notches above the MEHC consolidated credit rating. The companies are a notch apart. We do not see significant risks that the utility rating will fall as a result of adverse rating changes on MEHC, which also has a stable rating outlook.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of July 28, 2011	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Negative/A-2
	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,404.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
Funds from operations (FFO)	1,342.3	326.5	3,030.0
Capital expenditures	1,850.2	511.4	3,437.7
Cash and short-term investments	134.7	38.0	175.7
Debt	6,641.7	1,875.2	12,662.8
Preferred stock	34.2	0.0	258.0
Equity	5,926.2	1,404.3	10,032.3
Debt and equity	12,567.9	3,279.5	22,695.2
Adjusted ratios			
EBIT interest coverage (x)	2.8	2.2	2.9
FFO int. cov. (x)	4.3	3.5	4.1
FFO/debt (%)	20.2	17.4	23.9
Discretionary cash flow/debt (%)	(10.5)	(14.4)	(14.1)
Net cash flow/capex (%)	72.5	51.5	71.2
Total debt/debt plus equity (%)	52.8	57.2	55.8
Return on common equity (%)	7.2	6.3	11.1
Common dividend payout ratio (unadj.; %)	2.7	59.6	49.6

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Dec. 31--				
	2009	2008	2007	2006	2006
Rating history	A-/Stable/A-2	A-/Watch Neg/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,896.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
Capital expenditures	2,297.1	1,757.0	1,496.4	1,375.0	1,030.5
Cash and short-term investments	117.0	59.0	228.0	59.0	119.6
Debt	7,415.8	6,635.9	5,873.5	5,473.6	5,185.3
Preferred stock	20.5	41.0	41.0	41.3	41.3
Equity	6,711.5	5,987.0	5,080.0	4,426.8	3,750.7

Table 2.

PacifiCorp -- Financial Summary* (cont.)					
Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)
Net cash flow/capex (%)	76.6	72.3	66.3	66.1	66.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.; %)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2009--								
PacifiCorp reported amounts									
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**
Reported	6,416.0	6,732.0	1,609.0	1,609.0	1,060.0	359.0	1,500.0	1,500.0	2.0
Standard & Poor's adjustments									
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	78.2	43.1	260.1	(1.0)

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid
Adjusted	7,415.8	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of July 29, 2011)*

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (2 Issues)	BBB
Senior Secured (60 Issues)	A
Senior Unsecured (2 Issues)	A-
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2

Ratings Detail (As Of July 29, 2011)*(cont.)

MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (1 Issue)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (1 Issue)	BBB-/Stable
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (2 Issues)	A-
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Docket No. UE-246
Exhibit PAC/304
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct, April 28, 2011

March 2012

STANDARD &POOR'S

Global Credit Portal
RatingsDirect®

April 28, 2011

Summary:
PacifiCorp

Primary Credit Analyst:
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Summary:
PacifiCorp

Credit Rating: A-/Stable/A-2

Rationale

The 'A-' corporate credit ratings on PacifiCorp reflect what Standard & Poor's Ratings Services views as a "significant" financial profile and is supported by its modest use of leverage to finance a large capital program and adequate cash flow metrics. Its "excellent" business profile benefits from the geographical, market, and regulatory diversity provided by its six-state service territory. PacifiCorp is an electric utility that serves customers under the name Rocky Mountain Power in Utah, Wyoming, and Idaho, and as Pacific Power in Oregon, Washington, and California. Utah and Oregon are the most important regions for the company, providing around 42% and 24% of annual retail sales, respectively.

PacifiCorp's financial performance has held steady throughout the recession. The utility's credit metrics would have deteriorated slightly in 2010 but for the benefits of bonus depreciation, which added $700 million in deferred taxes to the company's $1.4 billion in cash flow. Beneath this benefit, authorized rate increases in Utah, Wyoming, and Idaho supported a 1% increase in gross margin, but operating revenues and operating income for the year were both down slightly, by 0.6% and 2.2%, respectively, largely due to lower wholesale volumes and margins and weaker growth in retail sales. In 2010, funds from operations (FFO) to total debt was 25%, FFO interest coverage was 5.4x, and leverage was 50%.

A key consideration in 2011 is whether resurgence in sales will occur to rekindle modest growth. Although overall 2010 retail sales revenues increased by about 1%, this growth has been led by Rocky Mountain Power (which accounted for roughly two-thirds of retail sales). Utah's population and economic growth continue to outpace the nation's. Declines have been meaningful for Pacific Power, with retail sales falling a cumulative 4.4% over 2009 and 2010 on a weather-adjusted basis. Industrial load loss has been especially significant in Oregon, but may have bottomed.

Our expectation in 2011 is that the sales growth for Rocky Mountain Power market will continue to improve. A slower, more hesitant recovery appears likely for Pacific Power sales, and we expect retail sales through 2012 there to remain below levels seen when MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable) acquired PacifiCorp in March 2006. As a result, growth led by Rocky Mountain should produce financial metrics in line with past performance, with FFO to total debt in the high teens and FFO interest coverage of 4.0x-4.5x. These expectations do not reflect any additional benefits for bonus depreciation. Leverage is not forecast to change from its current level of 50% of total capitalization.

PacifiCorp is wholly owned by MEHC. In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+). MEHC's stated strategy when it acquired PacifiCorp was to invest significant capital to upgrade its infrastructure. Its largest project is Energy Gateway, a new, 2,000-mile high-voltage transmission line that is being constructed in segments. In the company's 2010 10-K filing, it disclosed that it expects to spend $6 billion for the project, with about $1 billion of that amount to be spent over the next three years. MEHC has demonstrated a willingness to support the utility's capital program, providing PacifiCorp with $1.1 billion equity

contributions since 2006. This has allowed the company to grow without straining borrowings.

The company's consolidated earned return on equity, at 8.2%, is below authorized levels, which vary but are in the area of 10%. For the company's investment strategy to succeed, PacifiCorp's customers will be required to shoulder nearly annual increases in electric rates at a time when utility regulators around the U.S. are especially focused on holding down costs. A March ruling in Idaho, which is a small portion of PacifiCorp's franchise, reduced the company's request by $11 million to $13.8 million, noting that difficult economic conditions challenge customer ability to pay rate increases. Two large rate cases are in process in Utah and Wyoming. It has requested a $232 million increase in Utah effective September 2011 that would increase rates an average of 14% if approved as filed. Also pending is a $98 million rate case in Wyoming, representing a 17% increase, with rates also requested to go into effect in September.

Liquidity

On a stand-alone basis (i.e., unenhanced by the existing contingent equity agreement available to MEHC to support any of its regulated subsidiaries, including PacifiCorp) we view the company's liquidity as "adequate" under our corporate liquidity methodology. This methodology categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). Projected sources of liquidity, which consist of operating cash flow and available bank lines, exceed projected uses, the company's committed capital expenditures, debt maturities, and common dividends by more than 1.2x over the next 12 months. Under our criteria, we exclude as sources of liquidity any facilities expiring within one year of the liquidity assessment date. This assessment does not consider MEHC draws on its contingent equity that it could make to support PacifiCorp's projected capital requirements and debt maturities over the next two years.

As of Dec. 31, 2010, cash and cash equivalents totaled $31 million. The utility maintains unsecured credit facilities totaling nearly $1.4 billion that mature 2012-2013. (A $760 million facility decreases to $720 million in July 2011. This reduction is reflected in our liquidity calculations.) As of Dec. 31, 2010, the company had additional borrowing capacity of $1.1 billion, because of $36 million of borrowings under the facility and $304 million of liquidity reserved to support variable-rate tax-exempt bond obligations and letters of credit. There are no rating triggers on the credit lines. PacifiCorp's next substantial long-term debt maturities are $587 million due in 2011 and $261 million in 2013.

Outlook

The stable outlook on the PacifiCorp ratings incorporates our expectation that MEHC will continue to support the utility by contributing sufficient equity to manage its debt levels to 50% of total capitalization on a fully adjusted basis. We expect FFO to total debt and FFO interest coverage will be in the high teens and the 4.0x-4.5x range, respectively. We view these cash flow levels as minimum levels to maintain the rating. As in 2010, credit metrics could exceed these levels this year, depending on whether the company is able to utilize bonus depreciation benefits. We do not expect upward ratings momentum for the utility, given its heavy investment program. PacifiCorp benefits from regulatory insulation from its parent. Our criteria provide that the PacifiCorp corporate credit rating can be no more than three notches above the MEHC consolidated credit rating. The companies are a notch apart. We do not see significant risks that the utility rating will fall as a result of adverse rating changes on MEHC, which also has a stable rating outlook.

Docket No. UE-246
Exhibit PAC/305
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct, October 7, 2010

March 2012

PacifiCorp

Primary Credit Analyst:
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Secondary Contact:
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PacifiCorp

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Market and regulatory diversity is afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The company has made progress in putting into place fuel and purchased power adjusters in the six states it serves (an adjuster was put into effect in Idaho in 2009, and one is pending in PacifiCorp's largest market, Utah);
- The completion of new natural gas plants, along with wind farm investment, is reducing the company's reliance on purchased power; and
- A settlement reached in February 2010 regarding the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, which will not occur before 2020.

Weaknesses:

- Despite the company's policy of filing near annual rate cases in the states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. acquired the utility in 2006, cash flow metrics remain just adequate to support the rating;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling-back of capital plans; and
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility.

Rationale

The 'A-' corporate credit rating on PacifiCorp (PPW) reflects its "excellent" business risk profile, evidenced by a diverse and growing service territory, and "significant" financial risk profile. PPW has made modest strides in improving regulatory outcomes which should put the company on a path to achieving cash flow coverage metrics that comfortably support the rating. The company has made progress in increasing core earnings amid a recession and a period of heavy capital spending for the company. The company has achieved this by focusing on strengthening the regulatory mechanisms that are in place in the six states it serves and working to minimize regulatory lag by filing for nearly annual rate relief in almost all states it serves.

In 2010 PPW has continued to receive revenue increases through rate case outcomes, fuel adjustments and other recovery mechanisms. Highlights of key regulatory rulings that have provided increased revenues to the company in

2010 include a Utah general rate increase beginning in February 2010 for $32 million (or a 2% increase), and a $31 million increase for the recovery of two major projects approved in June. Also in Utah, the company's largest market, the company has received approval to establish an energy cost adjustment mechanism, with the mechanism design under consideration before the Utah Public Service Commission. In January 2010, the Oregon Public Utility Commission (OPUC) approved a stipulation in the company's 2009 general rate case increasing base rates by $42 million, effective Feb. 2, 2010. In January 2010, PPW received a rate increase of $14 million, or 5%, in Washington. In March 2010, PPW filed a new general rate case in Oregon requesting an increase in the rates by $131 million, or 13% increase, and in July reached a multiparty stipulation for an increase of $85 million, or 8%. If approved by the OPUC, the rates will be effective Jan. 1, 2011.

As with many electric utilities, the company's 2008 and 2009 credit metrics have been buoyed by deferred tax increases, which boosted funds from operations metrics. But these effects notwithstanding, the company's funds from operations (FFO) to total debt has been consistently in the high teens, slightly below our expected credit metrics for the rating, since it was acquired by MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). Leverage has also been somewhat high for the rating at 53% at year-end 2009. However, we expect that credit metrics will improve in the coming years, producing FFO to total debt in the area of 20%, FFO interest coverage of 20% or better and in the range of 4.0x-4.5x, and leverage of about 50%. (We would note that PPW has, over the last three years, produced FFO to total debt of more than 20%, but this is due to benefits of deferred taxes.)

PPW serves 1.7 million customers in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The company operates as Pacific Power in Oregon, Washington, and California, and as Rocky Mountain Power in Utah, Wyoming, and Idaho. The company's two largest markets, Utah and Oregon, accounted for about 67% of the company's retail electric sales in 2009, with Wyoming and Washington at 25%, and the balance being sold to customers in Idaho and California. As of Dec. 31, 2009, the utility's long-term debt was $6.4 billion.

PPW completed $2.3 billion in capital expenditures in 2009, up from $1.8 billion in 2008. The company projects that it will spend $4.6 billion in 2010-2012, excluding non-cash allowance for funds used during construction. The largest component of PPW's capital program is the construction of the Gateway transmission project, an estimated $4.6 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines being placed in service as early as 2010 and a tentative completion date of 2018. About 34% of the company's total capital budget over the next three years (2010-2012) is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

PPW is owned by MEHC. In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+). MEHC has demonstrated a willingness to deploy equity to support the utility's large capital program, providing the utility with $865 million in equity contributions since it purchased the company in March 2006. Although PPW is investing heavily in its system, we expect PPW distributions to MEHC to be minimal.

MEHC's credit profile is supported by Berkshire Hathaway, which has in place through February 2011 a $3.5 billion equity commitment agreement between itself and MEHC in which MEHC can unilaterally call upon Berkshire Hathaway to support either its debt repayment or the capital needs of its regulated subsidiaries, including PPW. In March 2010, the agreement was extended through February 2014 at a lower level of $2 billion. We view

this agreement between PPW's parent and a 'AA+' rated entity as reducing the likelihood of a PPW default.

Nevertheless, we expect PPW to grow into a stand-alone credit profile consistent with the 'A-' rating on the company. We take this view because the utility has no right to cause MEHC to make an equity contribution, either from MEHC or via Berkshire Hathaway through an MEHC board request. Although MEHC would typically have strong incentives to support the utility by tapping the Berkshire Hathaway contingent equity, we would note that in a catastrophic utility event, MEHC would be expected to do so only if doing so were in the parent's best economic interests. Such a scenario is remote and would require an unprecedented event such as what occurred during the western energy crisis, when regulators refused to allow utilities to recover power procurement costs.

Short-term credit factors

On a stand-alone basis (i.e., unenhanced by the existing contingent equity agreement available to MEHC to support any of its regulated subsidiaries, including PPW) we view PPW's liquidity as "strong" under our corporate liquidity methodology. This methodology categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). Projected sources of liquidity, which consist of operating cash flow and available bank lines, exceed projected uses, the company's committed capital expenditures, debt maturities, and common dividends by about 1.5x. Under our criteria, we exclude as sources of liquidity any facilities expiring within one year of the liquidity assessment date. Presuming that MEHC draws on its contingent equity to support PPW's projected capital requirements and debt maturities over the next two years, liquidity would be bolstered to more than 2x, or "exceptional."

As of June 30, 2010, PPW's cash and cash equivalents totaled $110 million. The utility maintains unsecured credit facilities totaling nearly $1.4 billion that mature 2012-2013. As of June 30, 2010, PPW had additional borrowing capacity of $1.1 billion, because $304 million of liquidity is reserved to support variable-rate tax-exempt bond obligations and letters of credit. There are no rating triggers on the credit lines. PPW's next substantial long-term debt maturities are $600 million due in 2011 and $284 million in 2013.

Outlook

The stable outlook on the PPW ratings incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that fully adjusted debt to total capitalization is managed over the next few years to a level of closer to 50% and that FFO to total debt and FFO interest coverage will be in the area of 20% and the 4.0x-4.5x range, respectively. Given that PPW's financial risk profile is weak for the ratings, we do not expect near-term upward ratings momentum for the utility. PPW's regulatory and structural insulation shields the utility from MEHC credit deterioration, to an extent. Specifically, our criteria provide that the PPW corporate credit rating can be no more than three notches above the MEHC consolidated credit rating. The company is comfortably within this range, so we do not see significant risks that the utility rating will fall as a result of adverse rating changes on MEHC, which also has a stable rating outlook.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of Sept. 22, 2010	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Watch Neg/A-2

Table 1.

PacifiCorp -- Peer Comparison* (cont.)

	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,404.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
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Capital expenditures	1,850.2	511.4	3,437.7
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Debt	6,641.7	1,875.2	12,662.8
Preferred stock	34.2	0.0	258.0
Equity	5,926.2	1,404.3	10,032.3
Debt and equity	12,567.9	3,279.5	22,695.2
Adjusted ratios			
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FFO int. cov. (x)	4.3	3.5	4.1
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Discretionary cash flow/debt (%)	(10.5)	(14.4)	(14.1)
Net cash flow/capex (%)	72.5	51.5	71.2
Total debt/debt plus equity (%)	52.8	57.2	55.8
Return on common equity (%)	7.2	6.3	11.1
Common dividend payout ratio (unadj.) (%)	2.7	59.6	49.6

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Dec. 31--				
	2009	**2008**	**2007**	**2006**	**2006**
Rating history	A-/Stable/A-2	A-/Watch Neg/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,896.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
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Debt	7,415.8	6,635.9	5,873.5	5,473.6	5,185.3
Preferred stock	20.5	41.0	41.0	41.3	41.3
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Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)

Table 2.

PacifiCorp -- Financial Summary* (cont.)					
Net cash flow/capex (%)	76.6	72.3	66.3	66.1	66.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.) (%)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2009--									
PacifiCorp reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	6,416.0	6,732.0	1,609.0	1,609.0	1,060.0	359.0	1,500.0	1,500.0	2.0	2,328.0
Standard & Poor's adjustments										
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--	4.1
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--	(35.0)
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	78.2	43.1	260.1	(1.0)	(30.9)

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	7,415.8	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0	2,297.1

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of October 7, 2010)*

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB
Senior Secured (69 Issues)	A
Senior Unsecured (1 Issue)	A-
Senior Unsecured (2 Issues)	A/Developing
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
06-Mar-2006	A-/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
CE Casecnan Water and Energy Co. Inc.	
Senior Secured (1 Issue)	BB+/Stable
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+/Stable
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2

Ratings Detail (As Of October 7, 2010)* **(cont.)**

Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2
MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (2 Issues)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-/Stable
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (2 Issues)	BBB-/Stable
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (1 Issue)	A-
Senior Unsecured (1 Issue)	A-/Stable
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Docket No. UE-246
Exhibit PAC/306
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct April 30, 2010

March 2012

Exhibit PAC/306
Williams/1

April 30, 2010

PacifiCorp

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Secondary Credit Analyst:
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PacifiCorp

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Market and regulatory diversity afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The company has made progress in putting into place fuel and purchased power adjusters in the six states it serves (an adjuster was put into effect in Idaho in 2009, and one is pending in PacifiCorp's largest market, Utah);
- The completion of 1,068 megawatts of new natural gas plants, along with wind farm investment, is reducing the company's reliance on purchased power; and
- A tentative resolution in the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, as is now envisioned.

Weaknesses:

- 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 return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. (MEHC) acquired it in 2006, cash flow metrics remain weak;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling-back of capital plans;
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility.

Rationale

The 'A-' corporate credit rating (CCR) on PacifiCorp reflects its "excellent" business risk profile, evidenced by a diverse and growing service territory, and "aggressive" financial risk profile that reflects a large capital program and the need to shore up its cash flow metrics. While the ring-fenced utility's credit metrics are more consistent on a stand-alone basis with a 'BBB' category rating, Standard & Poor's Ratings Services expects that management will achieve cash flow metrics more consistent with an 'A' category rating over the next several years. PacifiCorp is owned by MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+), which at year-end 2009 had an 89.5% interest in MEHC on an undiluted basis. (MEHC's remaining common equity is owned by Walter Scott [9.7%] and President and Chief Executive Officer Greg Abel [0.8%]). MEHC has demonstrated a willingness to deploy equity to support the utility's large capital program, providing the utility with $865 million in equity contributions since it purchased

the company in March 2006.

MEHC's credit profile is supported by Berkshire, which has in place through February 2011 a $3.5 billion equity commitment agreement between itself and MEHC in which MEHC can unilaterally call upon Berkshire to support either its debt repayment or the capital needs of its regulated subsidiaries, including PacifiCorp. In March 2010, the agreement was amended to extend through February 2014 at a lower level of $2 billion. We view this agreement between PacifiCorp's parent and a 'AA+' rated entity as reducing the likelihood of a PacifiCorp default.

Nevertheless, we expect PacifiCorp to grow into a stand-alone credit profile consistent with the 'A-' rating on the company. We take this view because the utility has no right to cause MEHC to make an equity contribution, either from MEHC or via Berkshire through an MEHC board request. While MEHC would typically have strong incentives to support the utility by tapping the Berkshire contingent equity, we would note that in a catastrophic utility event, MEHC would be expected to do so only if doing so were in the economic best interests of the parent. Such a scenario is remote and would require an unprecedented event such as what occurred during the western energy crisis, when regulators refused to allow utilities to recover power procurement costs.

PacifiCorp serves 1.7 million customers in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The company operates as Pacific Power in Oregon, Washington, and California, and as Rocky Mountain Power in Utah, Wyoming, and Idaho. The company's two largest markets, Utah and Oregon, accounted for about 67% of the company's retail electric sales in 2009, with Wyoming and Washington at 25%, and the balance being sold to customers in Idaho and California. As of Dec. 31, 2009, the utility's long-term debt was $6.4 billion. Consolidated long-term debt at MEHC (which includes PacifiCorp's debt) was nearly $20 billion as of the same date.

Supportive rate case outcomes remain key to maintaining and improving upon the company's financial performance. When MEHC purchased PacifiCorp in 2006 from ScottishPower, the utility had consistently been unable to earn its authorized return on equity (ROE), which varies by jurisdiction but ranges from 10% to 10.6%. Management has focused on improving its returns, with some success. In 2009, our calculations suggest that the consolidated ROE for PacifiCorp was 8.5%. Regulatory lag remains an issue for the company, although the company is permitted under state regulation to use forward test years for rate cases in Utah, Oregon, Wyoming, and California. (Idaho and Washington require historical test years.)

In 2009, several parties, interveners, and the company reached a settlement to implement fuel and purchased power adjustments, which the IPUC approved. The Utah Public Service Commission (UPSC) is considering the design of a new fuel adjuster, and the company in February 2010 filed to seek approval to defer the difference between the net power costs allowed in the company's 2009 rate case and actual costs incurred. That request is pending before the commission.

Recent general rate case activity includes the company's settlement agreement with the UPSC on Feb. 18, 2010, for a retail rate increase of $32 million, an average price increase of 2%, as compared with the original $67 million sought. In Wyoming, the company has filed a general rate case with the Wyoming Public Service Commission for an increase of as much as $71 million. Early this year, the commission in Oregon approved a stipulation agreement that includes an annual increase to $42 million, as well as three tariff riders for the collection of an additional $8 million that is associated with various cost initiatives over the course of the next three years. In Washington, the commission and PacifiCorp reached a settlement agreement for an annual increase of $14 million, or an average price increase of

5%. Pro forma rate adjustments in California were made in January 2009 to address energy cost adjustments and attrition adjustments. The company has filed a general rate case with the California Public Utilities Commission for an annual increase of $8 million that remains pending.

PacifiCorp completed $2.3 billion in capital expenditures in 2009, up from $1.8 billion in 2008. The company is projected to spend $4.6 billion in 2010-2012, excluding non-cash allowance for funds used during construction. The largest component of PacifiCorp's capital program is the construction of the Gateway transmission project, an estimated $4.6 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines being placed in service as early as 2010 and a completion date scheduled for 2018. About 34% of the company's total capital budget over the next three years (2010-2012) is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

Lower fuel prices, decreased volume of wholesale electricity purchases, and favorable rate approvals on retail electricity sales and sales of renewable energy credits affected PacifiCorp's 2009 results. Although revenues declined slightly, by almost 1%, gross margins per megawatt-hour sold increased by almost 6%, as did the company's earnings before interest and taxes. Operating income increased about 11% due in large part to retail revenues increases provided by regulatory rate relief. For 2009, cash flows from operations rose by $508 million to $1.5 billion, but the majority of this was attributable to the deferred income taxes. In 2009, retail sales declined by 3%, while wholesale sales were approximately flat. About 30%-32% of PacifiCorp's total electric sales are to industrial customers. As a result, we had expected sales contraction to be a drag on 2009 performance, as industrial sales are more sensitive to the business cycle than is residential electric consumption. Industrial sales declined 7% in 2009.

Year-end leverage for the company was 53%, virtually unchanged year over year. Borrowing in 2009 was partially offset by $125 million of equity contribution from MEHC. These equity investments will be key to maintaining a balanced capital structure throughout the company's capital program. Debt to total capitalization reflects several adjustments we make, the largest of which include adding $395 million for power purchase obligations and $370 million for post-retirement obligations. We expect that PacifiCorp will not be in a position to make distributions to its parent while it is executing its capital program and that MEHC will manage PacifiCorp's debt leverage downward to the 50% area in the next several years.

Short-term credit factors

The company's liquidity position is strong. The PacifiCorp 'A-2' short-term rating reflects that although the contingent equity agreement between MEHC and Berkshire supports MEHC and its subsidiaries, the agreement is not a source of instantaneous liquidity. The agreement allows Berkshire up to 180 days to fund a request by MEHC. Given the recent turmoil in both the liquidity and capital markets, we have taken a firmer view on the need to link the PacifiCorp short-term ratings to its stand-alone credit quality, which supports an 'A-2' short-term rating. However, we note that although Berkshire contractually has up to six months to respond to an MEHC call for liquidity, it has strong economic incentives to do so.

PacifiCorp's cash and cash equivalents totaled $117 million as of Dec. 31, 2009. In addition, the company has $1.395 billion in unsecured revolving credit structured in two separate agreements: an $800 million line expiring July 2013 and a $700 million line extending through October 2012. The company had letters of credit in place for $258 million, leaving $1.137 billion available under its revolving facilities.

Outlook

The stable outlook on the PacifiCorp ratings incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that our fully adjusted debt to total capitalization is managed over the next few years to an adjusted level of closer to 50% and that FFO to total debt and FFO interest coverage will be 20% or better and in the range of 4.0x-4.5x, respectively. Given that PacifiCorp's financial risk profile is weak for the current ratings, we do not expect near-term upward ratings momentum for the utility. PacifiCorp's regulatory and structural insulation shields the utility from some MEHC credit deterioration, to an extent. Specifically, our criteria provide that the PacifiCorp CCR can be no more than three notches above the MEHC consolidated credit rating. The company is comfortably within this range, so we do not see significant prospects for the utility rating to fall as a result of adverse rating changes on MEHC, which also enjoys a stable outlook.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of April 28, 2010	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Stable/A-2
	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,404.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
Funds from operations (FFO)	1,342.3	326.5	3,030.0
Capital expenditures	1,850.2	511.4	3,437.7
Debt	6,641.7	1,875.2	12,662.8
Equity	5,926.2	1,404.3	10,032.3
Adjusted ratios			
Oper. income (bef. D&A)/revenues (%)	35.8	25.9	29.3
EBIT interest coverage (x)	2.8	2.2	2.9
EBITDA interest coverage (x)	4.0	3.8	4.4
Return on capital (%)	8.0	7.6	10.2
FFO/debt (%)	20.2	17.4	23.9
Debt/EBITDA (x)	4.2	4.1	3.3

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Mar. 31--				
	2009	2008	2007	2006	2006
Rating history	A-/Stable/A-2	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,896.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
Capital expenditures	2,297.1	1,757.0	1,496.4	1,375.0	1,030.5
Cash and short-term investments	117.0	59.0	228.0	59.0	119.6

Table 2.

PacifiCorp -- Financial Summary* (cont.)					
Debt	7,415.8	6,635.9	5,873.5	5,473.6	5,185.3
Preferred stock	20.5	41.0	41.0	41.3	41.3
Equity	6,711.5	5,987.0	5,080.0	4,426.8	3,750.7
Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)
Net cash flow/capex (%)	76.6	72.3	66.3	66.1	66.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.) (%)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2009--									
PacifiCorp reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
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Standard & Poor's adjustments										
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--	4.1
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--	(35.0)
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--	--

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	78.2	43.1	260.1	(1.0)	(30.9)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	7,415.8	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0	2,297.1

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of April 30, 2010)*

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB
Senior Secured (70 Issues)	A
Senior Unsecured (1 Issue)	A-
Senior Unsecured (3 Issues)	A-/A-2
Senior Unsecured (2 Issues)	A/Developing
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
06-Mar-2006	A-/Stable/A-2
25-May-2005	A-/Watch Neg/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Aggressive
Related Entities	
CE Casecnan Water and Energy Co. Inc.	
Senior Secured (1 Issue)	BB-/Stable
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+/Stable
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable

Ratings Detail (As Of April 30, 2010)* **(cont.)**

Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2
MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (2 Issues)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-/Stable
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (3 Issues)	BBB-/Stable
Utah Power & Light Co.	
Senior Secured (1 Issue)	AAA/Negative
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (1 Issue)	A-
Senior Unsecured (1 Issue)	A-/Stable
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard

Ratings Detail (As Of April 30, 2010)* **(cont.)**

& Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

PACIFICORP
Electric Operations
Pro-Forma Cost of Long-Term Debt Summary
December 31, 2012

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**	**$6,106,189,000**	**($64,243,264)**	**($24,305,918)**	**$6,017,639,818**	**$350,061,949**	**5.602%**	**5.733%**	**24.1**	**18.3**	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$359,815,000	($9,686,651)	($9,475,282)	$340,653,067	$10,561,315	2.629%	2.935%	29.1	9.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$4,866,647	1.278%	1.440%	27.8	5.2	5
6	**Total Pollution Control Revenue Bonds**	**$697,715,000**	**($13,980,883)**	**($17,096,511)**	**$666,637,606**	**$15,427,962**	**1.975%**	**2.211%**	**28.5**	**7.4**	6
7											7
8	**Total Cost of Long Term Debt**	**$6,803,904,000**	**($78,224,146)**	**($41,402,429)**	**$6,684,277,424**	**$365,489,911**	**5.230%**	**5.372%**	**24.5**	**17.2**	8
9											9

Exhibit PAC/307
Williams/1

PACIFICORP
Electric Operations
Pro-Forma Cost of Long-Term Debt Detail
December 31, 2012

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		[redacted]													2
3	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	22	2	$28,218,000	$2,623,000	$0	$0	$2,623,000	$100.000	8.733%	$229,067	3
4	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	23	2	$46,946,000	$8,034,000	$0	$0	$8,034,000	$100.000	8.293%	$666,260	4
5	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	24	3	$18,750,000	$4,672,000	$0	$0	$4,672,000	$100.000	8.634%	$403,380	5
6	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	24	3	$19,609,000	$6,131,000	$0	$0	$6,131,000	$100.000	8.469%	$519,234	6
7	**8.472%**	**Subtotal - Amortizing FMBs**			**23**	**3**		**$21,460,000**	**$0**	**$0**	**$21,460,000**		**8.471%**	**$1,817,941**	7
8															8
9	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	2	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	9
10	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	19	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	10
11	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	22	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	11
12	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	22	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	12
13	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	24	$350,000,000	$350,000,000	($4,048,881)	$0	$345,951,119	$98.843	6.185%	$21,647,500	13
14	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	24	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	14
15	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	25	$600,000,000	$600,000,000	($5,877,281)	$0	$594,122,719	$99.020	6.323%	$37,938,000	15
16	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	6	$500,000,000	$500,000,000	($3,972,221)	$0	$496,027,779	$99.206	5.756%	$28,780,000	16
17	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	26	$300,000,000	$300,000,000	($3,961,333)	$0	$296,038,667	$98.680	6.450%	$19,350,000	17
18	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	6	$350,000,000	$350,000,000	($4,808,293)	$0	$345,191,707	$98.626	5.682%	$19,887,000	18
19	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	26	$650,000,000	$650,000,000	($12,309,687)	$0	$637,690,313	$98.106	6.139%	$39,903,500	19
20	3.850%	Series due Jun 2021	05/12/11	06/15/21	10	8	$400,000,000	$400,000,000	($3,749,612)	$0	$396,250,388	$99.063	3.963%	$15,852,000	20
21	2.950%	Series due Feb 2022	01/06/12	02/01/22	10	9	$350,000,000	$350,000,000	($2,647,615)	$0	$347,352,385	$99.244	3.038%	$10,633,000	21
22	4.100%	Series due Feb 2042	01/06/12	02/01/42	30	29	$300,000,000	$300,000,000	($3,652,385)	$0	$296,347,615	$98.783	4.171%	$12,513,000	22
23	4.296%	Series - Cur Mat LT Debt (repriced)	12/31/12	12/31/42	30	30	$260,729,000	$260,729,000	($2,581,379)	$0	$258,147,621	$99.010	4.355%	$11,354,748	23
24	**5.453%**	**Subtotal - Bullet FMBs**			**24**	**19**		**$5,660,729,000**	**($60,699,963)**	**($1,295,995)**	**$5,598,733,042**		**5.549%**	**$314,096,748**	24
25															25
26	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	9	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	26
27	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	9	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	27
28	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	9	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	28
29	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	9	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	29
30	**8.421%**	**Subtotal - Series C MTNs**			**30**	**9**		**$29,000,000**	**($217,439)**	**($3,970,915)**	**$24,811,646**		**9.939%**	**$2,882,320**	30
31															31
32	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	10	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	32
33	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	10	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	33
34	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	10	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	34
35	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	10	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	35
36	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	10	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	36
37	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	10	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	37
38	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	10	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	38
39	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	10	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	39
40	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	10	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	40
41	**8.099%**	**Subtotal - Series E MTNs**			**30**	**10**		**$155,000,000**	**($1,227,725)**	**($16,164,025)**	**$137,608,250**		**9.210%**	**$14,275,920**	41
42															42
43	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	11	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	43
44	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	11	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	44
45	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	11	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	45
46	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	11	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	46
47	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	11	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	47
48	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	11	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	48
49	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	11	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	49
50	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	11	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	50
51	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	11	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	51

Exhibit PAC/307
Williams/2

PACIFICORP
Electric Operations
Pro-Forma Cost of Long-Term Debt Detail
December 31, 2012

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)	
52	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	11	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	52
53	**7.044%**	**Subtotal - Series F MTNs**			**30**	**11**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	53
54															54
55	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	13	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	55
56	**6.710%**	**Subtotal - Series G MTNs**			**30**	**13**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	56
57															57
58	**5.602%**	**Total First Mortgage Bonds**			**24**	**18**		**$6,106,189,000**	**($64,243,264)**	**($24,305,918)**	**$6,017,639,818**		**5.733%**	**$350,061,949**	58
59															59
60		[redacted]													60
61	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	1	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	61
62	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	2	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	62
63	1.338%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	3	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	1.705%	$767,250	63
64	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	4	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	64
65	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	9	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	65
66	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	11	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	66
67	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	11	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	67
68	1.062%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	12	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	1.174%	$109,945	68
69	1.062%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	12	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	1.206%	$98,771	69
70	1.110%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	12	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	1.282%	$1,563,271	70
71	1.178%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	12	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	1.313%	$197,738	71
72	1.039%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	12	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	1.150%	$244,490	72
73	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	13	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	73
74	4.337%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	13	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.449%	$978,780	74
75	**2.629%**	**Subtotal - Secured PCRBs**			**29**	**9**		**$359,815,000**	**($9,686,651)**	**($9,475,282)**	**$340,653,067**		**2.935%**	**$10,561,315**	75
76															76
77	1.062%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	1	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	1.249%	$143,635	77
78	1.062%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	3	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	1.158%	$810,600	78
79	1.062%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	3	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	1.438%	$647,100	79
80	1.096%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	4	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	1.203%	$601,500	80
81	1.062%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	5	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	1.185%	$533,250	81
82	1.062%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	5	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	1.193%	$491,516	82
83	1.242%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	8	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.346%	$302,648	83
84	1.242%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	8	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.381%	$128,916	84
85	1.242%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	8	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.413%	$89,090	85
86	1.060%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	13	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	1.166%	$284,504	86
87	6.150%	Emery 96 due Sep 2030	09/24/96	09/01/30	34	18	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	87
88	**1.278%**	**Subtotal - Unsecured PCRBs**			**28**	**5**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**1.440%**	**$4,866,647**	88
89															89
90	**1.975%**	**Total PCRB Obligations**			**28**	**7**		**$697,715,000**	**($13,980,883)**	**($17,096,511)**	**$666,637,606**		**2.211%**	**$15,427,962**	90
91															91
92	**5.230%**	**Total Long-Term Debt**			**25**	**17**		**$6,803,904,000**	**($78,224,146)**	**($41,402,429)**	**$6,684,277,424**		**5.372%**	**$365,489,911**	92
93															93

Exhibit PAC/307
Williams/3

Docket No. UE-246
Exhibit PAC/308
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Methodology for Imputing Debt For U.S. Utilities' PPAs

March 2012

STANDARD &POOR'S

RATINGSDIRECT®

May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Docket No. UE-246
Exhibit PAC/309
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Cost of Preferred Stock

March 2012

PACIFICORP
Electric Operations
Cost of Preferred Stock
Pro Forma December 31, 2012

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%	65,854	$6,585,400	($28,596)	$6,556,804	99.566%	4.741%	$312,186	9
10	4.56% Series	Feb-65	102.34%	4.560%	81,326	$8,132,600	($47,177)	$8,085,423	99.420%	4.587%	$373,010	10
11												11
12		May-95	(d)								$67,955	12
13		Oct-95	(e)								$84,019	13
14												14
15	**Total Cost of Preferred Stock**			**5.032%**	**407,331**	**$40,733,100**	**($183,498)**	**$40,549,602**		**5.427%**	**$2,210,740**	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	(d) Column 11 is the after-tax annual amortization of expenses related to the 8.375% QUIDS due 6/30/35 which were redeemed 11/20/00.											22
23	(e) Column 11 is the annual amortization of expenses related to the 8.55% QUIDS due 12/31/25 which were redeemed 11/20/00.											23
24												24

Exhibit PAC/309
Williams/1

Docket No. UE-246
Exhibit PAC/310
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Indicative Forward PCR Variable Rates

March 2012

Indicative Forward PCRB Variable Rates
Pro-Forma for December 31, 2012

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%

Indicative Forward PCRB Variable Rates
Pro-Forma for December 31, 2012

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%

Indicative Forward PCRB Variable Rates
Pro-Forma for December 31, 2012

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Jan-10	0.23%	0.32%	138%
Feb-10	0.23%	0.32%	137%
Mar-10	0.24%	0.32%	135%
Apr-10	0.26%	0.35%	134%
May-10	0.33%	0.34%	101%
Jun-10	0.35%	0.33%	93%
Jul-10	0.33%	0.30%	90%
Aug-10	0.27%	0.31%	115%
Sep-10	0.26%	0.31%	119%
Oct-10	0.26%	0.27%	106%
Nov-10	0.25%	0.27%	107%
Dec-10	0.26%	0.29%	110%
Jan-11	0.26%	0.26%	100%
Feb-11	0.26%	0.26%	98%
Mar-11	0.25%	0.24%	96%
Apr-11	0.22%	0.24%	106%
May-11	0.20%	0.20%	100%
Jun-11	0.19%	0.12%	62%
Jul-11	0.19%	0.07%	38%
Aug-11	0.21%	0.18%	83%
Sep-11	0.23%	0.18%	78%
Oct-11	0.24%	0.17%	69%
Nov-11	0.25%	0.18%	70%
Dec-11	0.28%	0.18%	62%
Average			92%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
12/31/2012	0.54%	92%	0.50%

* Source: Bloomberg L.P. (1/30/12)

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

A. My name is Mark R. Tallman. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. My present position is Vice President of Renewable Resources. I am responsible for hydro-powered and wind-powered generation resources owned by the Company.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Master of Business Administration from City University of Seattle. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resources since January 2011. Before that, I was Vice President of Renewable Resource Acquisition from December 2007 to January 2011 and Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 26 years in a variety of positions of increasing responsibility including the commercial and trading organization, the engineering organization, and the retail organization (as a District Manager).

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe two additions to hydro generation plant and increases in costs related to non-labor-related operations and maintenance ("O&M") activities for the Company's wind and hydro generation

resources. I will also demonstrate why these plant additions and O&M costs are reasonable, prudent, and should be included the Company's revenue requirement in this case.

Q. Please summarize your testimony.

A. My testimony describes how the wind and hydro O&M cost projections were developed and identifies the key cost drivers for the increases in O&M costs. While there is an overall net increase in hydro and wind O&M, I will address both increases and decreases.

The Company's non-labor-related wind generation O&M costs are projected to increase approximately $1.5 million over the historical base year ending June 30, 2011. In addition, the Company's non-labor-related hydro generation O&M expenses are projected to increase approximately $5.9 million over the base year. A more granular breakdown of hydro and wind O&M is shown in Mr. R. Bryce Dalley's Exhibit PAC/1102, pages 4.9.2 and 8.11.1.

My testimony also describes fish passage projects required by the Federal Energy Regulatory Commission ("FERC") licenses issued to the Company for the Lewis and North Umpqua hydroelectric projects. These hydro plant additions consist of fish passage construction on the North Umpqua River (the "Soda Springs Fish Passage" plant addition) and fish passage for the Lewis River hydroelectric project (the "Swift Fish Collector").

Q. For background, please provide a brief description of PacifiCorp's wind and hydro facilities.

A. PacifiCorp currently owns 12 wind projects in Oregon, Washington, and

Wyoming that generate nearly 1,000 megawatts ("MW") of electricity. Through long-term purchase agreements, the Company also adds over 600 MW from wind projects owned by other companies. Since 2006, the Company has added more than 1,400 MW of wind-generated electricity to our resource mix.

The Company operates seven hydroelectric projects in the Pacific Northwest and 20 in the Rocky Mountains. Together, they provide approximately 1,074 MW of low-cost, carbon-free electricity to our customers. Lewis River and North Umpqua River are the Company's two largest projects with a generating capacity of approximately 510 MW and 188.49 MW respectively.

Wind-Powered Generation Resources

Q. Please describe the primary areas of changing costs related to wind-powered generation resources.

A. The primary areas of cost increases and decreases related to O&M of wind-powered generation resources are: (1) materials; (2) third-party contracts; and (3) oil changes.

Q. What is the net impact of these changing O&M costs?

A. The net impact of test year O&M costs compared to the base year is shown in the table below.

O&M Category	**Test Year – Base Year** ($ millions)
Materials	$5.0
Third Party Contracts	($4.6)
Oil Changes	$1.2
Other	($0.1)
Net Total	**$1.5**

Q. What is the source of the increase in materials cost?

A. The increase in materials cost for wind generation from the base year to the test period is primarily driven by several wind projects that will no longer have warranty agreements in effect during the test year. As part of a wind turbine warranty, the manufacturer supplies replacement parts. Post-warranty, the Company must purchase replacement parts.

Q. Which wind projects are impacted by warranties that will no longer be in effect during the test year?

A. Ten of the Company's 12 wind projects have warranties that expired during the base year or will have expired going into the test year. The Seven Mile Hill, Seven Mile Hill II, High Plains, McFadden Ridge I, Glenrock, Glenrock III, Dunlap, Marengo, and Marengo II wind projects will be off warranty for the entire test year. Leaning Juniper I and Goodnoe Hills are the only wind projects that had their warranties expire prior to the base year, and Foote Creek I is the only wind project that will have a warranty agreement in effect following the test year.

Q. How did the Company determine the test year cost estimate for replacement parts and materials?

A. The Company used historical costs to arrive at a cost estimate for materials on a per-turbine basis. This estimate was then used for the projects with turbines out of warranty during the test year.

Q. Please explain the cost decreases related to third-party contracts.

A. The net decrease in expense related to third-party contracts is driven by new

O&M contracts at many of the Company's wind plants and lower road maintenance costs during the test year. The net decrease also includes an assumption that an O&M contract for Marengo and Marengo II can be replaced at a cost lower than experienced during the base year. Conversely, the net decrease includes an increase in annual O&M costs during the test year for the Dunlap I wind project. Dunlap I began operations during the base year so only a partial year's expense was incurred. A full year's contract expense for Dunlap I is included in the test year.

Q. How did the Company determine the test year cost estimate associated with third-party contracts?

A. The Company combined historical actual costs by project and contract category with costs related to committed contracts in effect during the test year.

Q. Please explain the expense increases related to wind turbine oil changes.

A. Consistent with the manufacturer's recommended maintenance schedules, routine oil changes will be performed at two of the Company's 12 wind projects during the test year.

Q. How did the Company determine the test year cost estimate for oil changes?

A. The cost per turbine of the most recent oil change activity performed by contractors was used to estimate the cost of oil changes during the test year.

Hydro-Powered Generation Resources

Q. Please describe the changes in hydro-powered generation O&M costs that affect the test year.

A. The primary sources of cost increases related to O&M of hydro-powered

generation resources are: (1) FERC fees; (2) costs to implement and comply with the FERC license issued for the Lewis River hydroelectric project; (3) costs to implement and comply with the FERC license issued for the North Umpqua River hydroelectric project; and (4) costs to implement and comply with the Klamath River Hydroelectric Settlement Agreement ("KHSA").

Q. What is the net impact of these items on O&M costs?

A. The net impact of these items on test year O&M costs compared to the base year is shown in the table below.

O&M Category	**Test Year – Base Year** ($ millions)
FERC fees	$1.4
Lewis River FERC license compliance	$1.7
North Umpqua river FERC license compliance	$0.9
KHSA	$0.8
Other	$1.1
Net Total	**$5.9**

Q. What is driving the increase in FERC fees?

A. The increased FERC fees from the base year to the test year are associated with higher FERC land use fees and higher FERC administration fees. In the case of the land use fees, PacifiCorp participated in a successful industry challenge of FERC's process to revise the fee determination methodology during the base year. Because of this successful challenge, which was based on a procedural flaw, the then-new land use fee structure did not become effective during the base year, but is expected to be effective during the test year. During the FERC challenge, the Company accrued expenses for increased land use fees. The accrued expense

reversal due to the successful challenge took place in early 2011, resulting in an abnormally low level of annualized expense appearing in the base year. The cost associated with FERC land use fees in the test year is based on the revised methodology FERC is proposing in a notice of proposed rulemaking ("NOPR"). The revised methodology is the same methodology that FERC previously attempted to implement. FERC is basing its proposed land use fees on a U.S. Bureau of Land Management methodology. This will result in higher FERC land use fees during the test year.

Q. What is driving the increase in FERC administration fees?

A. FERC administration fees are determined by FERC. The fees recover FERC's funding requirement by allocating costs to entities that hold FERC hydroelectric licenses. FERC allocates its costs by invoicing the Company annually. FERC administration fees for 2011 were approximately 8.6 percent higher than for 2010.

Q. How did the Company determine the test year cost estimate for FERC fees?

A. In the NOPR issued November 22, 2011, FERC proposes to again revise its fee schedule applicable to federal lands within the boundaries of FERC licensed projects. For the FERC land use fees, the Company used the invoice amount proposed by FERC in its 2009 revised fee schedule, which was vacated in early 2011 due to a successful appeal by PacifiCorp and other licensees. FERC's methodology is unchanged, making the 2009 invoice a valid estimate for costs during the test year. For the FERC administration fees, the Company used historical actual costs as the basis for predicting these fees in the test year.

Q. What is the increased cost associated with the Lewis River hydroelectric license?

A. To implement and comply with the Lewis River license issued by FERC, the Company has acquired wildlife mitigation lands and is investing in a fish passage system designed to collect, trap, and haul juvenile and adult anadromous fish around the three Lewis River dams. An anadromous fish is born in fresh water, spends most of its life in the sea, and returns to fresh water to spawn. The compliance measures result in higher O&M costs to: (1) manage the newly acquired forest lands; (2) operate the fish passage system and (3) operate fish transport vehicles that haul juvenile fish downstream and adult fish upstream. In addition, this category also includes increased costs to provide Lewis River recreation services to the public in compliance with FERC license requirements and to maintain aging recreational facilities.

Q. How did the Company determine the test year cost estimate associated with the Lewis River hydroelectric license?

A. The O&M costs for newly acquired wildlife lands are estimated using the costs to manage similar lands. For fish passage operations beginning during the test year, costs were estimated using similar operational systems found at PacifiCorp's currently operating fish hatcheries. Fish transportation costs are based on the estimated number of daily truck trips correlated with the expected timing of migrating fish. Increased costs for recreation result from an enhanced campsite reservation system to account for increasing user demand. The estimated costs for the reservation system are based on a comparison with similar state and utility

systems that use outside contracted systems. The costs to maintain the aging infrastructure are based on previously completed work.

Q. What is the source of the increased costs associated with the North Umpqua River hydroelectric license?

A. The Company is investing in a number of improvements to its North Umpqua River hydroelectric project to implement and comply with its FERC license. The key improvements are installation of fish passage facilities at the Company's Soda Springs dam and installation of a structure so fish can bypass the Slide Creek plant. The increase in O&M costs is to evaluate the environmental performance of these new facilities as well as to address National Historic Preservation Act requirements related to a cultural site.

Q. How did the Company determine the test year cost estimate associated with the North Umpqua River hydroelectric license?

A. The test-year cost estimate associated with these O&M activities is based on prior evaluation efforts at other similar facilities. With respect to the cultural site, the Company developed a curation plan in consultation with the Oregon State Historic Preservation Office to survey applicable areas and curate artifacts. The plan will be implemented in the test year. The cost of the plan was based on past experience for similar activities.

Q. What is the source of the incremental O&M costs associated with the KHSA?

A. The incremental costs are predominantly associated with required hatchery funding. Under the terms of the KHSA, the Company is obligated to increase its funding of the Iron Gate Hatchery from 80 percent to 100 percent. Similarly, a

Hatchery and Genetics Management plan for Iron Gate Hatchery is under regulatory review by the National Marine Fisheries Service. The hatchery plan is expected to further increase costs during the test year as new programs and practices at the hatchery are required to be implemented. Finally, under the KHSA, PacifiCorp is obligated to study options for continuing to meet hatchery production goals in the Klamath basin for an eight-year period following the time when the Iron Gate dam is envisioned to be removed under the terms of the KHSA. This hatchery study also drives an increase in costs during the test year.

Q. How did the Company determine the test year cost estimate associated with the KHSA?

A. The O&M costs in the test year were determined using the Company's hatchery funding obligation in the KHSA, as well as estimates of the costs to implement the Iron Gate Hatchery and Genetics Management plan. The plan includes measures for genetic broodstock management testing, spawning surveys, and fish testing procedures. Committed contract amounts for the hatchery production study were used to determine costs that will be incurred during the test year.

Plant Additions: Hydro-Powered Generation Resources

Q. Please describe the need for the Soda Springs Fish Passage addition.

A. As indicated above, the Company is investing in fish passage facilities at the Soda Springs dam to comply with the FERC license issued for the North Umpqua River hydroelectric project. These fish passage facilities are a requirement of the FERC license.

Q. Please describe the Soda Springs Fish Passage facilities.

A. The facilities consist of a fish ladder, spillway improvement, fish screen, and evaluation facility to provide upstream and downstream fish passage for anadromous fish at the Soda Springs dam.

Q. Does the Soda Springs Fish Passage addition meet more than one requirement of the FERC license?

A. Yes. The Soda Springs Fish Passage plant addition complies with three separate FERC license requirements: (1) an upstream fish ladder; (2) a downstream fish screen; and (3) modification of the spillway to protect juvenile fish. Because the footprints for these requirements overlap, they are included in one overall construction project.

Q. Was the design of the Soda Springs Fish Passage facilities subject to review and approval by resource agencies?

A. Yes. The Company worked with the National Oceanic and Atmospheric Administration (aka the National Marine Fisheries Service), the U.S. Forest Service, the U.S. Fish and Wildlife Service, and the Oregon Department of Fish and Wildlife to design the fish passage facilities. Although the Company gives its input, these agencies have final authority over the design. Based on the design required by these agencies, the plant addition included in this filing for the Soda Springs Fish Passage is $74 million total Company.

Q. When are the Soda Springs Fish Passage facilities scheduled to be placed in service?

A. The Company plans to place the facilities into service prior to the test period.

Q. Please describe the need for the Swift Fish Collector plant addition.

A. The Swift Fish Collector is another investment necessary to implement the fish passage system designed to collect, trap, and haul juvenile and adult anadromous fish around the three Lewis River dams. The purpose of the Swift Fish Collector is to implement and comply with the Lewis River hydroelectric license issued by FERC.

Q. Please describe the Swift Fish Collector facilities.

A. The facility is designed to attract and collect juvenile and adult fish so that they can be hauled downstream past the dams on the Lewis River and released back into the river to continue their out-migration to the ocean. The moored fish collection facility floats on the surface of the reservoir. Guide nets lead fish to a collection entrance designed to simulate the hydraulic conditions of a natural lake outlet. A series of pumps will draw water through a screen such that the fish are slowly accelerated to a speed where they are unable to escape. After the fish are captured, they are sorted by size to minimize injury and predation. The fish are then transferred into a truck for transport and release downstream of Merwin dam.

Q. Was the design of the Swift Fish Collector subject to review and approval by resource agencies?

A. Yes. Per the FERC license that incorporated the Lewis River settlement agreement, the Company engaged in design reviews with parties to the Lewis River settlement agreement, which included the National Oceanic and Atmospheric Administration (aka the National Marine Fisheries Service), U.S. Fish and Wildlife Service, and Washington Department of Fish and Wildlife. The

final design was ultimately approved by the National Oceanic and Atmospheric Administration and the U.S. Fish and Wildlife Service. Although the Company gives its input, these agencies have final authority over the design. Based on the design required by these agencies, the plant addition included in this filing for the Swift Fish Collector is approximately $63 million total Company.

Q. When is the Swift Fish Collector scheduled to be placed in service?

A. The Company plans to place the addition into service prior to the test period.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF CHAD A. TEPLY

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ATTACHED EXHIBITS

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

A. My name is Chad A. Teply. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah. My position is Vice President of Resource Development and Construction for PacifiCorp Energy, a division of the Company.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I joined MidAmerican Energy Company in November 1999 and held positions of increasing responsibility within the generation organization, including the role of project manager for the 790-megawatt Walter Scott Energy Center Unit 4 completed in June 2007. In April 2008, I moved to Northern Natural Gas Company as senior director of engineering. In February 2009, I joined the PacifiCorp team as vice president of resource development and construction at PacifiCorp Energy. In my current role, I have responsibility for development and execution of major resource additions and major environmental projects.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Purpose of Testimony
2. Comprehensive Air Initiative Overview
3. Emerging Environmental Regulations Overview
4. Alternatives, Cost Effectiveness and Benefits
5. Customer Considerations

6. Project-Specific Discussion
7. Carbon Plant Depreciation
8. Ongoing Planning
9. Conclusion

Introduction and Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information supporting the prudence of capital investments in emissions control equipment being placed in service during the test period at five of the 19 coal fueled generation units the Company operates. My testimony will specifically focus on emissions control equipment investments at Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3. These investments will be placed in service by December 31, 2012, and have not been considered by this Commission in past rate case dockets. Certain projects at the Company's Hunter Unit 2, Wyodak, and Jim Bridger Unit 3 facilities were placed in service prior to the test period for this case with only nominal project costs included in plant additions adjustments in this docket, but I describe these projects nonetheless. As can be seen in Company witness Mr. R. Bryce Dalley's Exhibit PAC/1102, Tab 8, these investments constitute a significant portion of the new capital investments anticipated to be placed in service by December 31, 2012.

My testimony will also discuss accelerated depreciation of costs associated with the Company's Carbon plant. Unless otherwise stayed as a result of litigation filed over the final rules or otherwise delayed by legislative action,

the Company currently anticipates that retiring the Carbon plant in early 2015 will be the least-cost alternative, accounting for risk and uncertainty, to comply with the EPA's recently finalized Mercury and Air Toxins Standards ("MATS"), formerly referred to in the industry as hazardous air pollutants ("HAPs") maximum achievable control technology ("MACT") regulations.

Overview of Testimony

Q. Please identify the primary environmental regulations requiring the emissions control investments described in this testimony.

A. The primary environmental regulations requiring the emissions control investments described in this testimony are Regional Haze Rules and National Ambient Air Quality Standards ("NAAQS"). The specific environmental requirements affecting individual investments will be discussed in detail later in my testimony.

Q. Please provide a general description of the emissions targeted for reduction by the control equipment described in this testimony.

A. The emissions control equipment investments described in this testimony primarily result in the reduction of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_X"), and particulate matter ("PM") emissions from the retrofitted facilities as required to comply with the environmental regulations identified above. In certain instances, it is also anticipated that the emissions control equipment investments will support improved mercury emissions control, as well as compliance with emerging environmental regulations such as the MATS.

Q. Please provide a general description of the benefits gained from the investments.

A. The Company has developed and executed its emissions control plan, including the investments described in this testimony, with a focus on maintaining a reasonable balance between protecting the interests of customers, meeting the obligation to serve the current and reasonably projected demands of our customers, and complying with environmental requirements, all in the face of an uncertain regulatory environment.

Q. Has the Company completed analyses of the emissions control investments described in this testimony versus other compliance alternatives to demonstrate that the investments provide the least-cost outcome, accounting for risk and uncertainty, for its customers?

A. Yes. The analyses completed by the Company, described in this testimony and provided in accompanying work papers support the emissions control equipment investments included in this case. These emissions control equipment investments will allow ongoing energy production from the retrofitted facilities through the currently approved depreciable life for ratemaking as the least-cost outcome, accounting for risk and uncertainty, for customers.

Q. Please provide a general description of the analyses the Company is undertaking to evaluate MATS compliance options for the Carbon plant.

A. The Company's preliminary assessment of the recently finalized MATS concludes that it is likely that the least-cost compliance option, accounting for risk and uncertainty, for the Carbon plant will be to retire it by the April 2015 MATS

compliance deadline established in the final rule unless other conditions, described herein, inherently effectuate an extension or otherwise necessitate an extension as contemplated by the final rule. The Company has begun its detailed analysis of compliance options, as well as transmission system impacts associated with the anticipated retirement. The Company has also begun preliminary analysis of facility decommissioning and closure costs that are expected to be incurred following the anticipated retirement. I will discuss these items in additional detail later in my testimony.

Comprehensive Air Initiative Overview

Q. When did the Company begin development and implementation of its emissions control plan?

A. Through the Western Regional Air Partnership, the Company worked with states, tribes, and federal agencies to develop and implement regional planning processes to improve visibility in national parks and wilderness areas in the western United States. The Company's early efforts, beginning in 1999, with state agencies in Utah and Wyoming led to the development of the Company's Comprehensive Air Initiative ("CAI"). The CAI was designed to reduce power plant emissions in accordance with Regional Haze Rules and other air quality regulations that would require emission reductions.

Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from man-made emissions in designated national parks and wilderness areas. This goal resulted in development of the Regional Haze Rules, adopted in 2005 by the U.S.

Environmental Protection Agency ("EPA"). The first phase of these rules trigger Best Available Retrofit Technology ("BART") reviews for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Visibility-impairing pollutants include SO_2, NO_X and PM. The Company operates 14 units that meet the construction and emissions threshold criteria and are therefore "BART-eligible units". Under federal regulations in 40 CFR 51.308(e)(1)(ii), each state is required to determine which BART-eligible sources are also "subject to BART". BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to impairment of visibility in any designated national park or wilderness area. The investments in emissions control equipment at the Company's BART-eligible units have been determined by the state environmental regulators to be necessary after considering available technology; costs of compliance; energy and non-air quality environmental impacts; existing control equipment and the remaining useful life of the facility; and the degree of improvement in visibility reasonably anticipated to result from the use of such technology.

Since 2005, the Company's CAI has been updated to include additional controls that the states have required. The Regional Haze State Implementation Plans initially submitted by Utah in 2008 and Wyoming in 2010, and updated since those initial filings, incorporate the emissions controls included in the Company's CAI.

Q. Please provide an overview of the Company's long-term emissions compliance plan and other environmental compliance plans up to and including December 31, 2022.

A. Currently, PacifiCorp's long-term emissions control plan consists of those projects and implementation timelines identified in Exhibit PAC/501, Overview of PacifiCorp's Environmental Control Plan. A summary of key assumptions regarding anticipated regulatory requirements and environmental control technologies is provided in Exhibit PAC/502, Known Regulatory Drivers and Environmental Projects. Exhibit PAC/503, Mercury Control Projects, provides similar project planning and environmental drivers for currently planned mercury control projects. Exhibit PAC/504, List of CCR Projects Included in 10-Year Plan, provides similar project planning and environmental drivers for proxy coal combustion residuals ("CCR") compliance projects.

Q. How many of the Company's coal fueled facilities are potentially impacted by current and emerging environmental regulations?

A. The Company owns or has a partial share in 26 coal fueled units within the states of Wyoming, Utah, Arizona, Colorado and Montana. The Company maintains operational responsibility for 19 of those units and, as previously noted, 14 of those units are BART-eligible units under the Regional Haze Rules. The Company's CAI has been developed and maintained to ensure compliance with environmental regulations governing each of the coal fueled generation facilities it operates. The current and emerging environmental regulations discussed in this

testimony will potentially impact all 26 of the Company's coal fueled facilities in some fashion.

Q. Does the Company need to make the emissions control equipment investments described in this testimony if it expects to continue operating the affected facilities?

A. Yes. The emissions control equipment investments described in this testimony are required to comply with existing regulations including Regional Haze Rules, the Regional SO_2 Milestone and Backstop Trading Program developed in alignment with existing federal regulations and administered in Utah and Wyoming, NAAQS, and New Source Review requirements. In order to comply with the requirements that result from those regulations and that are set forth in the Company's air quality permits and the state implementation plans ("SIPs") of Utah and Wyoming, it is necessary to install and operate the emissions controls presented in this case. The Company believes that certain emissions control projects described in this testimony or currently required by permit are also projects that would have otherwise been required to achieve the emission rates established under the EPA's recently promulgated MATS for acid gases and non-mercury metallic HAPs at the facilities receiving said controls. Installing and operating the emissions control equipment described in this testimony allows the affected facilities to continue operating as the least-cost option, accounting for risk and uncertainty, while meeting all applicable requirements, as proven by the Company's analyses.

Q. What has been the initial focus of the Company's CAI?

A. The initial focus of the Company's CAI has been on installing controls to reduce SO_2 emissions, which are the most significant contributors to regional haze in the western United States. In addition, the Company continues to rely on installation of low NO_X burners to significantly reduce NO_X emissions. The Company also anticipates completing installation of five selective catalytic reduction systems ("SCRs") (or otherwise reducing NO_X emissions) at its owned and operated facilities by 2022. The Company's CAI also includes the installation or retrofit of several baghouses to control particulate matter emissions. For certain units which utilize dry scrubbers, baghouses have the added benefit of improving SO_2 removal. Baghouses also significantly improve mercury emissions control capability.

Q. What level of emissions reductions is expected to occur at the Company's Wyoming, Utah, and Arizona facilities as a result of the Company's CAI?

A. The following figures represent the reductions in SO_2 and NO_X emissions that are expected to occur at units owned by the Company in Wyoming, Utah, and Arizona as a result of the Company's CAI.

Figure 1

2005 - 2010 Actual and 2011 - 2023 Projected SO_2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units

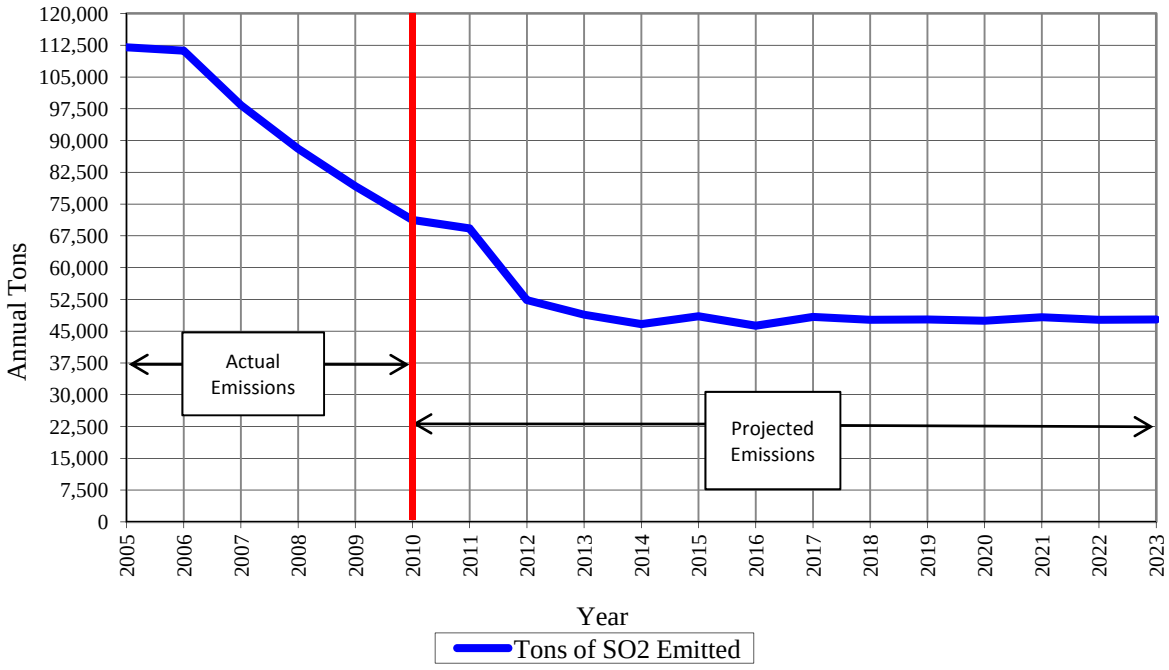
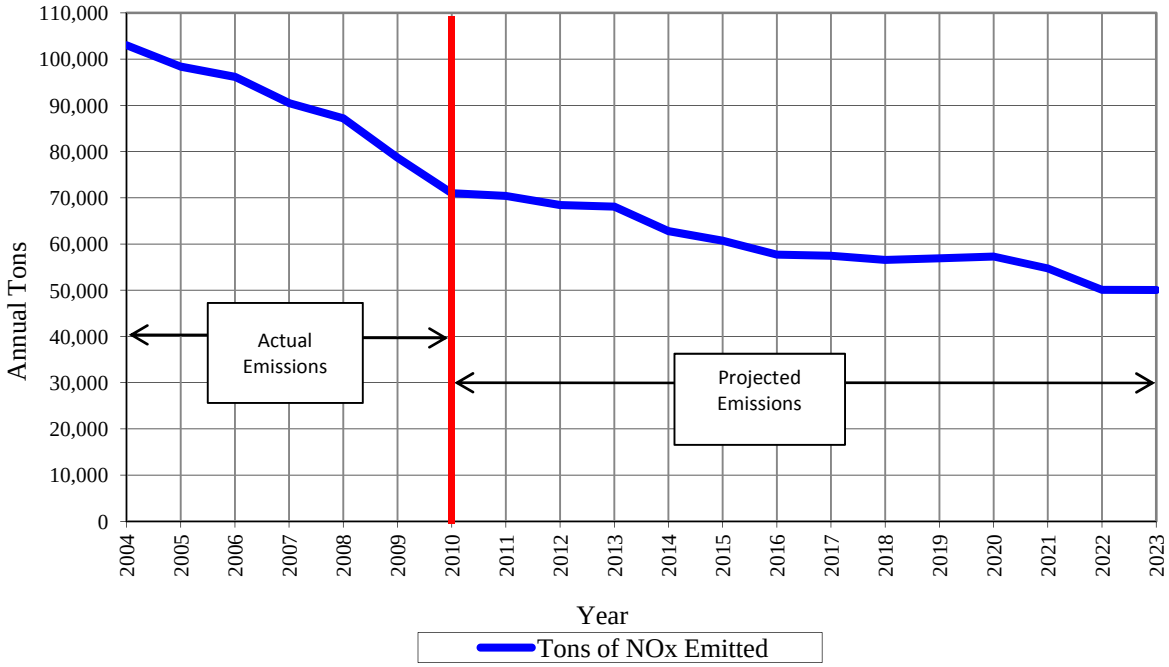


Figure 2

2004 - 2010 Actual and 2011 - 2023 Projected NOx Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units



Q. Does the Company believe that its CAI properly balances stakeholder interests?

A. Yes. Environmental benefits, including visibility improvements, will flow from the projects installed under the Company's CAI. The Company believes that the emission reduction projects and their timing appropriately balance the need for emission reductions with the concerns of our customers for low-cost energy, concerns of state utility commissions, and concerns of other stakeholders. The Company believes this plan is complementary to, and consistent with, BART and Regional Haze planning requirements of the states in which the facilities operate. Furthermore, it is a reasonable approach to achieving required emission reductions pursuant to state requirements in Wyoming, Utah and other states. As currently planned, the Company's CAI incorporates emissions control projects at 17 of 19 Company-operated coal fueled units (excluding Carbon Units 1 and 2, which are currently under review with respect to MATS compliance), affecting approximately 6,200 net megawatts of generation capacity (approximately 5,200 net megawatts Company share). Nonetheless, the Company will continue to review all CAI projects prior to execution to ensure that they remain economically justified given any environmental, regulatory or policy changes that may occur going forward.

Q. Have the costs of the Company's CAI projects been prudently managed?

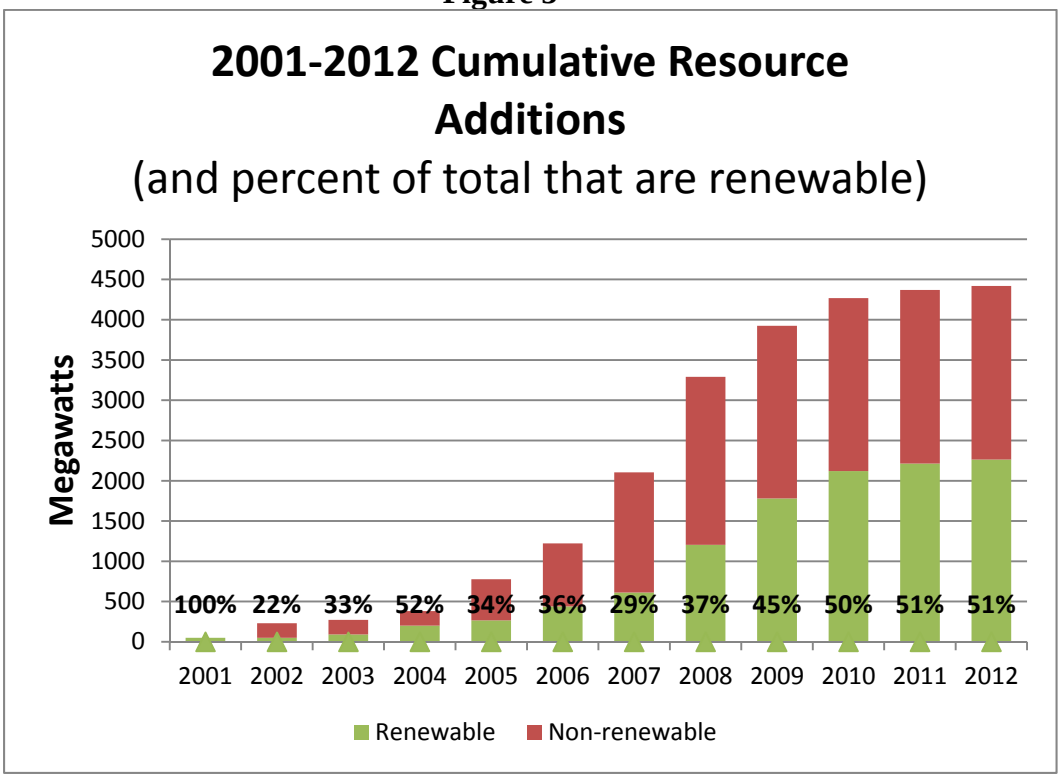
A. Yes. The Company's scrubber and baghouse projects have typically been contracted under lump-sum, turnkey, engineer, procure, and construct ("EPC") contract terms which resulted from competitive bidding processes. The

Company's low NO_X burners ("LNB") projects have typically been contracted (1) under multiple lump-sum contracts which resulted from competitive bidding processes or (2) job-specific work releases under established service level agreement rate structures. Company management continues to provide oversight of the projects and closely manages any project execution plan changes or potential contract scope changes.

Q. In addition to the Company's emissions control plan investments, what actions has the Company taken to avoid increasing emissions while diversifying its generation resource portfolio?

A. In addition to reducing emissions at existing facilities, the Company has also avoided increasing emissions by adding more than 1,400 megawatts of non-emitting renewable wind generation between 2006 and 2010. Figure 3 below depicts the Company's cumulative resource additions from 2001 through 2012 along with the percentage of the total that are from renewable generation.

Figure 3



Q. What types of generation comprise the non-renewable portion of the cumulative resource additions shown in Figure 3 above?

A. The non-renewable generation resource additions depicted in Figure 3 are primarily natural gas resources. The most significant of these resources are the Company's Currant Creek block 1 combined cycle combustion turbine ("CCCT") facility that was placed in service in March 2006, the Company's Lake Side block 1 CCCT facility that was placed in service in September 2007, and the Chehalis CCCT facility acquired in September 2008. The Company has also recently begun construction of the Lake Side block 2 CCCT facility that is scheduled to be placed in service in 2014. In total, those projects will add more than 2,200 megawatts of new gas fueled generation to the Company's generation mix.

Q. Does the Company's fleet of generation assets continue to face changing environmental compliance obligations?

A. Yes. The Company's fleet of generation assets faces a constantly changing landscape of environmental regulations. Although the extent and effect of these changes remains uncertain, they are expected to impact the Company's future operating costs. See Exhibit PAC/505 for additional discussion regarding emerging and changing environmental regulations.

Q. Is the Company obligated to install emissions controls required by state permits, regardless of whether final EPA review and approval of the respective Regional Haze state implementation plans remains pending?

A. Yes. The BART permits and construction permits issued by the respective state agencies for the emissions control investments contemplated in this case include stand-alone requirements enforceable by the laws of the respective states. These requirements are enforceable independent of whether EPA has approved the respective state implementation plans.

Q. What is the Company's current assessment of potential impacts of EPA's MATS on the Company's facilities?

A. The Company's current assessment of the MATS suggests that scrubbers, baghouses, electrostatic precipitators, and activated carbon and/or reagent injection systems are contemplated by EPA to be readily available, cost effective controls to meet the following proposed standards (in general terms): 1.2 pounds per trillion British thermal unit ("lb/TBtu") for mercury; 0.0020 pounds per million British thermal unit ("lb/MMBtu") (0.02 pounds per megawatt-hour

("lb/MWh")) for acid gases or a surrogate 0.20 lb/MMBtu SO_2 limit; and individually prescribed limits for non-mercury metals or a surrogate 0.030 lb/MMBtu (0.3 lb/MWh) filterable particulate matter limit. The Company believes that the emissions control projects described in this testimony and those currently permitted are consistent with the EPA's MATS and will support the Company's ability to comply with the rules' standards for acid gases and non-mercury metallic HAPs at the facilities receiving said controls. The Company does, however, anticipate having to take additional actions to reduce mercury emissions and otherwise comply with the rule's other requirements such as monitoring, reporting and recordkeeping. The Company has incorporated costs for mercury emissions control equipment into its business planning processes. Other compliance costs will be incorporated as the specific requirements of the final rules are more fully assessed.

Q. Does the Company anticipate that final EPA approval of the respective state implementation plans addressing regional haze will require alternate emissions control equipment to be installed, making the equipment contemplated in this case obsolete?

A. No. While it is possible that the EPA will require more stringent emission limits or accelerated project timing, any such requirement will be in addition to–not in place of–the emissions control technology selections completed to date, which apply best available retrofit technology, comply with existing state and federal regulations, and support Regional Haze Rule objectives. The Company also incorporates into its emissions control equipment contract specifications design

considerations intended to provide appropriate levels of operating margin, equipment redundancy, and system maintainability and reliability provisions to support an expected range of process inputs, operating conditions, and system performance. Although the Company cannot predict future emissions control regulations and associated emissions limits, the Company does take steps to procure a prudent level of design flexibility to accommodate potential changes in system performance requirements, where practical.

Emerging Environmental Regulations Overview

Proposed CCR Regulations

Q. What is the Company's current assessment of potential impacts of proposed EPA CCR regulations on it existing facilities?

A. As the Company assesses options regarding continued investment in its coal fueled generation assets, it is important to note that the Company will be faced with certain CCR storage, handling, and long-term management costs at its existing facilities whether the facilities continue to operate or not. Therefore, the Company periodically updates its CCR-related costs and asset retirement obligations in its planning processes. In response to the rulemaking regarding CCR proposed by EPA in June 2010, the Company has updated its CCR-related costs and asset retirement obligations on a preliminary basis to incorporate proposed Subtitle D or near-Subtitle D infrastructure requirements in its business planning processes, which will serve as a planning proxy for the Company until such time as EPA completes its CCR rulemaking process. It is currently anticipated that compliance with final CCR rules will be required five years after

final rulemaking, or by late 2017. Until a final rule is promulgated, the cost, timing, equipment, monitoring, and recordkeeping to comply with the rule cannot be fully ascertained. However, the costs of the Company's proxy CCR Subtitle D compliance projects have been incorporated into the Company's business plans.

Q. Has the Company participated in the public comment period associated with the EPA's proposed CCR regulations?

A. Yes. The Company participated in the public hearing process and filed written comments in the EPA rulemaking on this matter, Docket ID No. EPA-HQ-RCRA-2009-0640. The Company's written comments are included as Exhibit PAC/506. In general, the Company believes that the Subtitle C hazardous waste regulatory approach proposed by the EPA would lead to a myriad of draconian results for all utilities and the U.S. economy, because agricultural, transportation, infrastructure, and construction benefits of CCR use would be halted. PacifiCorp vigorously supports the development of CCR as a non-hazardous waste under the RCRA Subtitle D non-hazardous waste rule. The uncertainty surrounding the breadth of Subtitle C impacts on the industry and the economy makes attempting to analyze the associated economics unproductive. Therefore, PacifiCorp has not completed specific studies to fully ascertain the impacts of the proposed Subtitle C rulemaking outcome.

Proposed Clean Water Act 316(b) Regulations

Q. What is the Company's current assessment of potential impacts of proposed Clean Water Act 316(b) water intake regulations on the Company's facilities?

A. Due to the preliminary status of the 316(b) rulemaking process, the Company has not completed plant-specific studies to fully ascertain and verify that intake structure retrofits or new technologies are necessary to comply with the currently proposed 316(b) water intake regulations. A key element of the 2011 proposed rule is anticipated to require conducting plant-specific studies and assessments. However, a majority of the Company's facilities utilize cooling towers and closed cycle cooling, which we believe significantly reduces potential 316(b) rulemaking exposure. Nonetheless, modifications may still be needed at the cooling water intake structures of certain facilities to comply with the proposed impingement mortality standards. As such, the Company has developed preliminary estimates of the costs associated with potential studies and potential mitigation projects at its facilities by extrapolating results of a 2007 study completed at the Company's Dave Johnston facility prior to the suspension of the then current Phase II Section 316(b) rule. The preliminary estimates for the Company's proxy 316(b) compliance projects have been incorporated into the Company's business plans.

Q. Has the Company participated in the public comment period associated with the EPA's proposed 316(b) rulemaking?

A. Yes. The Company's filed comments in the EPA rulemaking on this matter, Docket ID No. EPA-HQ-OW-2008-0667, are included as Exhibit PAC/507. In

general, the Company's perspective is supportive of EPA's willingness to provide for case-by-case, site-specific flexibility for facilities related to the establishment of and compliance with entrainment standards. However, the Company does have concerns with: (1) the ability of regulated entities to achieve the proposed numeric limits for impingement; (2) the potentially subjective interpretation and implementation of entrainment standards by the delegated state permitting authorities; (3) the potential multiple definitions and redefinitions of Best Technology Available; (4) the proposed cost-benefit analysis process for species of concern; (5) the lack of a de minimis impact exemption; (6) the proposed monitoring and recordkeeping requirements; and (7) the proposed timing of compliance requirements. In addition, the Company asserted its position that since closed cycle cooling already represents Best Technology Available, installations utilizing that technology should be deemed to meet compliance with the 316(b) requirements.

Future Effluent Rulemaking

Q. What is the Company's current assessment of potential impacts of the anticipated EPA effluent limit rulemaking on its facilities?

A. The EPA's announced intention to undertake effluent rulemaking has not yet materialized into a proposed rule to regulate effluent limits for wastewater discharges from steam electric plants. The Company is, however, aware that the effluent guidelines may be revised; how the guidelines may be revised is entirely speculative. While certain Company facilities do have effluent outflows that may be impacted by the proposed rulemaking, attempting to analyze hypothetical

scenarios with no basis for direction would not produce meaningful results. The EPA's "Steam Electric Power Generating Point Source Category: Final Detailed Study Report," dated October 2009, largely reviewed plants in the eastern United States and was not sufficient to provide the Company with information regarding what the revised guidelines would entail and/or how the coal combustion byproduct rulemaking may impact those guidelines.

Q. Has the Company participated in the EPA's discovery process related to proposed effluent rulemaking?

A. Yes. The Company responded to the EPA's effluent limitation guideline questionnaire Information Collection Request on September 15, 2010. On February 3, 2011, Eastern Research Group, Incorporated, a contractor for the EPA, contacted the Naughton plant with follow-up questions. The Company responded to those questions on February 14, 2011.

Alternatives, Cost Effectiveness and Benefits

Q. Has the Company appropriately assessed compliance alternatives, cost effectiveness, and benefits associated with the emissions control investments described in this testimony?

A. Yes. The Company has appropriately assessed compliance alternatives, cost effectiveness, and benefits associated with the emissions control investments described in this testimony. As an initial matter, the Company assessed its environmental compliance obligations and the timing of those obligations. With that backdrop, the Company assessed the overall costs and availability of various emissions control technologies and compliance alternatives. As the Company

considered when, whether and what capital investments to make in environmental controls, it incorporated factors including current and emerging state and federal environmental regulatory requirements, forward-looking market price projections, and potential CO_2 cost drivers into its decision-making.

Q. Does the Company focus solely on investment in emissions control equipment as a means of environmental compliance?

A. No. As part of the Company's compliance planning efforts, consideration is given to selection of appropriate emissions control technologies as well as alternate compliance options such as idling a unit and replacing it with market power purchases.

Q. What is the Company's assessment of the costs of continuing to invest in individual coal fueled generation assets versus replacing the lost generation with market purchases?

A. The Company has developed economic analyses that provide an overview of the present value revenue requirement differential ("PVRR(d)") benefits associated with its emissions control investments versus market power purchases, with consideration given to potential CO_2 costs and resulting market pricing assumptions. The results of these analyses are discussed on a case-by-case basis in my testimony below describing the individual projects included in this case or otherwise not previously considered by this Commission in past rate case dockets. These PVRR(d) analyses demonstrate prudence of the emissions control investments.

Q. Do the Company's analyses demonstrate that continuing to invest in individual coal fueled generation assets is the least-cost option, accounting for risk and uncertainty, for customers?

A. Yes. The Company's analyses demonstrate that maintaining the ability to operate the existing coal units by retrofitting the units with the emissions control equipment described in this testimony represents the least-cost option, accounting for risk and uncertainty, for customers. This is true even before considering factors associated with retirement of the coal units prior to their currently approved depreciation lives for ratemaking, such as the economic impact on the states in which the units operate, the loss of fuel diversity in the generation portfolio, and the potential impact on system reliability.

Q. Please describe the efforts taken to evaluate available control technologies.

A. In support of the BART review processes administered by the respective states, the Company evaluated several technologies for their ability to economically achieve compliance and support an integrated approach to control criteria pollutants (*e.g.*, SO_2, NO_X, and PM). The analyses reviewed available retrofit emission control technologies and their associated performance and cost metrics. Each of the technologies was reviewed against its ability to meet a presumptive BART emission limit based on technology and fuel characteristics. Measures of capital cost on a dollars per ton of pollutant removed basis have been reviewed, which is applied specifically as part of the BART determination process. In addition, the analyses outlined the cost for projected improvement in visibility which can be expected by the installation of the respective technology. For each

unit or source subject to BART, the respective state environmental regulatory agencies identify the appropriate control technology to achieve what the air quality regulators determine are cost-effective emission reductions. Once the appropriate BART technology was identified, the Company moved forward with its competitive bidding process to evaluate and ultimately select the preferred provider for the projects.

Q. What other project-specific factors does the Company typically consider when making its investment decisions?

A. Factors such as ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life/performance considerations, and operational efficiencies are typically included in the Company's investment decisions.

Q. How has ongoing compliance with existing operating requirements factored into planning of environmental compliance investments?

A. The waste handling phase of the Hunter Units 1 and 2 scrubber projects described in this testimony are good examples of how ongoing compliance with current regulations factors into the Company's environmental compliance investment planning process. The scrubber waste handling system will ensure that the final scrubber waste product from the units will not contain any free liquids and can be appropriately disposed of in the onsite landfill in compliance with current regulations. This waste handling addition was required because the higher level of sulfur dioxide removal required by Regional Haze Rules combined with less

ash in the coal have made the previous method of waste handling (mixing scrubber waste with dry fly ash) incompatible with disposal regulations.

Q. How has fuel supply flexibility factored into planning of emissions control investments?

A. The Hunter Units 1 and 2 scrubber projects are good examples of how fuel supply flexibility has factored into the Company's emissions control investment planning process. As the Company contemplated BART requirements for Hunter Units 1 and 2, emissions control equipment that would meet required emission limits and would allow utilization of coal with higher coal sulfur content was evaluated. The ability to fuel the Hunter units on coal with higher sulfur content while meeting new emission limits will help to contain fuel and generation costs at this facility.

Q. How have existing emissions control equipment end of life/performance considerations factored into planning of new emissions control investments?

A. The replacement of various scrubber system elements at Hunter Units 1 and 2 is an example. These elements include scrubber vessel work scope, scrubber recycle pump replacements, and scrubber reagent injection nozzle replacements, as well as the scrubber reagent preparation system replacement. By planning the Hunter Units 1 and 2 scrubber project tie-in to coincide with planned maintenance outage cycles for the units, the projects were able to replace equipment and components that had exhausted their useful life, and at the same time address system capacity and compliance requirements.

Q. How have operational considerations factored into planning of environmental compliance investments?

A. Operational considerations are included in the technical specifications for each of the Company's environmental compliance projects. The waste handling phase of the Hunter Units 1 and 2 scrubber projects is a key example of the Company's efforts to improve operational efficiencies. This project results in the installation of scrubber waste dewatering equipment that eliminates the manual management of fly ash blending processes. Thus, in addition to addressing system capacity concerns and maintaining waste disposal compliance, these projects improve operational efficiencies allowing plant staff to focus on other operational responsibilities.

Customer Considerations

Q. What are the benefits to customers of installing environmental compliance equipment?

A. Customers directly benefit from the continued availability of low-cost generation produced at the facilities while also achieving environmental improvements from these resources. In addition, the tie-in of these necessary controls is being accomplished during planned maintenance outages across the generation fleet, as opposed to scheduling additional stand-alone tie-in outages for this work. This approach reduces replacement power costs. The Company has 10 BART-eligible units in Wyoming and four in Utah. The BART controls for each of these units must be installed prior to the compliance dates specified in the respective permits.

As the compliance deadlines for existing environmental requirements and

emerging environmental regulations across the country draw closer, the demand for equipment and skilled labor is likely to increase, making timely compliance more difficult, and potentially impracticable without incurring significant additional cost. Attempting to postpone installation of required emissions control equipment installations to later planned maintenance outages, or mid-cycle stand-alone tie-in outages, would make it virtually impossible for the Company to ensure that all of its affected units effectively meet compliance deadlines. It would also place the Company at risk of not having access to necessary capital, materials, and labor while attempting to perform these major equipment installations in a compressed timeframe.

Q. Has the Company installed the emissions control investments in an efficient manner?

A. Yes. Emission reduction projects of the number and size described in this testimony take many years to engineer, plan, and build. When considering a generation fleet the size of the Company's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time, as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of the Company's electrical system during these extended outages. In other words, it is not practical, and is unduly

expensive for customers, to expect to build these emission reduction projects all at once or even in a compressed time period.

Q. Does the Company believe that the emissions control investments described in this testimony meet the used and useful standard?

A. Yes. Customers need the energy produced by these resources. Each of these investments provides benefit to customers, and allows the Company to maintain compliance with state issued permits, state implementation plans, and regional SO_2 milestones and backstop trading programs.

Project-Specific Discussion

Q. Are the Company's analyses completed in support of the emissions control investments described below in this testimony consistent with the analyses supporting emissions control investments deemed prudent by the Commission in the Company's most recent general rate case, UE 217?

A. Yes. The Company's analyses completed in support of the emissions control investments described in this testimony are consistent with the analyses completed in support of the Dave Johnston Unit 3 and Huntington Unit 1 emissions control investments that were approved in UE 217.

The Dave Johnston Unit 4 emissions control project described in this testimony is for the most part identical to that approved in UE 217 for the Dave Johnston Unit 3 scrubber-baghouse addition project. The Dave Johnston Unit 3 scrubber-baghouse addition project was constructed concurrently with the Dave Johnston Unit 4 scrubber-baghouse project, but on an earlier completion schedule.

The Hunter Units 1 and 2 emissions control projects described in this

testimony are for the most part identical to those approved in UE 217 for the Huntington Unit 1 scrubber upgrades, scrubber waste material handling, low NOx burners, and baghouse conversion projects. The Hunter Units 1 and 2 projects were contracted concurrently with the Huntington Unit 1 projects, but on earlier completion schedules. One difference in the Hunter Units 1 and 2 emissions control projects is the inclusion of a scrubber reagent preparation system that was not required as part of the Huntington Unit 1 scrubber project.

Naughton Unit 1

Q. Please describe the Naughton facility and Naughton Units 1 and 2 in particular.

A. The Naughton plant consists of three coal-fueled units that are 100 percent owned and operated by the Company. The Naughton plant is capable of producing an aggregated nominal 700 megawatts ("MW") of net generation. The Company also owns 100 percent of the Viva Naughton reservoir which stores water for consumptive use at the Naughton plant and provides regional recreation opportunities.

Naughton Unit 1 began commercial operation in 1963 and has a nominal net generation capacity of 160 MW. The unit is configured with an Alstom (formerly Combustion Engineering) natural circulation boiler and a General Electric steam turbine-generator. The unit configuration also includes a closed loop cooling system with a mechanical draft cooling tower, and an electrostatic precipitator.

Naughton Unit 2 began commercial operation in 1968 and has a nominal

net generation capacity of 220 MW. The unit is configured with an Alstom (formerly Combustion Engineering) natural circulation boiler and a General Electric steam turbine-generator. The unit configuration also includes a closed loop cooling system with a mechanical draft cooling tower, and an electrostatic precipitator.

The Naughton plant property is also adjacent to the Kemmerer Mine, which supplies approximately 2.8 million tons per year of sub-bituminous coal to the plant. Coal combustion residuals are currently disposed of on plant property in surface impoundments.

The Naughton plant currently employs approximately 138 personnel, including 107 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

Q. Please describe the Naughton Unit 1 scrubber addition and associated equipment included in this case.

A. The scrubber addition project on Naughton Unit 1 includes the installation of SO_2 controls. The capital investment for the project being placed in service during the test period is approximately $121 million. Construction began in 2010, and the project is expected to be placed in service by May 2012. The new emissions control equipment will be tied into the existing unit during a scheduled plant maintenance outage. The project will install a wet flue gas desulfurization ("FGD") system. The wet FGD system injects reagent slurry containing sodium carbonate and sodium bicarbonate in the top of an open spray absorber vessel ("scrubber") with a network of spray nozzles. The distribution of spray nozzles

causes the sodium carbonate slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the sodium carbonate in the slurry to form a waste slurry of sodium sulfite and sodium sulfate. Oxidation air is mixed with the waste slurry to convert the sodium sulfite completely to sodium sulfate in a tank external to the absorber vessel. The liquid waste slurry is then transported to a scrubber waste impoundment for disposal. Once that scrubber waste impoundment is full, the scrubber waste will be dewatered and retained in the closed and capped scrubber waste impoundment. Other equipment to be installed as part of the project includes booster fans, boiler reinforcement, flue gas path reinforcement, new ductwork, a new chimney, makeup water supply upgrades, sodium carbonate slurry reagent preparation systems, waste material handling systems, a new waste disposal pond, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Are costs associated with common facilities between the Naughton Units 1 and 2 scrubber addition projects included in this case?

A. Yes. This case includes the cost of common facilities that are required to be placed in service to allow prudent operation of either unit's new emission control equipment, although the majority of common facilities were placed in service when the Naughton Unit 2 scrubber addition came online in 2011. The Naughton Unit 2 scrubber addition is also included in this case and will be discussed in detail later in my testimony. Common facilities include reagent preparation, waste disposal, electrical supply, control system upgrades, and ancillary utility systems, as well as site preparation and the chimney.

Q. Are costs associated with ancillary projects required to support the Naughton Unit 1 scrubber addition included in this case?

A. Yes. This case includes the cost of boiler reinforcement work required to maintain National Fire Protection Association ("NFPA") code compliance due to the additional flue gas fan capacity required as a result of the scrubber. New booster fans are required to overcome flue gas pressure losses across the scrubber and additional ductwork.

Q. Please describe the Naughton Unit 1 low NO_X burners installation project.

A. The LNB installation project on Naughton Unit 1 includes the installation of NO_X combustion controls. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions. The capital investment for the project being placed in service during the test period is approximately $9 million. Construction will begin in 2012, and the project is expected to be placed in service by May 2012. The new emissions control equipment will be installed during a scheduled plant maintenance outage.

Q. Has the Commission previously considered whether the emissions control project costs included in this case for Naughton Unit 1 are prudent?

A. No.

Q. What are the key permits and/or regulations requiring the Naughton Unit 1 wet FGD system to be installed?

A. To continue compliant operation of Naughton Unit 1, PacifiCorp must install the wet FGD ("scrubber") systems described herein to control emissions of criteria

pollutants as required by NAAQS, the state of Wyoming's § 309 Implementation Plan, and the State of Wyoming's permit (MD-5156) dated May 2009.

Q. What are the key permits and/or regulations requiring the Naughton Unit 1 LNB system to be installed?

A. To continue compliant operation of Naughton Unit 1, PacifiCorp must install the LNB systems described herein to control emissions of criteria pollutants in response to Regional Haze Rules, the state of Wyoming's § 309 (g) Implementation Plan, and the state of Wyoming's BART review, decision and permit (MD-6042) dated December 2009, and the state of Wyoming's permit (MD-5156) dated May 2009.

Q. What is the post-project SO_2 emission limit for Naughton Unit 1 as prescribed by the state of Wyoming's permit (MD-5156)?

A. The post-project SO_2 emission limit for Naughton Unit 1 as prescribed by permit (MD-5156)[1] is as follows:

Pollutant	Emissions Limit (lbs. per MMBtu[(a)])	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
SO_2	0.15 (12-month rolling)	833 (3-hour block)	NA

(a) Million British Thermal Units

Q. When is the Company required to demonstrate compliance with BART permit conditions?

A. The BART permit for the project requires that Naughton Unit 1 emissions control equipment be installed and operating with emissions performance test results in

[1] Permit MD-5156, Article 8.

compliance with emissions limits before December 31, 2012.[2] The permit emissions limits[3] are as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.26 (30-day rolling)	481 (30-day rolling)	2,107
PM/PM_{10} [(a)]	0.040 [(b)]	74	324

[(a)] Filterable portion only

Q. Are Naughton Unit 1 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Naughton Unit 1 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with Chapter 14, Sections 2 and 3, of the Wyoming Air Quality Standards and Regulations ("WAQSR"). The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Naughton Unit 1 of 0.15 pounds SO_2 per MMBtu. The investment in the Naughton Unit 1 wet FGD system addition will meet this emission threshold and will also support compliance with the EPA's MATS limits for acid gases.

Q. Are Naughton Unit 1 SO_2 and NO_X emissions considered in the development of the plant-wide applicability emission limits ("PALs") for the Naughton plant?

A. Yes. The state of Wyoming's permit (MD-11754) dated May 2011 establishes PALs for emissions of SO_2 and NO_X at Naughton. The SO_2 and NO_X PALs limit the annual tons of SO_2 and NO_X that may be emitted from the facility. Typically, past actual emissions are used to develop PAL limits. However, since historical

[2] Permit MD-6042, Article 16.
[3] Permit MD-6042, Articles 5 and 7.

data is not available for Naughton Units 1 and 2 and with the new SO_2 and NO_X control projects being placed in service, the post-project potential emissions from these units are used. The annual SO_2 potential to emit for each unit was calculated using the post-project potential emission rate of 0.15 pounds SO_2 per MMBtu, and the annual NO_X potential to emit for each unit was calculated using the post-project potential emission rate of 0.26 pounds NO_X per MMBtu. The following table summarizes the emissions from each source that was included in the development of the Naughton plant PALs:

Component Description	**Annual NO_X Emissions (tons per year)**	**Annual SO_2 Emissions (tons per year)**
Naughton Unit 1 (potential-to-emit basis)	2,107	1,215
Naughton Unit 2 (potential-to-emit basis)	2,733	1,577
Naughton Unit 3 and Non-Boiler Sources (past actual baseline)	6,233	5,958
Naughton PSD Significance Threshold	40	40
Total Annual Emissions (PALs)	11,113	8,790

Q. How is the Naughton Unit 1 scrubber addition expected to support the EPA's MATS?

A. Emissions limits for acid gases, particularly hydrogen chloride ("HCl"), and non-mercury metals are included in the EPA's MATS. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is the surrogate for MATS acid gases emissions compliance, and a PM emissions limit of 0.030 pounds filterable PM per MMBtu is the surrogate for MATS non-mercury metals emissions compliance. As such, installation of the wet FGD system with performance requirements described above and contract guarantees as described below is expected to support compliance with those portions of the MATS. With respect to mercury emissions

control, the Company's current plan to control mercury emissions by the April 2015 compliance date will involve the application of a coal supply additive to oxidize mercury as the coal is burned in the furnace. Oxidized mercury can be removed in the wet FGD system. The use of a FGD system additive can prevent the recovered mercury from being re-emitted from the FGD system.

Q. What emissions performance guarantees are provided via the scrubber addition project EPC contract?

A. The scrubber system is specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]
PM/PM_{10} [(a)]	[redacted]

(a) [redacted]

Q. What emissions performance guarantees are provided via the LNB supply contract?

A. The LNB supply contract includes guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
NO_X	[redacted]

Q. Did the Company consider alternative technologies to the Naughton Unit 1 emissions control projects included in this case?

A. Yes. The Company completed three technical studies of note to evaluate NO_X,

PM and SO_2 emission control technology alternatives for Naughton Unit 1. In October 2002 Sargent and Lundy completed a coal fleet-wide Multi-Pollutant Control Report; in January 2005 Sargent and Lundy completed the NO_X Emission Reduction Technologies Study; and in February of 2007 CH2M Hill completed the BART Analysis for Naughton Units 1 through 3.

The Multi-Pollutant Control Report investigated the cost and necessity of NO_X controls (including both boiler in-combustion and post-combustion controls), PM controls (including upgraded electrostatic precipitators ("ESPs"), polishing baghouses and full- scale fabric filter replacements), and SO_2 controls (including upgrading the existing scrubbers).

The NO_X Emission Reduction Technologies Study compared 16 emission control technologies, status of the technology development, performance, approximate initial capital costs, and approximate fixed and variable operational and maintenance costs.

The BART Analysis for Naughton Units 1 through 3 was conducted for criteria pollutants NO_X, PM_{10} and SO_2. In completing this BART Analysis, technology alternatives were investigated and potential reductions in emissions were quantified. The BART Analysis for Naughton Units 1 through 3 was considered in the state of Wyoming's BART determination, permit requirements, and SIP discussed above.

Q. Has the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Naughton Unit 1?

A. Yes. Prior to executing the EPC contract for the project in May 2009, the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to add the wet FGD system and install new LNBs versus idling Naughton Unit 1 in 2009 and replacing the generation with market power purchases. The evaluation calculated a present value revenue requirement differential, PVRR(d), between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation, through the end of the unit's depreciable life. The revenue was derived using the December 31, 2008 PacifiCorp official forward price curve at a corresponding CO_2 price of $8 per ton beginning in 2013. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Naughton Unit 1 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted].

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Naughton Unit 1?

A. Yes. The Naughton Unit 1 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable

CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	Bus Bar Cost Contribution of Environmental Projects ($/MWh)	Bus Bar Cost After Installation of Environmental Projects ($/MWh)	Incremental CO_2 Price Revenue Requirement ($/MWh)	Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs referenced above compare to other generation resource types in the Company's available generation mix?

A. Comparable bus bar costs are [redacted] per MWh (excluding CO_2 cost adjustment) for PacifiCorp's combined cycle Lakeside Unit 1 and [redacted] per MWh (excluding CO_2 cost adjustment) for PacifiCorp's natural gas converted Gadsby Units 1, 2 and 3. The fuel costs associated with these bus bar cost references are [redacted] and [redacted] per MWh, respectively. Future variations in major capital and operational expenditures, changes to unit dispatch cycles, and other factors could impact these costs going forward. Variable costs include those associated with fuel, reagents, and proxy compliance costs for emerging environmental regulations.

Q. Has the Company developed emerging CCR regulations compliance costs for the Naughton facility?

A. Yes. Although information regarding the currently emerging CCR regulations, which were proposed in 2010, was not available at the time of decision-making and planning of the multi-year Naughton Unit 1 scrubber project included in this case, the Company is committed to understanding and anticipating the effect of

emerging environmental regulations in its economic evaluations and environmental plans. As discussed later in my testimony, the Company has developed proxy compliance project costs for emerging rules regulating CCR for use in its forward-looking business planning processes. In fact, the aforementioned costs have been incorporated into the Company's Confidential Coal Replacement Study ("IRP Supplement"), filed in Docket LC 52 and discussed later, which did not identify an accelerated retirement date for Naughton Unit 1.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Naughton facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations, which were proposed in 2011, was not available at the time of decision-making and planning of the multi-year Naughton Unit 1 scrubber project included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Naughton Unit 1.

Naughton Unit 2

Q. Please describe the Naughton Unit 2 scrubber addition and associated equipment included in this case.

A. The scrubber addition project on Naughton Unit 2 was constructed concurrently with the Naughton Unit 1 scrubber project, but on an earlier completion schedule. The description of the Naughton Unit 2 scrubber project is for the most part

identical to that provided above for Naughton Unit 1. The capital investment for the project being placed in service during the test period is approximately $155 million. Construction began in 2010, and the project was placed in service November 2011. The new emissions control equipment was tied into the existing unit during a scheduled plant maintenance outage.

Q. What benefits were achieved by constructing the Naughton Units 1 and 2 scrubber addition projects concurrently, but on different completion schedules?

A. The planned major maintenance outages for the Company's generation assets are scheduled on a control area basis, considering optimal frequency between overhauls and to minimize the number of major units off line at any one time. The Company completed its most recent planned maintenance overhaul to Naughton Unit 1 in 2008 and is scheduled for its next planned maintenance overhaul in the spring of 2012. The Company completed its most recent planned maintenance overhaul for Naughton Unit 2 in the fall of 2011. The Company's intent in establishing the tie-in schedules for the Naughton Units 1 and 2 emissions control projects was to benefit from aggregated construction costs and schedules for the emissions control equipment projects and to effectively integrate project schedules with the established planned maintenance overhaul schedules, work plans, and budgets for the respective units.

Q. Are costs associated with ancillary projects required to support the Naughton Unit 2 scrubber addition included in this case?

A. Yes. This case includes the cost of boiler reinforcement work required to

maintain NFPA code compliance due to the additional flue gas fan capacity required as a result of the scrubber. New booster fans are required to overcome flue gas pressure losses across the scrubber and additional ductwork.

Q. Please describe the Naughton Unit 2 low NO_X burners installation project.

A. The LNB installation project on Naughton Unit 2 includes the installation of NO_X combustion controls. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions. The capital investment for the project being placed in service during the test period is approximately $9 million. The project was installed during a scheduled plant maintenance outage and was placed in service in November 2011.

Q. Has the Commission previously considered whether the emissions control project costs included in this case are prudent?

A. No.

Q. What are the key permits and/or regulations requiring the Naughton Unit 2 wet FGD system to be installed?

A. To continue compliant operation of Naughton Unit 2, PacifiCorp must install the wet FGD systems described herein to control emissions of criteria pollutants as required by NAAQS, the state of Wyoming's § 309 Implementation Plan, and the State of Wyoming's permit (MD-5156) dated May 2009.

Q. What are the key permits and/or regulations requiring the Naughton Unit 2 LNB system to be installed?

A. To continue compliant operation of Naughton Unit 2, PacifiCorp must install the LNB systems described herein to control emissions of criteria pollutants in

response to Regional Haze Rules, the state of Wyoming's § 309 (g) Implementation Plan, and the state of Wyoming's BART review, decision and permit (MD-6042) dated December 2009, and the state of Wyoming's permit (MD-5156) dated May 2009.

Q. What is the post-project SO_2 emission limit for Naughton Unit 1 as prescribed by the state of Wyoming's permit (MD-5156)?

A. The post-project SO_2 emission limit for Naughton Unit 1 as prescribed by permit (MD-5156)[4] is as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
SO_2	0.15 (12-month rolling)	1,080 (3-hour block)	NA

Q. When is the Company required to demonstrate compliance with BART permit conditions?

A. The BART permit for the project requires that Naughton Unit 2 emissions control equipment be installed and operating with emissions performance test results in compliance with emissions limits before June 1, 2012.[5] The permit emissions limits[6] are as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.26 (30-day rolling)	624 (30-day rolling)	2,733
PM/PM_{10} [(a)]	0.040 [(b)]	96	421

[(a)] Filterable portion only

[4] Permit MD-5156, Article 8.
[5] Permit MD-6042, Article 16.
[6] Permit MD-6042, Articles 5 and 7.

Q. Are Naughton Unit 2 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Naughton Unit 2 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with Chapter 14, Sections 2 and 3, of the WAQSR. The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Naughton Unit 2 of 0.15 pounds SO_2 per MMBtu. The investment in the Naughton Unit 2 wet FGD system addition will meet this emission threshold and will also support compliance with the EPA's MATS limits for acid gases.

Q. Are Naughton Unit 2 SO_2 and NO_X emissions considered in the development of the PALs for the Naughton plant?

A. Yes. The state of Wyoming's permit (MD-11754) dated May 2011 establishes PALs for emissions of SO_2 and NO_X at Naughton. The specific considerations for Naughton Unit 2 are discussed earlier in my testimony.

Q. How is the Naughton Unit 2 scrubber addition expected to support the EPA's MATS?

A. Emissions limits for acid gases, particularly HCl, and non-mercury metals are included in the EPA's MATS. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is the surrogate for MATS acid gases emissions compliance, and a PM emissions limit of 0.030 pounds filterable PM per MMBtu is the surrogate for MATS non-mercury metals emissions compliance. As such, installation of the wet FGD system with performance requirements described above and contract guarantees as described below is expected to support compliance with those

portions of the MATS. With respect to mercury emissions control, the Company's current plan to control mercury emissions will involve the application of a coal supply additive to oxidize mercury as the coal is burned in the furnace. Oxidized mercury can be removed in the wet FGD system. The use of a FGD system additive can prevent the recovered mercury from being re-emitted from the FGD system.

Q. What emissions performance guarantees are provided via the scrubber addition project EPC contract?

A. The scrubber system is specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]
PM/PM_{10}[(a)]	[redacted]

(a) [redacted]

Q. What emissions performance guarantees are provided via the LNB supply contract?

A. The LNB supply contract includes guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
NO_X	[redacted]

Q. Did the Company consider alternative technologies to the Naughton Unit 2 emissions control projects included in this case?

A. Yes. The Company completed three technical studies of note, which were discussed previously in my testimony, to evaluate NO_X, PM and SO_2 emission control technology alternatives for Naughton Unit 2.

Q. Has the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Naughton Unit 2?

A. Yes. Prior to executing the EPC contract for the project in May 2009, the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to add the wet FGD system and install new LNBs versus idling Naughton Unit 2 in 2009 and replacing the generation with market power purchases. The evaluation calculated a PVRR(d) between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation, through the end of the unit's depreciable life. The revenue was derived using the December 31, 2008 PacifiCorp official forward price curve at a corresponding CO_2 price of $8 per ton beginning in 2013. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Naughton Unit 2 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted].

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Naughton Unit 2?

A. Yes. The Naughton Unit 2 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	Bus Bar Cost Contribution of Environmental Projects ($/MWh)	Bus Bar Cost After Installation of Environmental Projects ($/MWh)	Incremental CO_2 Price Revenue Requirement ($/MWh)	Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs referenced above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Naughton facility?

A. Yes. As discussed previously in my testimony, the Company has incorporated proxy compliance project costs for emerging rules regulating CCR into the Company's IRP Supplement, which did not identify an accelerated retirement date for Naughton Unit 2.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Naughton facility?

A. Yes. As discussed previously in my testimony, the Company has incorporated

proxy compliance project costs for emerging 316(b) regulations into the Company's IRP Supplement, which did not identify an accelerated retirement date for Naughton Unit 2.

Dave Johnston Unit 4

Q. Please describe the Dave Johnston facility and Dave Johnston Unit 4 in particular.

A. The Dave Johnston plant is a four unit, coal fueled power plant with a net maximum capacity of 762 MW located near Glenrock, Wyoming. The Company owns 100 percent of the Dave Johnston plant and adjacent reclaimed mine including the land, equipment, and infrastructure. The site consists of approximately 2,500 acres at an elevation of 4,950 feet above sea level. The plant consists of four units: two rated at 106 megawatts, one rated at 220 megawatts, and one rated at 330 megawatts. Dave Johnston Unit 4 began commercial operation in 1972 and has a nominal net generation capacity of 330 MW. Unit 1 and Unit 2 are equipped with Babcock & Wilcox ("B&W") front wall-fired steam generators, Unit 3 is equipped with a B&W opposed-wall burner steam generator, while Unit 4 is equipped with a tangentially-fired Combustion Engineering steam generator. All four units are also equipped with General Electric tandem-compound, two-casing, two-flow condensing, single-reheat turbines.

All four units are designed to burn sub-bituminous coal from the local area or from the Powder River Basin. Coal for the plant is received on unit trains. Railroad access is via the Burlington Northern–Santa Fe Railway Company.

The Company owns water rights in the North Platte River for plant boiler

water make-up and circulating water use. Due to utilization of once-through cooling water systems the Dave Johnston plant is the most likely to be impacted by emerging 316(b) regulations. The Dave Johnston plant also utilizes various CCR landfills and retention ponds, as well as wastewater ponds for its processes.

The Dave Johnston plant currently employs approximately 185 personnel, including 147 union craft personnel represented by the Utility Worker Union of America Local 127.

Q. Please describe the Dave Johnston Unit 4 emissions control project and associated equipment included in this case.

A. The emissions control project at the Dave Johnston Unit 4 power plant is being completed in conjunction with the Dave Johnston Unit 3 emissions control project that was be placed in service in 2010. The Dave Johnston Unit 4 emissions control project will upgrade and improve the unit's PM and SO_2 controls. The capital expenditure for the project during the test period is approximately $104 million. Construction began in 2008, and the project will be operational by April 2012. The new emissions control equipment is being tied into the existing unit during a scheduled plant maintenance outage. The project will install a dry flue gas desulfurization ("DFGD") system with fabric filter. A DFGD system injects lime slurry in the top of an absorber vessel with a rapidly rotating atomizer wheel. The rapid rotation of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form calcium sulfate in the form of dry PM. The dry PM is then captured in the downstream baghouse along with fly ash from

the boiler. The DFGD system will produce a nonhazardous dry waste product suitable for landfill disposal. Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, lime slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Is the Dave Johnston Unit 3 emissions control project already in service and in rates?

A. Yes. As mentioned above the Dave Johnston Unit 3 emissions control project, which was constructed concurrently with the Dave Johnston Unit 4 emissions control project, including common facilities for both units, was placed in service during the 2010 planned major maintenance outage for that unit. The planned major maintenance outages for the Company's generation assets are scheduled on a control area basis, considering optimal frequency between overhauls and to minimize the number of major units off line at any one time. The Company's Dave Johnston Unit 4 completed its most recent overhaul in 2009 and is scheduled for its next overhaul in the spring of 2012. The Company's intent in establishing the tie-in schedules for the Dave Johnston Unit 3 and Dave Johnston Unit 4 emissions control equipment was to benefit from the aggregated construction costs and schedules for the emissions control equipment projects to effectively integrate the project schedule into the established planned maintenance overhaul schedules, work plans, and budgets for the respective units.

Q. Has the Commission previously considered whether the emissions control project costs included in this case for Dave Johnston Unit 4 are prudent?

A. No. However, the Company's 2010 general rate case included approval of the Dave Johnston Unit 3 scrubber project with the same basic scope and underlying requirements. The Dave Johnston Unit 3 scrubber project was constructed concurrently with the Dave Johnston Unit 4 scrubber project but placed in service during a planned major maintenance outage for Dave Johnston Unit 3 in 2010. In UE 217, the Commission deemed the previously completed Dave Johnston Unit 3 scrubber project used and useful and found that the costs associated with the project were prudently incurred.

Q. What are the key permits and/or regulations requiring the Dave Johnston Unit 4 DFGD with fabric filter system to be installed?

A. To continue compliant operation of Dave Johnston Unit 4, the Company must install the DFGD with fabric filter system described herein to control emissions of criteria pollutants as required by Regional Haze Rules, the State of Wyoming's § 309 (g) Implementation Plan, the state of Wyoming's BART review, decision and permit (MD-6041) dated December 2009, and the state of Wyoming's Air Quality Permit (MD-5098) dated June 2008.

Q. What is the post-project SO_2 emission limit for Dave Johnston Unit 4 as prescribed by the state of Wyoming's permit (MD-5098)?

A. The post-project SO_2 emission limit for Dave Johnston Unit 4 as prescribed by permit (MD-5098)[7] is as follows:

[7] Permit MD-5098, Article 10.

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
SO_2	0.15 (12-month rolling)	615 (24-hour rolling)	NA

Q. When is the Company required to demonstrate compliance with BART permit conditions?

A. The BART permit for the project requires that emissions control equipment be installed and operating with emissions performance test results in compliance with emissions limits before December 31, 2012.[8] The permit emissions limits[9] are as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.15 (30-day rolling)	615 (30-day rolling)	2,694
PM/PM_{10} [(a)]	0.015 (annual testing)	61.5 (annual testing)	269

[(a)] Filterable portion only

Q. Are Dave Johnston Unit 4 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Dave Johnston Unit 4 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with Chapter 14, Sections 2 and 3, of the WAQSR. The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Dave Johnston Unit 4 of 0.15 pounds SO_2 per MMBtu. The investment in the Dave Johnston Unit 4 DFGD with fabric filter system will meet this emission threshold and will also support compliance with the EPA's proposed MATS for acid gases.

[8] Permit MD-6041, Article 15.
[9] Permit MD-6041, Article 5.

Q. Are Dave Johnston Unit 4 SO_2 and NO_X emissions considered in the development of the PALs for the Dave Johnston plant?

A. Yes. The state of Wyoming's Air Quality Permit (MD-5098) establishes PALs for emissions of SO_2 and NO_X at Dave Johnston. The SO_2 and NO_X PALs limit the annual tons of SO_2 and NO_X that may be emitted from the facility. Typically, past actual emissions are used to develop PALs. However, since historical data was not available for Units 3 and 4 with the new SO_2 and NO_X controls projects being placed in service, the post-project potential emissions from these units are used. The annual SO_2 potential to emit for each unit was calculated using the post-project potential emission rate of 0.15 pounds SO_2 per MMBtu. The annual NO_X potential to emit for Unit 3 was calculated using the post-project potential emission rate of 0.28 pounds NO_X per MMBtu and the potential to emit for Unit 4 was calculated using the post-project potential emission rate of 0.15 pounds NO_X per MMBtu, The following table summarizes the emissions from each source that were included in the development of the Dave Johnston PALs:

Component Description	Annual NO_X Emissions (tons per year)	Annual SO_2 Emissions (tons per year)
Dave Johnston Unit 1 (actual emissions)	2,382	3,842
Dave Johnston Unit 2 (actual emissions)	2,222	3,704
Dave Johnston Unit 3 (potential-to-emit)	3,434	1,840
Dave Johnston Unit 4 (potential-to-emit)	2,694	2,694
PSD Significance Threshold	40	40
Total Annual Emissions (PALs)	10,772	12,120

Q. How is the Dave Johnston Unit 4 DFGD with fabric filter addition expected to support the EPA's MATS?

A. Emissions limits for acid gases, particularly HCl, and non-mercury metals are

included in the EPA's MATS. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is the surrogate for MATS acid gases emissions compliance, and a PM emissions limit of 0.030 pounds filterable PM per MMBtu is the surrogate for MATS non-mercury metals emissions compliance. As such, installation of the DFGD with fabric filter system with performance requirements described above is expected to support compliance with those portions of the MATS. With respect to mercury emissions control, the Company's current plan to control mercury emissions will involve the application of a coal supply additive to oxidize mercury as the coal is burned in the furnace. Oxidized mercury can be removed in the new FGD system including the fabric filter. While activated carbon injection ("ACI") can also be used to meet the final MATS mercury emissions limit, the new FGD equipment is expected to significantly reduce or eliminate the need for ACI.

Q. What emissions performance guarantees are provided via the DFGD with fabric filter project EPC contract?

A. The DFGD with fabric filter system is specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]
PM/PM_{10}[(a)]	[redacted]

(a) [redacted]

Q. Did the Company consider alternative technologies to the Dave Johnston Unit 4 emissions control projects included in this case?

A. Yes. The Company completed three technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Dave Johnston Unit 4. In October 2002 Sargent and Lundy completed a coal fleet-wide Multi-Pollutant Control Report; in January 2005 Sargent and Lundy completed the NO_X Emission Reduction Technologies Study; and in February 2007 CH2M Hill completed the BART Analysis for Dave Johnston Units 3 through 4.

The basis of the Multi-Pollutant Control Report and the NO_X Emission Reduction Technologies Study were described earlier in my testimony.

The BART Analysis for Dave Johnston Units 3 and 4 was conducted for criteria pollutants NO_X, PM_{10} and SO_2. In completing this BART Analysis, technology alternatives were investigated and potential reductions in emissions were quantified. The BART Analysis for Dave Johnston Units 3 and 4 was considered in the state of Wyoming's BART determination, permit requirements, and SIP discussed above.

Q. Has the Company evaluated whether the risk-adjusted, least-cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Dave Johnston Unit 4?

A. Yes. Prior to executing the EPC contract for the project in January 2008, the Company evaluated whether the risk-adjusted, least-cost alternative to comply with environmental requirements was to add the DFGD with fabric filter system versus idling Dave Johnston Unit 4 in 2008 and replacing the generation with

market power purchases. The evaluation calculated a PVRR(d) between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation, through the end of the unit's depreciable life. The revenue was derived using the December 31, 2007 PacifiCorp official market forward price curve at a corresponding CO_2 price of $8 per ton beginning in 2012. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Dave Johnston Unit 4 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted].

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Dave Johnston Unit 4?

A. Yes. The Dave Johnston Unit 4 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	**Bus Bar Cost Contribution of Environmental Projects ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects ($/MWh)**	**Incremental CO_2 Price Revenue Requirement ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs reference above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Dave Johnston facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year Dave Johnston Unit 4 DFGD with fabric filter project included in this case, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed later in my testimony, the Company has incorporated proxy compliance project costs for emerging rules regulating CCR into the Company's IRP Supplement, which did not identify an accelerated retirement date for Dave Johnston Unit 4.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Dave Johnston facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of decision-making and planning of the multi-year Dave Johnston Unit 4 DFGD with fabric filter project included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the

Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Dave Johnston Unit 4.

Hunter Units 1 and 2

Q. Please describe the Hunter facility and Hunter Units 1 and 2 in particular.

A. The Hunter plant is a three-unit coal-fueled power plant with a net generation capacity of approximately 1,320 MW. The plant is located approximately 158 miles south of Salt Lake City, Utah near the town of Castledale, Utah. Units 1 and 2 are co-owned, while Unit 3 is 100 percent owned by the Company. Unit 1 is 93.8 percent owned by the Company and 6.2 percent owned by the Utah Municipal Power Agency. Unit 2 is 60.3 percent owned by the Company, 24.9 percent owned by Deseret Generation and Transmission Cooperatives, and 14.8 percent owned by Utah Associated Municipal Power Systems. However the entire plant is under an exclusive owner operation and maintenance contract with the Company. The site covers an area of approximately 1,000 acres at 5,644 feet above sea level, which includes the main power station buildings, water storage reservoirs, coal stocks, ash disposal, and a small research farm to reclaim wastewater and a proportion of storm water.

The plant consists of three coal fired boiler units with associated steam turbine generator units, operating under a base load operating regime. Units 1 and 2 are identical units. The steam generators are tangentially-fired, controlled circulation boilers supplied by Combustion Engineering. The units are designed to burn sub-bituminous coal from the local area. Each Westinghouse steam turbine is a tandem-compound, two-casing, two-flow condensing, single-reheat

turbine. Each Westinghouse generator has a hydrogen cooled stator and rotor. The units were originally equipped with electrostatic precipitators to control particulate emissions. The Unit 2 electrostatic precipitator has since been converted to a fabric filter baghouse. Unit 3 is identical in layout to Units 1 and 2 except the boiler and turbines are from different manufacturers and the unit was originally equipped with a fabric filter baghouse to control particulate emissions. The steam generator is a front and rear wall fired Babcock and Wilcox unit. The General Electric steam turbine is tandem-compound, two-casing, two-flow condensing, single-reheat turbines. All three units are equipped with wet lime scrubbers to control sulfur dioxide emissions.

Water for plant use is released into the Cottonwood Creek from Joe's Valley conveyed by a direct pipeline from the Millsite Reservoir to the plant. Potable water is piped from the cities of Castledale, Utah or Clawson, Utah. Hunter is a zero discharge plant. The balance of water is evaporated from a pond or used for irrigation of hay crops. Plant sewage is treated and discharged to the evaporation pond.

Coal is supplied by truck from the nearby Sufco, Cottonwood, Dugout, and Deer Creek mines. Hunter has a blending facility in the fuels preparation facility, which allows for combustion of various coal types. Fuel expense at Hunter Units 1 and 2 is shared on an energy usage basis while all other production expenses are shared on an ownership basis.

The Hunter plant currently employs approximately 221 personnel, including 171 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

Q. Please describe the Hunter Unit 1 scrubber project and associated equipment.

A. The Hunter Unit 1 scrubber project will result in improved SO_2 controls for the unit and will install a new scrubber reagent preparation system and an improved scrubber waste material handling system to meet environmental requirements, especially in anticipation of an increase in sulfur content of available coal supplies. The scrubber project will increase the unit's existing wet FGD slurry delivery system capacity by replacing recycle pumps and reagent supply piping and appurtenances, effectively increasing the liquid ("slurry") to flue gas ratio within the absorber vessels; installing a new higher capacity scrubber reagent preparation system; and expanding waste material handling system capacity with a new system. The wet FGD system injects lime slurry in the top of an absorber vessel with a network of spray nozzles. The distribution of spray nozzles causes the lime slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the calcium in the slurry to form a slurry waste of calcium sulfite and calcium sulfate. The waste material handling portion of the project will add oxidation air blowers to the system to ensure conversion of the calcium sulfite to calcium sulfate, which is easier to dewater and transport to a scrubber waste landfill for disposal. Additional reagent preparation and waste disposal capacity is critical to addressing anticipated coal sulfur content increases.

The Company's share of the capital investment for the scrubber project being placed in service during the test period is approximately $52 million. The overall scrubber project work scope is being completed in three primary phases: (1) scrubber vessels and associated equipment modifications and replacement, (2) reagent preparation system replacement, and (3) waste material handling system replacement. The reagent preparation and waste material handling systems being constructed for the project will serve both Hunter Units 1 and 2, with costs allocated accordingly. Hunter Unit 1 construction activities began in 2011, and all phases of the Hunter Unit 1 scrubber project are scheduled to be completed and placed in service by the end of June 2012. Installation of all phases of the Hunter Unit 1 scrubber project are being completed while the plant is in service by converting absorber vessels one at a time and will not require an extended plant maintenance outage for tie-in.

Equipment being installed as part of the various portions of the Hunter Unit 1 scrubber project includes lime slurry reagent preparation equipment; waste material handling system equipment including forced oxidation air blowers, hydroclones as a replacement for the existing thickener, and vacuum drum filters; electrical infrastructure; controls; and other miscellaneous appurtenances and support systems.

Q. Please describe the Hunter Unit 2 scrubber project and associated equipment.

A. The Hunter Unit 2 scrubber project will result in improved SO_2 controls for the unit and will install a new scrubber reagent preparation system and an improved

scrubber waste material handling system to meet environmental requirements. The detailed description of the Hunter Unit 2 scrubber project is for the most part identical to that provided for Hunter Unit 1 above. Also as noted above, the Hunter Unit 2 scrubber project shares certain common scopes of work, with project costs allocated accordingly.

The Company's share of the capital investment for the Hunter 2 scrubber project being placed in service during the test period is approximately $25 million. Construction of the Hunter Unit 2 scrubber project began in 2010 and all phases of the project will have been placed in service by the end of March 2012. To date, modifications and replacement of the scrubber vessels and associated equipment, as well as waste material handling system replacement have been completed and placed in service. Installation of the remaining reagent preparation system phase of the project will be completed while the plant is in service and will not require an extended plant maintenance outage for tie-in.

Q. How do the Hunter Units 1 and 2 scrubber projects benefit from concurrent construction and shared sub-systems?

A. The Hunter Units 1 and 2 scrubber projects are being constructed concurrently but on different schedules to benefit from installation and operational costs synergies achieved through the use of common facilities between the two units.

Q. Please describe the Hunter Unit 2 baghouse conversion project and associated equipment.

A. The Hunter Unit 2 baghouse conversion project converted an existing electrostatic precipitator to a baghouse to meet PM and mercury emissions control

requirements. The baghouse will capture PM and help remove mercury from the flue gas stream as it passes through the baghouse. The dry PM waste stream is then transported to an on-site landfill for disposal.

Other equipment to be installed as part of the project includes upgraded scrubber booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney, relocation of the stack opacity monitors, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The Company's share of the capital investment for the baghouse conversion project placed in service in May 2011, prior to the test period of this docket, is approximately $50 million. Approximately $1.5 million of that capital investment, associated with project close-out, is included in the plant additions adjustment in this docket. Construction began in 2010, and the baghouse conversion was completed during a scheduled plant maintenance outage.

Q. Please describe the Hunter Unit 2 LNB installation project.

A. The LNB installation project on Hunter Unit 2 includes the installation of NO_X combustion controls. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions.

The Company's share of the capital investment for the project placed in service in May 2011, prior to the test period for this docket, is approximately $5 million. Approximately $0.5 million of that capital investment, associated with

project close-out, is included in the plant additions adjustment in this docket. The project was installed during a scheduled plant maintenance outage.

Q. What are the key permits and/or regulations requiring the Hunter Units 1 and 2 scrubber projects and the Hunter Unit 2 baghouse and LNB projects to be installed?

A. To continue compliant operation of Hunter Units 1 and 2, the Company must install the projects described herein to control emissions of criteria pollutants as required by Regional Haze Rules, the State of Utah's § 309 (g) Implementation Plan, the state of Utah's BART review process, and the state of Utah's Approval Order (DAQE-AN0102370012-08) dated March 2008.

Q. What are the Company's specific obligations under the Hunter Units 1 and 2 permit conditions?

A. The permits for the project require that emissions control equipment for each unit be installed and operate with emissions performance test results in compliance with the following emissions limits[10]:

Pollutant	Emissions Limit (lbs. per MMBtu)
NO_X	0.26 (30-day rolling)
SO_2	0.12 (30-day rolling)
PM/PM_{10} [(a)]	0.015 (annual testing)

[(a)] Filterable portion only

[10] Permit DAQE-AN0102370012-08, Article 10.

Q. Are Hunter Units 1 and 2 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Hunter Units 1 and 2 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program. Specific unit SO_2 requirements are identified in Section XX D6 Table 5 of the Utah State Implementation Plan. The SO_2 Backstop Trading program utilizes the BART SO_2 emission rates for Hunter Units 1 and 2 of 0.12 pounds SO_2 per MMBtu. The investments in the Hunter Units 1 and 2 scrubber projects will meet this emission threshold and will also support compliance with the EPA's MATS for acid gases.

Q. How are the Hunter Units 1 and 2 scrubber projects expected to support the EPA's MATS regulations?

A. Emissions limits for acid gases, particularly HCl, are included in the EPA's MATS. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is the surrogate for MATS acid gases emissions compliance. As such, the Hunter Units 1 and 2 scrubber projects with performance requirements described above are expected to support compliance with that portion of the MATS.

Q. How is the Hunter Unit 2 baghouse project expected to support the EPA's MATS regulations?

A. Emissions limits for non-mercury metals are also included in the EPA's MATS. A PM emissions limit of 0.030 pounds filterable PM per MMBtu is the surrogate for MATS non-mercury metals emissions compliance. As such, installation of the baghouse with performance requirements described above is expected to support compliance with that portion of the MATS. With respect to mercury emissions

control, the Company currently expects that the Hunter 2 baghouse will effectuate compliance with MATS mercury emissions limits without the need for application of a coal supply additive to oxidize mercury as the coal is burned in the furnace or the need for ACI.

Q. What emissions performance guarantees are provided via the Hunter Units 1 and 2 scrubber projects EPC contract?

A. The scrubber projects are specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]

Q. What emissions performance guarantees are provided via the Hunter 2 baghouse project EPC contract?

A. The baghouse project was specified with contractually guaranteed performance emission threshold at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
PM/PM_{10}[(a)]	[redacted]

(a) [redacted]

Q. What emissions performance guarantees are provided via the Hunter 2 LNB supply contract?

A. The LNB supply contract includes guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the

operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
NO_X	[redacted]

Q. Did the Company consider alternative technologies to the Hunter Units 1 and 2 emissions control projects included in this case?

A. Yes. The Company completed two technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Hunter Units 1 and 2. In October 2002 Sargent and Lundy completed a coal fleet-wide Multi-Pollutant Control Report and in August 2007 Sargent and Lundy submitted the Hunter Station Units 1 and 2 FGD Upgrade Study, which was supplemented with additional options data in February 2008.

The basis of the Multi-Pollutant Control Report was described earlier in my testimony.

The Hunter Station Units 1 and 2 FGD Upgrade Study was conducted to evaluate SO_2 emissions control options. In completing the study, technology alternatives were investigated and potential reductions in emissions were quantified.

Q. Has the Company evaluated whether the risk-adjusted, least-cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Hunter Units 1 and/or 2?

A. Yes. Prior to executing the EPC contract for the scrubber and baghouse projects in December 2009, the Company evaluated whether the risk-adjusted, least-cost alternative to comply with environmental requirements was to complete the projects versus idling Hunter Units 1 and/or 2 at the end of 2012 and replacing the

generation with market power purchases. The evaluation calculated a PVRR(d) between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation, through the end of the unit's depreciable life. The revenue was derived using the September 30, 2009 PacifiCorp official forward price curve at a corresponding CO_2 price of $8 per ton beginning in 2013. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Hunter Units 1 and 2 in lieu of idling the facilities and replacing the generation with market power purchases. The resulting PVRR(d)s showed positive differentials of [redacted] for Hunter Unit 1 and [redacted] for Hunter Unit 2. It is important to note that the PVRR(d) at the time of the analysis for Hunter Unit 2 included approximately $100 million (Company share) for an SCR installation. Without the SCR installation costs, the PVRR(d) would have been approximately [redacted]. The Hunter Unit 1 PVRR(d) analysis did not include an SCR installation.

Q. Has the Company evaluated the impact of the environmental projects described above on the bus bar cost of Hunter Units 1 and 2?

A. Yes. The Hunter Units 1 and 2 bus bar costs before and after installation of environmental projects described above, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Facility	Bus Bar Cost Before Installation of Env Projects ($/MWh)	Bus Bar Cost Contribution of Env Projects ($/MWh)	Bus Bar Cost After Installation of Env Projects ($/MWh)	Incremental CO_2 Price Revenue Requirement ($/MWh)	Bus Bar Cost After Installation of Env Projects and with CO_2 Price ($/MWh)
Hunter 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs referenced above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Hunter facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year Hunter Units 1 and 2 scrubber projects included in this case, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed in my testimony, the Company has incorporated proxy compliance project costs for emerging rules regulating CCR into the Company's IRP Supplement, which did not identify an accelerated retirement date for Hunter Units 1 or 2.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Hunter facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations

was not available at the time of decision-making and planning of the multi-year Hunter Units 1 and 2 scrubber projects included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Hunter Units 1 or 2.

Wyodak

Q. Please describe the Wyodak facility.

A. Wyodak plant is a single-unit coal-fired power plant located near Gillette, Wyoming in Campbell County, with 64 full-time employees. The site consists of about 36.08 acres at an elevation of 4,400 feet above sea level. A railroad siding connects the plant site to the Burlington Northern-Santa Fe Railroad. PacifiCorp owns 80 percent of Wyodak plant including land, structures and machinery. Black Hills Power owns the remaining 20 percent of the plant. Black Hills Power also shares the substation facilities with the Wyodak plant.

The plant consists of one 335 net megawatt unit with a dry sulfur dioxide scrubber. The steam generator is a front and rear wall-fired, natural circulation boiler supplied by Babcock and Wilcox. The unit is designed to burn sub-bituminous coal from the Powder River Basin. The General Electric steam turbine is a tandem-compound, two-casing, two-flow condensing, single-reheat turbine. The General Electric generator has a water-cooled stator and hydrogen-cooled rotor.

The plant is equipped with an air-cooled condenser which significantly

reduces the plant water makeup requirements. The Wyodak plant's water treatment facility is supplied by discharge water from the Gillette sewage treatment plant. The plant site also has water wells for back-up water supply. Potable water is supplied from Black Hills Power, which is supplied by Fort Union wells. Wyodak Plant is essentially a zero discharge plant. All plant waste streams discharge to the bottom ash pond that serves as an evaporation pond. An NPDES permit is maintained to discharge to Donkey Creek in the event of high precipitation or other upset conditions.

Coal is transported from the adjacent Wyodak mine to the plant by an in-pit mine mouth conveyor system. The Wyodak mine is owned by Black Hills Corporation and operated by its subsidiary, Wyodak Resources. Because this is a mine-mouth plant, no active coal pile is maintained. Coal is delivered to a coal silo that feeds the plant conveyor system.

All of the bottom ash, fly ash, and scrubber waste product are landfilled in the Wyodak Resources mine. Bottom ash is transported to an ash slurry pond, which is partially dredged every two years with the dredged material being landfilled in the mine. Fly ash is pneumatically conveyed to a silo and then periodically trucked to the mine.

Q. Please describe the Wyodak baghouse project and associated equipment.

A. The Wyodak emissions control project consists of installing a stand-alone baghouse for control of PM, SO_2 and mercury emissions from the unit. In order to increase the SO_2 removal efficiency of the unit above 90 percent as required to comply with environmental requirements, a baghouse must be utilized in

conjunction with the existing dry spray dryer absorbers ("SDAs"). Without a baghouse, the best SO_2 removal efficiency the existing SDA on the unit can achieve with Wyodak coal is between 70 and 80 percent. Adding the baghouse is necessary to achieve the permitted SO_2 removal requirements. The baghouse will also improve the unit's efficiency in removing mercury from the flue gas. The dry particulate waste stream captured by the baghouse and containing both fly ash and scrubber waste will be transported to an ash collection pond on adjacent coal mine property for disposal by the mine operator.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The Company's share of the capital investment for the Wyodak baghouse project placed in service in April 2011 is approximately $103 million. Approximately $2 million of that capital investment, associated with project close-out, is included in the plant additions adjustment in this docket. Construction began in 2010, and the baghouse was tied into the existing unit during a scheduled plant maintenance outage.

Q. Please describe the Wyodak LNB installation project.

A. The LNB installation project on Wyodak includes the installation of NO_X combustion controls. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions.

The Company's share of the capital investment for the project placed in service in April 2011, prior to the test period for this docket, is approximately $11 million. The project was installed during a scheduled plant maintenance outage.

Q. What are the key permits and/or regulations requiring the Wyodak baghouse and LNB projects to be installed?

A. To continue compliant operation of Wyodak, the Company must install the baghouse and LNB projects described herein to control emissions of criteria pollutants as required by Regional Haze Rules, the State of Wyoming's § 309 (g) Implementation Plan, the state of Wyoming's BART review, decision and permit (MD-6043) dated December 2009, and the state of Wyoming's Air Quality Permit (MD-7487) dated May 2009.

Q. What are the post-project emission limits for Wyodak as prescribed by the state of Wyoming's permit (MD-7487)?

A. The post-project emission limits for Wyodak as prescribed by permit (MD-7487)[11] is as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.23 (30-day rolling)	1,081 (30-day rolling)	NA
SO_2	0.16 (30-day rolling)	2,115 (3-hour block)	NA
PM/PM_{10} [(a)]	0.015 (annual testing)	71.0 (annual testing)	308.8

[(a)] Filterable portion only

[11] Permit MD-7487, Article 8.

Q. When is the Company required to demonstrate compliance with BART permit conditions?

A. The BART permit for the project required that emissions control equipment be installed and operating with emissions performance test results in compliance with emissions limits before December 31, 2011.[12] The permit emissions limits[13] are as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.23 (30-day rolling)	1,081 (30-day rolling)	4,735
PM/PM_{10} [(a)]	0.015 (annual testing)	71.0 (annual testing)	309

[(a)] Filterable portion only

Q. Are Wyodak SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Wyodak emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with Chapter 14, Sections 2 and 3, of the WAQSR. The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Wyodak of 0.15 pounds SO_2 per MMBtu. The investment in the Wyodak baghouse will support this emission threshold and will also support compliance with the EPA's MATS limits for acid gases.

Q. Are Wyodak SO_2 and NO_X emissions considered in the development of the PALs for the Wyodak plant?

A. Yes. The state of Wyoming's Air Quality Permit (MD-7487) establishes PALs

[12] Permit MD-6043, Article 14.
[13] Permit MD-6043, Article 5.

for emissions of SO_2 and NO_X at Wyodak. The SO_2 and NO_X PALs limit the annual tons of SO_2 and NO_X that may be emitted from the facility. Typically, past actual emissions are used to develop PALs. However, since historic data was not available for Wyodak with the new SO_2 and NO_X controls projects being placed in service, the post-project potential emissions from these units are used. The annual SO_2 potential to emit for each unit was calculated using the post-project potential emission rate of 0.16 pounds SO_2 per MMBtu. The annual NO_X potential to emit was calculated using the post-project potential emission rate of 0.23 pounds NO_X per MMBtu. The following table summarizes the emissions that were included in the development of the Wyodak PALs:

Component Description	**Annual NO_X Emissions (tons per year)**	**Annual SO_2 Emissions (tons per year)**
Wyodak (potential-to-emit)	4,736	3,294
Total Annual Emissions (PALs)	4,736	3,294

Q. How is the Wyodak baghouse expected to support the EPA's MATS?

A. Emissions limits for acid gases, particularly HCl, and non-mercury metals are included in the EPA's MATS. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is the surrogate for MATS acid gases emissions compliance, and a PM emissions limit of 0.030 pounds filterable PM per MMBtu is the surrogate for MATS non-mercury metals emissions compliance. As such, installation of the baghouse with performance requirements described above is expected to support compliance with those portions of the MATS. With respect to mercury emissions control, the Company's current plan to control mercury emissions will involve the application of a coal supply additive to oxidize mercury as the coal is burned in

the furnace. Oxidized mercury can be removed in the scrubber–baghouse system. While ACI can also be used to meet the final MATS mercury emissions limit, the new baghouse is expected to significantly reduce or eliminate the need for ACI.

Q. What emissions performance guarantees are provided via the baghouse EPC contract?

A. The baghouse is specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]
PM/PM_{10}[(a)]	[redacted]

(a) [redacted]

Q. What emissions performance guarantees are provided via the Wyodak LNB supply contract?

A. The LNB supply contract includes guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
NO_X	[redacted]

Q. Did the Company consider alternative technologies to the Wyodak emissions control projects described in this testimony?

A. Yes. The Company completed three technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Wyodak. In October 2002 Sargent and Lundy completed a coal fleet-wide Multi-Pollutant Control Report; in January 2005 Sargent and Lundy completed the NO_X Emission

Reduction Technologies Study; and in February of 2007 CH2M Hill completed the BART Analysis for Wyodak.

The basis of the Multi-Pollutant Control Report and the NO_X Emission Reduction Technologies Study were described earlier in my testimony.

The BART Analysis for Wyodak was conducted for criteria pollutants NO_X, PM_{10} and SO_2. In completing this BART Analysis, technology alternatives were investigated and potential reductions in emissions were quantified. The BART Analysis for Wyodak was considered in the state of Wyoming's BART determination, permit requirements, and SIP discussed above.

Q. Has the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to invest in the emissions control equipment described in this testimony or to idle Wyodak?

A. Yes. Prior to executing the EPC contract for the project in May 2009, the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to add the baghouse system versus idling Wyodak in 2009 and replacing the generation with market power purchases. The evaluation calculated a PVRR(d) between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation, through the end of the unit's depreciable life. The revenue was derived using the March 31, 2009 PacifiCorp official forward price curve at a corresponding CO_2 price of $8 per ton beginning in 2013. The results of the

evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Wyodak in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted].

Q. Has the Company evaluated the impact of the environmental projects described in this testimony on the bus bar cost of Wyodak?

A. Yes. The Wyodak bus bar costs before and after installation of environmental projects described in this testimony, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	Bus Bar Cost Contribution of Environmental Projects ($/MWh)	Bus Bar Cost After Installation of Environmental Projects ($/MWh)	Incremental CO_2 Price Revenue Requirement ($/MWh)	Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs referenced above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Wyodak facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year Wyodak baghouse project included in this case, the Company is committed to

understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed in my testimony, the Company has incorporated proxy compliance project costs for emerging rules regulating CCR into the Company's IRP Supplement, which did not identify an accelerated retirement date for Wyodak.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Wyodak facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of decision-making and planning of the multi-year Wyodak baghouse project included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Wyodak.

Jim Bridger Unit 3

Q. Please describe the Jim Bridger facility and Jim Bridger Units 3 in particular.

A. The Jim Bridger plant is a four unit coal-fired power plant located in Sweetwater County, Wyoming with a total net maximum capacity of 2,117 MW, with 328 full-time employees. The site consists of about 1,000 acres at an elevation of 6,500 feet above sea level. Rail access to the plant is from Union Pacific rail lines. PacifiCorp owns two-thirds (66.7 percent) of Bridger plant including land,

structures and machinery. Idaho Power Company owns the remaining one-third (33.3 percent).

The plant consists of four almost-identical units with the exception that Unit 4 has a sulfur dioxide scrubber of a different design than Units 1-3. Unit 4 also has vane-axial induced-draft fans, rather than the centrifugal fans on Units 1-3. The steam generators are tangentially-fired, controlled circulation boilers supplied by Combustion Engineering. The units are designed to burn sub-bituminous coal from the local area. The General Electric steam turbines are tandem-compound, two-casing, four-flow condensing, single-reheat turbines. The General Electric generators have water-cooled stators and hydrogen cooled rotors. Each tangentially-fired boiler typically consumes 250 tons of coal per hour, for a total of 8.5 million tons of coal per year.

Coal is transported from the Bridger Mine to the plant by a 2.4 mile overland belt conveyor, as well as by truck and rail. The Bridger Coal mine is owned by PacifiCorp and operated by the PacifiCorp subsidiary, Bridger Coal Company. Secondary and supplemental fuel sources are from Black Butte Coal Company and are delivered by rail. A portion of the fly ash produced at the plant is sold to the cement industry. The remaining bottom ash and fly ash is landfilled on the plant site.

The ash landfill contains bottom ash, fly ash, and industrial waste. The landfill meets RCRA Subtitle D requirements. Two flue-gas desulfurization slurry ponds exist at Jim Bridger plant. FGD Pond 1is currently full and is now being capped and re-claimed. FGD Pond 2 is currently being utilized.

Water is supplied to the plant via two 8-mile supply lines from the Green River, at the pump station just south of the town of Green River, Wyoming. Raw water discharges into a large raw water surge pond at the plant.

Q. Please describe the Jim Bridger Unit 3 scrubber project and associated equipment.

A. The Jim Bridger scrubber project primarily included the upgrade and replacement of existing pumps, spray headers, trays, induced draft fans, and ancillary equipment to improve the control of SO_2 emissions from the unit. The capital investment for the project placed in service in June 2011 is approximately $17 million. Approximately $1 million of that capital investment, associated with project close-out, is included in the plant additions adjustment in this docket. Construction began in 2010, and the project was tied into the existing unit during a scheduled plant maintenance outage. The project will improve sulfur dioxide removal efficiency while enabling the bypass dampers to bypass less flue gas from the unit.

Q. What are the key permits and/or regulations requiring the Jim Bridger Unit 3 scrubber project to be completed?

A. To continue compliant operation of Jim Bridger Unit 3, the Company must install the scrubber project described herein to control emissions of criteria pollutants as required by NAAQS, the state of Wyoming's § 309 Implementation Plan, and the State of Wyoming's permit (MD-5156) dated May 2009.

Q. What are the key permits and/or regulations requiring the Jim Bridger Unit 3 scrubber project to be completed?

A. To continue compliant operation of Jim Bridger Unit 3, the Company must install the scrubber project described herein to control emissions of criteria pollutants as required by Regional Haze Rules and the state of Wyoming's Air Quality Permit (MD-1552A) dated March 2009.

Q. What is the post-project SO_2 emission limit for Jim Bridger Unit 3 as prescribed by the state of Wyoming's permit (MD-1552A)?

A. The post-project SO_2 emission limit for Jim Bridger Unit 3 as prescribed by permit (MD-1552A)[14] is as follows:

Pollutant	Emissions Limit (lbs. per MMBtu)	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
SO_2	0.15 (12-month rolling)	900 (24-hour rolling)	NA

Q. Are Jim Bridger Unit 3 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Jim Bridger Unit 1 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with Chapter 14, Sections 2 and 3, of the WAQSR. The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Jim Bridger Unit 3 of 0.15 pounds SO_2 per MMBtu. The investment in the Jim Bridger Unit 3 scrubber project will meet this emission threshold and will also support compliance with the EPA's MATS limits for acid gases.

[14] Permit MD-1552A, Article 8.

Q. Are Jim Bridger Unit 3 SO_2 and NO_X emissions considered in the development of the PALs for the Jim Bridger plant?

A. Yes. The state of Wyoming's permit (MD-1552) dated April 2007 establishes PALs for emissions of SO_2 and NO_X at Jim Bridger. The SO_2 and NO_X PALs limit the annual tons of SO_2 and NO_X that may be emitted from the facility. The PALs established in 2007 included a step decrease approach. The first PALs went into effect when the permit was issued and were based on the past actual annual SO_2 and NO_X emissions from the four units. The second PALs go into effect following the installation of the upgraded SO_2 and NO_X controls. The calculation of the reduced PAL rates is based on the facility's potential annual heat input and the permitted SO_2 and NO_X emission rates. The SO_2 emission rate used to calculate the PAL is 0.15 pounds SO_2 per MMBtu, and the NO_X emission rate used in the PAL calculation is 0.26 pounds NO_X per MMBtu. The following table summarizes the PAL rates prior to completion of the pollution control equipment, and those rates that go into effect following the installation of the controls:

Component Description	Annual NO_X Emissions (tons per year)	Annual SO_2 Emissions (tons per year)
Total Annual Emissions (PALs); prior to controls	33,607	22,215
Total Annual Emissions (PALs); following installation of controls	24,233	13,980

Q. How is the Jim Bridger Unit 3 scrubber project expected to support the EPA's MATS?

A. Emissions limits for acid gases, particularly hydrogen chloride ("HCl"), and non-mercury metals are included in the EPA's MATS. An SO_2 emissions limit of 0.20

pounds SO_2 per MMBtu is the surrogate for MATS acid gases emissions compliance, and a PM emissions limit of 0.030 pounds filterable PM per MMBtu is the surrogate for MATS non-mercury metals emissions compliance. As such, completion of the scrubber project with performance requirements described above and contract guarantees as described below is expected to support compliance with those portions of the MATS. With respect to mercury emissions control, the Company's current plan to control mercury emissions will involve the application of a coal supply additive to oxidize mercury as the coal is burned in the furnace. Oxidized mercury can be removed in the wet FGD system. The use of a FGD system additive can prevent the recovered mercury from being re-emitted from the FGD system. While ACI can also be used to meet the final MATS mercury emissions limit, the use of a FGD system additive in conjunction with a coal supply additive is currently expected to significantly reduce or eliminate the need for ACI more economically.

Q. What emissions performance guarantees are provided via the scrubber project EPC contract?

A. The scrubber project is specified with a contractually guaranteed performance emission threshold at the following limit:

Pollutant	Emissions Limit
SO_2	[redacted]

Q. Did the Company consider alternative technologies to the Jim Bridger Unit 3 scrubber project described in this testimony?

A. Yes. The Company completed three technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Jim Bridger Unit 3. In

October 2002 Sargent and Lundy completed a coal fleet-wide Multi-Pollutant Control Report; in January 2005 Sargent and Lundy completed the NO_X Emission Reduction Technologies Study; and in February of 2007 CH2M Hill completed the BART Analysis for Jim Bridger Units 1 through 4.

The basis of the Multi-Pollutant Control Report and the NO_X Emission Reduction Technologies Study were described earlier in my testimony.

The NO_X Emission Reduction Technologies Study compared 16 emission control technologies, status of the technology development, performance, approximate initial capital costs, and approximate fixed and variable operational and maintenance costs.

The BART Analysis for Jim Bridger Units 1 through 4 was conducted for criteria pollutants NO_X, PM_{10} and SO_2. In completing this BART Analysis, technology alternatives were investigated and potential reductions in emissions were quantified. The BART Analysis for Jim Bridger Units 1 through 4 was considered in the state of Wyoming's BART determination, permit requirements, and SIP discussed above.

Q. Has the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to invest in the emissions control equipment described in this testimony or to idle Jim Bridger Unit 3?

A. Yes. Prior to executing the EPC contract for the project in December 2008, the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to complete the

scrubber project versus idling Jim Bridger Unit 3 in 2008 and replacing the generation with market power purchases. The evaluation calculated a PVRR(d) between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation, through the end of the unit's depreciable life. The revenue was derived using the September 30, 2008 PacifiCorp official forward price curve at a corresponding CO_2 price of $8 per ton beginning in 2013. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Jim Bridger Unit 3 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted].

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Jim Bridger Unit 3?

A. Yes. The Jim Bridger Unit 3 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	**Bus Bar Cost Contribution of Environmental Projects ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects ($/MWh)**	**Incremental CO_2 Price Revenue Requirement ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs referenced above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Jim Bridger facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year Jim Bridger Unit 1 scrubber project discussed in this testimony, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed in my testimony, the Company has developed proxy compliance project costs for emerging rules regulating CCR for use in its forward-looking business planning processes. In fact, the aforementioned costs have been incorporated into the Company's IRP Supplement, which did not identify an accelerated retirement date for Jim Bridger Unit 3.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Jim Bridger facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of decision-making and planning of the multi-year Jim Bridger Unit 3 scrubber project included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP

Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Jim Bridger Unit 3.

Emissions Control Operating Costs

Q. Are there additional operating costs that will be incurred as a result of the installation of each of the emissions control projects described in this testimony?

A. Yes. Unfortunately, but unavoidably, the operation of the new emissions control equipment results in increased operation and maintenance costs associated with reagent, waste disposal, and equipment maintenance. Incremental operation and maintenance costs associated with the emissions control equipment described in this testimony are explained in Company witness Mr. Dana M. Ralston's direct testimony.

Carbon Plant Depreciation

Q. Does existing emissions control equipment installed on Carbon Units 1 and 2 facilitate compliance with the EPA's MATS?

A. No. The EPA's recently finalized MATS incorporate specific emissions requirements for mercury, non-mercury metallic HAPs, and acid gases. The current emissions profiles of Carbon Units 1 and 2 do not demonstrate compliance with MATS limits for the pollutants regulated under that rule. Emissions control equipment currently installed on the units is limited to electrostatic precipitators for particulate matter control. The units have not been retrofitted with scrubbers, baghouses, or other emissions control equipment that would foster the units' abilities to comply.

Q. Are there additional air emissions regulations beyond MATS that must also be considered in long-term decision making for Carbon Units 1 and 2?

A. Yes. In addition to MATS, Carbon Units 1 and 2 are also subject to NAAQS requirements and long-term Regional Haze Rule planning. The Company anticipates that Carbon Units 1 and 2 will not likely be capable of demonstrating compliance with the 1-hour NO_2 or 1-hour SO_2 NAAQS, as would be expected to be required under any major plant modification permitting process, primarily due to the plant's unique geographic location.

Q. Will the Company assess emissions compliance options, notwithstanding anticipated difficulties in meeting the emissions requirements discussed above?

A. Yes. The Company is in the process of assessing emerging technologies, namely dry sorbent injection into the combustion processes of the units, in order to identify possible MATS compliance options. Should the testing provide positive results for all MATS regulated emissions, the Company will further assess the long-term commercial viability and cost of such emerging technologies, as well as the ability of said technologies to support compliance with other emissions regulations such as NAAQS and long-term Regional Haze Rule planning.

Q. Will the Company also assess the feasibility, economics, and associated emissions reductions of major environmental equipment retrofits and conversion of the units to natural gas as a fuel source?

A. Yes. The Company has assessed the feasibility and economics of major environmental equipment retrofits of Carbon Units 1 and 2 in the past and did not

identify viable least-cost options, accounting for risk and uncertainty, for the units. The Company has also assessed conversion of the units to natural gas as a fuel source and did not find that approach to result in favorable economics nor an acceptable emissions profile for long-term environmental compliance. Each of those assessments will be further reviewed against current environmental requirements and economic drivers to ensure that the most current and appropriate inputs are being assessed.

Q. Has the Company communicated with key stakeholders, particularly community and governmental leaders in the Carbon plant area, to keep them apprised of the Company's assessment of compliance alternatives for the Carbon facility?

A. Yes. While the Company's decision-making regarding the Carbon plant must be demonstrated to be in the best interests of the Company's customer base as a whole, the Company does recognize that retirement of a major power generation facility significantly impacts the state, region, and communities most directly tied to its support infrastructure and employee base. The Company has been and will continue to openly communicate with key stakeholders with respect to its compliance plans and considerations in that regard.

Q. Does the Company currently anticipate that retiring the Carbon plant in early 2015 will be the least-cost alternative, accounting for risk and uncertainty, to comply the EPA's MATS and other environmental regulations?

A. Yes. While the assessments described above will continue, the Company does not

expect to identify a least-cost option, accounting for risk and uncertainty, other than retiring Carbon Units 1 and 2. However, the Company is also currently assessing potential transmission system impacts associated with potential retirement of the Carbon units, particularly with respect to long-term regional transmission system reliability, that may result in a need to request an extension of the initial April 2015 compliance deadline for the Carbon facility to accommodate transmission system improvements. The initial results of that study are expected in April 2012. Should reliability concerns or other considerations support the need for an extended compliance schedule, the Company will work within the conditions included within the MATS regulations and administrative guidance to request an appropriate compliance extension.

Q. What would be the anticipated duration of such a compliance extension?

A. The Company would currently not anticipate a MATS compliance extension to extend beyond one year of the originally anticipated compliance deadline. While there are provisions for additional extensions discussed in MATS administrative guidance, any such extension request is currently only anticipated to be available after a unit has demonstrated non-compliance with MATS and subjects itself to an Administrative Order process with the EPA. The Company does not believe that knowingly planning for such an approach is plausible or aligned with its Environmental Respect policy.

Q. What does the Company currently estimate the cost of decommissioning the Carbon facility and remediating the site after retirement to be?

A. The Company currently estimates the cost of completely decommissioning the

facility and remediating the site to be approximately [redacted] million. The Company will be refining that estimate over the coming months as its compliance assessment continues.

Q. Is the Company legally obligated to decommission the facility and remediate the site after the Carbon units are retired?

A. The Company is legally obligated to decommission and remediate certain portions of the facility upon removing them from service, namely the coal combustion residuals landfill, the coal pile footprint, and certain other ancillary facility services.

Q. When would the Company plan to decommission the balance of the facility infrastructure?

A. Although there are currently no legal obligations for the Company to decommission and remediate the balance of the Carbon facility infrastructure, it is the Company's position that other liabilities such as hazardous materials, primarily asbestos and lead-based paint, and other long-term site infrastructure related exposures are most appropriately addressed immediately and under today's environmental and safety standards, rather than deferring action and potentially incurring additional remediation costs and obligations in the future. As such, the Company's position is that it is most appropriate to decommission the balance of the facility infrastructure immediately following retirement to address hazardous materials and to prevent the facility from becoming an unsafe and/or unsecure environment due to lack of maintenance and/or available resources in a deferred decommissioning approach.

Q. How does the Company propose to address remaining Carbon plant depreciation expense?

A. The Company's witness, Mr. Dalley, will address the Company's proposed treatment of plant depreciation expense.

Ongoing Planning

Q. Will the Company continue to account for emissions control investments in its forward-planning cycles?

A. Yes. The Company makes every effort to identify, quantify, and include forward-looking environmental compliance projects in its planning processes.

Q. What process is in place to explore ongoing investment in the Company's coal units?

A. The existing integrated resource planning ("IRP") process conducted across the six states served by the Company provides the process to analyze and address ongoing investment in the Company's coal units versus alternatives including retirement, replacement and repowering. Future IRPs will increasingly focus upon the complexity in balancing factors such as:

(1) Pending environmental regulations and requirements to reduce emissions in addition to addressing waste disposal and water quality concerns;

(2) Avoidance of excessive reliance on any one generation technology;

(3) Costs and trade-offs of various resource options including energy efficiency, demand response programs, and renewable generation;

(4) State-specific energy policies, resource preferences, and economic development efforts;

(5) The need for additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and

(6) Managing the impact on customer rates.

Q. Does the Company continue to improve its analysis of market risk associated with emerging environmental regulations, particularly risks associated with greenhouse gases?

A. Yes. In support of the Company's 2011 IRP development process, the Company incorporated System Optimizer coal utilization case studies 20-24. These case studies were designed to investigate the impacts of CO_2 cost and gas price scenarios on the Company's existing coal fleet after accounting for coal plant incremental costs. This study used new modeling functionality that enables representation of existing plant repowering and retrofitting as future resource options. Additionally, the Company acquired and used customized enhancements to the model for estimating carbon dioxide emissions and regulatory costs associated with spot market balancing sales and purchases. These case studies included capital expenditures for planned and/or ongoing emissions control equipment investments included in the Company's business plan, including MATS compliance costs. However, due to the timing of developing inputs to these case studies in 2010, the Company's preliminary capital cost estimates for compliance with the EPA's proposed CCR rules and Clean Water Act Section

316(b) cooling water intake rules were not incorporated. Proxy CCR and Clean Water Act Section 316(b) compliance project cost estimates have since been incorporated into the Company's business planning processes.

Q. Has the Company developed updated System Optimizer modeling as part of its 2011 IRP process subsequent to the case studies discussed above?

A. Yes. The Company has built upon the 2011 IRP coal utilization case studies to better evaluate the economics associated with the Company's CAI investments. The specific results of this update can be reviewed in the IRP Supplement filed in response to party comments in the 2011 IRP dockets in the various states the Company serves.

Q. What improvements were made in the updated System Optimizer modeling?

A. Improvements were made in three areas. First, the Company made improvements in the study design to better capture the tradeoff in cost between existing coal resources requiring CAI investments and costs for replacement resource options. Second, the Company updated environmental compliance cost assumptions for all coal resources to reflect updated information regarding emerging regulations. Third, the Company revisited the market price and CO_2 cost scenarios to update alignment with current economic conditions and policy developments.

Q. How did the Company improve the design of the coal utilization sensitivities to better capture cost tradeoffs between existing coal resources and potential replacement resources?

A. In the original coal utilization sensitivities, the Company allowed existing coal resources to be replaced only by natural gas combined cycle resources located at

the site of the coal unit being displaced. These natural gas resource replacement options were scalable in size so that the replacement option equaled the size of the coal unit it could displace. In the IRP Supplement, the Company allowed existing coal resources to be displaced by a wide range of resource options consistent with the resource alternatives used in the 2011 IRP and did not allow these resources to be scalable in size. As such, coal resources could be displaced by green field combined cycle resources, green field simple cycle resources, firm market purchases and demand side management ("DSM") resources in much the same way that resource portfolios were developed in the 2011 IRP process; however, the Company did not allow growth resources to fill long-term resource needs.

Q. What is a growth resource and why was it excluded as a resource replacement option in the IRP Supplement?

A. Growth resources are included as a generic resource alternative in the out years of the IRP planning horizon – beginning 2021 in the 2011 IRP. This resource is intended for capacity balancing in each load area to ensure that capacity planning margins are met in the out years of the planning horizon. Growth resources are ascribed costs that are derived from forward power market prices. Growth resources have traditionally been used in the IRP to manage simulation run time by simplifying resource selection beyond the first 10-years of the planning period. Because growth resources are generic resources with costs tied to the power market, they do not accurately reflect the true cost of a replacement resource

requiring capital investment or ongoing fixed costs.[15] Allowing growth stations to replace coal resources would provide an artificial incentive for the System Optimizer model to retire units assuming they could be replaced by a generic resource option without appropriate cost metrics.

Q. Did the IRP Supplement assume that intermittent renewable resources such as wind could replace coal fueled generation?

A. No. Intermittent resources such as wind can supply system energy, but are limited in their ability to provide system capacity given the non-dispatchable and intermittent nature of wind resource generation. Because the Company's coal fueled generation provides capacity to the system, intermittent resources such as wind are not suitable replacement alternatives and were not included as a resource replacement option.

Q. What other improvements were made to the study design for the IRP Supplement?

A. To more accurately report findings for specific coal units in the IRP Supplement, the Company forced existing coal units to be idled and decommissioned at the end of their currently established depreciable lives. To this end, the IRP Supplement forces the removal of eight coal units from the existing resource mix within the 20-year planning period. In the IRP Supplement, the Carbon plant is assumed to be idled and decommissioned at the end of its currently approved depreciable

[15] Growth resources, which can be added as system resources in a given load area, should not be confused with front office transactions. Front office transactions are firm forward market purchases made at market hubs.

life[16] in 2020, the Dave Johnston plant is assumed to be idled and decommissioned at the end of its currently approved depreciable life in 2027, and the Naughton plant is currently assumed to be idled and decommissioned at the end of its currently approved depreciable life in 2029.

Q. Please describe the environmental compliance cost assumption updates adopted for the IRP Supplement.

A. The original coal utilization sensitivities reported in the 2011 IRP were performed using then current CAI costs needed to achieve compliance with expectations for best available retrofit technology requirements under the EPA's Regional Haze Rules and increasingly stringent NAAQS for criteria pollutants. Costs in the original sensitivities also reflected then current expectations to meet compliance with MATS technology requirements. Total costs, inclusive of Allowance for Funds Used During Construction ("AFUDC"), for all CAI in the original sensitivities totaled approximately [redacted] for the period 2011 through 2022.

In the IRP Supplement, the scope was expanded to include expected investment costs needed to meet compliance for CCR and Clean Water Act Section 316(b) regulations. Costs for out-year SCR installations with proxy in-service dates beyond 2022 at the Company's Hunter, Huntington, and Wyodak facilities were also included to add conservatism to results by reflecting potential future environmental project requirements, although no such requirements or obligations currently exist. With those costs included, total environmental

[16] The depreciable life assumptions utilized for each unit in the IRP Supplement were aligned with the depreciable lives currently stipulated by each of the state utility commissions with Company oversight, other than Oregon. The Oregon stipulated depreciable lives for the Carbon, Dave Johnston, and Naughton facilities are 2016, 2023, and 2028, respectively.

compliance costs, inclusive of AFUDC, in the IRP Supplement total just over [redacted] for the period 2011 through 2030.

Q. How have CO_2 cost sensitivities been incorporated into the Company's assessments of continuing to invest in individual coal fueled generating units?

A. The Company has incorporated three different CO_2 cost scenarios in the Company's IRP Supplement: a base case, a high case and a low case. The base case represents the Company's most current expectations for CO_2 price levels and timing in conjunction with the Company's most current official forward price curve. The high case captures higher CO_2 costs beginning sooner than assumed in the base case alongside a future having higher natural gas prices. The low case represents a future where no policy is effectuated that places CO_2 costs on emissions in the power sector through the 20-year study horizon and gas prices are lower than those expected under the base case. The high and low cases are variations on the base case that represent a reasonable range of high and low market conditions having potential to influence the economic viability of environmental investments required on the Company's coal fueled generation fleet. The CO_2 costs and natural gas prices assumed for these three scenarios are further described in the IRP Supplement.

Q. How did the Company develop its CO_2 cost assumptions for the low and high case scenarios used in the IRP Supplement?

A. The Company compared external forecasts of CO_2 cost to develop a reasonable range around the base case representative of plausible high and low cost outcomes. For the low case, the Company assumed there would be no policy

developments that would impute a cost on CO_2 emissions in the power sector within the 20-year study period. This assumption is consistent with reports from PIRA who have indicated that there is real potential for a zero CO_2 cost scenario, with no regulation of CO_2 in the foreseeable future. The high CO_2 cost assumptions adopted for the IRP Supplement are higher and start sooner than any of the current projections from a variety of third party forecast services, including PIRA, Wood Mackenzie, and IHS CERA, but remain consistent with an upper limit that would have been established under the American Power Act of 2010 as proposed by Senators Kerry and Lieberman in May 2010, although the proposed legislation was not passed into law.

Q. What other cost assumption updates were made for the IRP Supplement?

A. Assumptions for the recovery of remaining depreciation costs that would be incurred as a result of an early retirement were improved. In the original coal utilization sensitivities, recovery of any remaining depreciation for the underlying resource, before accounting for incremental capital associated with CAI costs, was incorporated as a cost that encumbered the natural gas replacement resource. Because these costs are applicable regardless of whether the coal resource is kept in service or if the coal resource is retired, the IRP Supplement removed the cost of recovery for any remaining depreciation associated with the underlying resource. Rather, in the IRP Supplement, only recovery of depreciation remaining from incremental environmental compliance costs at any point in time beyond the initial investment period is included in the replacement decision being made by the System Optimizer model.

Q. Did the results of the IRP Supplement identify coal fueled generation assets operated by the Company as candidates for accelerated idling?

A. No.

Q. Has the Company committed to update the IRP Supplement as part of its 2011 IRP Update?

A. Yes. The Company has included an action item in its 2011 IRP Revised Action Plan to provide an updated Coal Replacement Study as part of its 2011 IRP Update. The updated Coal Replacement Study will be performed using the System Optimizer model and will explore a range of natural gas prices and CO_2 costs in varying combinations.

Conclusion

Q. Please summarize your testimony.

A. The emissions control equipment investments presented in this case are required to comply with existing environmental regulations, and support compliance with newly promulgated environmental regulations such as the EPA's MATS. The investments allow for the continued operation of low-cost coal-fired generation facilities, while achieving significant environmental improvements. The Company's coal fueled generation facilities produce energy at costs lower than market prices, enabling the Company to serve its customers at some of the lowest retail electricity prices in the United States. Prudent investment in the Company's existing coal fueled generating units increases the probability of continued safe, compliant, and reliable operation of these low-cost resources, and is appropriately balanced with the Company's ongoing investments in additional natural gas

fueled and renewable generation resources. The capital investments described in this testimony are reasonable and prudent, and the Company should be granted full cost recovery for these investments.

The Company also currently anticipates that retiring the Carbon plant in early 2015 will be the least-cost alternative, accounting for risk and uncertainty, to comply with the EPA's MATS. The Company has proposed a rate treatment methodology for remaining depreciation expense, as well as asset retirement obligation costs. The Company believes this rate treatment methodology is in the best interest of customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-246
Exhibit PAC/501
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Overview of PacifiCorp's Environmental Control Plan - Company Operated Facilities

March 2012

Overview of PacifiCorp's Environmental Control Plan

				NOx Emission Controls					SO_2 Emission Controls		Particulate Controls			MATS (HAPs MACT) Compliance	CCR Compliance		
Unit	Year Installed	Regulatory Depreciation Life (non-OR)	Accredited Net MW Rating (100% Share)	Neural Network System	Low Nox Burners	Overfire Air	Selective Non-Catalytic Reduction	Selective Catalytic Reduction	Dry Scrubber	Wet Scrubber	Electrostatic Precipitator	Wet Scrubber	Baghouse	Mercury (Hg) Control	Pond closure, wet-to-dry conversion, new facilities (In-service dates shown represent currently anticipated initial compliance requirement)	Potential to Operate on Full Load Natural Gas	PacifiCorp Ownership
Carbon 1	1954	2020	67	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	In Service Cold Side	-	Not Planned	Under Review	2017	Not Planned	100.00%
Carbon 2	1957	2020	105	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	In Service Cold Side	-	Not Planned	Under Review	2017	Not Planned	100.00%
Cholla 4	1981	2042	395	Not Planned	In Service	In Service	Not Planned	Not Planned	N/A	In Service	N/A	-	In Service	2014 - Coal Oxidizer	2017	Not Planned	100.00%
Colstrip 3	1984	2046	740	Not Planned	In Service	In Service	Not Planned	Not Planned	N/A	In Service	N/A	In Service	N/A	In Service	2017	Not Planned	100.00%
Colstrip 4	1986	2046	740	Not Planned	In Service	In Service	Not Planned	Not Planned	N/A	In Service	N/A	In Service	N/A	In Service	2017	Not Planned	100.00%
Craig 1	1980	2034	428	Not Planned	In Service	In Service	2017	Not Planned	N/A	In Service	N/A	-	In Service	2014 - Coal Oxidizer	2017	Not Planned	19.28%
Craig 2	1979	2034	428	Not Planned	In Service	In Service	Not Planned	2016	N/A	In Service	N/A	-	In Service	2014 - Coal Oxidizer	2017	Not Planned	19.28%
Dave Johnston 1	1958	2027	106	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	100.00%
Dave Johnston 2	1960	2027	106	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	100.00%
Dave Johnston 3	1964	2027	220	Not Planned	In Service	In Service	Not Planned	Not Planned	In Service	N/A	N/A	-	In Service	2014 - Sorb Inj + Oxidizer	2017	Not Planned	100.00%
Dave Johnston 4	1972	2027	330	Not Planned	In Service	In Service	Not Planned	Not Planned	2012	N/A	In Service Cold Side	-	2012	2014 - Sorb Inj + Oxidizer	2017	Not Planned	100.00%
Hayden 1	1965	2030	184	Not Planned	In Service	In Service	Not Planned	2015	In Service	N/A	N/A	-	In Service	2014 - Sorbent Injection	2017	Not Planned	24.46%
Hayden 2	1976	2030	262	Not Planned	In Service	In Service	Not Planned	2016	In Service	N/A	N/A	-	In Service	2014 - Sorbent Injection	2017	Not Planned	12.60%
Hunter 1	1978	2042	446	Not Planned	2014	2014	Not Planned	2026[1]	N/A	In Service 2012 -	In Service Cold Side	-	2014	Not Planned	2017	Not Planned	93.75%
Hunter 2	1980	2042	446	Not Planned	In Service	In Service	Not Planned	2023[1]	N/A	In Service 2012 -	N/A	-	In Service	Not Planned	2017	Not Planned	60.31%
Hunter 3	1983	2042	460	Not Planned	In Service	In Service	Not Planned	2024[1]	N/A	In Service	N/A	-	In Service	Not Planned	2017	Not Planned	100.00%
Huntington 1	1977	2036	459	Not Planned	In Service	In Service	Not Planned	2023[1]	N/A	In Service	N/A	-	In Service	Not Planned	2017	Not Planned	100.00%
Huntington 2	1974	2036	450	Not Planned	In Service	In Service	Not Planned	2026[1]	N/A	In Service	N/A	-	In Service	Not Planned	2017	Not Planned	100.00%
Jim Bridger 1	1974	2037	531	Not Planned	In Service	In Service	Not Planned	2022	N/A	In Service	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	66.67%
Jim Bridger 2	1975	2037	527	Not Planned	In Service	In Service	Not Planned	2021	N/A	In Service	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	66.67%
Jim Bridger 3	1976	2037	523	Not Planned	In Service	In Service	Not Planned	2015	N/A	In Service	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	66.67%
Jim Bridger 4	1979	2037	530	Not Planned	In Service	In Service	Not Planned	2016	N/A	In Service	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	66.67%
Naughton 1	1963	2029	160	Not Planned	2012	2012	Not Planned	Not Planned	N/A	2012	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	100.00%
Naughton 2	1968	2029	210	Not Planned	In Service	In Service	Not Planned	Not Planned	N/A	In Service	In Service Cold Side	-	Not Planned	2014 - Sorb Inj + Oxidizer	2017	Not Planned	100.00%
Naughton 3	1971	2029	330	Not Planned	In Service	In Service	Not Planned	2014	N/A	In Service 2014-Upgrade	In Service Cold Side	-	2014	2014 - Sorb Inj + Oxidizer	2017	Under Review	100.00%
Wyodak	1978	2039	335	Not Planned	In Service	In Service	Not Planned	2026[1]	In Service	N/A	N/A	-	In Service	2014 - Sorb Inj + Oxidizer	2017	Not Planned	80.00%

1. PacifiCorp has included these SCRs in its economic analyses to add conservatism to the results presented. SCRs are required at Jim Bridger Units 1-4 and Naughton Unit 3; however, no company commitments or agency actions have been taken that require installation of the other SCRs listed.

Currently required environmental compliance projects yet to be placed in service

Required environmental projects placed in service during the test period for this docket

Exhibit PAC/501
Teply/1

Known Regulatory Drivers and Environmental Projects - Company Operated Facilities

(PacifiCorp Pollution Control Projects Over $5m)

									Environmental Regulations and Requirements for Installing Control Equipment					Preliminary Assesment Proposed 40 CFR Part 63 MATS (HAPs MACT Rules) Does Project Support Compliance?				Preliminary Assesment Additional Existing, Proposed, and Probable Rules Does Project Support Compliance?			
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	BART Analyses/Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates	State Issued BART Permit	State Implementation Plan	Underlying Regulation	Non-Hg Metals	Acid Gases	Hg	One-Hour SO2 NAAQS Standard	One Hour NO2 NAAQS Standard	Proposed Ozone Standard	PM2.5 NAAQS Revision
Traditional GRC Review/Wyoming CPCN Process																					
1	10003748	NAU U3 Clean Air - PM (Baghouse)	Naughton 3	LNTP Awarded / CPCN Application	Mar. 2006 - S&L	10003748	May 2012	May 2014	40 CFR 51.309(g)	MD-5156 May 2009	Dec. 31, 2014 based on BART permit MD-6042	MD-6042 Dec. 2009 MD-6042A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.6	40 CFR Part 63	YES	N/A	YES	N/A	N/A	N/A	YES
2	10007228	NAU 3 Clean Air - NOx (SCR)	Naughton 3	LNTP Awarded / CPCN Application	BART - Oct. 2007 - CH2 Study - Dec. 2009 - S&L (2 vol)	10007228	May 2012	May-14	40 CFR 51.309(g)	MD-11894 Aug. 2011	Dec, 31, 2014 based on BART permit MD-6042	MD-6042 Dec. 2009 MD-6042A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.6	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
3	10003396	JB U3 Clean Air - NOx (SCR)	Jim Bridger 3	In Development	BART - Oct. 2007 - CH2	10003396	Dec. 2012	Jun. 2015	40 CFR 51.309(g)	N/A	Dec. 31, 2015 based on BART settlement agreement	MD-6040 Dec. 2009 MD-6040A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.4	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
4	10009398	JB U4 Clean Air - NOx (SCR)	Jim Bridger 4	In Development	BART - Oct. 2007 - CH2	10009398	Dec. 2012	Jun. 2016	40 CFR 51.309(g)	N/A	Dec. 31, 2016 based on BART settlement agreement	MD-6040 Dec. 2009 MD-6040A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.4	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
5	10009395	JB U2 Clean Air - NOx (SCR)	Jim Bridger 2	In Development	BART - Oct. 2007 - CH2	10009395	Dec. 2018	Jul. 2021	40 CFR 51.309(g)	N/A	Dec. 31, 2021 based on BART settlement agreement	MD-6040 Dec. 2009 MD-6040A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.4	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
6	10003391	JB U1 Clean Air - NOx (SCR)	Jim Bridger 1	In Development	BART - Oct. 2007 - CH2	10003391	Dec. 2018	Jun. 2022	40 CFR 51.309(g)	N/A	Dec. 31, 2022 based on BART settlement agreement	MD-6040 Dec. 2009 MD-6040A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.4	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
Traditional GRC Review																					
7	10003747	NAU U3 Clean Air - SO2 (FGD)	Naughton 3	LNTP Awarded	BART - Oct. 07 - CH2	10003747	May 2012	May 2014	40 CFR 51.309	N/A	Prior to 2013 based on regional haze milestones - WY RH 309 SIP.	N/A	WY Regional Haze 309 SIP	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
8	10000939	HTR U1 Clean Air - PM (Baghouse, Incl. Wet Stack Modification)	Hunter 1	In Development	Nov. 2003 - EPSCO Aug. 2007 - S&L	10000939	Apr. 2012	May 2014	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 Mar. 2008	2011 based on permit schedule dated Dec. 18, 2009. Prior to 2012 to meet state R307-424-4 Hg rules.	N/A	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	N/A	YES	N/A	N/A	N/A	YES
9	10002881	HTR U1 Clean Air - Nox (LNB)	Hunter 1	In Development	Study - Oct. 2002 - S&L Tech Review - Nov. 08 - S&L	10002881	Jun. 2013	May 2014	40 CFR 51.309 40 CFR 76.7, 76.11	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 Mar. 2008	2011 based on permit schedule dated 12/18/2009. Spring 2011 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
10	SDVJ/2007/C/901	DJ U4 SO2 & PM Emission Cntrl Upgrades	Dave Johnston 4	Under Construction	Jan. 2007 - CH2 Mar. 2008 - Adden.	10002175 Jan. 2008	Jan. 2008	Apr. 2012	40 CFR 51.309 40 CFR 51.309(g)	MD-5098 Jun. 2008	Sep. 2012 based on MD-5098 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP. Prior to Dec. 31, 2012 based on BART permit MD-6041A.	AP-6041 May 2009 MD-6041 Dec. 2009 MD-6041A Dec. 2010	WY Regional Haze 309 SIP WY Regional Haze 309(g) SIP Section 6.5.5	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
11	SNAU/2008/C/C04	NAU U1 Flue Gas Desulfurization Sys	Naughton 1	Under Construction	Feb. 2007 - CH2 Mar. 2008 - Adden.	10003745 Apr. 2009	May 2009	May 2012	40 CFR 51.309 40 CFR 52.21	MD-5156 May 2009	May 2012 based on MD-5156 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP.	N/A	WY Regional Haze 309 SIP	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
12	SNAU/2009/C/101/BUILD	NAU U1 Clean Air - NOx (LNB)	Naughton 1	Under Contract	Feb. 2007 - CH2 Mar. 2008 - Adden.	10003752 Apr. 2011	Apr. 2011	May 2012	40 CFR 51.309(g) 40 CFR 76.7, 76.11	MD-5156 May 2009	May 2012 based on MD-5156 permit application. Jun. 2012 based on BART permit MD-6042A	AP-6042 May 2009 MD-6042 Dec. 2009 MD-6042A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.6	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
13	SHTR/2007/C/DU2	HTR U2 SO2 & PM Emission Cntrl Upgrades	Hunter 2	Under Construction	Aug. 2007 - S & L Feb. 2009 - Adden.	10002884 Dec. 2009	Dec. 2009	May-2011 (Phase 1) Aug-2011 (Phase 2) Mar-2012 (Phase 3)	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4 Utah R317-1-2	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 Mar. 2008 UGW 150001	2011 based on permit schedule dated Dec. 18, 2009. Prior to 2013 based on regional haze milestones. Prior to 2012 to meet state R307-424-4 Hg rules. Spring 2011 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	YES	YES	YES	N/A	N/A	YES
14	SHTR/2007/C/DU1	HTR U1 SO2 & PM Emission Cntrl Upgrades	Hunter 1	Under Construction	Aug. 2007 - S & L Feb. 2009 - Adden.	10002883 Dec. 2009	Dec. 2009	Apr-2011 (Phase 1) Aug-2011 (Phase 2) Jun-2012 (Phase 3)	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4 Utah R317-1-2	UDAQ Permit 1500101001 DAQE-AN0102370012-08 Mar. 2008 UGW 150001	2014 based on permit schedule dated Dec. 18, 2009. Prior to 2018 based on regional haze milestones. Prior to 2012 to meet state R307-424-4 Hg rules. Spring 2014 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	YES	YES	YES	N/A	N/A	YES
15	SNAU/2008/C/C05	NAU U2 Flue Gas Desulfurization Sys	Naughton 2	In Service	Feb. 2007 - CH2 Mar. 2008 - Adden.	10003746 Apr. 2009	May 2009	Nov-11	40 CFR 51.309 40 CFR 52.21	MD-5156 May 2009	Nov.-2011 based on MD-5156 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP.	N/A	WY Regional Haze 309 SIP	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
16	SNAU/2009/C/202	NAU U2 Clean Air - NOx (LNB)	Naughton 2	In Service	Feb. 2007 - CH2 Mar. 2008 - Adden.	10003744 Feb. 2010	May 2011	Nov-11	40 CFR 51.309(g) 40 CFR 76.7, 76.11	MD-5156 May 2009	Nov.-2011 based on MD-5156 permit application. Prior to Jun. 30, 2012 based on BART permit MD-6042A.	AP-6042 May 2009 MD-6042 Dec. 2009 MD-6042A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.6	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A

Required environmental projects placed in service during the test period for this docket.

Exhibit PAC/502
Teply/1

Known Regulatory Drivers and Environmental Projects - Company Operated Facilities

(PacifiCorp Pollution Control Projects Over $5m)

									Environmental Regulations and Requirements for Installing Control Equipment					Preliminary Assesment Proposed 40 CFR Part 63 MATS (HAPs MACT Rules) Does Project Support Compliance?				Preliminary Assesment Additional Existing, Proposed, and Probable Rules Does Project Support Compliance?			
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	BART Analyses/Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates	State Issued BART Permit	State Implementation Plan	Underlying Regulation	Non-Hg Metals	Add Gases	Hg	One-Hour SO2 NAAQS Standard	One Hour NO2 NAAQS Standard	Proposed Ozone Standard	PM2.5 NAAQS Revision
Projects Placed In Service Prior to Test Period																					
17	SJIM/2007/C/207	JB U3 SO2 & PM Emission Cntrl Upgrades	Jim Bridger 3	In Service	Jan. 2007 - CH2 Mar. 2008 - Adden.	10003390 Sep. 2007	Dec. 2008	Jun-11	40 CFR 51.309 40 CFR 51.309(g)	MD-1552 Apr. 2007 MD-1552A Mar. 2009	Jun.-2011 based on MD-1552A permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP.	AP-6040 May 2009 MD-6040 Dec. 2009 MD-6040A Nov. 2010	WY Regional Haze 309 SIP WY Regional Haze 309(g) SIP Section 6.5.4	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
18	SHTR/2009/C/150	HTR U2 Clean Air - NOx (LNB)	Hunter 2	In Service	Study - Oct. 2002 - S&L Tech Reivew - Nov 08 - S&L	10002882 Feb. 2010	Jan. 2011	May-11	40 CFR 51.309 40 CFR 76.7, 76.11	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 Mar. 2008	2011 based on permit schedule dated Dec. 18, 2009. Spring 2011 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
19	SHTR/2010/C/050	HTR U2 Clean Air - PM (Baghouse)	Hunter 2	In Service	Nov. 2003-EPSCO	10002886 Aug. 2008	Dec. 2009	May-11	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 Mar. 2008	2011 based on permit schedule dated Dec. 18, 2009. Prior to 2012 to meet state R307-424-4 Hg rules. Spring 2011 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	N/A	YES	N/A	N/A	N/A	YES
20	SWDK/2007/C/724	WDK U1 SO2 and PM Emiss Control Upgrade	Wyodak 1	In Service	Feb. 2007 - CH2 Mar. 2008 - Adden.	10004047 Apr. 2009	May 2009	Apr-11	40 CFR 51.309 40 CFR 51.309(g)	MD-7487 May 2009	Apr.-2011 based on MD-7487 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP. Prior to Dec. 31, 2011 based on BART permit MD-6043A.	AP-6043 May 2009 MD-6043 Dec. 2009 MD-6043A Dec. 2010	WY Regional Haze 309 SIP WY Regional Haze 309(g) SIP Section 6.5.7	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
21	SWDK/2009/C/009	WDK U1 Clean Air - NOx (LNB)	Wyodak 1	In Service	Feb. 2007 - CH2 Mar. 2008 - Adden.	10004049 Mar. 2010	Mar. 2010	Apr-11	40 CFR 51.309(g) 40 CFR 76.5, 76.11	MD-7487 May 2009	Apr.-2011 based on MD-7487 permit application. Prior to Dec. 31, 2011 based on BART permit MD-6043A.	AP-6043 May 2009 MD-6043 Dec 2009 MD-6043A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.7	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
22	SHTN/2010/C/013	HTG U1 Clean Air - NOx (LNB)	Huntington 1	In Service	Study - Oct. 2002 - S&L Tech Review - Nov. 2008 - S&L	10002666 Dec. 2008	May 2010	Nov-10	40 CFR 51.309 40 CFR 76.7, 76.11	DAQE-AN0102380019-09 Aug. 2009	Nov.-2010 based on DAQE-AN0102380019-09 permit application. Fall 2010 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A
23	SHTN/2007/C/273	HTG U1 SO2 & PM Em Cntrl Upgrades	Huntington 1	In Service	Aug. 2007 - S & L Feb. 2009 - Adden.	10002667 Dec. 2009	Dec. 2009	May-11	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4 Utah R317-1-2	UDAQ Permit 1501001003 Aug. 2010 DAQE-AN0102380019-09 Aug. 2009 UGW 15002	Nov. 2010 based on DAQE-AN0102380019-09 permit application. Prior to 2013 based on regional haze milestones. Prior to 2012 to meet state R307-424-4 Hg rules. Fall 2010 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	YES	YES	YES	N/A	N/A	YES
24	SHTN/2010/C/006	HTG U1 Clean Air - PM (Baghouse)	Huntington 1	In Service	Nov. 2003 - EPSCO	10007059 Aug. 2008	Sep. 2008	Nov-10	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4	UDAQ Permit 1501001003 Aug. 2010 DAQE-AN0102380019-09 Aug. 2009	Nov-2010 based on DAQE-AN0102380019-09 permit application. Prior to 2012 to meet state R307-424-4 Hg rules. Fall 2010 based on Utah SIP Section XX Regional Haze.	N/A	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	N/A	YES	N/A	N/A	N/A	YES
25	SDVJ/2007/C/898	DJ U3 SO2 & PM Emission Control Upgrades	Dave Johnston 3	In Service	Jan. 2007 - CH2 Mar. 2008 - Adden.	10000815 Jan. 2008	Jan. 2008	May-10	40 CFR 51.309 40 CFR 51.309(g)	MD-5098 Jun. 2008	Sep.-2010 based on MD-5098 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP. Prior to Dec 31, 2010 based on BART permit MD-6041A.	AP-6041 May 2009 MD-6041 Dec. 2009 MD-6041A Dec. 2010	WY Regional Haze 309 SIP WY Regional Haze 309(g) SIP Section 6.5.5	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES	N/A	N/A	YES
26	SDVJ/2008/C/CA3	DJ U3 Clean Air - NOx (LNB)	Dave Johnston 3	In Service	Jan. 2007 - CH2 Mar. 2008 - Adden.	10000814 Jan. 2009 90000405 Nov. 2010	Jun. 2008	May-10	40 CFR 51.309(g) 40 CFR 76.5, 76.11	MD-5098 Jun. 2008	Sep.-2010 based on MD-5098 permit application. Prior to Dec. 31, 2010 based on BART permit MD-6041A.	AP-6041 May 2009 MD-6041 Dec. 2009 MD-6041A Dec. 2010	WY Regional Haze 309(g) SIP Section 6.5.5	N/A	N/A	N/A	N/A	N/A	YES	YES	N/A

Required environmental projects placed in service during the test period for this docket.

Exhibit PAC/502
Teply/2

Mercury Control Projects - Company Operated Facilities

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Wyoming Projects											
1	10002178	DJ U1 Clean Air - Hg (Ox/ACI)	Dave Johnston 1	In Development	DJ2 baseline testing in Oct. 2010 results applicable	10002178	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
2	10002178	DJ U2 Clean Air - Hg (Ox/ACI)	Dave Johnston 2	In Development	DJ2 baseline testing in Oct. 2010	10002178	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
3	10002180	DJ U3 Clean Air - Hg (Ox/ACI)	Dave Johnston 3	In Development	DJ3 baseline testing in Mar. 2011	10002180	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
4	10002181	DJ U4 Clean Air - Hg (Ox/ACI)	Dave Johnston 4	In Development	DJ3 baseline testing in Mar. 2011 - results applicable	10002181	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
5	10003392	JB U1 Clean Air - Hg (Ox/FGD Add./ACI)	Jim Bridger 1	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011 - results applicable	10003392	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
6	10003393	JB U2 Clean Air - Hg (Ox/FGD Add./ACI)	Jim Bridger 2	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011	10003393	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
7	10003394	JB U3 Clean Air - Hg (Ox/FGD Add./ACI)	Jim Bridger 3	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011 - results applicable	10003394	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
8	10003395	JB U4 Clean Air - Hg (Ox/FGD Add./ACI)	Jim Bridger 4	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011 - results applicable	10003395	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
9	10003749	NT U1 Clean Air - Hg (Ox/FGD Add.)	Naughton 1	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011 - results applicable	10003749	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
10	10003750	NT U2 Clean Air - Hg (Ox/FGD Add.)	Naughton 2	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011 - results applicable	10003750	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
11	10003751	NT U3 Clean Air - Hg (Ox/FGD Add.)	Naughton 3	In Development	JB2 baseline testing in Nov. 2010 - additional tests in Oct. 2011 - results applicable	10003751	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD
12	10004048	WY Clean Air - Hg (Ox/ACI)	Wyodak	In Development	DJ3 baseline testing in Mar. 2011 - results applicable	10004048	TBD	Dec-14	Fed: 40 CFR Part 63	N/A	TBD

Mercury Control Projects - Company Operated Facilities

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Utah Projects											
13	10001846	CB U1 Clean Air - Hg (ACI)	Carbon 1	Under Review	No testing or screening scheduled - State rule does not apply due to Unit 1 size	10001846	TBD	Fed: Dec-14	Fed: 40 CFR Part 63 State: R307-424	N/A	N/A
14	10001847	CB U2 Clean Air - Hg (ACI)	Carbon 2	Under Review	No testing or screening scheduled - State rule does not apply due to Unit 2 size	10001847	TBD	Fed: Dec-14	Fed: 40 CFR Part 63 State: R307-424	N/A	N/A
15	10002887	HTR U1 Clean Air - Hg	Hunter 1	Not Planned	No testing or screening scheduled - results with baghouse indicate no additional controls required	10002887	TBD	Fed: Dec-14 State: Jan-13	Fed: 40 CFR Part 63 State: R307-424	N/A	State: Jan. 2013 - is expected to be superceded by final federal rule.
16	10002888	HTR U2 Clean Air - Hg	Hunter 2	Not Planned	No testing or screening scheduled - results with baghouse indicate no additional controls required	10002888	TBD	Fed: Dec-14 State: Jan-13	Fed: 40 CFR Part 63 State: R307-424	N/A	State: Jan. 2013 - is expected to be superceded by final federal rule.
17	10002889	HTR U3 Clean Air - Hg	Hunter 3	Not Planned	No testing or screening scheduled - results with baghouse indicate no additional controls required	10002889	TBD	Fed: Dec-14 State: Jan-13	Fed: 40 CFR Part 63 State: R307-424	N/A	State: Jan. 2013 - is expected to be superceded by final federal rule.
18	10002668	HTG U1 Clean Air - Hg	Huntington 1	Not Planned	No testing or screening scheduled - results with baghouse indicate no additional controls required	10002668	TBD	Fed: Dec-14 State: Jan-13	Fed: 40 CFR Part 63 State: R307-424	N/A	State: Jan. 2013 - is expected to be superceded by final federal rule.
19	10002669	HTG U2 Clean Air - Hg	Huntington 2	Not Planned	No testing or screening scheduled - results with baghouse indicate no additional controls required	10002669	TBD	Fed: Dec-14 State: Jan-13	Fed: 40 CFR Part 63 State: R307-424	N/A	State: Jan. 2013 - is expected to be superceded by final federal rule.

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Wyoming Projects											
1	10005923	CCB DJ - LANDFILL STAGE II CLOSURE	Dave Johnston	In Development	Grade, cap, and close Dave Johnston Stage 2 "Ash Landfill Closure Proposal," TetraTech, 03/2011	10005923	TBD	2012	See Note 1	SHWD file # 20.460 Ongoing scheduled to be completed in 2012	2012
2	10013720	CCB DJ: Landfill Closure-Horseshoe	Dave Johnston	Proposed	Grade, cap, and close	10013720	TBD	2014	See Note 1	SHWD file # 20.460	TBD
3	10013726	CCB DJ: Lined Pond 1B Replace Liner...	Dave Johnston	Proposed	Dredge, partition, double line, and monitor	10013726	TBD	2015	See Note 1	TBD	TBD
4	10013727	CCB DJ: Lined Pond 4A Replace Liner...	Dave Johnston	Proposed	Dredge, partition, double line, and monitor	10013727	TBD	2015	See Note 1	TBD	TBD
5	10005922	CCB DJ - Landfill South Ash Mtn Closure	Dave Johnston	Proposed	Grade, cap, and close	10005922	TBD	2015	See Note 1	SHWD file # 20.460	TBD
6	10013725	CCB DJ: Lined Pond 1A Replace Liner...	Dave Johnston	Proposed	Dredge, partition, double line, and monitor	10013725	TBD	2016	See Note 1	TBD	TBD
7	10014292	CCB DJ: Lined Pond 4B Replace Liner...	Dave Johnston	Proposed	Dredge, partition, double line, and monitor	10014292	TBD	2016	See Note 1	TBD	TBD
8	10014340	CCB DJ: Landfill Construct 5-7 yr cell Develop	Dave Johnston	Proposed	Partition, double line, and monitor	10014340	TBD	2015	See Note 1	SHWD file # 20.460	TBD
9	10014341	CCB DJ Pond Liner Replace/Leachate Develop	Dave Johnston	Proposed	Dredge, partition, double line, and monitor	10014341	TBD	2013	See Note 1	TBD	TBD
10	10013719	CCB DJ: Landfill Closure-Expansion #3	Dave Johnston	Proposed	Partition, double line, and monitor	10013719	TBD	2016	See Note 1	SHWD file # 20.460	TBD
11	10013723	CCB DJ: Landfill Ongoing Manage 5-7yr Cell	Dave Johnston	Proposed	Partition, double line, and monitor	10013723	TBD	2021	See Note 1	SHWD file #20.460	TBD
12	SJIM/2008/L/001	CCB JB: FGD Pond 1 Closure	Jim Bridger	Under Construction	Dewater, cap, grade, and close "Jim Bridger Power Plant FGD Pond 1 Closure Plan," MWH, 11/2008	SJIM/2008/L/001	2008	2016	See Note 1	Permit #02.081R Ongoing scheduled to be completed in 2016	2016
13	10013777	CCB JB: FGD Pond 2 Retrofit - Phase 1	Jim Bridger	In Development	Partition, double line, and monitor "Feasibility Study for FGD Pond 2 Lining Options," TetraTech, 08/2011	10013777	TBD	2013	See Note 1	TBD	TBD
14	10013736	Landfill Purchase and Construction	Jim Bridger	Proposed	Partition, double line, and monitor. "Potential Landfill Sites," WET, 06/2011.	10013736	TBD	2014	See Note 1	TBD	TBD

Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Wyoming Projects (Continued)											
15	10013778	CCB JB: FGD Pond 2 Retrofit - Phase 2	Jim Bridger	Proposed	Partition, double line, and monitor	10013778	TBD	2015	See Note 1	TBD	TBD
16	SJIM/2011/C/200	CCB JB: FGD Pond 2 Liner Installation Pond -	Jim Bridger	Proposed	Partition, double line, and monitor "Feasibility Study for FGD Pond 2 Lining Options," TetraTech, 08/2011	SJIM/2011/C/200	TBD	2015	See Note 1	TBD	TBD
17	10013729	CCB JB: Pond Closure FGD Pond 2	Jim Bridger	Proposed	Dewater, cap, grade, and close	10013729	TBD	2018	See Note 1	Permit #04.204	TBD
18	10013735	CCB JB: Landfill Closure Ash Landfill	Jim Bridger	Proposed	Grade, cap, and close	10013735	TBD	2017	See Note 1	SHWD File # 20.455	TBD
19	10013732	CCB JB: FGD Pond 5-7yr Cell	Jim Bridger	Proposed	Partition, double line, and monitor.	10013732	TBD	2019	See Note 1	TBD	TBD
20	10013737	CCB JB: Landfill Constr 5-7yr Cell	Jim Bridger	Proposed	Partition, double line, and monitor	10013737	TBD	2019	See Note 1	TBD	TBD
21	10013738	CCB JB: Landfill Closure 5-7yr Cell	Jim Bridger	Proposed	Grade, cap, and close	10013738	TBD	2020	See Note 1	TBD	TBD
22	10013733	CCB JB: FGD Pond 5-7yr Cell, Ongoing Management	Jim Bridger	Proposed	Partition, double line, and monitor	10013733	TBD	2023	See Note 1	TBD	TBD
23	10013779	CCB Naughton: Landfill Retrofit North Ash Pond	Naughton	In Development	Partition, double line, and monitor "Naughton Ash Landfill Siting Report," TetraTech, 04/2011	10013779	TBD	2013	See Note 1	TBD	TBD
24	10014344	CCB Naughton: Landfill Retrofit - Development	Naughton	Proposed	Partition, double line, and monitor	10014344	TBD	2013	See Note 1	TBD	TBD
25	10013739	CCB Naughton: Pond Closure FGD Pond #1	Naughton	Proposed	Dewater, cap, grade, and close	10013739	TBD	2014	See Note 1	TBD	TBD
26	10014345	CCB Naughton: South Ash Pond 2, development study	Naughton	Proposed	Partition, double line, and monitor	10014345	TBD	2013	See Note 1	TBD	TBD
27	10013740	CCB Naughton: Pond Closure FGD Pond #2	Naughton	Proposed	Dewater, cap, grade, and close	10013740	TBD	2015	See Note 1	Permit # WYR 100826	TBD
28	10013746	CCB Naughton: South Ash Pond 2 construction	Naughton	Proposed	Partition, double line, and monitor	10013746	TBD	2015	See Note 1	TBD	TBD

Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA.
Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

Exhibit PAC/504
Teply/2

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Wyoming Projects (Continued)											
29	10014317	CCB Naughton: FGD Pond Closure - Dev	Naughton	Proposed	Dewater, cap, grade, and close	10014317	TBD	2012	See Note 1	Permit #WYR 100826	TBD
30	10013744	CCB Naughton: South Clear Water Pond	Naughton	Proposed	Partition, double line, and monitor	10013744	TBD	2016	See Note 1	TBD	TBD
31	10013750	CCB Naughton: Land Purchase	Naughton	Proposed	Partition, double line, and monitor	10013750	TBD	2017	See Note 1	TBD	TBD
32	10013753	CCB Naughton: NT 3 Dry Bottom Ash Conversion	Naughton	Proposed	Dredge, double line, and monitor "Naughton Station Subtitle D Coal Combustion Residue Disposal Evaluation," 08/2011.	10013753	TBD	2017	See Note 1	TBD	TBD
33	10014343	CCB Naughton:Dry Bottom Ash Conversion Process Dev	Naughton	Proposed	Submerged scraper conveyor. "Naughton Station Subtitle D Coal Combustion Residue Disposal Evaluation," Sargent and Lundy, 08/2011.	10014343	TBD	2014	See Note 1	TBD	TBD
34	10014346	CCB Naughton: Pond Lining and Retrofit - North Process	Naughton	Proposed	Partition, double line, and monitor	10014346	TBD	2017	See Note 1	TBD	TBD
35	10014348	CCB Naughton: Pond Construction FGD #3 Pond Dev	Naughton	Proposed. Will use FGD Pond 4 as a model.	Partition, double line, and monitor "Naughton Ash Landfill Siting Report," 04/2011.	10014348	TBD	2015	See Note 1	TBD	TBD
36	10013741	CCB Naughton: Pond Close North Ash Pond	Naughton	In Development	Dewater, cap, grade, and close "Naughton Station Subtitle D Coal Combustion Residue Disposal Evaluation," Sargent and Lundy, 08/2011.	10013741	TBD	2017	See Note 1	TBD	TBD
37	10013742	CCB Naughton: Pond Close South Ash Pond	Naughton	Proposed	Dewater, cap, grade, and close	10013742	TBD	2017	See Note 1	Permit # WY 0020311	TBD
38	10013745	CCB Naughton: FGD Pond Closure 5-7yr Cell	Naughton	Proposed	Dewater, cap, grade, and close	10013745	TBD	2018	See Note 1	TBD	TBD
39	10014347	CCB Naughton: Pond Closure - Development	Naughton	Proposed	Dewater, cap, grade, and close	10014347	TBD	2016	See Note 1	TBD	TBD
40	10013757	CCB Wyodak: Lndfill Constr 5-7yr Cell (BH)	Wyodak	Proposed	Partition, double line, and monitor	10013757	TBD	2014	See Note 1	TBD	TBD
41	10014350	CCB Wyodak: Landfill Construction - Development	Wyodak	Proposed	Partition, double line, and monitor	10014350	TBD	2012	See Note 1	TBD	TBD

Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

Exhibit PAC/504
Teply/3

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Wyoming Projects (Continued)											
42	10014319	CCB Wyodak: Pond Closure/Retrofit - Development	Wyodak	Proposed	Dewater, cap, grade, and close	10014319	TBD	2014	See Note 1	TBD	TBD
43	10013754	CCB Wyodak: Pond Closure/Retro-Ash Collct Pd	Wyodak	Proposed	Dewater, cap, grade, and close	10013754	TBD	2017	See Note 1	TBD	TBD
44	10013755	CCB Wyodak: Pond Closure/Retro-Clear Water Pd	Wyodak	Proposed	Dewater, cap, grade, and close	10013755	TBD	2017	See Note 1	TBD	TBD
45	10013756	CCB Wyodak: Landfill Closure Ash (Black Hills)	Wyodak	Proposed	Grade, cap, and close	10013756	TBD	2017	See Note 1	TBD	TBD
46	10014349	CCB Wyodak: Landfill Closure - Development	Wyodak	Proposed	Grade, cap, and close	10014349	TBD	2017	See Note 1	TBD	TBD
47	10013758	CCB Wyodak: Landfill Ongoing Mgmnt 5-7yr Cell (BH)	Wyodak	Proposed	Grade, cap, and close	10013758	TBD	2020	See Note 1	TBD	TBD
48	10013759	CCB Wyodak: Landfill Closure 5-7yr Cell	Wyodak	Proposed	Grade, cap, and close	10013759	TBD	2021	See Note 1	TBD	TBD
Utah Projects											
49	10013702	CCB Carbon: Landfill Closure-Ash Landfill	Carbon	In Development	Grade, cap, and close "Carbon Plant Ash Landfill Closure Plan," WET, 06/2011	10013702	TBD	2017	See Note 1	TBD	TBD
50	SCAR/2011/L/001	CCB Carbon: Landfill Closure	Carbon	In Development	Grade, cap, and close "Carbon Plant Ash Landfill Closure Plan," WET, 06/2011	SCAR/2011/L/001	TBD	2013	See Note 1	TBD	TBD
51	10013708	CCB Hunter: Landfill Constr 5-7 yr Cell	HunterC3	Proposed	Grade, cap, and close	10013708	TBD	2016	See Note 1	TBD	TBD
52	10013711	300 CCB Hunter: Pond Retrofit Add Liner/Leach coll	HunterC3	Proposed	Partition, double line, and monitor	10013711	TBD	2016	See Note 1	TBD	TBD
53	10014334	CCB Hunter: Landfill Const 5-7 yr Cell Develop	HunterC3	Proposed	Partition, double line, and monitor	10014334	TBD	2014	See Note 1	TBD	TBD
54	10014336	CCB Hunter: Pond Liner/Leach Collect Developme	HunterC3	Proposed	Partition, double line, and monitor	10014336	TBD	2014	See Note 1	TBD	TBD

Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

Exhibit PAC/504
Teply/4

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Utah Projects (Continued)											
55	10013706	CCB Hunter: 300 Landfill Closure-CCB Landfill	HunterC3	Proposed	Grade, cap, and close	10013706	TBD	2018	See Note 1	TBD	TBD
56	10014315	CCB Hunter: Landfill Closure-Development	HunterC3	Proposed	Grade, cap, and close	10014315	TBD	2013	See Note 1	TBD	TBD
57	10013707	CCB Hunter: Landfill Purchase 10-14 Yr Cell	HunterC3	Proposed	Partition, double line, and monitor	10013707	TBD	2020	See Note 1	TBD	TBD
58	10013709	300 CCB Hunter: Landfill Ongoing Mangement 5-7 yr	HunterC3	Proposed	Partition, double line, and monitor	10013709	TBD	2021	See Note 1	TBD	TBD
59	SHTN/2011/C/012	CCB Huntington: Lacey's Lake Water Study	Huntington	Complete	Dewater, cap, grade, and close. "Lacey's Lake Closure Study, URS, 04/2011.	SHTN/2011/C/012	2010	2011	See Note 1	UGW150002	Dec. 2011
60	SHTN/2011/C/026	CCB Huntington: Lacey's Lake Waste Water Diversion	Huntington	Under Construction	Dewater, cap, grade, and close	SHTN/2011/C/026	2010	2011	See Note 1	UGW150002	Dec. 2011
61	SHTN/2011/L/001	CCB Huntington: Lacey's Lake Removal	Huntington	Under Construction	Dewater, cap, grade, and close	SHTN/2011/L/001	2010	2011	See Note 1	UGW150002	Dec. 2011
62	10008182	CCB Huntington: Ash Landfill Cover - CY13	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008182	TBD	2013	See Note 1	TBD	TBD
63	10008183	CCB Huntington: Ash Landfill Cover - CY14	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008183	TBD	2014	See Note 1	TBD	TBD
64	10008184	CCB Huntington: Ash Landfill Cover - CY15	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008184	TBD	2015	See Note 1	TBD	TBD
65	10013714	CCB Huntington:Landfill Lining Retrofit 5-7yr Cell	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10013714	TBD	2016	See Note 1	TBD	TBD
66	10008185	CCB Huntington: Ash Landfill Cover - CY16	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008185	TBD	2016	See Note 1	TBD	TBD
67	10014337	CCB Huntington:Landfill Retrofit 5-7 yr - Development	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10014337	TBD	2014	See Note 1	TBD	TBD
68	10008185	CCB Huntington: Ash Landfill Cover - CY16	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008185	TBD	2016	See Note 1	TBD	TBD

Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

Exhibit PAC/504
Teply/5

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Utah Projects (Continued)											
69	10008186	CCB Huntington: Ash Landfill Cover - CY17	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008186	TBD	2017	See Note 1	TBD	TBD
70	10008186	CCB Huntington: Ash Landfill Cover - CY17	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008186	TBD	2017	See Note 1	TBD	TBD
71	10008187	CCB Huntington: Ash Landfill Cover - CY18	Huntington	Proposed	On-site top soil creation for landfill grading and revegetation	10008187	TBD	2018	See Note 1	TBD	TBD
72	10013713	CCB Huntington: Land Purchase 10-14yr Cell	Huntington	Proposed	Partition, double line, and monitor	10013713	TBD	2020	See Note 1	TBD	TBD
73	10013715	CCB Huntington: Landfill Ongoing Mangmt 5-7yr Cell	Huntington	Proposed	Partition, double line, and monitor	10013715	TBD	2021	See Note 1	TBD	TBD
Arizona Projects											
74	10013761	CCB Cholla: Pnd Clsur/5-7yr Cell-Fly Ash Pond-RESD	Cholla	Proposed	Dewater, cap, grade, and close	10013761	TBD	2013	See Note 1	TBD	TBD
75	10013781	CCB Cholla: Fly Ash Pond 5-7yr Retrofit-RESD	Cholla	Proposed	Dewater, cap, grade, and close	10013781	TBD	2015	See Note 1	TBD	TBD
76	10014312	CCB Cholla: DEV STDY Pnd Cls Bttm Ash/Fly Ash-RESD	Cholla	Proposed	Dewater, cap, grade, and close	10014312	TBD	2012	See Note 1	TBD	TBD
77	10013760	CCB Cholla: Pond Closure Bottom Ash Pond-RESD	Cholla	Proposed	Dewater, cap, grade, and close	10013760	TBD	2017	See Note 1	TBD	TBD
78	10014314	CCB Cholla: DEV STDY-Lndfll Clsure 5-7yr Cell-RESD	Cholla	Proposed	Grade, cap, and close	10014314	TBD	2018	See Note 1	TBD	TBD
79	10013762	CCB Cholla: Pond Constr FGD Pond 5-7yr Cell-RESD	Cholla	Proposed	Partition, double line, and monitor	10013762	TBD	2020	See Note 1	TBD	TBD
80	10014313	CCB Cholla: DEV STDY-Pnd Constr FGD Pnd 5-7yr-RESD	Cholla	Proposed	Partition, double line, and monitor	10014313	TBD	2017	See Note 1	TBD	TBD
81	10013763	CCB Cholla: Landfill Closure 5-7yr Cell-RESD	Cholla	Proposed	Grade, cap, and close	10013763	TBD	2021	See Note 1	TBD	TBD

Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

Exhibit PAC/504
Teply/6

List of CCR Projects Included in 10-Year Plan (2012-2021)

									Environmental Regulations and Requirements for Installing Control Equipment		
Proj	WBS Element	Project/WBS Short Text	Plant/Unit	Status	Tech. Screening	APR	NTP	In-Service	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	Compliance Dates
Other Partner-Owned Projects											
82	10013764	CCB Colstrip: Pnd Clsur 5-7yr Cell Effient Pd-RESD	Colstrip	Proposed	Dewater, cap, grade, and close	10013764	TBD	2013	See Note 1	TBD	TBD
83	10013766	CCB Colstrip: Pond Constr 5-7yr Cell-RESD	Colstrip	Proposed	Partition, double line, and monitor	10013766	TBD	2014	See Note 1	TBD	TBD
84	10013782	CCB Colstrip: Effluent Hlding Pd 5-7yr Retrft-RESD	Colstrip	Proposed	Partition, double line, and monitor	10013782	TBD	2015	See Note 1	TBD	TBD
85	10013765	CCB Colstrip: Bottom Ash Pond-RESD	Colstrip	Proposed	Partition, double line, and monitor	10013765	TBD	2017	See Note 1	TBD	TBD
86	10013767	CCB Colstrip: Pnd Constr 5-7yr Cell-Ongo Mgmt-RESD	Colstrip	Proposed	Partition, double line, and monitor	10013767	TBD	2020	See Note 1	TBD	TBD
87	10013768	CCB Colstrip: Pond Closure 5-7yr Cell-RESD	Colstrip	Proposed	Dewater, cap, grade, and close	10013768	TBD	2021	See Note 1	TBD	TBD
88	10013774	CCB Hayden: Landfill Constr 5-7yr Cell (Mine)-RESD	Hayden	Proposed	Partition, double line, and monitor	10013774	TBD	2014	See Note 1	TBD	TBD
89	10013769	CCB Craig: Landfll Closur-Ash Landfill (Mine)-RESD	Craig	Proposed	Grade, cap, and close	10013769	TBD	2018	See Note 1	TBD	TBD
90	10013773	CCB Hayden: Lndfll Clsure Ash Landfill (Mine)-RESD	Hayden	Proposed	Grade, cap, and close	10013773	TBD	2017	See Note 1	TBD	TBD
91	10013771	CCB Craig: Lndfll Const 5-7yr Cell(Mine)-Ongo-RESD	Craig	Proposed	Partition, double line, and monitor	10013771	TBD	2019	See Note 1	TBD	TBD
92	10013770	CCB Craig: Landfill Constr 5-7yr Cell (Mine)-RESD	Craig	Proposed	Partition, double line, and monitor	10013770	TBD	2020	See Note 1	TBD	TBD
93	10013775	CCB Hayden: Lndfll Const 5-7yr Cell(Mine)Ongo-RESD	Hayden	Proposed	Partition, double line, and monitor	10013775	TBD	2020	See Note 1	TBD	TBD
94	10013772	CCB Craig: Landfill Closure 5-7yr Cell-RESD	Craig	Proposed	Grade, cap, and close	10013772	TBD	2021	See Note 1	TBD	TBD
95	10013776	CCB Hayden: Lndfill Closure 5-7yr Cell (Mine)-RESD	Hayden	Proposed	Grade, cap, and close	10013776	TBD	2021	See Note 1	TBD	TBD

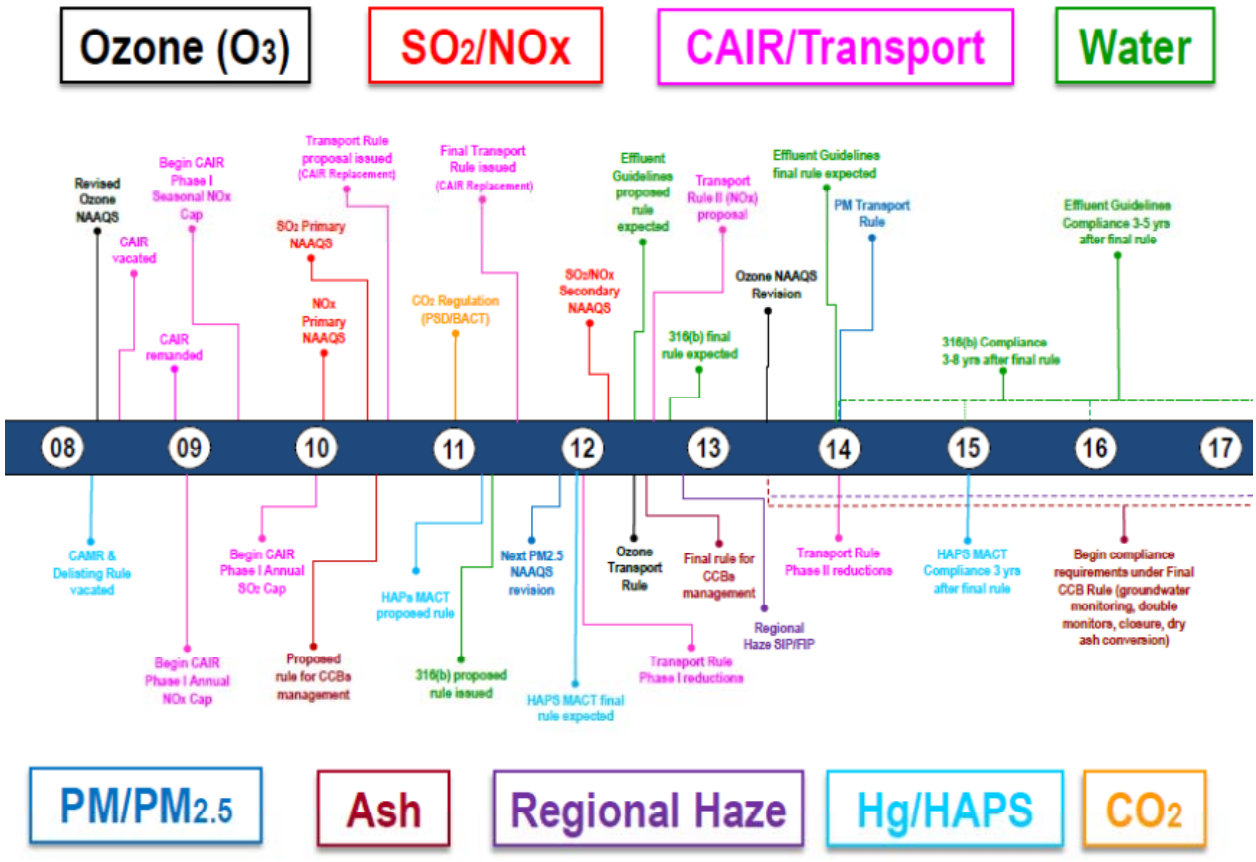
Note 1. In June 2010, EPA proposed two primary regulatory options for coal combustion residuals (CCR) disposed of in landfills and/or surface ponds: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Construction and Recovery Act (RCRA); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Final CCR rulemaking is currently anticipated from EPA no earlier than late 2012 with a resulting compliance deadline no earlier than late 2017. For planning and budgeting purposes, the Company is currently utilizing Subtitle D compliance as a proxy until better information becomes available.

Emerging Environmental Regulations Overview

PacifiCorp's parent company, MidAmerican Energy Holdings Company, has been an active long-term member of the Edison Electric Institute ("EEI") modeling group, especially regarding the analysis of potential EPA regulatory scenarios.

In January 2011, the EEI published a report titled "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet", which reflects a collaborative effort by the EEI and its members to model a variety of prospective EPA rules for air quality, GHGs, coal combustion residuals and cooling water intakes. The report summarizes the potential impact of uncertain regulatory outcomes on unit retirements, idling, capacity additions, pollution control installations, and capital expenditures, based on national-level average input assumptions. The results contained in the report help guide PacifiCorp's long-term environmental planning.

The EPA has undertaken a multiple-path approach to minimize air, land and water-based environmental impacts. Many environmental regulations from the EPA are in various stages of parallel development, as represented in the timeline below:



Each of these regulations could have an impact on PacifiCorp's long-term environmental plan, could change dispatch scenarios, and could ultimately impact the economic viability of PacifiCorp's electric generation units.

PacifiCorp continues to evaluate the potential impact of climate change legislation at the federal level. The impact of federal climate change legislation would vary significantly depending on key criteria. While significant measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. . Further, in April 2011, the United States House of Representatives voted 255-177 on a bill (H.R. 910) that would prevent the EPA from regulating GHG emissions. No action has been taken by the Senate on the bill.

The EPA regulatory timeline above identifies several categories of regulations for *non-GHG* emissions, some of which are represented below:

Clean Air Act ("CCA") Criteria Pollutants – Currently, PacifiCorp's generation units must comply with the CAA which is implemented by state agencies and subject to EPA approval and oversight. The CAA requires the EPA to set National Ambient Air Quality Standards ("NAAQS") for certain pollutants considered harmful to the environment and public health. For a specific NAAQS, the EPA and/or a state agency identifies various control measures that when implemented are meant to achieve an ambient air quality standard for a certain pollutant.

PM, SO_2, ozone, NO_2, carbon monoxide and lead are frequently grouped together under the CAA because each of these categories is linked to one or more NAAQS. The criteria pollutants, while undesirable, are not toxic in typical concentrations in the ambient air. Under the CAA, they are regulated differently from other types of emissions, such as HAPs and GHGs which will be mentioned below. As a result of its periodic review of the NAAQS, the EPA established new standards for NO_2, PM, and SO_2. In addition, the EPA was expected to complete reconsideration of the previously established ozone standards in 2011. However on September 2, 2011, President Obama requested that EPA Administrator Jackson withdraw the draft ozone standard because the standard would be reconsidered in 2013 and he did not support implementation of a new standard that would be reconsidered shortly after issuance. President Obama cited concern about the new standard negatively affecting jobs and economic recovery. This recent decision is indicative of the level of environmental rulemaking uncertainty.

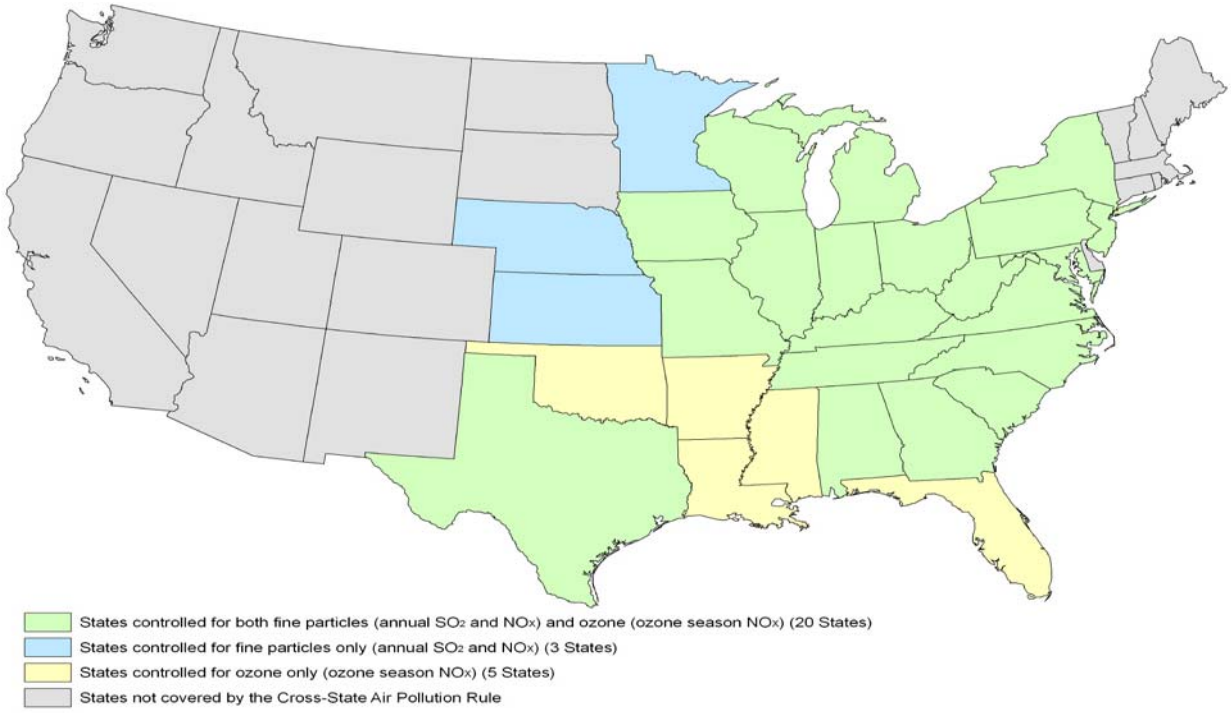
Regional Haze – The EPA's rule to address Regional Haze visibility concerns drives emission reductions from steam electric plants operating in PacifiCorp's service territories. On June 15, 2005, the EPA issued amendments to its July 1999 Regional Haze rule. The amendments apply to provisions of the Regional Haze rule that require emission controls known as BART for steam electric plants with emissions that have the potential to impact visibility. These emissions of primary concern include $PM_{2.5}$, NO_X, and SO_2. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which steam electric plants must install controls and the type of controls the steam electric plants must implement during the program's first five-year planning period. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities, including steam

electric plants that would be required to reduce criteria pollutant emissions under BART as well as establishing BART emissions limits for those facilities. These facilities, after undergoing a review of their emissions and their contribution to visibility impairment, may be required to install additional emission control equipment no later than five years after the EPA approves a state's Regional Haze implementation plan. In 2008, the state of Utah submitted its regional haze state implementation plan to the EPA for approval, and the state of Wyoming submitted its plan in January 2011. The EPA has not yet provided its initial or final approval or disapproval of the Wyoming or Utah state implementation plans. The EPA's rejection of other regional haze state implementation plans has resulted in lawsuits being filed by states and affected entities. Such appeals are pending before the Tenth Circuit Court of Appeals by New Mexico and Oklahoma.

Mercury and Air Toxics Standards – In March 2005, the EPA issued the Clean Air Mercury Rule ("CAMR") to permanently limit and reduce mercury emissions from coal-fueled steam electric plants under a market-based cap-and-trade program. However, the CAMR was vacated in February 2008, with the court finding the mercury rules inconsistent with the stipulations of Section 112 of the CAA. A replacement rule, proposed in March 2011, was published in the Federal Register February 16, 2012, and will become final in April 2012. The rule requires existing coal-fueled generating facilities to achieve stringent emission standards for mercury, acid gases and other non-mercury hazardous air pollutants within three years after the rule is final, with individual sources granted an additional year to comply if approved by the permitting authority. Mercury emissions control equipment is included in PacifiCorp's environmental and capital plans. Installation of emissions control equipment for SO_2 and particulate matter assist in achieving compliance with the Mercury and Air Toxics Standard.

Cross-State Air Pollution Rule – On July 6, 2011, the EPA finalized a rule which requires new reductions in SO_2 and NO_X emissions from electricity generating units in 27 states. This rule, known as the Cross-State Air Pollution Rule ("CSAPR"), requires emission reductions to take effect starting January 1, 2012, for SO_2 and annual NO_X reduction, and May 1, 2012, for ozone season NO_X reduction. The CSAPR was intended to replace the Bush administration's Clean Air Interstate Rule ("CAIR"), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with PM and ozone NAAQS. CSAPR also replaces the July 2009 EPA proposed Clean Air Transport Rule intended to help states attain NAAQS established in 1997 for fine PM and ozone emissions. Implementation of the CSAPR was stayed by the D.C. Circuit Court of Appeals in December 2011 pending consideration of several petitions for review before the court; the court held that the CAIR should be administered pending the resolution of the pending petitions for review.

PacifiCorp does not own generation units in states identified by the CSAPR Rule and is not directly impacted; however, PacifiCorp continues to monitor other CSAPR related state and supplementary EPA actions and pending challenges of the CSAPR for indications that these actions extend the geographic extent of impacted states. A map of CSAPR impacted states follows and includes states covered in the SNPR:



The EPA regulatory timeline above also identifies several key initiatives for regulating GHG emissions to include:

New Source Review and Prevention of Significant Deterioration - On May 13, 2010, the EPA issued a final rule that addresses GHG emissions from stationary sources under CAA permitting programs, known as the greenhouse gas "tailoring" rule. This final rule sets thresholds for GHG emissions that define when permits under the NSR, PSD and Title V Operating Permit programs are required for new and existing steam electric plants. This final rule, "tailors" the requirements of CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The GHG tailoring rule required new or modified sources of GHG emissions to determine the best available control technology for their GHG emissions beginning in January 2011. Litigation is currently pending in the D.C. Circuit Court of Appeals on EPA's GHG endangerment finding and the tailoring rule, with oral arguments schedule to take place in February 2012.

New Source Performance Standards ("NSPS") - On December 23, 2010, in a settlement reached with several states and environmental groups in New York v. EPA, the EPA agreed to promulgate emissions standards covering GHGs from new and existing fossil-fueled electric generating units under Section 111 of the CAA by July 26, 2011 (which was subsequently extended) and issue final regulations by May 26, 2012. The EPA has not yet issued proposed NSPS for either new or existing sources. NSPS are established

under the CAA for certain industrial sources of emissions determined to endanger public health and welfare and must be reviewed every eight years.

Regional Climate Change Initiatives – While national GHG legislation has yet to be successfully adopted, regional and state initiatives continue with the active development of climate change regulations that are likely to impact PacifiCorp. The Western Climate Initiative was established as a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative initially included the state of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. However, only California, British Columbia and Quebec are moving forward under the initiative, with the other states focused on efforts to design, promote and implement cost-effective policies to reduce GHG emissions and crate economic opportunities.

State-Specific Initiatives - Many states have developed climate action plans and formed legislative advisory groups. PacifiCorp continues to actively monitor and participate in state and regional policy discussions relevant to all of its retail jurisdictions.

In October 2011, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations will be imposed on entities beginning in 2013. California also adopted a greenhouse gas emissions performance standard (S.B. 1368) the precludes long-term investments in base load generation (through ownership or through long-term contract) in power plants unless the facility meets a greenhouse gas emission rate of 1,100 pounds per megawatt hour.

Oregon and Washington Initiatives The Washington and Oregon governors signed executive orders in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of GHGs in their respective states. Washington's goals seek to: (1) by 2020, reduce emissions to 1990 levels; (2) by 2035, reduce emissions to 25 percent below 1990 levels; and (3) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. Oregon's goals seek to: (1) by 2010, cease the growth of Oregon GHG emissions; and (2) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

In addition, both Washington and Oregon have adopted GHG emission performance standards of 1,100 pounds of carbon dioxide per megawatt hour and prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

Water Quality Standards - In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities.

The proposed rule establishes requirements for all power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the United States. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers, but also withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The rule is required to be finalized by the EPA by July 2012. Assuming the final rule is issued by July 2012, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2013.

Coal Combustion Byproduct Disposal - In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the RCRA. Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C. The public comment period closed in November 2010. The EPA has not indicated when the rule will be finalized, and the substance of the final rule is not known. The United States House of Representatives passed H.R. 2273 in October 2011, which would regulate coal combustion byproducts under RCRA Subtitle D. A Senate bill similar to the House bill has been introduced, but action has not been taken on the bill. PacifiCorp has begun evaluating surface impoundment and landfill compliance plan options to ensure that physical infrastructure decisions are aligned with the potential outcomes of the rulemaking.

Docket No. UE-246
Exhibit PAC/506
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

MEHC Comments on Proposed Coal Combustion Residuals Rule

March 2012

November 19, 2010

Hazardous Waste Management System
U.S. Environmental Protection Agency
Mailcode: 5305T
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

Re: Docket ID No. EPA-HQ-RCRA-2009-0640
Comments of MidAmerican Energy Holdings Company on Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule.

To Whom It May Concern:

MidAmerican Energy Holdings Company ("MidAmerican") is a global energy services provider serving almost 6.9 million customers worldwide. MidAmerican's United States business platforms subject to U.S. Environmental Protection Agency ("EPA") regulation include MidAmerican Energy Company, an Iowa-based utility providing regulated electric and natural gas service; CalEnergy, an independent power producer with facilities in California, New York, Arizona, Texas, and Illinois; Kern River Gas Transmission Company, providing natural gas transportation from Wyoming to Southern California; Northern Natural Gas, an interstate natural gas transmission pipeline that spans from Texas to the Upper Midwest; and PacifiCorp, which provides regulated electric service in California, Idaho, Oregon, Utah, Washington and Wyoming. MidAmerican facilities generate electricity utilizing geothermal, hydroelectric, wind, natural gas, coal and nuclear resources. MidAmerican Energy Company and PacifiCorp generate, contract for the beneficial use of, and dispose of coal combustion residuals ("CCR") and will be directly impacted by this proposed rule (hereafter the "CCR rule").

MidAmerican appreciates the opportunity to provide comments to the EPA on this proposed CCR rule as set forth herein. MidAmerican is a member of the Utility Solid Waste Activities Group ("USWAG") and also incorporates by reference the comments submitted to the regulatory docket by USWAG. MidAmerican requests that the EPA not perceive the absence of comments by MidAmerican on any specific issue or other matter as a conclusive indication of MidAmerican's implied consent or indifference with respect thereto.

MidAmerican, through its operating entities, has been handling and continues to handle CCR in a safe and environmentally sound manner. MidAmerican and its contracted vendors have also been safely and beneficially reusing CCR in multiple applications for

over twenty years. MidAmerican has undertaken numerous voluntary and proactive measures to ensure the safe and environmentally sound disposal of CCR.

All of MidAmerican's new CCR disposal monofills have been constructed with protective liners and leachate collection systems. For example, the monofill at MidAmerican Energy's Walter Scott Energy Center was constructed in 2007 to include a synthetic liner, leachate collection, and groundwater monitoring wells. MidAmerican's newly constructed surface impoundments also include liners with pumpback systems and monitoring wells. PacifiCorp is in the process of constructing a surface impoundment with dual synthetic liners and interstitial monitoring at one of its Wyoming facilities. MidAmerican's operating entities have also been active signatories of the USWAG Voluntary Action Plan ("Action Plan"). This Action Plan is a voluntary commitment by utility industry partners to install and actively monitor groundwater monitoring wells around existing CCR disposal monofills and surface impoundments. All of these above referenced actions clearly demonstrate that MidAmerican and other utility industry members have been responsible actors proactively ensuring the safe and environmentally sound disposal and or beneficial use of CCR.

As MidAmerican communicated during the EPA's public hearings on this proposed rule,[1] we ***support*** ***the development of federal regulations for CCR as a non-hazardous waste under a Resource Conservation and Recovery Act ("RCRA") Subtitle D "Prime" non-hazardous waste rule***. MidAmerican strongly opposes the regulation of CCR under the RCRA Subtitle C hazardous waste program. While MidAmerican does have some concerns with the proposed Subtitle D option, and proffers some specific changes in these submitted comments, we believe this regulatory framework provides an appropriate legal structure under which the EPA may develop federal CCR regulations. Under this proposed Subtitle D option, unlike a Subtitle C option, EPA would not impermissibly, and illegally, reverse its final 2000 CCR Regulatory Determination. Under the Subtitle D approach, CCR would remain classified as a non-hazardous waste, and EPA would develop self-implementing national regulations for CCR disposal facilities that are enforceable by the states and by citizens under RCRA citizen suit provisions. The EPA would also retain its "imminent and substantial" endangerment authority to take action in the event that CCR units are determined to pose a risk to human health and the environment. As further described in the following pages, the proposed Subtitle C regulatory approach would lead to a myriad of draconian results including issues involving liability and the ability to achieve continuing regulatory compliance.

Most importantly, despite EPA's contention to the contrary, a "special waste" designation under RCRA Subtitle C would stigmatize CCR and effectively eliminate all beneficial use applications. As EPA heard repeatedly during the public hearings held in conjunction with this rulemaking, the beneficial uses of CCR are numerous and

[1] MidAmerican Energy Company and PacifiCorp presented oral testimony at the EPA CCR Public Hearings in Chicago and Denver, respectively.

extensive—ranging from agricultural applications, transportation infrastructure projects, and building construction activities. The ripple effects of a hazardous waste characterization for CCR would be felt throughout the entire U.S. economy. While, as a core principle of its business, MidAmerican advances the tenents of environmental RESPECT, including the responsible management and disposal of wastes, it cannot support the development of unjustified regulation of CCR based on fear, speculation and public pressure resulting from the unfortunate dam failure at TVA's Kingston facility and a handful of cases demonstrating inadequate management of CCR materials. It is difficult to comprehend how one of the most successful waste minimization programs in history, implemented on a nationwide basis, can be jeopardized when, in the vast majority of cases, CCR repeatedly fail to exhibit hazardous characteristics. To be clear, MidAmerican does not assert that CCR should not be regulated at all. We believe that well-developed regulations that ensure the responsible management of waste, no matter what its characterization, are good for the environment and good for business. However, over-regulation adds costs without a sufficient corresponding benefit and the potential for unanticipated and unintended consequences in the over-regulation of CCR is significant.

CCR Does Not Warrant Hazardous Waste Regulation

The EPA has a long history of assessing the environmental risks posed by CCR. Over a period of nearly 30 years, the EPA has consistently and unequivocally reported both to the U.S. Congress and the general public that CCR does not exhibit hazardous waste characteristics. In 1976, Congress enacted RCRA to regulate the disposal of a growing volume of municipal and industrial wastes. Members of Congress recognized the public policy implications of this legislation on the nation's energy independence and expressed concern that RCRA would create an incentive for electric utilities to switch from domestic coal to foreign oil. To address those concerns, Congress amended RCRA in 1980 (hereafter "Bevill Amendment") to single out CCR for special consideration and required the EPA to demonstrate that the regulation of CCR would not discourage its beneficial reuse by imposing unnecessary regulatory costs specifically related to disposal. The Bevill Amendment excluded CCR from regulation as a hazardous waste under RCRA Subtitle C and prescribed a series of statutorily defined environmental and economic assessments that the EPA was required to undertake prior to regulating CCR.

Over the course of the next two decades the EPA worked to implement the Bevill Amendment requirements by conducting the statutorily required environmental and economic assessments of CCR. The EPA issued its first reported to Congress in 1998 and, utilizing its own, well-established test methodologies, concluded that large volume CCR – fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes – did not exhibit hazardous characteristics and should not be regulated as a hazardous waste under Subtitle C. The EPA's subsequent 1993 Regulatory Determination reaffirmed the determination that large volume CCR was not a hazardous waste. Following the 1993 regulatory determination, the EPA began work on assessing low volume CCR. The EPA reported to Congress in 1999 that low volume CCR also did not warrant regulation as a

hazardous waste under Subtitle C. The EPA final Regulatory Determination in 2000 confirmed the 1999 assessment. The EPA's current proposal to regulate CCR as a hazardous waste under RCRA Subtitle C would be **contrary** to and inconsistent with EPA's own findings, test methodologies, the law, and the regulatory construct, based on nearly 30 years of assessment and analysis without any additional or scientifically-based evidence that CCR exhibits hazardous characteristics. EPA should consider regulation of CCR as hazardous only those materials that are hazardous (the exception) rather than regulating all CCR as hazardous (the rule).

EPA Has Impermissibly Reversed its Position on CCR Regulation under Subtitle C

MidAmerican submits that the EPA's proposal to regulate CCR under Subtitle C is impermissible, in part, because the Agency failed to follow the procedural process that was explicitly prescribed under the Bevill Amendment. As indicated above, Congress required the EPA to engage in a specific decision making process prior to making a final regulatory determination about CCR. The EPA was first required to assess CCR under the eight factors proscribed in the statute.[2] EPA was then required to publish a report detailing the results of the study and submit that report to the U.S. Senate Committee on Environment and Public Works and the U.S. House of Representative Committee on Energy and Commerce. Following submission of this report, the EPA was required to conduct public hearings and solicit comments to Congress before issuing a final regulatory determination. The initial determination in 2000 concluded that hazardous waste regulation was not warranted.

In the current proposal, the EPA has requested public comments on regulating CCR under Subtitle C without first conducting a study and submitting the results of that study to Congress as required under the Bevill Amendment. The EPA's disregard for the Bevill Amendment requirements is especially disconcerting given that the EPA is considering reversing the 1993 and 2000 findings that were submitted to Congress. The rationale behind the Bevill Amendment was to involve Congress in the regulatory process and ensure that any CCR regulations reflect Congressional intent and do not discourage the beneficial reuse of CCR. The Bevill Amendment clearly requires that the EPA's final CCR regulatory determination be based on information EPA received from the process prescribed in the statute, including the report of Congress. Presently, there is no new report to Congress that justifies the EPA's proposal to regulate CCR under Subtitle C. By failing to complete the required assessment and submit a report for congressional review, the EPA is bypassing the process required by Congress and ignoring the plain language of the Bevill Amendment. *Assuming arguendo* that it is the EPA's intent to regulate CCR under Subtitle C, the EPA must conduct a detailed and comprehensive study as envisioned by the statute, provide a report to Congress detailing the adverse affects on human health and the environment, solicit comments on the report to Congress and make a final determination based on the report and public input.

[2] See RCRA Section 8002(n).

Regulation Under Subtitle C Would Result in Unintended and/or Unanticipated Consequences

1. Difficulties in Practical Implementation – As a general rule, utilities undertake significant efforts to minimize their generation of hazardous wastes. MidAmerican's facilities strive to maintain their status as conditionally exempt small quantity generators through judicious management of potentially-waste producing materials. Placing CCR in the category of hazardous waste immediately changes the status of coal-fueled facilities to large quantity generators of hazardous waste. The nature and volume of CCR materials, in conjunction with the points of generation, including pollution control equipment such as baghouses, makes implementation of robust waste management measures extremely challenging from a compliance perspective.

2. What Constitutes Disposal? – Under a Subtitle C approach, the EPA would subject CCR destined for disposal to the full range of RCRA Subtitle C hazardous waste regulations. The Agency would regulate CCR as a hazardous waste under the Subtitle C hazardous waste rules by listing CCR as a hazardous waste under the "listed waste" criteria. While the EPA proposes to label CCR subject to hazardous waste regulation as a "special waste", this designation would not alter the fact that under Subtitle C, CCR destined for **disposal** would still be entirely subject to federal hazardous waste regulations. However, EPA has also proposed to apply Subtitle C criteria more stringently than it has to other listed and or characteristic hazardous wastes by retroactively applying Subtitle C hazardous waste criteria to previously closed and/or inactive CCR surface impoundments. This unusual, and potentially untested, application of Subtitle C is misplaced. While, under certain circumstances, it may be appropriate to apply CERCLA requirements to materials that, when disposed, were not subject to regulation, effectively requiring cleanup activities under Subtitle C is inappropriate.

3. One Size Doesn't Fit All – As reflected in the Bevill Regulatory Determination, an inflexible, one-size-fits-all Subtitle C hazardous waste program is not appropriate as it fails to account for the diverse nature of CCR disposal facilities. EPA previously explained as part of the Bevill Regulatory Determination *Federal Register* notice that "…since sites vary widely in terms of hydrological characteristics (e.g., depth to groundwater, annual rainfall, distance to drinking water sources, soil type) and the wastes' potential to leach into the groundwater and travel to exposure points is linked to such factors, it is more appropriate for individual States to have the flexibility necessary to tailor specific controls to the site…specific risks posed by these wastes."[3] The inflexible, one-size-fits-all nature of the Subtitle C program does not take into consideration geographical and other site specific factors that affect environmental and safety risks, nor does it take into consideration that not all CCR materials are created equally.

[3] See 58 *Federal Register* at 41477

With its new proposal, there is no "possibility of subjecting CCR to Subtitle C; it is a reality. As such, it is amazing that EPA would not once again consider the stigmatizing effect of this option and effectively rule out consideration of potential Subtitle C regulation.

It is clear that beneficial use of CCR would be effectively eliminated under a Subtitle C designation. This result would cause substantial shortfalls in Subtitle C disposal capacity in the United States. Under this option, at least 80 million tons of CCR would now enter the Subtitle C hazardous waste commercial disposal market on an annual basis. This contrasts with the 2 million tons of hazardous waste currently disposed of in commercial hazardous waste landfills. The influx of Subtitle C wastes would quickly overwhelm the approximately 30 million tons of total commercial hazardous waste landfill disposal capacity in the nation and create an immediate compliance issue for electric utilities. For MidAmerican Energy Company, the nearest permitted Subtitle C landfill is located in Peoria, Illinois. Conversations with facility representatives indicated that this landfill's capacity would be exhausted within months (not years) of this rule becoming finalized. MidAmerican Energy Company would be left with no disposal options independent of siting and permitting Subtitle C landfills on facility property. Siting of a Subtitle C hazardous waste landfill is currently a difficult, long and contentious process. Public reactions to such proposals are extremely negative. It is unrealistic to believe that Subtitle C capacity can be expanded exponentially to adequately accommodate the additional quantities of waste generated through CCR. Many utilities are not in a position to expand on existing, company-owned property and, even if they are, they are subject to Subtitle C permitting requirements in addition to local siting provisions that may contain use restrictions precluding the intended use.

There are Negative Impacts with the Mandatory Retrofitting and or Closure of Surface Impoundments

EPA's proposed regulation under either Subtitle C or D will result in dramatic changes to the current wet handling management of CCR regardless of any potential impacts to human health or the environment. Under the proposed Subtitle C regulatory option, for surface impoundments built before the rule is finalized, all solids would need to be removed and the impoundment would be required to retrofit with a liner no later than five years after the effective date of the rule and close within two years after that time. EPA further anticipates that unless surface impoundments already meet the prescribed liner requirements they will close within four years of the effective date of the rule. Under the proposed Subtitle D regulatory option, for surface impoundments built before the rule is finalized, all solids must be removed and the impoundment must be retrofitted with a composite liner or cease receiving CCR within five years of the effective date of the rule and close the unit.

Regardless of the regulatory option chosen by EPA, the requirements to remove solid materials from surface impoundments and either close or retrofit with a composite liner

within a five to seven year period is challenging from an operational perspective and is very costly. MidAmerican submits that the EPA's regulatory impact analysis for this proposed rule has grossly underestimated costs by failing to adequately account for all costs of compliance and their associated impacts on electric customers. PacifiCorp operates eleven CCR surface impoundments and MidAmerican Energy Company operates eight. Conversion of these surface impoundments within a five to seven year time frame is a significant undertaking particularly considering all of the other regulatory requirements that electric generating facilities may be required to comply with in the next few years including the Clean Air Transport Rule, regional haze BART determinations and reasonable progress goals, the utility hazardous air pollutant maximum achievable control technology rulemaking, climate change-related regulatory requirements, and a potential Clean Water Act section 316(b) final rulemaking.

To comply with these surface impoundment closure requirements, the majority of MidAmerican's facilities will be required to convert from wet handling (sluicing) to dry handling systems which could have major impacts on system reliability, and cost each facility tens of millions of dollars. Specifically, units will need to schedule forced outages that could last up to several months to accommodate system changes. It will be near impossible to close and or retrofit all surface impoundments while ***simultaneously*** accommodating scheduled outages for multiple base load generation units. Mandatory closures will be extremely costly. It has been estimated that the present value cost to the electric utility industry of a mandatory CCR surface impoundment closure rule is over $43 billion.[19] Accounting for lost generation capacity and or replacement costs could add another $12 to $37 billion.[20] At the same time, these same facilities will be required to install emissions controls to comply with air quality regulations; some of these mandated controls will actually increase the generation of CCR required to be disposed of as hazardous waste and that, based on existing plans, may have otherwise been destined for storage in surface impoundments.

MidAmerican also has concerns about the proposed period of time by which a closure must be completed once a surface impoundment stops receiving CCR. The EPA proposal provides that an owner and or operator must begin closure activities within 30 days after the date on which the CCR landfill or impoundment receives the final receipt of CCR and must complete closure within 180 days following the start of closure activities.[21] This effectively means that a CCR impoundment that is still operating on the effective date of the final rule, but subsequently ceases receiving CCR after the effective date of the final rule, has only 210 days to complete closure after the final receipt of CCR to the unit. It will be operationally impossible to meet this compliance timeframe. Because a substantial number of sites nationwide will have to be closed at roughly the same time period, electric utilities will be competing for a limited supply of personnel

[19] *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for Management of Coal Combustion Byproducts at Coal Fired Electric Utilities*, EOP Group, Inc.
[20] Id.
[21] See 75 *Federal Register* at 35244.

and equipment to close multiple sites. Assuming *arguendo* that there is no shortage of equipment and personnel, it will still be difficult for facilities to close their disposal units in the proposed timeframes that EPA proposes due to the sheer size and volume of these surface impoundments. Surface impoundments would be required to close by removing liquid wastes or solidifying remaining wastes. However, dewatering alone for larger units can take **years** (not months) to complete. EPA acknowledges that its closure time frames were borrowed directly from the existing closure time frames for municipal solid waste landfills under 40 Code of Federal Regulations Part 258. This is not an appropriate comparison as CCR disposal units are often much larger than solid waste landfills and contain significant amounts of water. Further, solid waste landfills are also frequently built in individual, smaller discrete cells which are typically closed when capacity is reached in each cell.

MidAmerican does not believe EPA has conducted sufficient analysis to justify its conclusion that closure or retrofitting of all surface impoundments is necessary. As set forth herein, EPA has failed to take into account any site specific conditions that may render existing surface impoundments to be fully adequate and pose no harm to human health or the environment.

The Timing and Transition Period is Inadequate

EPA's anticipated timing of implementation of Subtitle C regulation in states is extremely aggressive. Regardless of the length of time necessary for a state to adopt the requisite regulatory framework and program, the length of time for facilities to comply is inadequate. This situation is further complicated in a state without delegated authority to implement RCRA's Subtitle C program. Iowa is one of two states in that situation. MidAmerican Energy Company's facilities would be among the first to be subject to the onerous requirements associated with Subtitle C, which would be administered by EPA Region 7. A reduction in the time associated with compliance with Subtitle C requirements, simply because the state does not run the program is an unacceptable consequence of the lack of state delegation. MidAmerican Energy Company and other entities with coal-fueled generation in Iowa should not be penalized by requiring compliance any earlier than any other state. To the contrary, if EPA finalizes its Subtitle C option (which it should not, based on the comments herein), all states should be required to comply at the same time, on a date certain, rather than linking the compliance date to the date the state completes its rulemaking processes and that time should be, at a minimum, ten years from the final rule. In the event that a particular facility has created an "imminent and substantial harm" situation, EPA has current authority to, and should, address such a circumstance on an individual basis.

As further set forth below, MidAmerican believes that the EPA should adopt the Subtitle D "Prime" approach. However, if the EPA is to select a Subtitle C or D approach, MidAmerican recommends that the EPA extend the actual closure requirements to ten years. If warranted, facilities with the highest risk or demonstrated impacts could be addressed within the five to seven year time period. MidAmerican also recommends that

the EPA not establish a specific time frame for the closure of individual units. Instead, we urge the EPA to require utilities to close CCR surface impoundments consistent with a site specific closure plan approved by an individual state and developed/certified by a registered professional engineer or hydrologist.

EPA should adopt Subtitle D "Prime" Approach With Clarification/Modification

As highlighted earlier in our comments, MidAmerican supports the development of federal regulations for CCR as a non-hazardous waste under a RCRA Subtitle D "Prime" rule. The rulemaking record from the past twenty years, which has included two reports to Congress and two final Regulatory Determinations under the Bevill Amendment has consistently found that the Subtitle D approach was the appropriate course for the regulation of CCR. Most recently in its 2000 CCR Regulatory Determination, the EPA reaffirmed the appropriateness of the Subtitle D option, concluding that the Subtitle D regulations are the most appropriate mechanism for ensuring that CCR disposed in landfills and surface impoundments are managed safely.[22] In addition to the fact that CCR rarely exhibits hazardous waste characteristics, EPA explained that the decisive factors in reaching its final determination were: (1) improving trends in CCR disposal and utilization practices, (2) the current and potential utilization of CCR (i.e. beneficial use), and (3) Congress' admonition in the Bevill Amendment against duplication of efforts by other federal and state agencies.[23] EPA's focus on CCR disposal is understandable in the wake of the TVA incident. However, the TVA incident should not serve as the basis for an unjustified change in position without any new evidence. Nor should EPA respond blindly to unsubstantiated and often inaccurate claims of so-called damage cases.

Not only has there been consistent support in the previous record for Subtitle D regulation, over the past year (mid-2009 to present), the overwhelming majority of the states, municipal and local governments, over two-dozen state environmental protection agencies, state Departments of Transportation, other federal agencies, including the Department of Energy, have all expressed their support for regulation of CCR as a non-hazardous waste under RCRA Subtitle D. Given the breadth and depth of this federal, state, and local support for the Subtitle D option, the EPA's adoption and promulgation of a Subtitle C approach would run contra to the Bevill Amendment's directive that any federal regulatory program for CCR account for the views of other federal agencies and the states.[24]

A Subtitle D "Prime" regulatory approach would be fully protective of human health and the environment. The D "Prime" approach would include virtually of the same elements of the Subtitle D program with the exception that it would not require the closure or installation of composite liners in existing surface impoundments. Instead, these surface

[22] See 58 *Federal Register* at 42466.
[23] Second Report to Congress at 3-5.
[24] See RCRA Section 8002(n).

impoundments could continue to operate for the remainder of their useful life. Further, it is important to note that almost all of the technical and design requirements are the same under the Subtitle C or D programs (including D Prime). Specifically, all of the technical and design standards for CCR liner systems, groundwater monitoring and corrective action, and surface impoundment integrity standards are identical for both regulatory options.

One element of the Subtitle D Prime option that is different than under the Subtitle C and D programs is the requirement to retrofit and or close all existing CCR surface impoundments. MidAmerican submits that it is not appropriate to require the upgrade and or closure of existing CCR surface impoundments which operate in a manner that is protective of human health and the environment. Under the Subtitle D Prime approach, existing CCR surface impoundments would continue to be subject to groundwater monitoring requirements. MidAmerican submits that the EPA and/or state regulatory agencies should have the discretion to require closure and/or upgrades of certain surface impoundments that are not protective of public health and the environment.

One of EPA's stated concerns with the Subtitle D and D Prime options is the lack of direct federal enforceability to ensure that the individual states fully develop, implement and enforce a program. MidAmerican submits that the EPA has the authority to overcome any programmatic issues at the state level to develop Subtitle D program rules that are directly administered by the individual states with direct EPA enforcement authority. Specifically, the EPA can utilize the same combination of RCRA statutory authorities found under sections 4010(c) and 4005 (c) for the establishment of controls for CCR disposal units that it employed in promulgating the federally enforceable Subtitle D rules for municipal solid waste landfills. The combination of these two Subtitle D provisions enables the EPA to promulgate non-hazardous waste rules for CCR that can be directly administered through state permitting programs and directly enforced by EPA if the individual states fail to adequately implement federal rules. EPA's concern that it cannot require states to implement Subtitle D controls is misplaced. RCRA allows EPA to promulgate Subtitle D rules that can be directly administered through state permitting programs and backed by direct EPA enforcement powers in states that fail to implement the program. These rules would also be directly enforceable by the public under RCRA's citizen suit provisions.[25] EPA would also retain its "imminent and substantial endangerment authority" under RCRA to take action against any CCR unit that posed a risk to human health and the environment.[26]

[25] See RCRA Section 7002.
[26] Under RCRA Section 3008.

Preferred Subtitle D "Prime" Approach Clarification/Modification

As communicated above, MidAmerican supports the Subtitle D "Prime" approach but submits some of the following changes to the proposed rule:

The Subtitle D Prime rule should allow for alternate liner systems –

Under the EPA's proposal, new surface monofills and impoundments would be required to have a specified type of composite liner. EPA asks in the proposal whether the Subtitle D option "should allow facilities to use an alternative design for new disposal units" provided an independent, registered Professional Engineer or hydrologist certifies that an alternate design system would be protective of human health and the environment. **MidAmerican promotes that new surface impoundments should allow for the use of performance based alternate liner systems instead of specifying a given technology.** This flexibility in the CCR rule would allow a site specific design of appropriate liners which could reflect site specific conditions. Different locations will have different site specific considerations, including depth to groundwater, which will need to be factored into the design standards. Even in certain locations where potential risks to groundwater are greater, many alternate liner systems can meet or exceed the performance standards proposed in the rule. This option should also allow a company employed Registered Professional Engineers ("PE') and or hydrologists to accomplish compliance certifications; not just third party PEs or hydrologists.

Certain Terms need to be Better Defined –

CCR Surface Impoundment – MidAmerican submits that the EPA's proposed definition of "CCR Surface Impoundment" is overly broad and needs to be better defined. This definition as it is currently written would inappropriately capture impoundments that do not manage CCR and or are not designed to manage CCR. As currently drafted, the definition includes:

> "A facility or part of a facility…which is *designed* [emphasis added] to hold an accumulation of CCR containing free liquids…."[27]

A key limitation in this definition, as enumerated above, is that it is defined (and likely intended) to capture only impoundments "designed" to accumulate CCR. If applied as intended, this definition would and should only extend to those impoundments into which CCR are sluiced from air pollution control devices as these are the only impoundments "designed" to accumulate CCR. However, MidAmerican has concerns that this current proposed definition could be interpreted to include downstream impoundments, such as cooling water and or wastewater treatment ponds that receive wastewaters containing de minimis amounts of CCR. For example, a wastewater

[27] See 75 *Federal Register* at 35239 (proposed 40 CFR Section 257.2)

treatment impoundment at a facility that only receives non-CCR wastewaters may on occasion receive small amounts of CCR via stormwater runoff.

The potential for an overly broad application of this proposed definition capturing non-CCR surface impoundments is highlighted by the over-counting of CCR impoundments by the EPA in this proposed rule. Specifically, the EPA explained that it had previously estimated in the 1990s that there were 286 CCR surface impoundments in use.[28] However, the EPA now estimates that there are 584 CCR surface impoundments in use at roughly 495 coal-fueled power plants.[29] The EPA acknowledges that this substantial increase in numbers does not reflect an actual change in on-site management practices but likely results from counting units that receive wastewater that has been in contact with "even small amounts of coal ash".[30] This over-counting is likely the direct result of EPA's issued Information Collection Request ("ICR") from 2009 where the EPA requested that any impoundment receiving even de minimis amounts of CCR be identified. It was understood by the utility industry at the time of the ICR that the request could capture impoundments, such as wastewater treatment ponds, that are not CCR impoundments, but which may still contain de minimis amounts of CCR through potential stormwater runoff or other means/sources.

However, it is paramount that this over-counting not be perpetuated through a poorly written definition of CCR Surface Impoundments. The definition must be amended to make clear that downstream impoundments that receive only de minimis amounts of CCR are not labeled as CCR impoundments. In addition to including a more specific description of impoundments within the modified definition, EPA should also incorporate a size limit into the definition. This will ensure that smaller units that do not pose the potential risks associated with the types of CCR impoundments described in EPA's own damage cases are excluded from the definition. One appropriate size threshold would be the one proposed by the EPA for purposes of triggering the impoundment structural integrity requirements. In the proposed rule, the EPA proposes a storage capacity of 20 acre feet or more, as the threshold for requiring structural integrity testing.[31] The proposed definition should also not encompass units that have previously served as impoundments but have been subsequently dewatered and closed.

Fully accounting for all of these above described conditions, MidAmerican proffers the following modified definition for CCR Surface Impoundment. The language in italics reflects changes/additions to the definition.

> "CCR Surface Impoundment means a facility or part of a facility…*which has a storage volume of 20 acre-feet or more* and which is specifically designed *for and whose primary function is* to hold an accumulation of

[2828] See 75 *Federal Register* at 35151
[29] Id.
[30] Id.
[31] See 75 *Federal Register* at 35243

> CCR containing free liquids. Examples of CCR surface impoundments whose primary function is to hold an accumulation of CCR are primary holding, storage, settling, and aeration pits, ponds, and lagoons that are used to receive CCR that are sluiced directly from wet air pollution control devices, often in addition to other solid wastes. *This definition is not intended to encompass impoundments whose primary function is not to receive CCR but which receive de minimis amounts of CCR through the receipt of wastewaters that contain only small amounts of CCR. Examples of impoundments that are not CCR impoundments include, but are not limited to, cooling and polishing ponds and wastewater treatment ponds. CCR impoundments also do not include former impoundments that have been de-watered."*

Existing CCR Surface Impoundment – The EPA proposed definition of "Existing CCR Surface Impoundment" needs to be refined to clarify that it does not include impoundments that cease receiving CCR before the effective date of the final CCR rule. The currently proposed definition defines an impoundment that "was in operation…prior to the effective date of the rule." MidAmerican submits that this definition should be modified to define an existing surface impoundment as a unit that "was in operation and had not yet ceased receiving CCR prior to the effective date of the rule." This definitional clarification would clearly state that the definition does not encompass units that are no longer receiving CCR on the effective date of the final rule, even though the unit may not have completed final closure prior to said effective date.

CCR Landfill – The EPA proposed definition of "CCR Landfill" under proposed RCRA Subtitle D regulatory option includes the term "piles." At many utility generation facilities, CCR often are placed into piles for purposes of dewatering, staging, and/or consolidation prior to placement in a CCR landfill. MidAmerican submits that it is inappropriate to regulate such temporary CCR storage piles in the same manner as an actual landfill in which the CCR are permanently disposed. Even in the alternative proposed Subtitle D hazardous waste option, EPA recognizes the distinction between landfills and storage piles, and defines the two as separate management units. The proposed Subtitle C regulations expressly exclude "piles" from the definition of a "landfill." The definitions under the Subtitle D option should reflect the same distinction between landfills and piles.

EPA Administrator Jackson has often expressed her support for "the polluter pays" proposition; however, under this rulemaking, everyone will pay for the consequences of over-regulation of CCR, even when there is no pollution, if EPA adopts Subtitle C regulation for CCR. Does such an approach foster innovation and flexibility, or foster greater efficiency and cost savings? We submit that it does not.

MidAmerican appreciates your consideration of these comments on this proposed CCR rule. If you have any questions or require additional information, please feel free to call me at 563-333-8009.

Sincerely,

Cathy S. Woollums
Senior Vice President, Environmental Services and
Chief Environmental Counsel
MidAmerican Energy Holdings Company
106 East Second Street
Davenport, Iowa 52801

Docket No. UE-246
Exhibit PAC/507
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

MEHC Comments on Proposed Clean Water Act Section 316(b) Rule

March 2012

August 18, 2011

Via e-mail to www.regulations.gov

Ms. Nancy Stoner
Acting Assistant Administrator for the Office of Water
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Re: MidAmerican Energy Holdings Company Comments on the U.S. Environmental Protection Agency's Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at Existing Structures and New Units (EPA-HQ-OW-2008-0667).

Dear Administrator Stoner:

MidAmerican Energy Holdings Company ("MidAmerican") is a global energy services provider serving almost 6.9 million customers worldwide. MidAmerican's United States energy business platforms include: MidAmerican Energy Company, an Iowa-based utility providing regulated electric and natural gas service; CalEnergy, an independent power producer with facilities in California, New York, Arizona, Texas, and Illinois; Kern River Gas Transmission Company, providing natural gas transportation from Wyoming to Southern California; Northern Natural Gas, an interstate natural gas transmission pipeline that spans from Texas to the Upper Midwest; and PacifiCorp, which provides regulated electric service in California, Idaho, Oregon, Utah, Washington and Wyoming. MidAmerican facilities generate electricity utilizing geothermal, hydroelectric, wind, natural gas, coal and nuclear resources.

On behalf of two of MidAmerican's utility operating entities, MidAmerican Energy Company and PacifiCorp, which operate facilities with cooling water intake structures, we appreciate the opportunity to provide comments to the Environmental Protection Agency ("EPA") on the proposed Clean Water Act Section 316(b) rule for cooling water intake structures (hereafter "316(b) rule"). In general, MidAmerican appreciates the Environmental Protection Agency's willingness to provide for case by case, site-specific flexibility for facilities related to the establishment of and compliance with entrainment standards. However, MidAmerican does have certain issues and concerns with this proposed rule as further detailed on the following pages.

Specifically, MidAmerican has concerns about (1) the ability of regulated entities to achieve the numeric limits for impingement; (2) the potentially subjective interpretation and implementation of entrainment standards by the delegated state permitting authorities; (3) the potential multiple

definitions and redefinitions of Best Technology Available; (4) the cost-benefit analysis process for species of concern; (5) the lack of a de minimis impact exemption; (6) the monitoring and recordkeeping requirements; and, (7) the timing of the compliance requirements.

MidAmerican is a member of the Edison Electric Institute ("EEI") and PacifiCorp is a member of the Utility Water Act Group ("UWAG"); MidAmerican supports the comments of these organizations and incorporates by reference the EEI and UWAG comments submitted in this docket as if fully set forth herein. MidAmerican also requests that the EPA not perceive the absence of comments by MidAmerican as a conclusive indication of MidAmerican's implied consent or indifference with respect thereto.

I. Determination of Best Technology Available

A. MidAmerican Supports EPA's Determination Regarding Closed Cycle Cooling

MidAmerican agrees with EPA's conclusion that it is not cost-effective or practical to mandate closed cycle cooling (however, credit should be provided if a facility has installed closed cycle cooling as discussed further below in Section II). Mandating closed cycle cooling could have dramatic consequences on the availability of the nation's water supply. Once through cooling is not a consumptive water use and returns all the water utilized for cooling purposes downstream for irrigation and drinking water, among other uses. Installing cooling towers would increase the consumptive use of precious fresh water at a rate of nearly 3 billion gallons per year for each large facility (i.e., 700-800 megawatts). It would be difficult, if not impossible, for EPA to justify the costs of a rule mandating closed cycle cooling which would reduce water supplies for human consumption in the name of preventing impingement and entrainment of aquatic organisms, many of which are likely to be invasive species.

Installing cooling towers at existing facilities is expected to reduce generating capacity by approximately 3% and would have an adverse impact on the efficiency of electric generating facilities. A number of companies have already announced the near-term closure of thousands of megawatts of coal-fueled electricity generation in response to EPA's new and proposed air quality regulations – a situation that is further exacerbated by a reduction in the efficiency by an unnecessary requirement to install cooling towers. The linkage between the mandates under the 316(b) rule and air quality requirements cannot be ignored. As EPA acknowledged in its proposal, adding cooling towers increases particulate matter. Similarly, adding incremental baseload generation (as opposed to intermittent renewable generation) to compensate for megawatts lost through EPA's patchwork of environmental regulation also has the potential to increase criteria pollutants and increases the emissions intensity (on a pounds per megawatt-hour basis) at existing facilities.

Additionally, in many areas, closed cycle cooling poses a potential safety hazard. It is well established that the evaporative losses from a cooling tower can result in icing and fogging of roadways and airstrips, creating public safety concerns that do not currently exist.

For these and other reasons discussed herein, MidAmerican believes EPA has appropriately determined that closed cycle cooling should not be deemed to be Best Technology Available for existing facilities.

B. The Proposed Rule's Impingement Control Requirements Have Not Been Adequately Justified and May Not be Achievable

Under the proposed rule, an owner/operator of an existing facility with a design intake flow ("DIF") greater than 2 million gallons per day ("MGD") design intake may choose one of two options for demonstrating Best Technology Available ("BTA") for impingement mortality. The owner/operator may monitor to show the specified performance standards for impingement mortality of fish have been met (an upper limit on impingement mortality at 12% mortality annual average, and a not-to-exceed 31% monthly average for all life stages collected on 3/8-inch screens). Alternatively, the owner/operator may demonstrate that the intake velocity meets the specified design criteria (i.e., reduce intake velocity to 0.5 feet per second). MidAmerican has concerns with these proposed options for demonstrating BTA for impingement mortality. MidAmerican submits that these standards fail to account for site-specific facility impingement impacts, in many cases are not achievable, and are overly broad in applicability as they should apply only to identified "species of concern."

MidAmerican submits that the impingement mortality standards of 0.5 feet per second and/or 12% impingement mortality may not be achievable even by certain facilities that have installed, and properly operate and maintain, the technology on which these standards are based. Under the proposed rule, the EPA has concluded that modified traveling screens, such as Ristroph screens, are the best performing technology for fish impingement mortality. The proposed rule also requires the use of state of the art screens with fish buckets, low pressure spray wash, and a dedicated fish return line; however, the rule does not specify any particular screen configuration, mesh size or screen operations, so long as facilities can meet the numeric impingement mortality limits. MidAmerican questions the technical feasibility of certain facilities to achieve these impingement mortality standards even if they install these modified traveling screens. MidAmerican believes that the EPA has failed to account for the fact that even the best designed, operated, and maintained impingement control equipment cannot overcome other factors affecting impingement rates including the hardiness of the species, the life stages of the organisms impacted, natural biological factors which can impact impingement rates (i.e. refer to gizzard shad example detailed below) and specific waterbody characteristics such as flow and volume.

MidAmerican recommends that in any final rule the EPA **eliminate these numeric standards** and instead allow facilities to establish compliance by demonstrating that they have installed and are properly operating and maintaining the prescribed technology (the "BTA"). MidAmerican proposes that EPA provide specific operating and maintenance criteria for facilities to follow to demonstrate that they are properly operating and maintaining the prescribed technology. There is precedent for this approach as the EPA, under several of its Clean Water Act authorized programs, has prescribed specific work practices or best management practices to demonstrate

compliance. For example, best management practices are used to demonstrate operational compliance for facilities and sites with stormwater pollution prevention plans ("SWPPPs") required under Section 402 of the Clean Water Act.

C. The Proposed Rule's Entrainment Considerations Have Not Been Properly Developed

Under this proposed rule, entrainment controls would be established by the delegated permitting authority (i.e., state agency) on a case by case basis for all facilities with at least a 2 MGD design intake flow. For entrainment mortality, a facility must either (1) achieve site-specific standards that reflect the permit writer's determination of the maximum reduction of entrainment mortality warranted after consideration of all factors relevant for determining the BTA at each facility, including the "nine factors" specified in the proposed rule, or (2) demonstrate that they meet the entrainment mortality standards applicable to new units at existing facilities.

In general terms, MidAmerican supports the EPA's approach to provide for site-specific flexibility in establishing entrainment standards. This approach is reasonable and lawful in light of the decision of the Second Court of Appeals in Riverkeeper which acknowledged that EPA has discretion to implement 316(b) standards on a case by case basis in lieu of setting uniform standards.[1] A case by case approach is necessary to account for site-specific variation and ensure that additional entrainment controls are imposed only where the likely benefits of such additional controls are justified (while fully accounting for the actual costs). The EPA's proposed approach provides for the consideration of these costs and benefits through the comprehensive "nine factor" analysis. However, MidAmerican raises the following specific concerns with how these case by case entrainment mortality requirements have been proposed.

1. MidAmerican submits that the discretionary decision-making standard for entrainment does not clearly require state permit writers to reject technologies whose benefits do not justify the costs. This "justified standard" originates from Executive Order 13563 issued by the Obama Administration and effectively allows a regulated entity to argue to its permit writer that a permit requirement that would cost more than the benefits that it provides would be unjustified.[2] MidAmerican recommends that the 316(b) rule clearly and explicitly require individual state permit writers to reject a technology in which the costs do not justify its benefits.

2. Under this proposed rule, existing facilities that withdraw large amounts of water (at least 125 MGD) would be required to conduct "extensive, peer reviewed technology feasibility" studies to assist their delegated permitting authority in determining whether and what site specific controls, if any, would be required to reduce the number of aquatic organisms entrained into the cooling water systems. This requirement to obtain peer review of all four components of the site-specific entrainment characterization study is overly broad and unduly burdensome. MidAmerican submits the peer review requirement will add unnecessary time and expense to the review process. Further, EPA fails to consider the very likely scenario that two technology

[1] Riverkeeper, Inc. v. EPA, 358 F.3d 174 (2d. Cir. 2004)
[2] See Executive Order 13563 of January 18, 2011. *Improving Regulation and Regulatory Review*.

reviewers will not agree on the controls that may be required to reduce entrainment. MidAmerican does not believe the peer review process adds value; however, we believe it is appropriate for EPA and/or the state regulatory authority to establish an appellate review process in the event the proposed entrainment requirements are believed to be overly onerous or unachievable.

3. MidAmerican is concerned with how individual, delegated permitting authorities will interpret, develop, and implement site specific entrainment standards. Initial conversations with some of our state regulatory agencies indicate that the permit authorities do not have any understanding, and have not been provided any guidance or instructions from the EPA, on how they should interpret, develop and implement these proposed standards. Many questions and concerns remain unanswered or unaddressed following these initial conversations with state agencies, including:

- Related to the comprehensive "nine factor" review, how will delegated permitting authorities conduct this review? Will individual states have discretion as to whether all nine factors need to be reviewed and considered? Additionally, is there a comparative weighting analysis used for each of the individual nine factors? Further, do individual state permit writers have discretion to consider additional factors (outside and independent of these nine factors)?
- What factors can the delegated permitting authority use to reject any technologies as BTA for entrainment? The proposed rule only discusses that "social costs of compliance are not justified by social benefits". How will this be calculated?
- The proposed rule states that facilities must comply "as soon as possible" based on a schedule established by the delegated permitting authority. How flexible can the individual delegated permitting authority be on the specific compliance schedule, and how will this subjective standard be enforced?

As highlighted previously, MidAmerican supports the EPA's approach to provide for site specific flexibility in establishing entrainment standards. However, the delegated permitting authorities need to be provided detailed and prescriptive guidance on how to design and implement these entrainment standards in order to specifically address the many questions detailed above. This instructive guidance should be clearly included as part of the final rulemaking.

II. Exemptions

A. Facilities with Closed Cycle Cooling/Cooling Towers Should be Exempt from Further Review and Study

While MidAmerican agrees with and supports EPA's determination that closed-cycle cooling, including cooling towers, is not "best technology available" for existing steam-electric facilities because such technology is not feasible or cost-effective at many existing facilities that do not already have it, we believe that EPA should clearly acknowledge that if a facility already has

cooling towers and its water intake structure is utilized for cooling tower makeup water lost through evaporation, the facility should be exempt from the rule regardless of whether the make-up water is sourced from a water of the U.S. or state or whether the water is drawn continuously or intermittently. These facilities have already undertaken significant mortality reduction efforts through the installation of cooling towers. To impose additional requirements on these facilities by requiring the additional installation of alternative screens and/or measures to otherwise reduce impingement or entrainment penalizes these facilities and holds them to a higher (and unjustified) standard than facilities that have not undertaken such control measures.

B. Facilities Meeting BTA Should be Exempt from Further Review and Study

Similar to the discussion in the previous section regarding closed cycle cooling, facilities that install Ristroph travelling screens with fish return systems have, pursuant to the proposed rule, installed BTA, by the EPA's own definition. As such, they have met the underlying requirements of the rule (which should be affirmatively acknowledged by EPA), and should not be required to conduct additional studies or evaluation. MidAmerican believes it is duplicative and unnecessary to conduct studies or evaluation and doing so will only increase costs without any corresponding environmental benefit.

In addition, MidAmerican recommends that EPA broaden the suite of identified BTA to (a) allow facilities to take credit for impingement-reducing technologies that are already installed (i.e., an early off-ramp), and (b) provide flexibility if EPA's preferred BTA is technically unavailable or otherwise does not achieve the anticipated impact mortality reductions at a given site/facility.

C. Facilities Withdrawing Less than 5% of Flow Should be Exempt

As EPA determined in the remanded Phase II rulemaking, cooling water withdrawals of less than 5% of mean annual low flow from freshwater rivers and streams present a relatively low entrainment risk. MidAmerican also submits that the risk of impingement on intake structures on high flow water bodies is lower and there is insufficient support to include these facilities in the rule's requirements. These high flow water bodies, including the Missouri and Mississippi Rivers, which are among the most robust and fast-flowing fresh water bodies in the country, present a significantly lower risk of impingement and entrainment. MidAmerican Energy Company's facilities withdraw cooling water from the Missouri and Mississippi Rivers and their design intake rates are less than 3% of the average annual river flow. The arbitrary establishment of a 2 million gallon per day intake design flow, or 0.5 feet per second intake velocity have no relevance in establishing the impacts on impingement and entrainment without also considering site specific characteristics of the water bodies.

III. Site and Species Considerations Should be Incorporated

A. The Impingement Mortality Standards Should Only Apply to "Species of Concern"

Unfortunately, the proposed rule does not clearly define what constitutes a "species of concern" nor does it prescribe that the impingement and entrainment standards only apply to "species of concern." Instead, the required Impingement Mortality Reduction Plan ("IMRP") directs the delegated state permitting authority to cover all species targeted in the source water baseline biological characterization study ("SWBBCS"). The SWBBCS captures all species to include species that are numerically prevalent and dominant. Additionally, the IMRP does not specifically allow the delegated permit writer to select specific species for protection nor does it provide clear guidance as to what factors permit writers should consider if there is authority to select certain species for protection. MidAmerican promotes that the EPA should specifically modify this proposal to only address impingement mortality for those "species of concern," including criteria by which delegated permitting authorities may determine which species are "of concern". The EPA also needs to amend the requirements under the SWBBC so that only "species of concern," to include all associated life stages, are addressed. Further, the Agency needs to remove the requirements for an IMRP after completion of a SWBBC study since under MidAmerican's recommendations (as detailed in the preceding section), the regulated entities are demonstrating compliance by following the associated work practice standards for the prescribed BTA.

A. The Design Intake Criteria Are Arbitrary and Unjustified

The requirement that all facilities with a designed intake flow above 2 MGD must meet impingement standards, regardless of the number or type of fish impinged is arbitrary and fails to take into account, on a case by case basis, the actual site-specific facility impingement impacts. Under the proposed rule, the EPA fails to account for the fact that not every facility with a design intake flow above 2 MGD has the same impact on impingement mortality. Specifically, certain facilities draw from larger bodies of water with greater flows and therefore have minimal impacts on impingement. Indeed, the EPA's own data have consistently demonstrated that species-specific impingement rates vary by many orders of magnitude from site to site, even among facilities on the same type of waterbody.[3]

B. The Impingement Requirement Inappropriately Treats All Organisms Equally

Certain facilities only have impingement impacts on **non**-"species of concern." For example, MidAmerican Energy facilities along the Mississippi and Missouri rivers impinge predominately gizzard shad, a species which experiences natural die off events. This species is also particularly susceptible to impingement during the winter months because of specific physiological responses

[3] See EPA, *Economic and Engineering Analysis*, July 20, 2000, at Chapter 11-13.

that occur at colder water temperatures: at water temperatures below 51 degrees Fahrenheit, gizzard shad stop feeding but do not correspondingly reduce their activity levels.[4]

C. Invasive Species Should Not be Counted

Invasive fish, gastropods, and mussels should not be included in a facility's compliance obligation relative to impingement and mortality standards. Clearly, these are not the types of organisms the 316(b) rule was intended to consider in establishing BTA; furthermore, these invasive species pose a threat to many of the organisms the 316(b) proposal is designed to protect.

D. A De Minimis Impact Level Should be Established

At some facilities the absolute numbers of fish impinged is so minimal that the cost to achieve any required reductions would be significantly greater than any benefits. For example, if, over the course of a year, 100 species of concern are impinged and 10 die, the facility would be in compliance with the 12% standard; however, if the facility either has installed controls that operate at a high level in preventing impingement and/or site specific conditions or species are such that only 10 species of concern are impinged and two die, the facility would not achieve compliance with the 12% standard. In the latter example, 80% fewer fish perished than in the first example. MidAmerican does not believe EPA intends to penalize such facilities that have a de minimis impact on species of concern and submits that it is necessary and appropriate for EPA to establish a de minimis exemption to account for such a situation. MidAmerican submits that the EPA needs to adequately account for the actual site-specific impacts and should adopt some form of de minimis exemption from impingement control requirements for certain facilities based on the **number and type of organisms actually impacted**.

IV. Compliance Requirements, Monitoring and Reporting

A. The EPA Needs to Provide Greater Flexibility in the Compliance and Application Deadlines

MidAmerican has concerns that the six month timeline to complete the prescribed studies[5] in the draft proposal is far too aggressive considering the limited number of qualified consultants to conduct these studies at the hundreds of electric generating stations (and other affected facilities) with cooling water intakes around the United States. MidAmerican has previously contracted with a consultant (Burns & McDonnell) to conduct studies for all of its facilities spanning multiple states in the Upper Midwest and Rocky Mountain regions. The limited resources of this one qualified consulting firm will be further stretched to serve the many other utilities in the

[4] Burns & McDonnell, *Section 316(b) Compliance Feasibility Study*, prepared for MidAmerican Energy Company, November 2007.

[5] To include the source water physical data, cooling water intake structure data, source water baseline biological characterization data, impingement mortality reduction plan and entrainment characterization study.

upper Midwest and Western U.S. It is highly probable and quite likely that it will be impossible for all regulated entities to timely complete all of these required studies under this unreasonably tight compliance timeframe. The EPA should lengthen this tight compliance obligation to at least one year to allow affected facilities and the limited number of qualified consultants a reasonable time to complete the required studies.

On a related compliance matter, MidAmerican has questions about how the EPA and delegated state permitting authorities will treat facilities with recently issued NPDES permits, without these specific studies, as well as facilities with expired NPDES permits due to state regulatory agency delays. What is the specific timing for completing these studies for facilities with expired NPDES permits? Should facilities complete these studies as part of permit renewal process? Further, what are the grandfathering and reopener provisions for facilities with valid, recently issued NPDES permits?

MidAmerican also questions the need for extensive compliance monitoring with the established numeric impingement mortality standards. Compliance monitoring for the life of the facility is unduly burdensome, and creates risk and uncertainty, due to the potential for exceedances of impingement standards as a result of variability in both species and waterbody conditions. Further, actual monitoring procedures and methods have not been validated for various types of fish. Instead of these onerous compliance monitoring requirements, (associated with established numeric impingement mortality standards) MidAmerican recommends that the EPA allow individual permittees to demonstrate compliance with impingement standards by following prescribed operating and maintenance practices.

B. Facilities Should Not be Required to Re-Evaluate BTA on Facility Permit Renewal

The EPA's proposal requires existing facilities to resubmit BTA application information and requires permit writers to make new BTA determinations during every NPDES permit renewal, regardless of whether the facility has been modified or there is any reason to believe that in-stream conditions have changed. MidAmerican asserts that this requirement should be removed from this rule; once the BTA determination is made, it should be valid and effective until such time as the 316(b) rules are revised. To do otherwise is to subject facilities to potentially changing technologies every five years, making the cost of compliance exorbitantly high if spread over a five year period.

C. Facilities Should be Allowed to Use Already Completed Studies to Satisfy Compliance Obligations

MidAmerican submits that facilities that have already completed studies (to include impingement and entrainment characterization studies) within the past 10 years should be allowed to utilize such studies, to the extent no material cooling water intake modifications were made at the facilities since the time of the study, to meet this proposed rule's compliance obligations. Regulated entities have already invested substantial time, resources and costs into

these completed studies and rather than becoming obsolete and effectively stranded investments, these studies should be adequate to meet this rule's compliance obligations.

V. Cost/Benefit Analysis

A. Compliance Costs

MidAmerican is concerned about the costs to comply with the proposed 316(b) requirements for a multitude of reasons. While we support environmental regulations that are based on sound science and achieve environmental benefits, we have a responsibility to our customers to ensure that we carefully review the basis for the regulations and explore compliance options that maintain our ability to provide reliable electric service at a reasonable cost. In this particular circumstance, EPA's own estimate of the total annualized costs of compliance with the proposed impingement control requirements, as well as the permit application, monitoring, and reporting requirements is almost 22 times higher than the benefit derived from the requirements. Further, not all compliance costs have been captured in this figure – any costs associated with compliance with the entrainment requirements have not been included. EPA's own analysis fails to comport with the President's Executive Order on Improving Regulation and Regulatory Review[6] which directs agencies to tailor their regulations to impose the least burden on society.

B. Potential for Stranded Investment and Additional Costs Associated with Bifurcation of the Impingement and Entrainment Analyses

The review of impingement and entrainment and selection of the mitigating technology must be performed in parallel. Under EPA's proposal, large facilities will be required to comply with impingement standards at least two years before knowing what controls will be required for entrainment. If a facility invests in mitigation for impingement and it is only after two years that the entrainment requirements are determined – which could impose additional costly requirements on the facility – the initial decision to invest in impingement mitigation may have been different. The risk of making investments to address impingement without addressing entrainment at the same time places facilities at risk of making initial investments in impingement technologies that are not economic, lead to stranded investments, and unnecessarily increase costs to customers. MidAmerican believes these two analyses should be coordinated to avoid such a risk and to allow facilities to have the comprehensive set of information that will allow them to make well-informed decisions regarding the costs that a given facility can bear and still be competitive. In addition, there should not be a redetermination of BTA upon the renewal of the facility's permit. Once BTA is determined, it should remain as BTA unless and until the 316(b) requirements are modified. Again, without this clarification, additional costs will ultimately be borne by customers.

[6] Executive Order No. 13563 (Jan. 18, 2011), published at 76 Fed. Reg. 3821 (Jan. 21, 2011)

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

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah 84116. My present position is Vice President of Thermal Generation. I am responsible for the coal, gas, and geothermal resources owned by the Company.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I have been the Vice President of Thermal Generation for PacifiCorp Energy since January 2010. Prior to that, I held a number of positions of increasing responsibility with MidAmerican Energy Company for 28 years within the generation organization including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operation and maintenance ("O&M") of the thermal generation fleet.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain and support the level of O&M costs included in this rate case. The Company is experiencing increasing costs necessary to operate and maintain the Company's thermal generation resources as follows:

- Increased sulfur content of the fuel.

- Increased chemical usage due to the environmental control projects described in the direct testimony of Company witness Mr. Chad A. Teply.
- Environmental permit changes with which the Company must comply.
- Increased utilization of the plants.
- General inflationary cost impacts across our generation fleet.

Q. Please summarize your testimony.

A. The Company's thermal generation fleet non-labor[1], non-overhaul O&M expenses are projected to be approximately $191.5 million for the test period ending December 31, 2013 ("Test Period"), as compared to the expense in the historical base period ending June 30, 2011 ("Base Period"), of $174.0 million. As detailed in the direct testimony of Company witness Mr. R. Bryce Dalley, the escalation of costs from the Base Period to the Test Period is largely explained by the inflation adjustment included in the case for non-overhaul generation O&M costs of $10.9 million. However, upon careful review of plant level operating conditions, the Company believes that an overall increase in non-labor, non-overhaul O&M costs of $17.5 million (over the Base Period) is essential to maintain the plants. This is an increase of $6.6 million over the level of inflation.

Within the overall increase in costs, a major driver is related to the O&M impacts associated with environmental compliance activities. With the installation of environmental control equipment discussed in Mr. Teply's testimony, the Company's operating costs are increasing due to chemicals and reagents that are required to operate the equipment and the increasing sulfur

[1]O&M costs for the joint-owned, partner-operated plants on Mr. Dalley's Exhibit PAC/1102, Tab 4, page 4.9.1 include labor costs, while the Company-operated plants treat labor costs in a separate adjustment.

content of the coal supplies for the Utah plants. Furthermore, the Company anticipates increased costs due to (i) coal mill maintenance and the addition of a scale inhibitor at Cholla, and (ii) the imposition of costs related to jointly-owned, partner-operated generation stations by the other owners of such stations. These specific activities underlie the need for a higher level of generation O&M costs in rates.

Environmental Cost Increases

Q. Please explain the impact of the increase in the use of scrubber reagents and chemicals on operating costs.

A. A number of the Company's coal-fired power plants have been the subject of emission control permit changes which generally reduce the allowable emissions from the plants. In order to accomplish the emission reductions, new capital investments are scheduled to be, or have already been, installed and completed. The successful operation of the environmental control equipment is dependent upon chemicals to perform the emission reductions. In addition, two of our coal-fired power plants are subject to increased levels of sulfur in the fuel which also adds to the reagent needed to reduce emissions to meet new permit levels.

Q. Which plants' operating costs are impacted by environmental permit changes?

A. The Company's thermal generation resources at Dave Johnston Unit 4, the Wyodak Plant, and Naughton Units 1 and 2 are impacted by environmental permit changes related to emissions. The following are the impacts:

- Dave Johnston Unit 4 – The previously permitted SO_2 emission rate was 0.50

lbs per million Btu; the new permit lowers the rate to 0.15 lbs per million Btu. This decrease in permitted emissions rate requires the plant to use more lime in the scrubber to achieve the new permit emissions rate, which will increase forecast costs by approximately $0.69 million.

- Wyodak Plant – The new permit added a 30 operating day limit of 0.16 lbs per million Btu for SO_2, which will increase forecast costs by approximately $0.32 million.
- Naughton Units 1 and 2 – For each of these units, the permitted emissions rate was lowered from 1.20 lbs per million Btu to 0.15 pounds per million Btu. This decrease in the permitted emissions rate required the Company to install scrubbers on both units and add the associated reagent and O&M costs to operate these scrubbers. The increased O&M costs at Naughton Units 1 and 2 are forecast to be approximately $4.1 million.

The total increase in O&M costs due to permit changes for SO_2 for the PacifiCorp Energy thermal generation fleet in the Test Period is forecast to be approximately $5.11 million.

Q. Please explain which plants will experience an increase in the sulfur content of the fuel used.

A. Both the Hunter and Huntington plants will experience an increase in sulfur content. The average sulfur content for the Hunter plant is forecast to increase from 0.54 percent during the Base Period to 0.77 percent during the Test Period; the Huntington plant's sulfur content is experiencing a similar increase from 0.54 percent in the Base Period to 0.70 percent during the Test Period. This increase in

sulfur will require an increase in the use of lime and increase forecast costs by approximately $2.1 million.

Q. How much of the overall increase in O&M is associated with higher sulfur coal at the Hunter and Huntington plants?

A. This increase in sulfur will require more use of lime to meet SO_2 emissions permit levels and increase costs by approximately $2.1 million at the Hunter plant and $2.38 million at the Huntington plant for a total of approximately $4.48 million.

Q. Which Utah coal supplies are contributing to the increased sulfur content at the Hunter and Huntington plants?

A. The increase in sulfur content is due primarily to increased usage of West Ridge mine coal and an increase in the sulfur content of Deer Creek coal.

Q. Please discuss the Company's contract for West Ridge mine coal with Utah American Energy, Inc.

A. In December 2010, the Company executed a coal supply agreement with Utah American Energy for coal from the West Ridge mine for 2011 through 2014. The annual contract requirement has increased from 0.5 million tons in 2011 to 1.0 million tons for 2012 through 2014. The West Ridge coal supply replaced the high ash fusion coal historically provided by Arch's Dugout mine through 2010. The sulfur content of West Ridge mine coal is much higher than Dugout coal with a 1.25 percent typical quality specification.

Q. Please discuss the increasing sulfur content of Deer Creek mine coal.

A. Deer Creek's sulfur content has increased with the movement of longwall operations in December 2010 from the upper Blind Canyon seam to the lower

quality Hiawatha seam. Deer Creek has encountered pocket areas of high ash, high sulfur coal in the Hiawatha seam with the sulfur content at times exceeding one percent. The Company did not previously encounter pockets of high sulfur coal in the Blind Canyon seam.

Coal Mill Maintenance

Q. Please explain what coal mill maintenance is and why this cost is increasing.

A. Once the coal is mined and delivered to a power plant it needs to be ground to a fine powder before it is injected into the boiler. The previous mine that provided a long-term coal supply to Cholla Unit 4 closed, and the last coal from this source was used in September 2010. The new coal supply at Cholla Unit 4 is harder to grind and as a result, is causing increased wear on the grinding elements in the mill. This increase in wear is forecast to increase costs by approximately $0.9 million.

Scale Inhibitor at Cholla

Q. Why is a scale inhibitor at Cholla Unit 4 needed?

A. Cholla Unit 4 has experienced a buildup of scale in the scrubber to the point that it was necessary to take the unit offline for maintenance. The plant operator determined that the addition of dolomitic lime will reduce scale buildup. Prior to the use of dolomitic lime the scrubber needed to be operated in such a way to ensure compliance with existing permits even though scale was being formed during operation. The addition of dolomitic lime allows the scrubber to be operated within permit limits, but helps prevent the formation of scale. Dolomitic lime was added to the scrubber operations in December 2011 and will continue to

be added to the Cholla Unit 4 operations going forward, including during the Test Period. The increased cost attributed to the use of dolomitic lime is approximately $0.38 million.

Jointly-Owned, Partner-Operated Generation Plant O&M Costs

Q. Which plants are partially owned by PacifiCorp but operated by others?

A. The plants that the Company has a joint-ownership interest in, but are operated by a partner, include Camas, Cholla, Colstrip, Craig, Hayden and Hermiston. The operating companies of these plants establish the budgets necessary to maintain and operate the plants, and the Company, as a joint owner, is obligated to pay its share of these costs.

Q. What is the forecast increase in expense related to these plants?

A. The Company is forecasting an increase of $12.6 million in O&M costs associated with these jointly-owned plants, or an increase of $9.2 million over the general inflation included in the case of $3.4 million, as detailed in Mr. Dalley's Exhibit PAC/1102, Tab 4, page 4.9.1. Generally, the operators at these plants are facing the same types of operating issues and costs that the Company is facing. The Company works with the operating companies to review and comment on the costs forecasted and incurred by these plants, but is obligated to pay its share of the costs incurred. The cost increases at the Cholla plant are driven by increased reagent use due to increased utilization and the items described previously. At the Craig plant the increases are driven by increases in large O&M projects in the areas of coal mill maintenance, baghouse bag replacements, ductwork lagging repairs, and scrubber booster fan repairs. At the Hermiston plant, the Company is

expecting an increase in costs due to the timing of repairs and the cost of spare parts. During the Base Period, no repair charges were incurred. During the Test Period, however, it is forecast that repair costs will be necessary and the estimated costs are approximately $2.0 million.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF DARRELL T. GERRARD

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ATTACHED EXHIBITS

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

A. My name is Darrell T. Gerrard. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. I am Vice President of Transmission System Planning for PacifiCorp.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering (Electric Power Systems Major) from the University of Utah and Certificate of Completion with Honors in Electrical Technology from Utah Technical College at Salt Lake. My experience spans more than 30 years in the electric utility business and electric power industry in general. I have working experience and have had management responsibility for a number of functional organizations at PacifiCorp including Area Engineering, Area Planning, Region Engineering, T&D Facilities Management, Transmission, Substation and Distribution Engineering, System Protection and Control, T&D Project Management and Delivery, Asset Management, Electronic Communications, Hydro System Engineering, Transmission Grid Operations, and most recently Transmission System Planning.

Q. What are your responsibilities as Vice President of Transmission System Planning?

A. I am responsible for transmission planning activities required to support PacifiCorp's existing and future bulk transmission system and to ensure a safe and reliable transmission system that provides economical service to our customers.

I am also responsible for the conceptual and detailed system planning and architecture associated with the Company's long-term Energy Gateway Transmission Expansion Plan ("Energy Gateway").

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the test year costs associated with capital investments in the Company's transmission system. The new capital investments in this case include the costs to plan and build the Mona-to-Oquirrh 500/345 kV transmission project ("Mona-to-Oquirrh Project"), the costs to build the Clover substation and the costs to upgrade the Terminal substation. My testimony will provide evidence showing that the Company was prudent in managing these costs, and that these investments will be used and useful during the test year and beneficial to our retail customers.

Q. Please summarize your testimony.

A. First, I will provide a detailed description of the Mona-to-Oquirrh Project, including its costs and current status. I will show that, given existing limited capacity on the transmission system, the Mona-to-Oquirrh Project is needed to support both short and long term energy demands. The project will strengthen the overall reliability of the existing transmission system, and the project is necessary to maintain the Company's compliance with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards. Our customers' demand for energy continues to increase and the need for the Mona-to-Oquirrh Project at this

time has not changed.

Second, I will show that the Company prudently managed the costs of the Mona-to-Oquirrh Project by ensuring that it was built in an efficient and cost effective manner for the benefit of our customers. Finally, I will discuss the other capital investments included in the test year, and will demonstrate that these investments, as well as the Mona-to-Oquirrh Project, will be used and useful for our customers during the test year.

Q. What are the projected costs included in this case?

A. The projected costs included in rate base in this case are $380.6 million for the Mona-to-Oquirrh Project, $54.7 million for the Clover substation, and $46.4 million for upgrades at the Terminal substation.[1] Both the Clover and Terminal substations are scheduled to go into service prior to the 2013 test year, therefore, the costs are included in the rates proposed to go into effect January 1, 2013. As explained in the testimony of Mr. R. Bryce Dalley, the costs for the Mona-to-Oquirrh Project are included as a separate rider to go into effect once the project is in service in 2013.

Description of PacifiCorp's Transmission System and Energy Gateway

Q. Please describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates one of the largest privately held transmission systems in the U.S., consisting of more than 900 transmission and distribution substations and approximately 16,000 line miles throughout ten western states, ranging from 46 to 500 kV.

[1] See Exhibit PAC/1106 for the Mona-to-Oquirrh Project, and Exhibit PAC/1102, Dalley/8.6 for Clover substation and Terminal substation.

Q. Please describe PacifiCorp's Energy Gateway transmission expansion plan.

A. PacifiCorp's Energy Gateway transmission expansion plan ("Energy Gateway") is a multi-year, multi-segment transmission plan that will add approximately 2,000 miles of new transmission lines across the West (refer to the Energy Gateway map provided as Exhibit PAC/701). The planned transmission line segments are intended to address customer load growth, improve system reliability, reduce transmission system constraints, provide access to diverse generation resources, and improve the flow of electricity throughout PacifiCorp's multi-state service area. The first major segment of Energy Gateway—Populus to Terminal—was placed into service in November 2010. The Mona-to-Oquirrh Project, which is the project addressed in this case, is the second major segment of Energy Gateway. Outreach, siting, and permitting processes continue for future segments. Each proposed Energy Gateway transmission line segment will be re-evaluated to ensure it provides benefits to customers and to ensure the proper project timing before committing to move forward with construction.

Description of the Mona-to-Oquirrh Project and Clover Substation

Q. Please describe the Mona-to-Oquirrh Project.

A. The project is one component of the Company's long-range transmission plan and consists of a single-circuit 500 kV transmission line originating from the Clover substation (to be constructed near Mona in Juab County, Utah), extending northward about 70 miles to the proposed future Limber substation (to be located in Tooele County, Utah), and continuing as a double-circuit 345 kV line for approximately 30 miles to the existing Oquirrh substation in South Jordan, Utah

(refer to the project site map provided as Exhibit PAC/702).

To accommodate the Mona-to-Oquirrh Project's transmission lines, the Oquirrh substation must be upgraded and modified. In addition, the Company is currently constructing the 500kV/345kV/138kV Clover substation located approximately three miles south of the existing Mona substation. The Clover substation, with a December 14, 2012 in-service date, is the southern termination point of the Mona-to-Oquirrh Project and is necessary to provide local 138kV transmission service to reliably support customers. The Clover substation will also be the southern termination point for the future Gateway South project, although the upgrades necessary to accommodate Gateway South are not being done at this time, and the costs associated with those upgrades are not included in this case.

The future 500kV/345kV/138kV Limber substation will interconnect with the Mona-to-Oquirrh Project and is scheduled for completion in 2014. Costs for the Limber substation are not included in this proceeding.

Q. What is the current status of the Mona-to-Oquirrh Project and the expected in-service date?

A. Construction on the Mona-to-Oquirrh Project began in March 2011. At this time, construction access roads are in place for approximately 85 miles of the transmission line path. Foundations have been constructed for approximately 280 of the structures, and approximately 110 of the single-circuit 500 kV lattice towers have been erected. Delivery of the double-circuit 345 kV monopoles began in December 2011. Construction of the Clover substation started in August

2011. The final grade was achieved for the 345 kV yard and 138 kV yard in December 2011 and January 2012 respectively. The installation of ground grid and major equipment foundations began in January 2012, with equipment scheduled for delivery beginning in March 2012. The timing of these activities supports the projected December 14, 2012 in-service date for the Clover substation, and the May 18, 2013 in-service date for the 500/345 kV transmission line between the Clover and Oquirrh substations. See Exhibit PAC/703 which contains recent photos of construction progress on the Clover substation and the Mona-to-Oquirrh Project.

Q. What actions or steps have been taken to ensure the Mona-to-Oquirrh Project will be placed in service on time and at its current cost forecast?

A. The Company has in place a turnkey engineer, procure, and construct contract for the Mona-to-Oquirrh Project that establishes a lump sum cost for design and construction. The contract establishes monitoring and reporting controls to which the contractor must adhere in completing the Mona-to-Oquirrh Project. These include providing monthly progress reports on engineering, procurement, status of construction compared to schedule, risks identified and cost expenditures. If the contractor requests changes to the Mona-to-Oquirrh Project that would affect the contract schedule or cost, the Company requires a strict review process for the requested change. The contractor is not allowed to proceed with the requested change until approved by the Company.

Prudence in Project Delivery

Q. How did the Company ensure that the Mona-to-Oquirrh Project was engineered, designed, sited, and built in the most cost effective manner for its customers?

A. From a planning perspective, the Company applied prudent industry standards to identify the best transmission route and substation locations in order to balance engineering requirements, environmental impacts, project costs, and impacts to communities during the siting process, while ensuring that the siting criteria requirements were met. This included the completion of project siting and routing feasibility studies by the Company between 2005 and 2007, and the completion of the National Environmental Policy Act Environmental Impact Statement process between January 2007 and February 2011, resulting in an agency Record of Decision. This process determined the final preferred transmission line route and substation locations, which were then incorporated into the Company's competitive bidding process for construction.

Q. Please describe the Company's competitive bidding process.

A. The Company initiated a competitive bidding process to receive blind-sealed bids for the project to be delivered on a turnkey, fixed price, guaranteed completion date basis using an engineer, procure, and construct ("EPC") contract. The competitive bidding process began in July 2009 and provided two separate blind-sealed bidding opportunities—one in October 2009 and another in June 2010 after additional information was provided to bidders allowing a refinement of previously submitted design solutions and terms and conditions, including price.

Seven qualified bids were received in October 2009. After extensive evaluations of bidder proposals and review of exceptions to work scope and base terms and conditions from each bid proposal, the final two most qualified bidders were identified. The Company received best and final offers from the final two competing proposals in June 2010. The Company awarded the contract and issued a notice of intent in December 2010, with a notice to proceed issued in February 2011. Through the competitive bidding process, the Company was able to choose the bidder who proposed delivery of the Mona-to-Oquirrh Project at the lowest risk-adjusted cost.

Q. How did the Company ensure that the costs to construct the Mona-to-Oquirrh Project were controlled for the benefit of customers?

A. EPC contracts are regarded in the industry as a prudent approach to control costs and manage design, procurement, and construction risks. EPC contracts provide schedule and cost certainty to the benefit of customers and, where possible, cap potential cost escalations upon the occurrence of defined risks. EPC contracts also ensure more timely delivery of needed testing, commissioning, and in-service dates to support system needs and help ensure ongoing transmission system reliability.

The fixed-price EPC contract for the Mona-to-Oquirrh Project has strong provisions to control cost and schedule variances. Where cost and schedule variances were not included in the fixed price for certain contingent aspects of the work scope, these items were identified as risk items and a contingent capped price and schedule allowance were agreed to before contract execution.

Contingent risk items were limited to defined occurrences such as weather delays and environmental impacts.

Q. How does the Company ensure that the requirements and terms and conditions of the EPC contract are met?

A. The Company implements a management oversight structure that is responsible for ensuring that the requirements and terms and conditions of the EPC contract are met during the entire project construction cycle. This includes a detailed reporting requirement for the contractor regarding cost and schedule, submitted on a monthly basis. The Company also implements a quality assurance and quality controls program with qualified third-party inspectors to conduct onsite inspections during construction. The Company conducts a rigorous review of proposed changes in work requests by the contractor, which require Company approval before work associated with the requested change begins. The Company also obtains unit pricing during the EPC competitive bidding process to secure competitive market pricing should unforeseen changes to the project scope be required.

Benefits of the Project

Q. How will the Mona-to-Oquirrh Project benefit the Company's customers?

A. The Mona-to-Oquirrh Project is a key component required for executing the Company's current and future integrated resource plans. Those plans require reliable transport of designated network resources to network loads and adequate long-term transmission system capacity. Executing those plans is necessary to ensure an adequate, reliable, and low cost supply of energy is available and

benefits our customers. The importance of planning for and securing adequate transmission system capacity for purposes of the Company's resource planning is discussed in Volume I, pages 4 and 5, of the Company's Integrated Resource Plan ("IRP") dated March 31, 2011.

Q What analysis has the Company performed in order to quantify the benefits that the Mona-to-Oquirrh Project provides to all of the Company's customers?

A. The Mona-to-Oquirrh Project, including its associated costs and benefits, has been evaluated on multiple occasions over the last several years to reflect changes in the Company's business environment and to ensure it continued to meet customer needs and provided desired benefits. I will briefly discuss the results from these detailed evaluations below.

Evaluation of the Mona-to-Oquirrh Project began in early 2007 as part of the overall Energy Gateway analysis, where net power cost calculations were compared against Energy Gateway construction costs and the preferred resource portfolio in the Company's IRP at the time. Benefits were calculated for the entire Energy Gateway project, and the analysis showed a significant benefit to all of the Company's customers. Since the Energy Gateway project and its segments are planned to be delivered over the course of several years, the Company's intention is to perform additional and specific analysis for each individual Energy Gateway segment over time. A white paper entitled Summary of Energy Gateway Financial Analysis, dated November 19, 2009, summarizes a very detailed analysis that was performed on Energy Gateway, including analysis of

the Mona-to-Oquirrh Project. The analysis showed significant benefits for all customers in moving forward with Energy Gateway, including the Mona-to-Oquirrh Project. A copy of this analysis paper is attached as Confidential Exhibit PAC/704.

Q. Has additional analysis been performed since 2009 regarding the cost and benefits of the Mona-to-Oquirrh Project?

A. Yes. In further analysis performed in August 2010, variable power production cost savings were calculated through the IRP Production and Resource Model ("PAR") with and without the entire Energy Gateway project for a 50-year period, discounted back to net present values. The variable production cost inputs used four different combinations of CO_2 taxes per ton and variable future natural gas prices. Table I in Exhibit PAC/705 summarizes the total Energy Gateway variable power production cost savings and the Mona-to-Oquirrh Project's savings contribution to that total for each of the four scenarios. These results show that there is a range of expected variable production cost savings benefits from $331 million dollars to $549 million dollars for the Mona-to-Oquirrh Project.

Q. Was the lowest cost alternative selected and constructed to meet the Mona-to-Oquirrh Project requirements and to the benefit of customers?

A. Yes. All of our customers benefited from the project alternative that was selected and then ultimately constructed by the Company. This alternative selection resulted in an overall reduced capital investment amounting to an estimated $181 million savings over the next best alternative project. This resulted in a lower

overall revenue requirement for the project. See Table II and Table III in Exhibit PAC/705.

Q. Are there other benefits to customers associated with the completion of the Mona-to-Oquirrh Project?

A. Yes. Not only does the project provide new transmission capacity necessary to serve our customers, but it also provides significant system and operational reliability benefits to the existing system that mitigate the risk of customer outages and load curtailments. The Mona-to-Oquirrh Project provides transmission reliability improvements to the existing system between the Mona and Camp Williams substations and between Camp Williams and the Oquirrh substation. The Mona-to-Oquirrh Project provides a parallel and alternative transmission path providing backup capability to the existing system in the event of a system outage. See Exhibit PAC/706.

Specifically the project provides new transmission capacity between Camp Williams and Oquirrh and eliminates the need for capital expenditures estimated at $70 million for construction of a new 345 kV transmission line and corridor between the Camp Williams and Oquirrh substations that would otherwise be needed for reliability in the area.

In addition, the Mona-to-Oquirrh Project provides customers with reliability risk reduction benefits on the existing system between Mona and Camp Williams because it reduces the exposure to customer load loss and associated energy curtailments during transmission system outages, both planned and unplanned. This reduction in risks associated with transmission system outages

has benefits valued over a range of potential energy replacement costs. Table IV in Exhibit PAC/705 quantifies the cost of replacement energy due to the inability of Company generation resources to serve load due to a transmission line outage between the Mona and Camp Williams substations. Two scenarios were analyzed starting in 2013 where the benefits range from $29 million to $210 million and the risk reduction benefits continue to grow in 2020 to a range of $214 million to $1,765 million. The Mona-to-Oquirrh Project's operational reliability and risk reduction benefits are not captured in Company net power cost or IRP modeling activities.

Q. Will the Mona-to-Oquirrh Project provide other benefits to the Company's transmission system?

A. Yes. The transmission grid can be affected in its entirety by what happens on an individual transmission line. A single outage on an individual line due to storm, fire, or external human interference can and does affect the grid as a whole, potentially causing significant reductions in transmission capacity and negatively affecting our ability to serve customers. The Mona-to-Oquirrh Project will allow the Company to continue to meet native load service obligations in all of its states and continue to meet contractual obligations to third parties under its federal Open Access Transmission Tariff. The project connects to other existing and future segments of Energy Gateway that interconnect the Company's western and eastern control areas, increasing the ability to transport low-cost energy to the benefit of all of our customers. The Mona-to-Oquirrh Project will improve the Company's access to existing energy markets in the northwest, desert southwest,

and Four Corners area for the purpose of purchasing energy or selling any energy surplus when it is beneficial to do so for our customers. This access allows the Company to maintain a low-cost and reliable energy supply to the benefit of all our customers.

Q. Are there other benefits you see from this Mona-to-Oquirrh Project?

A. Yes. The Mona-to-Oquirrh Project is necessary to maintain the Company's compliance with mandatory standards, both national and regional, while providing the next necessary increment of transmission capacity for our customers. It also supports and can be reliably integrated with other future planned transmission investments that are currently proposed by the Company and other utilities in the WECC region. This project positions the Company to be more strongly interconnected to other regional projects currently being planned and provides options for access to additional future energy resources.

Q. Would the Company have constructed the Mona-to-Oquirrh Project even if other segments of Energy Gateway were not constructed?

A. Yes. The existing system north of Mona is fully subscribed and the Mona-to-Oquirrh Project provides the additional transmission capacity and reliability necessary to continue transport of existing and future planned generation resources located in central and southern Utah to growing customer load centers in the states served by the Company. The Company's 2011 IRP shows future planned additions of nearly 1,700 MW of new generation in the central and southern part of Utah (refer to Exhibit PAC/707). The Mona-to-Oquirrh Project

is necessary to fully utilize the company's existing and future planned generation resources to serve customers.

Q. When placed in service will the Mona-to-Oquirrh Project be used and useful?

A. Yes. When a transmission project or generation plant is energized and placed into service, all elements of the project are part of the interconnected system as a whole. These elements are fully used and useful in providing transmission or generation service on the system. Transmission and generation infrastructure additions inherently have some ability to provide future capacity after being placed in service. This results from using industry standard voltages and design criteria, and reliability requirements necessary for system operation and maintenance.

Q. You indicate that when a new transmission line is added, it becomes a part of the integrated system as a whole. Please explain.

A. Electrical transmission systems are made up of numerous electrical elements, including lines, substations, generation plants, and control systems that operate as a fully integrated network. All elements of the network are electrically dependent upon each other for the purpose of producing and transmitting energy instantaneously to customers on demand. New transmission capacity, when added to an existing system, is installed in increments based on standard system voltages, line conductors, equipment, and apparatus that are available in the utility industry. Electrical power flows across the entire system, and on any individual line or station, are a function of the physics of the entire interconnected network

and the level of generation and load present at any given instant in time. As a result, when a new line or substation is added, it immediately carries its full share of the total energy being transmitted by the system. Whenever a new line or substation is added to the transmission system, electrical capacity on the network is increased. The incremental capacity increase added to the network is based on both the new facility's capacity and its electrical interaction with all other facilities to which it is interconnected. While the Project provides benefits to the local areas where it is constructed, it also provides benefits to the wider interconnected transmission system.

Project Need and Justification

Q. Was the Mona-to-Oquirrh Project included in the Company's most recent IRP?

A. Yes. The Company's 2011 IRP includes the Mona-to-Oquirrh Project as part of the modeled transmission topology for the purpose of selecting the Company's preferred portfolio of future supply-side and demand-side resources. The 2011 IRP Action Plan, Chapter 9, consists of a number of actions needed to deliver the plan, one of which is to "[p]ermit and construct a 500 kV line between Mona and Oquirrh." In Chapter 10, Transmission System Action Plan, the Company provides detailed information for the Mona-to-Oquirrh Project. The project is necessary to integrate new network generation resources identified in the IRP into the Company's extensive transmission system in order to meet the Company's customers' current and future energy demands.

Q. Did Oregon Public Utility Commission Staff recommend acknowledgement of the Mona-to-Oquirrh Project in the Company's 2011 IRP?

A. Yes. While the Commission, at the time of this filing, has yet to issue an acknowledgement order on the Company's 2011 IRP, Commission Staff observed:

> "The Mona to Terminal project has the following non-economic benefits:
>
> - The project is necessary for PacifiCorp to be able to serve its current native load.
>
> - The existing transmission system has limited capability to deliver energy into the largest load center in Utah (the Wasatch Front area).
>
> - The Mona Substation is a critical hub through which power is imported from PacifiCorp's southern intertie lines. It also serves as an important interconnection point with other sources of generation.
>
> - This project is key to maintaining reliability since the capacity north of the Mona substation is fully subscribed and constrained.
>
> - This project has been assessed and compared to an alternative transmission line which costs approximately 40 percent more.
>
> - This project is key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability and performance standards during normal system operations and during certain transmission system and generation plant outages."[2]

[2] *In the Matter of PacifiCorp 2011 Integrated Resource Plan*, Docket No. LC 52, Staff's Final Comments and Recommendations at 41-42 (October 13, 2011).

Staff recommended "acknowledging the Mona to Terminal project, based on the information provided by the Company."[3]

Q. Has the Mona-to-Oquirrh Project been included in previous IRPs?

A. Yes. The Mona-to-Oquirrh Project was evaluated for cost-effectiveness from an integrated system benefits perspective as part of the 2007 IRP filed with the Commission in May 2007 and the 2008 IRP filed with the Commission in May 2009, both of which were acknowledged by the Commission. This analysis helped support the decision to include the Mona-to-Oquirrh Project as part of the Company's preferred resource portfolio.

Q. Were alternatives to the Mona-to-Oquirrh Project considered?

A. Yes. Long-term alternatives to constructing a new transmission line are limited; however, alternatives have been assessed by the Company during the IRP process. Alternatives considered included: (1) electric load and demand-side management and energy conservation as part of the Company's IRP; (2) the installation of new generation facilities in the Salt Lake City area; (3) additional capacity to existing transmission lines and alternative transmission technologies. As a result of the resource portfolio modeling conducted for the 2011 IRP, the Company concluded that none of these alternatives met the Company's immediate needs and long-term requirements, and additional transmission transfer capability in Utah was the best and lowest overall cost alternative for meeting our customers' demand for electricity.

[3] *Id*, at 42. Staff noted, "In Chapter 10 of PacifiCorp's 2011 IRP, the Company requests acknowledgment of the Mona to Oquirrh and Oquirrh to Terminal segments, which PacifiCorp refers to collectively as Energy Gateway Segment C." Accordingly, Staff's review and recommendations are based on the 100-mile Mona-to-Oquirrh Project, scheduled to be in service as of May 2013, as well as the 14-mile Oquirrh-to-Terminal line scheduled for completion in 2015.

Q. Has the Mona-to-Oquirrh Project's purpose and need been established and justified in previous regulatory proceedings?

A. Yes. The Mona-to-Oquirrh Project's purpose and need has been clearly established and justified through previous regulatory proceedings conducted in Utah. Detailed and credible evidence justifying the Mona-to-Oquirrh Project was presented by the Company through its efforts to successfully obtain a Certificate of Public Convenience and Necessity ("CPCN") and through the Company's request for siting authority by the Utility Facility Review Board of Utah.

Q. Did the Utah Commission find that the Mona-to-Oquirrh Project was needed, justified, and necessary in the interest of the public?

A. Yes. The Utah Commission granted a CPCN for the transmission line and related facilities, stating:

> We find the Company has adequately demonstrated the need for those elements of the Project it plans to construct by 2013. The record is clear that without the resultant increased transmission capacity, the Company will face an unacceptable risk of failure to meet its load service obligations. Moreover, we recognize the need for PacifiCorp to strengthen its transmission grid in order to comply with important regional and nation reliability standards and directives. The Project is a key component of this effort.[4]

Q. The Utility Facility Review Board of Utah was required to act on matters regarding this Mona-to-Oquirrh Project in order for it to be sited and constructed. Did the Board agree the Mona-to-Oquirrh Project was needed and was justified?

A. Yes. The Board conducted hearings on the siting and route selection for a portion

[4] *In the Matter of the Pending Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of Mona – Oquirrh New 500 kV Double Circuit Line,* Utah Public Service Commission Docket No. 09-035-54, Report and Order at 14-15 (June 16, 2010).

of the project and determined that the Mona-to-Oquirrh Project was needed and was justified:

> The Board, having reviewed the substantial, competent and credible evidence before it, unanimously finds the Company's proposed Transmission Project is needed to provide safe, reliable, adequate and efficient service to its customers.[5]

The Board made further findings on the Project's need and justification (page 29):

> The evidence demonstrates the Transmission Project will play an integral role in providing the new transmission capacity the Company needs to provide safe, reliable, adequate and efficient service.

Q. Please describe the current transmission situation for bringing power into the Wasatch Front and adjoining areas from the south and how the Mona-to-Oquirrh Project fits into that situation.

A. Please refer to Exhibit PAC/706 for a map of transmission import lines from the south of the critical load area. Currently, a majority of the electricity serving the northern Utah area is generated at Company facilities in Carbon, Juab, and Emery counties and is delivered on existing transmission lines that enter the Wasatch Front and adjoining areas from the south. These southern Utah generating facilities include the Carbon, Hunter, Huntington, and Currant Creek power plants. The Company's transmission system providing electrical service to this area from southern Utah presently consists of two 345 kV lines from the Huntington and Castle Dale (Emery substation) areas to the Spanish Fork and Camp Williams substations, four 345 kV lines from the Mona area to the Camp Williams substation, and two 138 kV lines from the Helper area (Carbon

[5] *In the Matter of the Petition for Review Between Rocky Mountain Power and Tooele County for Consideration by the Utility Facility Review Board*, Docket No. 10-035-39, Order at 1 (June 21, 2010).

substation) to the Spanish Fork substation. These transmission lines, along with other interconnected lines, are also used to import power into Utah from Nevada, the Four Corners region, and from other energy providers connected to the Mona substation. It is necessary to move this energy north to growing load centers in the Wasatch Front and surrounding areas. In addition, the Company's 2011 IRP preferred portfolio includes nearly 1,700 MW of new combined cycle natural gas generation resources located in central Utah. See Exhibit PAC/707 (2011 IRP, Volume I, Figure 4.4, page 61).

Q. Has the slowdown in the economy affected the need for the Mona-to-Oquirrh Project?

A. No. The Mona-to-Oquirrh Project is still needed by summer 2013 as planned and delivers benefits to all customers because it provides necessary transmission capacity to reliably integrate the Company's existing and future planned generation resource portfolios including renewable resources. The project is required to maintain compliance with mandatory NERC and WECC standards established for the bulk electric system. In addition our customer demand for energy is growing despite the slowdown in the economy.

Additional Investments

Q. What additional transmission capital investment costs are included in this case?

A. Approximately $46.4 million is included in this case for transformer and substation additions at the Terminal substation.

Q. Please describe the additional plant investments needed at the Terminal substation.

A. These plant investments consist of replacing two existing 345-138 kV transformers, affected circuit breakers, and electrical bus work and control systems. Specific details of this project include the following replacements:

- Terminal transformer #9 (421 MVA) with a 700 MVA transformer;
- Terminal transformer #10 (448 MVA) with a 700 MVA transformer;
- Breaker L180 with a breaker with continuous rating of 3000A;
- Several overstressed 138 kV breakers;
- Substation Bus work and related apparatus control systems;
- Control house and station controls; and
- Transformer and apparatus foundations and footings for seismic reasons.

Q. Please explain why these additional investments at the Terminal substation are needed.

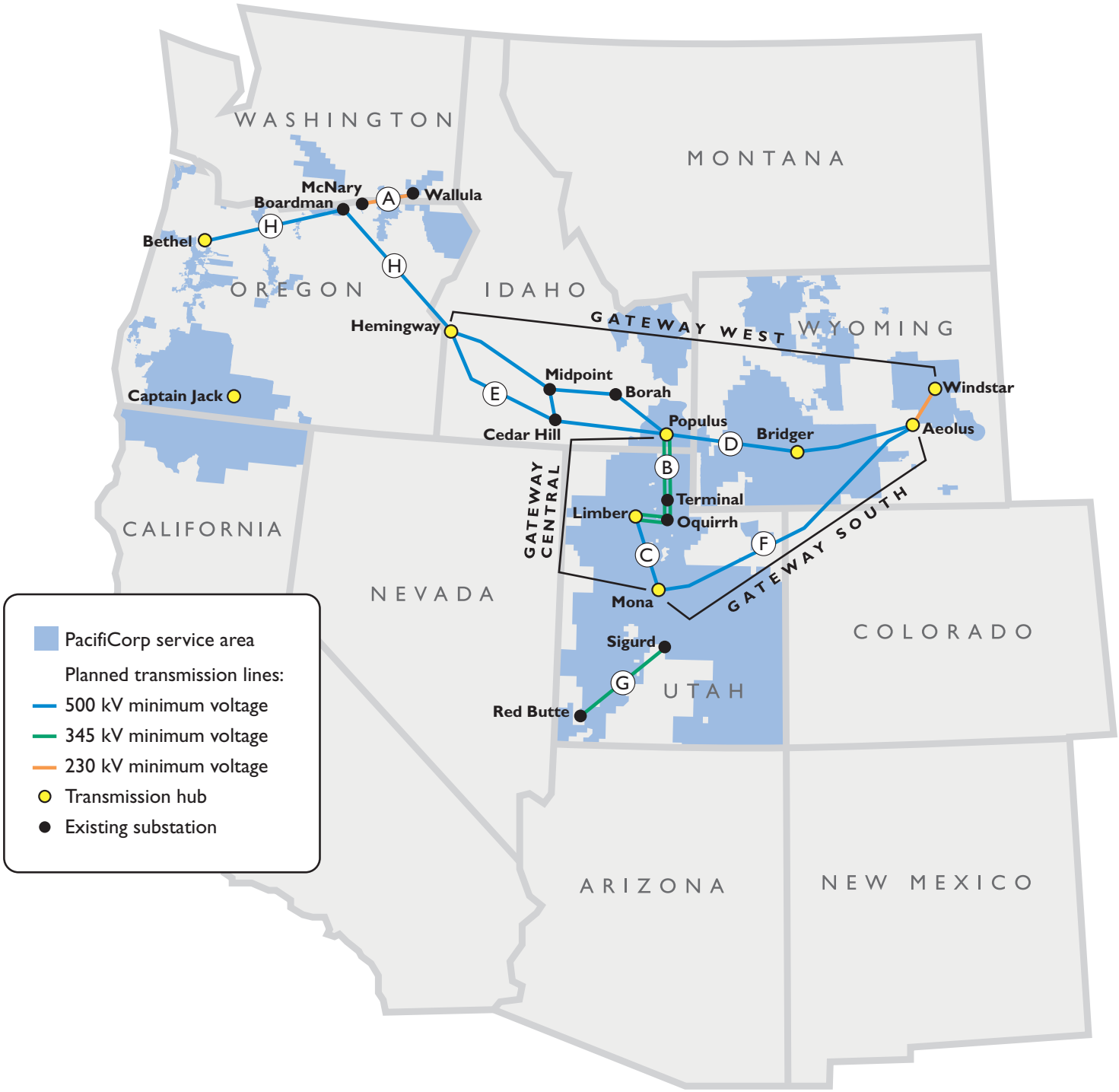
A. Load studies performed on the existing transformer for summer peak loads from 2010 to 2013 resulted in overloading of either 345-138 kV transformers for single element contingencies on the 138 kilovolt system. The Terminal substation which has multiple looped connections to the 345kV/138kV transmission main grid transmission system, is an antiquated design with some portions dating back to the WWI timeframe when Grace Hydro generation was tied into the substation to serve loads in the area. The current substation bus design and capacity is inadequate for the need capacity of the station, will not accommodate the new 700 MVA transformers, and poses a risk to service reliability. The project is

necessary for the Company to maintain compliance with NERC and WECC mandatory reliability standards, which dictate levels of electrical system performance and reliability.

Q. Does this conclude your direct testimony?

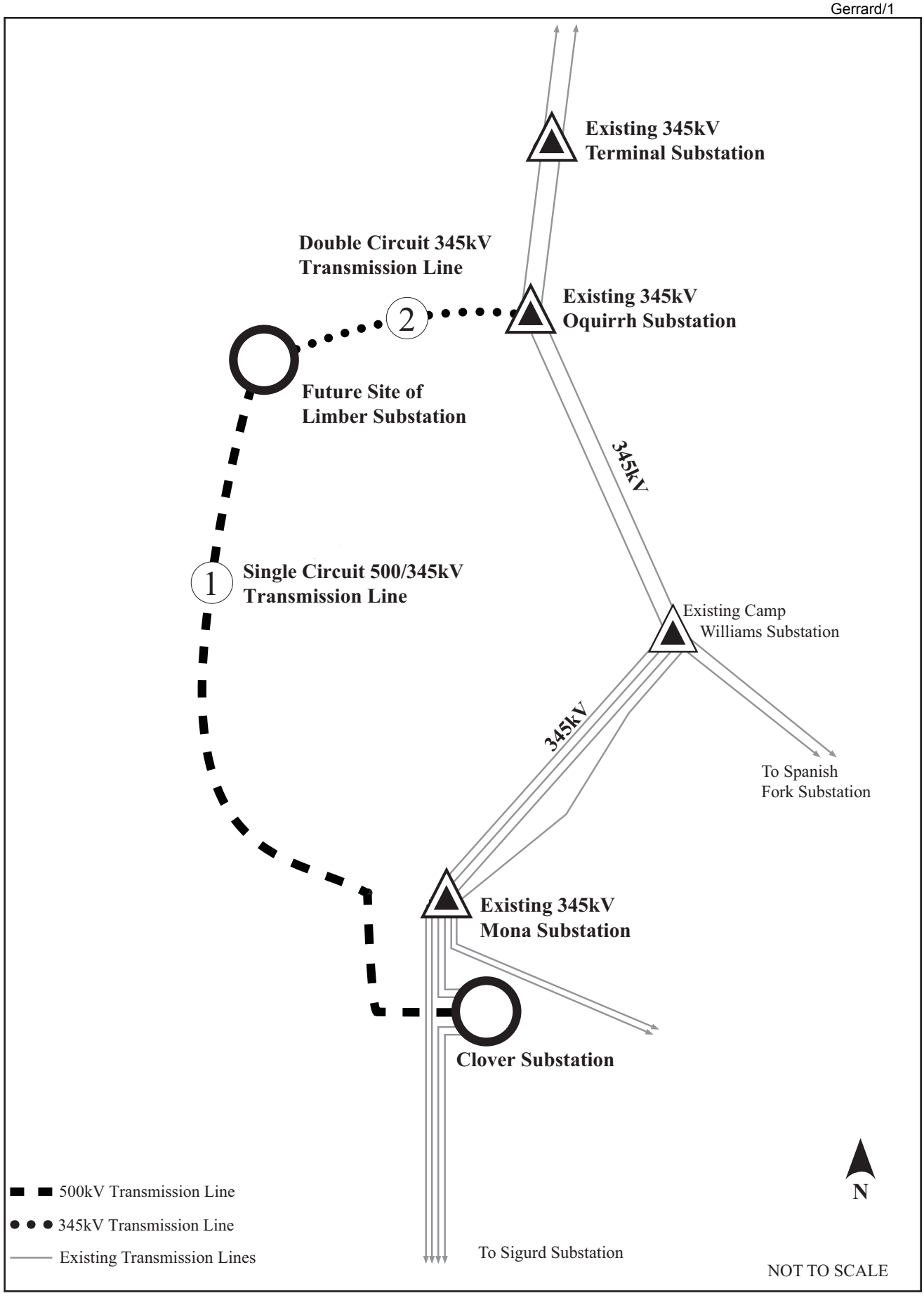
A. Yes.

Energy Gateway



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

February 2012



ROCKY MOUNTAIN POWER

MONA TO OQUIRRH 500/345kV TRANSMISSION PROJECT

Docket No. UE-246
Exhibit PAC/703
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Construction Photos – Clover Substation and Mona-to-Oquirrh Towers

March 2012

Exhibit PAC/703
Pg. 1 – Clover Substation

Exhibit PAC/703
Gerrard/1

Exhibit PAC/703
Pg. 2 – Clover Substation

Exhibit PAC/703
Pg. 3 – Mona-Oquirrh towers

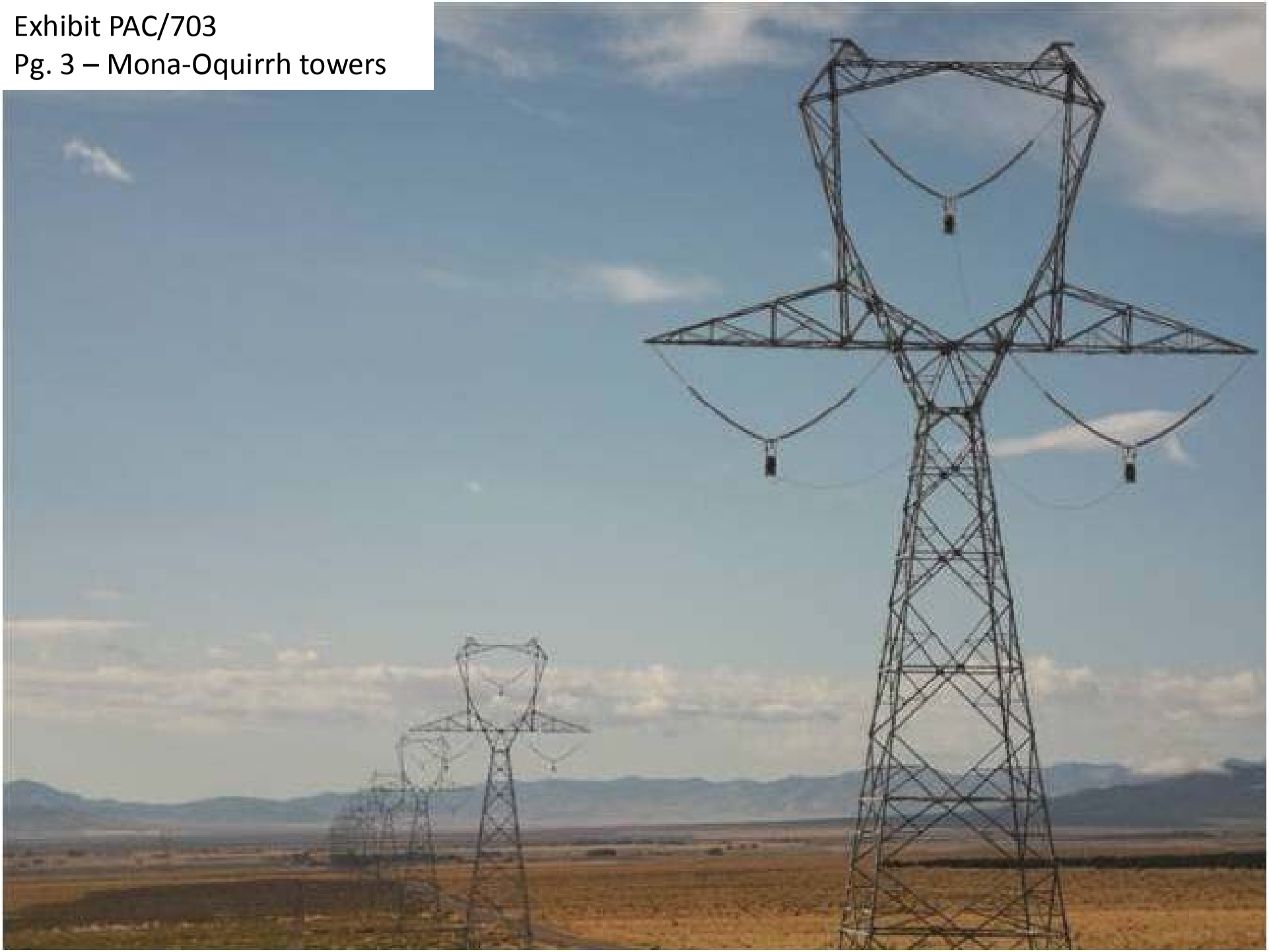


Exhibit PAC/703
Gerrard/3

Exhibit PAC/703
Pg. 4 – Mona-Oquirrh towers

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/704
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Summary of Energy Gateway Financial Analysis
November 19, 2009

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Mona – Oquirrh Project Customer Benefit Measures

TABLE I

Net Present Value Variable Production Cost Savings: Full Energy Gateway

Net Present Value Variable Production Cost Savings (50 Year Period)				
Scenario	Low Gas Price Low CO2 ($8/ton)	High Gas Price Low CO2 ($8/ton)	Low Gas Price High CO2 ($45/ton)	High Gas Price High CO2 ($45/ton)
Total Energy Gateway (1)	$4,152m	$5,662m	$6,110m	$6,887m
Mona – Oquirrh (2)	$331m	$451m	$487m	$549m

Notes:

1) Net present value variable production cost savings for total Energy Gateway calculated through IRP Production and Resource Model (PaR) with and without entire the Energy Gateway project for 50-year period
2) Portion of variable production cost savings were allocated to Mona – Oquirrh based on timing of incremental capacity added

TABLE II

Least Cost Alternative Between Recommended Construction and Two Phased 345 kV Transmission Lines

Total Capital Costs			
Scenario	500/345 kV Line (Recommended)	345 kV Line Phase 1 & 2(Next Best Alternative)	Difference
Mona - Oquirrh	$438m	$619m	($181m)

Notes:

1) The least cost alternative focused on delivering the minimum 1400 MW requirement for the least cost between 500 single circuit/345 double circuit kV line or two single circuit 345 kV lines
2) Total capital costs includes allowance for funds used during construction, capitalized property tax, cost inflation, capital surcharge and contingency for entire project

TABLE III

Mona – Oquirrh Transmission Segment Present Value Revenue Requirement and Net Present Value					
500 kV Line (Recommended)		345 kV Line Phase 1 & 2 (Next Best Alternative)		Difference 500 kV vs 345 kV Phased	
PVRR (1)	NPV (2)	PVRR (1)	NPV (2)	PVRR (3)	NPV (4)
$481m	($292m)	$622m	($372m)	($141m)	$80m

Notes:

1) PVRR is the present value of revenue requirements. It is the sum of annual revenue requirements, discounted by 7.1 percent per year. A 50 year planning horizon is used.

2) NPV is the net present value of after-tax cash flow. In order to analyze the underlying economics of the alternative investments, the cash flows used in these calculations are before regulatory recovery of the investment and associated expenses. A 7.1 percent discount rate and 50 planning horizon are used.

3) PVRR (D) is the difference between the present value of revenue requirements of the 500 kilovolt option and the phased 345 kilovolt option.

4) NPV (D) is the difference between the present value of revenue requirements of the 500 kilovolt option and the phased 345 kilovolt option.

TABLE IV

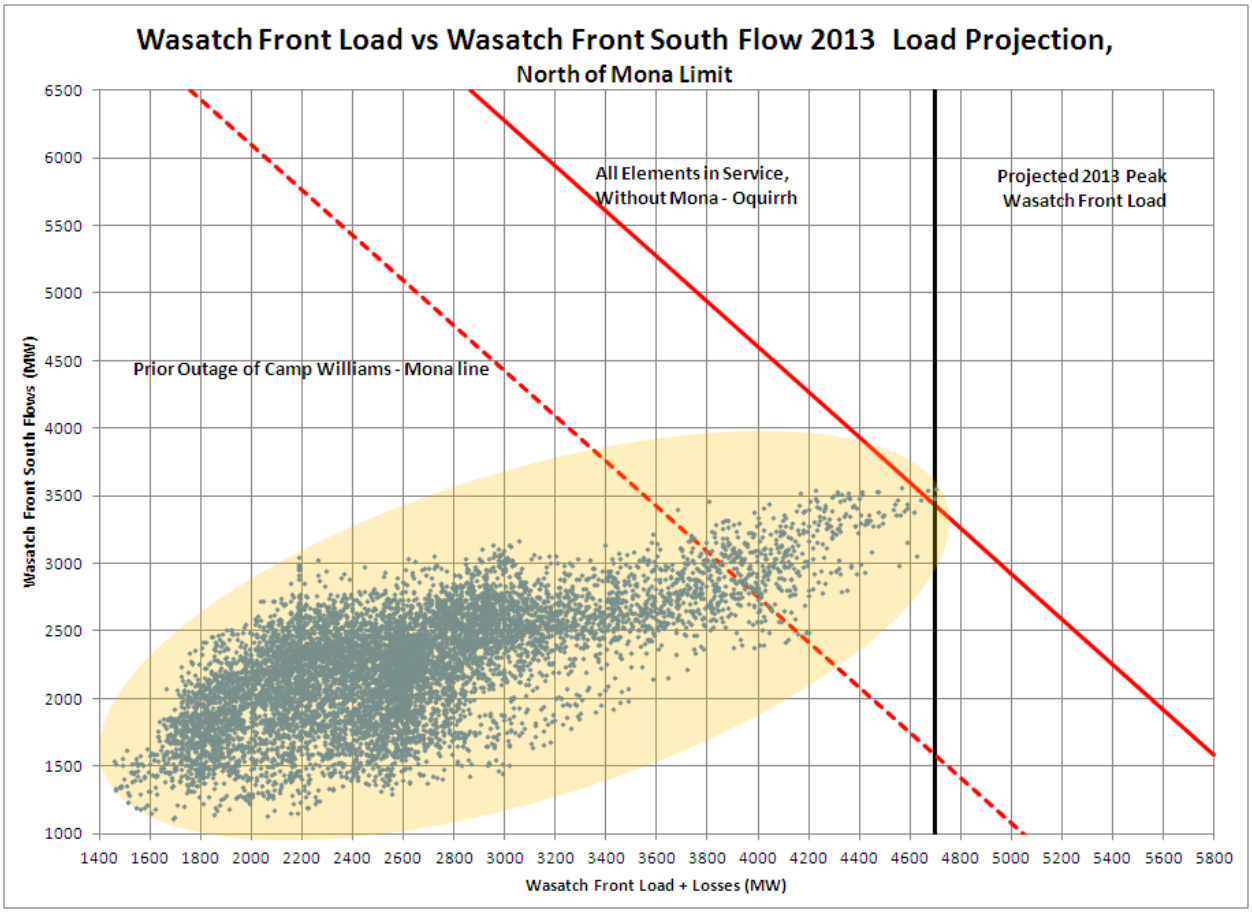
Wasatch Front Load at Risk Costs Due to Loss of Transmission Segment

Load at Risk Outage Costs Without Mona – Oquirrh Transmission Segment			
2013 Load Projection Forced Outage Exposure (1)		2020 Load Projection Forced Outage Exposure (1)	
Tiered ENS Pricing @ $400 MWh	FERC Cap Pricing @ $1,000 MWh	Tiered ENS Pricing @ $400 MWh (2)	FERC Cap Pricing @ $1,000 MWh (2)
$29m	$210m	$214m	$1,765m

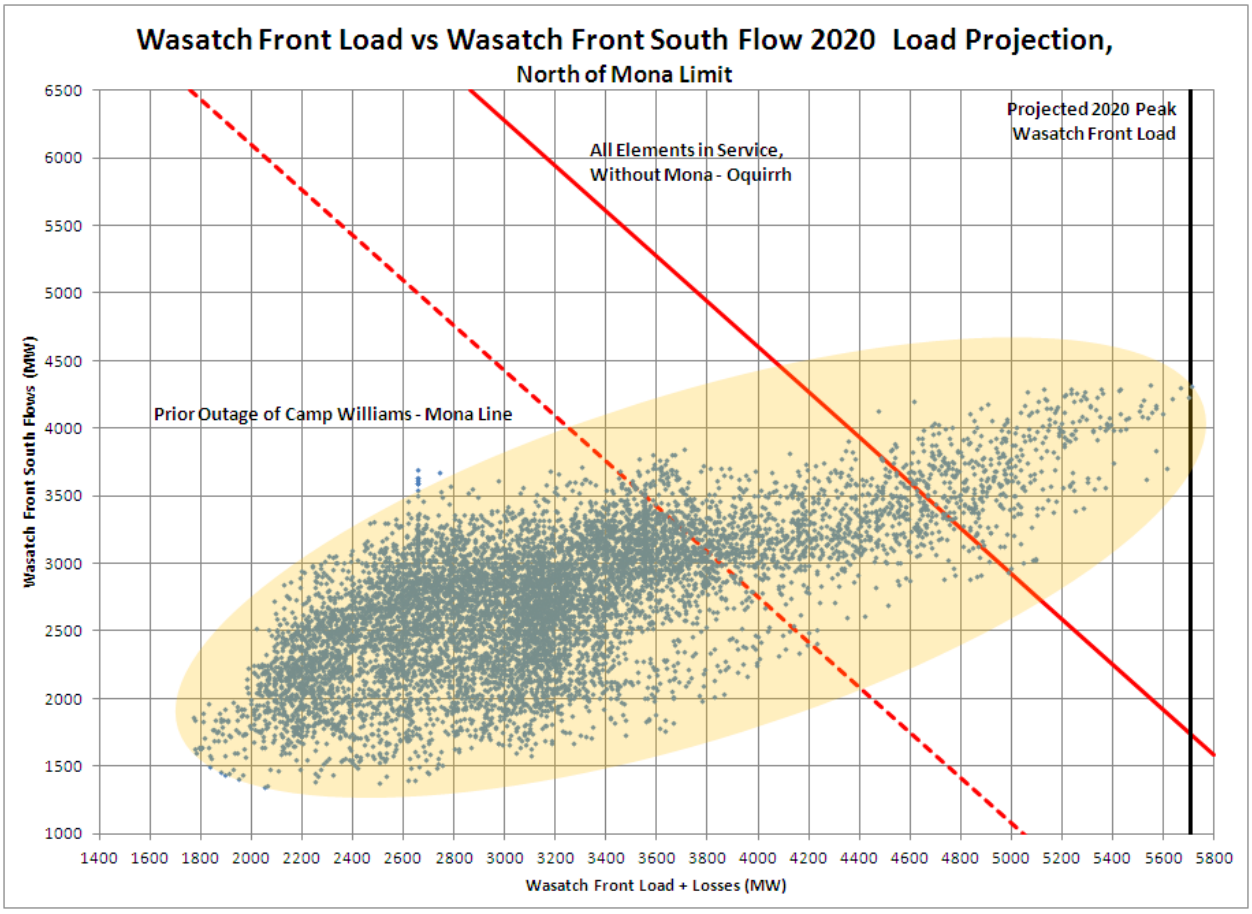
Notes:

1) Number of MWhs exposed come from 2013 and 2020 Load at Risk calculations
2) Energy not served (ENS) pricing is escalated for 2020
3) Maximum outage costs are MWhs multiplied by energy not served costs
4) The derivation of ENS pricing is discussed in PacifiCorp's 2011 IRP (page 199)

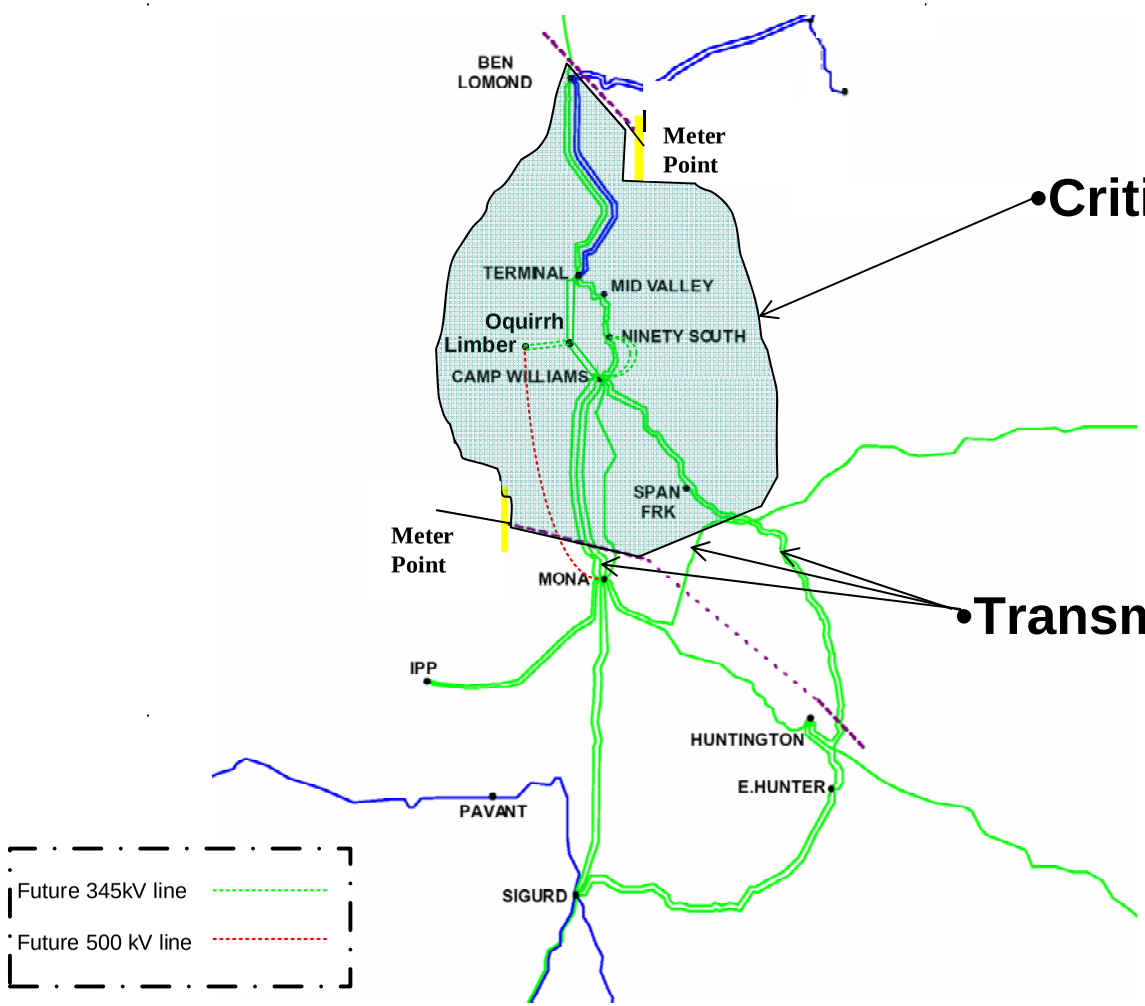
Data points for the 2014 Forced Outage Exposure are shown below:



Data points for the 2020 Forced Outage Exposure are shown below:



Critical Load Area

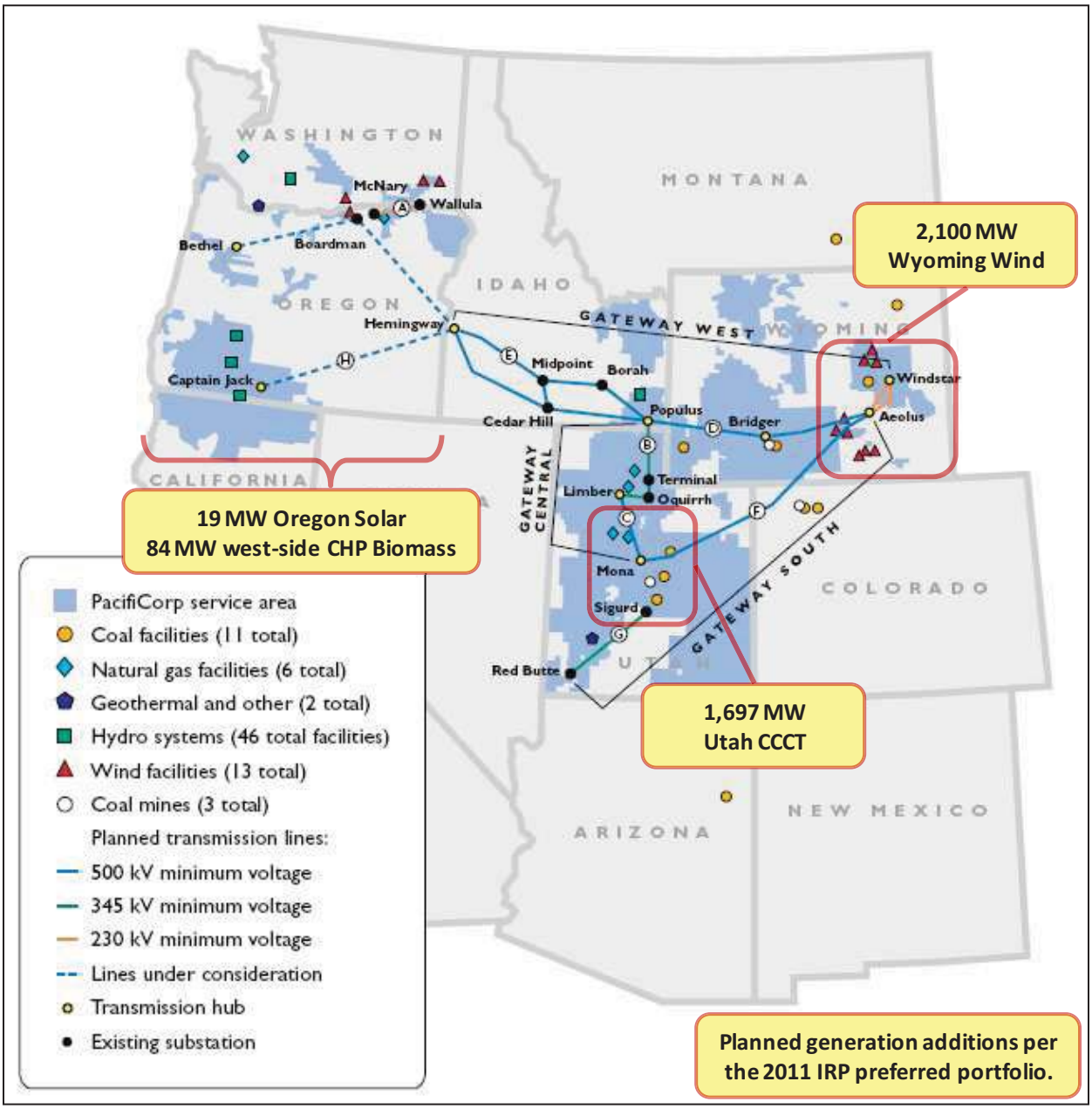


- Critical Load Area
- Transmission Import Lines From South

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

Figure 4.4 – PacifiCorp service territory, owned generation and Energy Gateway overlay[25]



This map is for general reference only and reflects current plans. It may not reflect the final routes, construction sequence, exact line configuration or facility locations.

[25] Visit PacifiCorp's Energy Gateway website for maps of renewable energy potential in the Western U.S. as provided by the National Renewable Energy Laboratory (NREL), including Energy Gateway overlays:

- Wind: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/WindPowerPotential.10.pdf
- Solar: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/SolarPotential.10.pdf
- Geothermal: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/GeothermalPotential.10.pdf
- Biomass: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/BiomassPotential.10.pdf

DIRECT TESTIMONY OF BRUCE W. GRISWOLD

TABLE OF CONTENTS

ATTACHED EXHIBITS

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

A. My name is Bruce W. Griswold. I am an employee of PacifiCorp, dba Pacific Power. I work in PacifiCorp's Commercial & Trading ("C&T") department as Director of Short-Term Origination and Qualifying Facility ("QF") Contracts. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon. C&T is PacifiCorp's merchant function responsible for the Company's electric generation and wholesale energy purchases and sales.

Qualifications

Q. Briefly describe your education and business experience.

A. I have B.S. and M.S. degrees in Agricultural Engineering from Montana State University and Oregon State University, respectively. I have been employed by PacifiCorp for over 25 years in various positions of responsibility in retail energy services, engineering, marketing, and wholesale energy services. I have also worked in private industry and with an environmental firm as a project engineer.

My current responsibilities as Director of Short-Term Origination and QF Contracts include the negotiation and management of wholesale power supply resource acquisition through requests for proposals ("RFP"), as well as direct responsibility for PacifiCorp QF power purchase agreements. I have appeared as a witness on behalf of PacifiCorp in multiple proceedings across its six state jurisdictions.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. In this case, the Company is seeking recovery of the costs associated with the acquisition of the 2.0 megawatt alternating current ("MW_{AC}") solar project from Black Cap Solar, LLC ("Black Cap Solar Project"). The purpose of my testimony is to describe the acquisition and demonstrate its prudence under ORS 757.370 and ORS 357.375. Specifically, my testimony:

- Describes the procedural history of the 2010 Solar Request for Proposals ("2010S Solar RFP") and selection of the Black Cap Solar Project through the 2010S Solar RFP.
- Provides a description of the transaction.
- Describes the economic analysis and prudency of the transaction.

Q. Please summarize your testimony.

A. The Black Cap Solar Project was acquired to contribute to PacifiCorp's required 8.7 MW_{AC} obligation under the solar photovoltaic capacity standard in ORS 757.370 and OAR 860-084-0020. The resource was acquired through a fair, transparent, and robust competitive bidding process begun in 2010. The Company will lease the new turn-key 2.0 MW_{AC} solar photovoltaic generating project under a solar assets agreement ("SAA") with Black Cap Solar, LLC, an affiliate of Obsidian Finance Group and a related project-finance lease agreement with Royal Bank of Scotland Asset Finance ("RBS"). The Project is located near Lakeview, Oregon, with an expected commercial operation date of October 1, 2012. The project-finance lease arrangement is the preferred least cost alternative

adjusted for risk. The nominal levelized Black Cap Solar Project cost is [redacted] per megawatt-hour ("MWh"). The revenue requirement for the Black Cap Solar Project is discussed in the testimony of Company witness Mr. R. Bryce Dalley.

Q. Please provide some background about Oregon's solar photovoltaic generating standard.

A. ORS 757.370(1) requires that, by January 1, 2020, the total solar photovoltaic generating nameplate capacity of all electric companies in Oregon be at least 20 MW_{AC} from qualifying systems generating at least 500 kW_{AC} but no more than 5 MW_{AC}. To comply with this standard, as established by OAR 860-084-0020, PacifiCorp must acquire 8.7 MW_{AC} of the total 20 MW_{AC} before January 1, 2020.

PacifiCorp may satisfy the solar photovoltaic generating capacity standard with systems owned by the Company or with power purchase agreements ("PPA") with qualifying systems. All costs prudently incurred to comply with the solar photovoltaic generating capacity standard are recoverable in rates. Electricity produced by qualified solar projects under ORS 757.375 may be used to comply with the renewable portfolio standard ("RPS") established in ORS 469A.005 to 469A.210, and each MWh generated by a project over 500 kW_{AC} that became operational before January 1, 2016, will be credited with two MWh of renewable energy credits ("RECs") toward PacifiCorp's RPS compliance.

The 2010S Solar RFP

Q. Please describe the 2010S Solar RFP process.

A. The 2010S Solar RFP, attached as Exhibit PAC/801, was issued on November 30, 2010, in response to ORS 757.370, and sought to acquire new qualifying solar resources located in Oregon and capable of delivering energy into the Company's network transmission system in Oregon. The Company requested proposals by January 7, 2011.

The 2010S Solar RFP contained technical specifications prepared by the Company and requested solar resources between 500 kW_{AC} and 2.0 MW_{AC}, compliant with existing renewable portfolio standards, and new to PacifiCorp's resource portfolio. In the 2010S Solar RFP, the solar resource was defined as a "solar photovoltaic energy system," meaning equipment and devices that have the primary purpose of collecting solar energy and generating electricity by photovoltaic effect, as stated in ORS 757.360. The Company requested a solar resource with a commercial operation date no later than December 31, 2011. Proposals were sought for either a PPA or as a build-own-transfer ("BOT").

Q. Please describe the 2010S Solar RFP selection process.

A. The Company analyzed the proposals received under the 2010S Solar RFP on a least-cost risk-adjusted basis. The Company used a screening process to derive an initial shortlist and a final shortlist. For the initial shortlist, PacifiCorp evaluated and summed the non-price factors and the price factors of the resource for a total proposal score. The price factor was weighted up to 80 percent, while the non-price factor was weighted up to 20 percent. Each proposal received up to a

maximum of 100 points. The price factor was derived by using the PacifiCorp RFP base model, which determines the top-performing proposals on the basis of the net present value revenue requirement ("Net PVRR") per kilowatt-month. The Net PVRR tallies the total costs of the resource against the total revenues of the resource over the life of the asset. The more positive the Net PVRR, the more valuable a given resource is to the Company's customers. The non-price factors evaluated were negative or positive based on the following criteria: (a) conformity with 2010S Solar RFP proposal requirements; (b) conformity with the pro-forma PPA or BOT documents that were exhibits to the 2010S Solar RFP; (c) development and feasibility of the proposal; (d) site control or permitting of the proposal; and (e) operational viability of the proposal. Based on the application of the price and non-price factors, the Company combined the price and non-price factors to derive the initial shortlist.

The final shortlist was determined using the Company's Alternative Compliance Cost ("ACC") method. The ACC method uses the Company's production cost simulation system and forward price curve to generate a market-based alternative comparison of the proposal resources. A negative ACC value, expressed on a dollar-per-MWh basis, indicates that the bid resource compares favorably to the market-based alternative; a positive ACC value indicates that the bid resource compares unfavorably to the market-based alternative.

Q. What was the outcome of the 2010S Solar RFP process?

A. A total of ten proposals were submitted by seven developers for seven separate sites. Results of the initial shortlist are included in Confidential Exhibit PAC/802.

The top two proposals were selected as the final shortlist. The top proposal was Bid E, a PPA-based proposal located in Christmas Valley, Oregon. Negotiations were initiated with the developer in April 2011; however, the developer's Oregon Business Energy Tax Credit ("BETC") application was denied by the Oregon Department of Energy in July 2011. Without the economic benefit of the BETC to reduce project costs, Bid E was no longer the least cost resource and negotiations were terminated. The alternative proposal was the Black Cap Solar Project, a BOT proposal submitted by Obsidian Finance Group.

Black Cap Solar Project Transaction

Q. Please describe the Black Cap Solar Project.

A. The Black Cap Solar Project is a utility scale photovoltaic solar system with a design output of 2.558 megawatt direct current ("MW_{DC}"), which converts to 2.0 MW_{AC}. The solar resource will be located on approximately 20 acres of relatively flat ground near Lakeview in Lake County, Oregon. The Black Cap Solar Project will consist of a total of 8,976 photovoltaic modules mounted on single-axis trackers. The trackers will be oriented in a north-south direction and will automatically track the path of the sun each day in an east-to-west direction. The following equipment make up the project: 2.558 MW_{DC} of Suntech crystalline silicon (c-Si) modules; eight blocks of Array Technologies' single axis tracker system, including controls; four 500kW_{AC} AE Solaron inverters; monitoring and communications systems; and interconnection facilities. The Project is expected be commercially operable on or before October 1, 2012. The resource has an average annual capacity factor of [redacted] percent. The Project cost is [redacted] million

and includes a [redacted] million BETC pre-certification that will be included in the SAA transaction with PacifiCorp for the benefit of RBS. The Project is being developed by Obsidian Finance Group, through Black Cap Solar LLC, and will be constructed by Swinerton Builders, Inc., under an engineering, procurement, and construction agreement ("EPC"). Obsidian Finance Group is headquartered in Lake Oswego, Oregon. Swinerton Builders, Inc., headquartered in San Diego, California, is a large international construction company that has constructed over 60 MW_{AC} of photovoltaic projects in California.

Q. What due diligence was completed on the resource as part of the RFP?

A. PacifiCorp completed a number of due diligence tasks consistent with its business practices, including permit review, property title documentation, and determination of party creditworthiness. In addition, the Black Cap Solar Project's capacity factor was calculated using the RFP specified solar performance model (PVSYST) and then validated by BEW Engineering, Inc., a third-party engineering firm hired by PacifiCorp. Photovoltaic panel layout and project placement on the property were modified to mitigate any site issues identified in a cultural study by Historical Research Associates, Inc., and a Phase 1 environmental study completed by WHPacific, Inc.

Q. What is the final structure of the transaction?

A. The structure of the transaction is a hybrid "sale-leaseback" transaction. Exhibit PAC/803 provides a diagram of how the transaction is structured. Upon Project completion and at closing, Obsidian sells all project equipment to RBS, and RBS in turn leases the project equipment to PacifiCorp. PacifiCorp will control the site

by acquiring the land directly from Obsidian at closing under a Real Estate Purchase and Sale Agreement, which was executed in conjunction with the Black Cap SAA. As part of the transaction, PacifiCorp will be assigned a conditional use permit for the Black Cap Solar Project, certain contractual rights, and the benefits of the equipment warranties. The lease agreement has a 16-year term, through 2028, with PacifiCorp retaining an early buyout option after 10years at [redacted] percent of the original purchase price.

Q. Why is the sale-leaseback the preferred transaction?

A. The lease arrangement provides PacifiCorp's customers with the least cost alternative because the lease captures the BETC tax credit and 50 percent bonus depreciation available to the project in 2012 and allows RBS to monetize the federal investment tax credit ("ITC") more effectively than PacifiCorp could under current tax laws.[1]

Q. What tax benefits are available to the Black Cap Solar Project if completed in 2012?

A. The facility qualifies for the federal ITC, 50 percent bonus depreciation in 2012 with the remaining tax basis recoverable as a five-year Modified Accelerated Cost Recovery System ("MACRS") asset, and the project specific Oregon BETC. RBS's sale-leaseback proposal will have RBS using the federal ITC, the 50 percent bonus depreciation in 2012 with 5-year MACRS on the remaining tax

[1] Under Internal Revenue Service code, IRC Section 50 (d)(2), regulated companies are required to normalize and pass-through the ITC to customers over the book life of the property, which is assumed to be 25 years for a solar PV project.

basis, and monetizing the BETC through a third-party pass-through partner.[2] Both the BETC pre-certification and 50 percent bonus depreciation expire at the end of 2012.

Q. What are the major drivers for executing this project in 2012?

A. The Project's BETC and 50 percent bonus depreciation are the key economic factors driving the acquisition of this resource today versus the delay of the acquisition. As part of the project development, Obsidian acquired an early generation BETC pre-certification for a larger 5.1MW_{DC} project up to $20 million in capital. Based on the Oregon Department of Energy's procedure and a revised BETC pre-certification issued in February 2012, the Black Cap Solar Project is eligible for a [redacted] million BETC. The Black Cap Solar Project BETC is a grandfathered benefit that will expire on December 31, 2012 if it is not used. With the entire BETC program expiring December 31, 2012, the availability of similar large energy tax credits in Oregon will be limited in 2013 and beyond. The Company's current projections show that PacifiCorp's own Oregon tax position cannot monetize the BETC until at least 2018[3] and that the Company's ability to utilize the BETC might be moved out further into the future. Therefore, it is more valuable to monetize the BETC through a third party now and pass the value of the sale of the BETC back to offset the project cost. In addition, the 50 percent bonus depreciation, while not as large a benefit as the BETC, will expire December 31, 2012 and not be available to the Black Cap Solar Project if the resource is delayed.

[2] The Black Cap BETC is a grandfathered BETC with a pass-through rate of 67 percent, compared to more recent BETCs at 75 percent.
[3] However, PacifiCorp cannot provide a firm commitment to use the BETC in 2018 at this time.

Q. What actions were undertaken to ensure the ability to monetize the BETC in 2013?

A. As part of its due diligence and negotiations with Obsidian and RBS, PacifiCorp (1) evaluated the BETC market for 2013, and (2) conducted its own search for a pass-through partner to line up with RBS. To assess the BETC market, PacifiCorp and Obsidian met with the Oregon Department of Energy and Moss-Adams LLP, a multi-state certified public accounting firm that specializes in the tax credit market and has assisted in the sale of millions of dollars of BETC certificates per year for the past several years. It was found that the BETC is valuable to Oregon businesses and has successfully been sold to a limited number of market participants since the program's inception. Thus far the market participants have been unwilling to commit to a purchase of the BETC until the year it actually becomes available, which is after January 1, 2013, for this resource. As a follow-up to the meeting, RBS and PacifiCorp collaborated to identify a number of parties interested in the BETC in 2013. The Company understands that RBS is in the process of securing a firm commitment from an entity with an Oregon tax position in 2013 sufficient to utilize the BETC.

Q. What is the cost of the Black Cap Solar Project under this lease structure?

A. Under the lease agreement structure with RBS, RBS will take the 30 percent federal ITC, the 50 percent bonus tax depreciation in 2012, 5-year MACRS tax depreciation on the remaining tax basis for the asset, and sell the BETC as a pass-through in 2013 to a qualified entity. The nominal levelized cost under the lease structure is [redacted] per MWh. Confidential Exhibit PAC/804 was prepared to

show the cost of the project and how the BETC and 50 percent bonus depreciation affect the final cost. The lease structure is described as the Preferred Transaction in the exhibit.

Prudency of the Transaction

Q. Were other acquisition options considered?

A. Yes. The Company considered two alternatives: (1) directly acquiring the asset from Obsidian upon commercial operation as a solar asset purchase; and (2) delaying the lease acquisition until 2015, which is the last year when a solar resource under the solar capacity standard would be eligible to receive two-for-one solar RECs available for the Oregon RPS.

Q. How did the purchase option compare to the lease?

A. The purchase option assumed that the Black Cap Solar Project closes as a SAA in 2012 and the Oregon BETC is monetized in 2013 by the Company as a pass-through with a third party. Under that option, PacifiCorp would take the 30 percent federal ITC, the 50 percent bonus tax depreciation, the five-year MACRS tax depreciation, and sell the BETC as a pass-through in 2013. As mentioned previously, the Company projections indicate that the BETC could not be used by PacifiCorp before January 1, 2018. Therefore, it is prudent to monetize the BETC in 2013 when there is a potential market. As noted above, under current tax laws, PacifiCorp must monetize the federal ITC over the 25-year life of the asset resulting in a higher project cost. The result is a nominal levelized cost for the purchase option of [redacted] per MWh, which is approximately 30 percent higher

than the project cost under the recommended lease structure. This alternative is described in Confidential Exhibit PAC/804 as the Solar Assets Agreement.

Q. What was the second alternative option?

A. The second option was to delay the lease transaction until 2015. The rationale for considering this option was that 2015 is the last year that a solar resource could be acquired under ORS 757.370 and still receive two-for-one solar RECs to apply toward the Company's Oregon RPS obligation. In the current market, solar panel prices have declined and are expected to decline further over the next several years. But under this option, the project would lose its BETC and the 50 percent bonus depreciation after 2012 but retain the federal ITC and five-year MACRS depreciation. Using an assumed panel price drop of 37 percent,[4] the project cost increases to [redacted] per MWh. This is described as the Alternative Transaction in Confidential Exhibit PAC/804.

Q. You mentioned that solar panel prices are expected to decline further over the next few years. Why is it reasonable to not wait for the prices to drop before acquiring a solar project?

A. While solar PV panel prices have dropped in the past 18 months and are expected to continue to decline as the panel inventories build up and manufacturing costs decline, it is not anticipated that prices will decline sufficiently to offset the current benefit of the BETC and to a lesser extent, the 50 percent bonus depreciation in 2012. PacifiCorp determined, based on the value of the BETC in 2013, solar panel prices would need to drop by nearly 75 percent to offset the value of the BETC. This would place the cost of panels significantly below the

[4] It was assumed that the panel price dropped by an average annual rate of 14.3 percent per year.

current estimated manufacturing floor cost of $0.70 per watt$_{DC}$. In other words, if a panel manufacturer sold their panels at a price below the $0.70 per watt$_{DC}$ level, they would be selling panels at a loss. Such an outcome is unrealistic based on current market forecast of solar panel prices over the next four years.[5]

Q. Has the Company pursued other measures to reduce the cost of the resource?

A. Yes. On January 18, 2012, PacifiCorp submitted an application to the Energy Trust of Oregon ("ETO") for funds to apply against the costs of the Black Cap Solar Project under the Company's Master Funding Agreement with the ETO. Under the Master Funding Agreement, PacifiCorp can request that the ETO access funds collected through the public purpose charge for renewable energy projects developed by PacifiCorp. The Master Funding Agreement lays out a collaborative process for review of PacifiCorp's application to determine a funding level. PacifiCorp is currently working with the ETO on the application evaluation and targeting a submittal to the ETO's review committee and the ETO board in mid-2012. If there are no funds in the 2012 budget for the project, the ETO has indicated that, if the board approves the project, ETO could set aside funds for the project from the 2013 budget. The Company will adjust the project cost if any funding is received by the ETO.

Q. What would be the impact of funding from the ETO on the resource cost?

A. While the funding level has not yet been determined by the ETO, a funding level of $1.00 per watt$_{DC}$ would result in the project cost being reduced by approximately $30 per MWh.

[5] Industry contacts and market research forecast solar panel prices to decline to a low of the $0.70 per watt$_{DC}$ level over the next four years.

Q. What contractual rights has PacifiCorp established to ensure the project is completed in a timely and prudent manner?

A. The Company has established several mechanisms to ensure the resource is built on budget and schedule. The SAA contains all project quality representations and warranties and indemnity protections for PacifiCorp. A guaranty of Black Cap Solar, LLC's obligations was executed by Obsidian providing PacifiCorp a guaranty that Obsidian will stand behind the Black Cap Solar Project's representations, warranties, and indemnification obligations in the SAA. PacifiCorp was involved in the negotiation of the EPC agreement between Obsidian and Swinerton, including its scope of work and technical specifications to ensure the EPC agreement meets PacifiCorp's standards as issued in the 2010S Solar RFP. At the closing, Black Cap Solar Project will assign PacifiCorp all of its rights under the EPC agreement so that PacifiCorp will be able to make any claims directly against Swinerton if there is a breach of the EPC agreement that leads to damages. In addition, PacifiCorp will assume Black Cap Solar Project's warranty rights under the EPC agreement. Because PacifiCorp is not a contractual party to the EPC agreement, an EPC consent agreement was executed that gives PacifiCorp the right, in the event that the EPC party defaults, to step into the EPC agreement as though PacifiCorp is the project owner. If either party to the EPC agreement defaults, the consent agreement gives PacifiCorp the right to require performance by either Black Cap Solar Project or Swinerton. It also gives PacifiCorp notice and consent rights largely parallel to Black Cap Solar

Project's rights under the EPC agreement. PacifiCorp will take title to the real estate through a warranty deed.

Q. What is schedule for resource construction?

A. PacifiCorp, Obsidian, and Swinerton executed the transaction documents on February 15, 2012. A notice to proceed was issued by Obsidian to Swinerton on February 15, 2012. Obsidian executed an interconnection agreement with PacifiCorp Transmission on December 23, 2011, with a target interconnection completion date of September 15, 2012. Resource construction is scheduled for June 1 through July 31, 2012. Start-up and testing is scheduled for September 15 through September 30, 2012, with commercial operation and project closing on October 1, 2012. PacifiCorp and Obsidian will work together with the Oregon Department of Energy to complete the BETC process for issuance of the certification before December 31, 2012.

Q. Is there an operating and maintenance ("O&M") agreement for Black Cap Solar Project after construction?

A. Yes. Terms and conditions for an O&M agreement have been negotiated with Swinerton for an initial term of five years to ensure that O&M services are available under known prices and terms. In addition, the equipment is covered by warranties and a five-year project warranty wrap by Swinerton.

Q. What solar energy performance assurances are in place?

A. The EPC agreement contains two performance measures. The first requires that the project is built to deliver the 2.0 MW_{AC} upon commercial operations. If the resource is under 2.0 MW_{AC} then Swinerton will make up the capacity deficiency

by incrementally adding solar panels. The second performance measure is an annual energy performance guarantee that contains liquidated damages for under delivery of the project.

Q. Will the public have access to the site?

A. No, not directly however, the property is located outside the Lakeview city limits, providing good security but limited visibility. The resource will be housed on the property with perimeter fencing and security cameras. To allow the public to view the resource, the Company will develop a website that shows the resource and provides performance data.

Q. Does this conclude your direct testimony?

A. Yes

PacifiCorp

Request for Proposal

Solar Resources

(RFP 2010S)

ISSUED: November 30, 2010

DUE DATE: January 7, 2011

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Appendices

SECTION 1. INTRODUCTION

This Solar Request for Proposal (2010S RFP) requests solar resources limited in size greater than 500 kilowatts alternating current (kW_{AC}) but no more than 2.0 megawatts alternating current (MW_{AC}), calculated as 85% of the manufacturer's direct current nameplate rating[1], that are compliant with existing or anticipated renewable portfolio standards and that are new to PacifiCorp's resource portfolio. The 2010S RFP is in response to Oregon Statute ORS 757.370 and will require new solar resources located within the state of Oregon and capable of delivering energy, within the prescribed timeframe, in or into the Company's Network Transmission system within the State of Oregon (www.oasis.pacificorp.com).

Under Oregon Statute ORS 757.370, on or before January 1, 2020, the total solar photovoltaic (PV) generating nameplate capacity, from qualifying systems generating at least 500 kW_{AC}, of all utilities in Oregon must be at least 20.0 MW_{AC} with no single project greater than 5.0 MW_{AC}. For the purpose of complying with the solar photovoltaic generating capacity standard, PacifiCorp is required to acquire 8.7 MW_{AC} of the total 20.0 MW_{AC} based on PacifiCorp's fractional portion of 2008 total utility retail sales in Oregon. PacifiCorp may satisfy the solar PV generating capacity standard with PV systems owned by the Company or with power purchase agreements from qualifying systems. All costs prudently incurred to comply with the solar PV generating capacity standard are deemed not above-market costs, recoverable in rates, and eligible for inclusion in the Company's automatic adjustment clause established by the Oregon Commission under ORS 469A.120. Electricity produced by qualified solar projects under ORS 757.375 may be used for RPS compliance and each megawatt-hour generated by a project over 500 kW_{AC} that became operational before January 1, 2016 will be credited with two MWhs of qualifying electricity toward PacifiCorp's RPS compliance.

The 2010S RFP is organized as follows:

- Section 1 - Type, timing and amount of resources sought.
- Section 2 - Procedural items.
- Section 3 - Logistics, minimum requirements, and important conditions and procedures.
- Section 4 - Required content and format.
- Section 5 - Resource information including price and non-price information, integration, interconnection and transmission services.
- Section 6 - Bid evaluation and selection process.
- Section 7 - Awarding of contracts.
- Appendices and Exhibits which are required are included.

PacifiCorp may opt to contract for more or less Solar Resources, depending among other things, quality of bids received in response to this RFP and changes in power supply market conditions.

For the purpose of the 2010S RFP, the Solar Resource shall be defined as a "solar photovoltaic energy system", meaning equipment and devices that have the primary

[1] In compliance with Oregon administrative rule 860-084-0040

purpose of collecting solar energy and generating electricity by photovoltaic effect as stated under ORS 757.360.

The Solar Resource must have a commercial operation date no later than December 31, 2011. Bidders may only bid in Solar Resources in the form of a Power Purchase Agreement (PPA) or as a Build Own Transfer (BOT).[2] To the extent that Bidders bid in variations of a PPA or BOT, such proposals will be considered at PacifiCorp's discretion and PacifiCorp reserves the right to reject non-compliant bids. Please refer to Section 4 for further information on asset transfers associated with a PPA.

SECTION 2. PROCEDURAL ITEMS

PacifiCorp is seeking proposals for Solar Resources with a projected online date prior to December 31, 2011. PacifiCorp is seeking proposals for up to the potential quantities set forth in Section 1 of this solicitation and may elect to select more or less than the resource potential quantity, or no proposals at all, as a result of this solicitation. PacifiCorp will evaluate the proposals based on cost effective economics, a viable implementation schedule, compliance with and verification of major equipment availability as defined in **Appendix A Oregon Solar Photovoltaic Project – Technical Specification** (such as photovoltaic panels, inverters, or other long lead-time equipment), appropriate ability to provide security for the Bidder's proposed obligation, transmission access and interconnection status, and conformance to the *pro forma* contracts attached as Appendices to this RFP.

Each proposal will be prepared at the sole cost and expense of the Bidder and with the express understanding that there will be no claims whatsoever for reimbursement from PacifiCorp. PacifiCorp is not liable for any costs incurred by Bidders in responding to this RFP or for any damages arising out of or relating to PacifiCorp's rejection of any proposal, or Bidder's reliance upon any communication received from PacifiCorp, for any reason. Bidder shall bear all costs and expenses of any response to PacifiCorp in connection with its proposal, including providing additional information and Bidder's own expenses in negotiating and reviewing any documentation.

To the extent that the proposals are deemed conforming, all proposals belong to PacifiCorp and will not be returned. PacifiCorp will use reasonable efforts to protect information clearly and prominently marked as proprietary and confidential on the page it appears, but PacifiCorp reserves the right to release such information to agents or contractors to help evaluate the Proposal, as well as to its regulators and non-bidding parties to regulatory proceedings subject to standard protective orders or confidentiality arrangements. PacifiCorp shall not be liable for any damages resulting from any disclosure of such information, howsoever occurring.

Proposals must be submitted in the legal name of the respondent who would be bound by any agreement with PacifiCorp.

[2] Form of Power Purchase Agreement is set forth in Appendix E and the Build Own Transfer is set forth in Appendix F.

SECTION 3. LOGISTICS

A. SCHEDULE

Chart 2 sets forth the anticipated schedule.

CHART 2 – ANTICIPATED SCHEDULE

Event	Estimated Timeline
2010S issued	November 30, 2010
Responses due	January 7, 2011
Bid evaluation completed	January 21, 2011
Shortlist selection	January 31, 2011
Bidder negotiations completed	February 28, 2011
Final selection	March 7, 2011

Bidders should note that the above schedule is an anticipated schedule only and is subject to change. PacifiCorp accepts no liability to the extent the actual schedule is different from the anticipated schedule.

Interested parties and Bidders may submit questions and such questions will be addressed in a timely fashion. All information, including the pre-bid materials, questions and answers will be posted on the PacifiCorp website at www.pacificorp.com. PacifiCorp will maintain and post all materials on PacifiCorp's website at www.pacificorp.com. Any questions on the RFP or related documents should be sent to Company via email at **rfpsolar@pacificorp.com.**

B. SUBMISSION OF BIDS

Bidders are required to submit proposal(s) to the following addresses. Bidders must submit the following to the address below:

1. one signed original and one (1) hard copy of each bid and any required forms including all exhibit sheets required in **Appendix A.**
2. one (1) electronic copies of the bid and any required forms in PDF format including all exhibit sheets required in **Appendix A.**
3. one (1) electronic copy of the Pricing Input Sheet.
4. one (1) electronic and hard copy of the solar plant performance estimation report using one of the modeling packages listed in **Appendix A Oregon Solar Photovoltaic Project - Section A.19.** Note: PacifiCorp's preferred solar performance model is PVSYST.

All submitted bids must be transmitted by express, certified or registered mail, or hand delivery to the following address:

PacifiCorp
Attention: RFP 2010S
825 NE Multnomah, Suite 600
Portland, Oregon 97232

Bids will be accepted until 5:00 p.m. Pacific Prevailing Time on January 7, 2011. **Any bids received after this time will be subject to return unopened to the Bidder.**

PacifiCorp will not accept any late proposals. The anticipated dates for evaluations, negotiations and definitive agreements are estimates, and actual dates will vary for reasons that include, but are not limited to, negotiation time, availability of key personnel, due diligence, the evaluation or negotiation of any issues unique to any bid, Bidder, or project, Bidder's willingness to agree to forms of agreements desired by PacifiCorp, PacifiCorp's evaluation of Bidder's creditworthiness, and actions required by any third parties.

C. RFP TEAM

The composition of the team and their primary roles and responsibilities are shown below in Chart 3.

CHART 3

Work Group	Roles
Origination	Overall coordinator of the process. Bid process management for all proposals and coordination with all work groups. Evaluation of the non-price components of the analysis.
Generation / Environmental	Specifying, evaluating and confirming conformity with design specifications; conducting, as needed, technological and operational due diligence, environmental due diligence on all resources. If applicable, review of local, state, and federal permits, permit applications, and supporting documentation, including but not limited to: wildlife assessments; rare plant habitat assessments; wetlands survey; historic, cultural, and archaeological resources survey; Phase One environmental site assessment; and project mitigation and monitoring plan (including any proposed conservation easements).
Structuring and Pricing and/or Third-Party consultants as required	Economic analysis and modeling including validation of the inputs to the risk assessment of the bids.
Credit	Evaluate credit requirements for Final Shortlist Bidders

Legal	Legal will confirm compliance of bids to requirements of RFP and its Forms, Attachments and Appendices; conduct of legal process; conducting due diligence inquiries; supervising any documentation entered into as part of the RFP process.

D. MINIMUM ELIGIBILTY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements are not met. To the extent proposals do not comply with these requirements they will be deemed ineligible and will not be considered for further evaluation. Reasons for rejection of a Bidder or its bid include:

1. Receipt of any proposal after the response deadline.
2. Failure to meet the requirements and provide all of the information requested in **Appendix C-1** or **Appendix C-2** of this RFP.
3. Failure to permit disclosure of information contained in the proposal to PacifiCorp's agents, contractors, regulators, or non-bidding parties to regulatory proceedings under appropriate confidentiality agreements.
4. Any attempt to influence PacifiCorp in the evaluation of the proposals, outside the solicitation process.
5. Any failure to disclose the real parties of interest in the proposal submitted.
6. The Bidder, or an affiliate of Bidder, is in current litigation with PacifiCorp or has, in writing, threatened litigation against PacifiCorp, respecting an amount in dispute in excess of one million dollars.
7. Proposal has failed to clearly specify all pricing terms.
8. Proposal has failed to offer unit contingent (as generated) or system firm capacity and energy, delivered into or in PACW-Oregon and include appropriate contract term lengths and commercial operation dates.
9. Proposal presents unacceptable level of development and technology risk.
10. Bidder fails to comply with preferred vendors for major PV components and technical specification requirements in **Appendix A.**
11. Failure to demonstrate a contract to purchase major equipment (i.e., photovoltaic panels, inverters) and a process to adequately acquire other critical long lead time equipment.
12. Bidder fails to demonstrate, to PacifiCorp's satisfaction, that it can meet the security requirements for the Solar Resource proposed.
13. Bidder fails to address satisfactorily both the price and non-price factors.
14. Bidder fails or is unable to abide by the applicable safety standards.
15. Bidder submits an unacceptable contract structure.
16. Collusive bidding or any other anticompetitive behavior or conduct exists.
17. Bidder or project being bid is involved in bankruptcy proceedings.
18. Failure of the Bidder's authorized officer to sign the proposal.
19. Misrepresentation or failure to abide by National Association of Attorneys General (NAAG) Environmental Marketing Guidelines.
20. Any change in regulations or regulatory requirements that make the Bidder's proposal non-conforming.
21. Any matter impairing the Bidder, the specified resources or the generation of power or Environmental Attributes of the Renewable Resource.
22. Failure to provide one year site-specific weather and solar radiation data.

23. Failure to provide a performance model output as identified in **Appendix A – Section A.19** including hourly output values.

E. COMPANY RESERVATION OF RIGHTS AND DISCLAMERS

The Company reserves the right, without qualification and in its sole discretion, to reject any or all bids, and to terminate this RFP in whole or in part at any time. Without limiting the foregoing, the Company reserves the right to reject as non responsive any or all bid proposals received for failure to meet any requirement of this RFP outlined in Section 4. The Company further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any Bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact the Company and/or any collusive bidding or other anticompetitive behavior or conduct.

Bidders who submit bid proposals do so without recourse against PacifiCorp, its parent company, its affiliates and its subsidiaries, or against any director, officer, employee, agent or representative of any of them, for any modification or withdrawal of this RFP, rejection of any bid proposal, failure to enter into an agreement, or for any other reason relating to or arising out of this RFP. Bidders will be required to execute the non-reliance Agreement in **Appendix H** after the Final Shortlist and prior to entering into final negotiations.

F. ACCOUNTING

All proposals will be assessed by PacifiCorp for appropriate accounting or tax treatment. Bidders must supply all information PacifiCorp reasonably requires in order to make such assessments.

G. CONFIDENTIALITY

PacifiCorp will attempt to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order, as long as such confidentiality does not adversely impact a regulatory proceeding. It is the Bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential. Bidders may not mark an entire proposal as confidential, but must mark specific information on individual pages to be confidential in order to receive confidential treatment for that information.

All information supplied to PacifiCorp or generated internally by PacifiCorp shall remain the property of PacifiCorp. Bidder shall maintain the confidentiality of such information and such information shall not be available to any entity before, during or after this RFP process unless required by law or regulatory order. The Bidder expressly acknowledges that PacifiCorp may retain information submitted by the Bidder in connection with this RFP.

Only those Company employees who are directly involved in this RFP process or with the need to know for business reasons will be afforded the opportunity to view submitted bids or Bidder information.

Bidders should be aware that information supplied by Bidders may be requested and supplied during regulatory proceedings, subject to appropriate confidentiality provisions

applicable to that particular proceeding. This means that parties to regulatory proceedings may request and view confidential information. If such a request occurs, PacifiCorp will attempt to prevent such confidential Bidder information from being supplied to intervening parties who are Bidders or who may be providing services to a Bidder, but PacifiCorp can not promise success in that endeavor and accordingly cannot be held liable for any information that it is ordered to be released or that is inadvertently released.

Lastly, PacifiCorp intends to utilize its internal, proprietary, forward price projections in its evaluation process. The resulting projections and evaluations will not be shared with entities external to PacifiCorp or its consultants, including with Bidders, unless required by law or regulatory order.

SECTION 4. REQUEST FOR PROPOSAL CONTENT

Bidders can submit proposals for either as a Power Purchase Agreement (PPA) or a Build Own Transfer (BOT) agreement.

A. POWER PURCHASE AGREEMENT

Appendix C-1 contains an explanation of the information required if a Bidder plans to pursue the PPA option. The Bidder must agree to meet its contractual obligations within the PPA during the Term of the Agreement, and agree to sell the Project to PacifiCorp at the end of the term as outlined in Section 5.6 of the PPA (**Appendix E**) or during the term of the PPA as outlined by the Bidder. The Bidder's proposal must contain the information requested in **Appendices B, C-1, D, J,** and any proposed changes to **Appendix E**. The Bidder must provide information sufficient to assure PacifiCorp that any proposed project has a reasonable probability of successful construction and operation by December 31, 2011.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must comply with preferred vendors for major PV components and technical and construction specifications contained in **Appendix A** and any engineer, procure, construct (EPC) contractor must meet credit provisions acceptable to PacifiCorp in its sole discretion.

B. BUILD OWN TRANSFER

Appendix C-2 contains an explanation of the information required if a Bidder plans to pursue the BOT option. The Bidder's proposal must contain the information requested in **Appendices B, C-2, D, J,** and any proposed changes to **F**. The Bidder must provide information sufficient to assure PacifiCorp that any proposed project has a reasonable probability of successful construction and operation by December 31, 2011.

Under the BOT option, PacifiCorp and the entity building the project must be counterparties. The BOT *pro forma* documents are attached as **Appendix F**. A BOT can be structured with progress payments with defined milestones, or as a single lump sum payment due upon achievement of commercial operation. PacifiCorp will in no event make progress payments to a Bidder unless each such payment results in the transfer of a tangible asset or a percentage ownership of an asset at the time each payment is made.

Bidders must submit bids that comply with one of these two payment structures. All Bidders in this category must complete the information requested in **Appendix C-2**.

PacifiCorp will only accept proposals in which PacifiCorp purchases a fully completed project which has reached commercial operation. Any proposals that consist of either only a site sale or only an engineer, procure and/or construct (EPC) contract(s) will be rejected as a nonconforming proposal.

The Bidder shall be responsible for all aspects of the development and construction of the facility, including, but not limited to, permitting, engineering, procurement, construction, interconnection and all related costs up to achieving commercial operation. Without limiting the foregoing, the Bidder shall be responsible for obtaining all rights and resources required to construct and provide an operational generation resource consistent with the Bidder's proposal.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must comply with preferred vendors for major PV components and technical and construction specifications contained in **Appendix A** and must utilize the services of a single primary Contractor, which must be a party to the BOT. To the extent the Bidder uses a Contractor or a separate legal entity other than the Bidder itself, this entity must be a party to the BOT and must be experienced with the type of facility being proposed and, meet credit provisions acceptable to PacifiCorp in its sole discretion.

SECTION 5. RESOURCE INFORMATION

A. PRICE AND NON-PRICE INFORMATION

Bids will be evaluated on the basis of price and non-price factors to determine the Initial Shortlist. The bids on the Initial Shortlist will then be evaluated using the IRP models to determine the Final Shortlist.

1. PRICE INFORMATION

The Price factors will be determined using the comparison metric of the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The net PVRR component views the value of the energy and capacity as a positive, and the offsetting costs as negative. The more positive the net PVRR, the more valuable a given resource is to PacifiCorp's customers. The net PVRR/kW-mo metric is the annuity value which, when applied to the nominal kilowatts on a monthly basis and present-valued, will result in the same net PVRR as a straight NPV calculation[3] with the appropriate adjustments. Price factors will recognize the value of the power (e.g., firm versus non-firm, delivery shape, but not an inferred value of environmental attributes associated with the facilities).

[3]The term "straight NPV calculation" refers to the act of present-valuing the net of the nominal capacity and energy value, and costs, to derive a net present value of the net margin between value and costs. To the extent a significant number of the proposals are above 140% of adjusted appropriate price curve in the two Initial Shortlists, such proposals will be ranked on a percentage in order to apply a ranking for price.

- *Build Own Transfer* –Bidder sells a fixed price turn key project payable in a single amount on delivery or upon achievement of milestones as progress payments, with an online date prior to December 31, 2011. Milestone payments shall be subject to PacifiCorp's internal allowance for funds used during construction rate.

All bids must include exclusive ownership by PacifiCorp of any and all Environmental Attributes[4] associated with all energy generated.

PacifiCorp will consider both the PPA or BOT options as described in Section 4 above.

2. NON-PRICE INFORMATION

The Non-Price factors will include:

1) Conformity to RFP preferred vendors for major PV components and technical specifications (**Appendix A)**
2) Conformity to RFP bid requirements (**Appendix B**)
3) Conformity to the form PPA (**Appendix E**) or BOT (**Appendix F**)
4) Development and feasibility of proposal
5) Site control and permitting
6) Operational viability.

For PPAs, PacifiCorp will consider the following delivery concepts if the Bidder supplies statistically valid information to permit effective evaluation:

- Unit contingent generation as generated by the facility interconnected directly to PacifiCorp's transmission or distribution system
- Firm, scheduled generation into PacifiCorp's system

All proposals will be contingent on firm transmission and must be able to be designated by PacifiCorp commercial and trading function as a Network Resource under the network service contract between PacifiCorp Transmission (www.oasis.pacificorp.com) and PacifiCorp Commercial and Trading.

B. POINT OF DELIVERY

PacifiCorp seeks resources that are capable of delivery into or in PacifiCorp's network transmission and distribution system in Oregon. If the source is located within the Bonneville or another balancing authority, the Bidder must show they have tariff: interconnection; transmission; balancing; reserve or other applicable balancing authority services from the resource to the delivery point to be able to schedule to the point(s) of interconnection between PacifiCorp's Oregon western control area and: (i) Bonneville Power Administration, and/or (ii) Portland General Electric such that transfer limitations are not exceeded.

[4] As defined in the Power Purchase Agreement.

C. THIRD-PARTY INTERCONNECTION AND INTEGRATION AND TRANSMISSION SERVICE

PPA Bidders are responsible for any current or future tariffs including, but not limited to: interconnection, variable energy resource, electric losses, reserves, transmission, integration, imbalance, scheduling, and ancillary service arrangements required to deliver the proposed firm capacity and associated energy to the bid specified Point(s) of Delivery. Such costs will not be included in the evaluation of the PPA proposals as they are assumed to be the responsibility of the Bidder. All proposals must identify all third-party interconnection, electric losses, transmission and ancillary service products, provider of reserves, and must provide a complete description of those service agreements, and provide documentation that such service(s) will be available to during the full term of offer(s) proposed or include contractual roll-over options if available.

Bidders who propose bids relying on third-party transmission should be aware that the use of transmission that is interruptible within the hour in any segment of the schedule or tagged from the source to the Point(s) of Delivery will require PacifiCorp to evaluate the need to carry reserves against the schedule, which can be up to 100% in the case of electricity moved from a third party control area to PACW.

D. FERC'S STANDARDS OF CONDUCT

Each Bidder responding to this RFP must conduct its communications, implementation and operations in compliance with FERC's Standards of Conduct for Transmission Providers (see **Appendix K**), requiring the separation of its transmission and merchant functions. The third-party transmission service is NOT a transmission service agreement with PacifiCorp's commercial and trading function; rather it is with PacifiCorp's transmission function or other third-party transmission providers, and hence Bidder must follow the transmission provider's OASIS process. Absolutely no communication by a Bidder to PacifiCorp's transmission function can be made through the submission of a bid in this RFP. Any bid seeking to do so will be summarily rejected if the attempt is not immediately withdrawn when discovered. If requested, short-listed Bidders shall execute a customer consent form consistent with FERC requirement that enables PacifiCorp's merchant function to discuss the Bidder's interconnection and/or transmission service application(s) with the transmission interconnection or transmission service provider.

E. INTERCONNECTION AND TRANSMISSION SERVICES

This RFP requires that all Bidders must enter into a separate Interconnection Agreement if their facilities are located within PacifiCorp's Oregon footprint in accordance with PacifiCorp's Open Access Transmission Tariff or completed as a Small Generating Facility subject to the jurisdiction of the Oregon Public Utility Commission "OPUC") and governed by OPUC Rule OAR 860, Division 082. Bidders must advise PacifiCorp Transmission if any such service is being requested as part of this RFP. As stated above, all such requests, if made, must be made directly to PacifiCorp's transmission function through OASIS or other applicable tariffs, and not made to PacifiCorp through the submission of a bid in this RFP. Any bid seeking to do so will be summarily rejected if the attempt is not immediately withdrawn when discovered.

All proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include a statement of the cost of interconnection (broken out between network upgrade costs and facility specific or direct assigned interconnection costs), together with a diagram of the interconnection facilities. The Bidder will be responsible for, and is required to include in its bid, all costs to interconnect to the transmission provider's system. The Bidder will be responsible to make application to the transmission provider for the appropriate Interconnection Agreement with PacifiCorp Transmission. The interconnection costs from all Bidders will be included in the bid evaluation. Bidders shall describe interconnection costs in their bids by disclosing that portion of costs associated with network upgrades and that portion that is facility specific. Bidders are reminded that they shall bear 100% of the costs to interconnect to the transmission provider's system. Bidders are encouraged to contact the applicable transmission function (PacifiCorp's transmission function at www.oasis.pacificorp.com) for information related to a system interconnection request.

F. PACIFICORP TRANSMISSION INTEGRATION SERVICE

Notwithstanding the foregoing, Bidders should not factor in the cost of integrating the proposed resources from bid-specified Points of Delivery into PacifiCorp's system. Such transmission integration costs and other integration costs, as applicable, will be factored in by PacifiCorp for determination of the Final Shortlist. Integration costs consistent with the IRP will be added to all bids.

After the Initial Shortlist is selected, the Structuring and Pricing group will provide the results of the Initial Shortlist to the PacifiCorp's IRP group. Pursuant to a consulting agreement between the IRP group and PacifiCorp Transmission, PacifiCorp Transmission will provide more refined cost estimates associated with integrating the Initial Shortlist resources into PacifiCorp's system. The IRP group will seek updated costs from PacifiCorp Transmission for only the Initial Shortlist. These integration costs will be used as inputs into the IRP model along with the Initial Shortlist proposals in order to determine the Final Shortlist.

G. RESOURCE TYPES ELIGIBLE TO BID

For the purpose of the 2010S RFP, the Solar Resource shall be a "solar photovoltaic energy system" meaning equipment and devices that have the primary purpose of collecting solar energy and generating electricity by photovoltaic effect as defined and stated under ORS 757.360.

The Solar Resource must have a commercial operation date no later than December 31, 2011. Solar Resources are eligible to be the subject of bids under this RFP, provided they are over 500 kW_{AC} and not greater than 2.0 MW_{AC}, calculated as 85% of the manufacturer's direct current nameplate rating[5].

Any bid submitted must be capable of clearly verifying time and amount of delivery of energy from the resource by metering or other means acceptable to PacifiCorp including without limitation metering on less than or equal to an hourly basis.

[5] In compliance with Oregon administrative rule 860-084-0040

This solicitation is for proposals that bundle *both* renewable energy credits[6] (RECs) and underlying generation from an associated Solar Resource. Bids that do not bundle the solar REC with the transfer of electricity from the associated Solar resource will not be accepted. As such, a Solar Resource must be directly connected to PacifiCorp's transmission or distribution system, or be scheduled to PacifiCorp's transmission system, to be eligible. Solar Resources interconnected to the electric system of a retail customer will not be accepted. Bids that combine solar RECs with undifferentiated wholesale power will not be accepted. The Solar Resource shall be located in Oregon

H. PRODUCTION TAX CREDIT AND INVESTMENT TAX CREDIT

Bidders shall bear all risks, financial and otherwise, associated with Bidder's or the facility's eligibility to receive Oregon Business Energy tax Credit (BETC), production or investment tax credits or qualify for accelerated depreciation for Bidder's accounting, reporting or tax purposes. The obligations of the Bidder to perform under any executed agreement as a result of this solicitation shall be effective and binding regardless of whether the sale of output from the Bidder's facility under such agreement is eligible for, or receives, BETC, production, or investment tax credits during the term of the agreement.

I. ACCOUNTING

All contracts proposed to be entered into as a result of this RFP will be assessed by the Company for appropriate accounting and/or tax treatment. Bidders shall be required to supply the Company with any and all information that the Company reasonably requires in order to make such assessments. Specifically, given term lengths that PPA or BOT accounting and tax rules may require either: (i) a contract be accounted for by PacifiCorp as a Capital Lease or Operating Lease[7] pursuant to SFAS No. 13, or (ii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a Variable Interest Entity[8] (VIE) onto PacifiCorp's balance sheet. To the extent a Bidder's proposal results in an applicable contract, the following shall apply with respect to VIE treatment:

The Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment. As a result, after Bidders are selected in the Final Shortlist, if required by the Company accounting department, Bidders will be required to certify, with supporting information sufficient to enable the Company to independently verify such certification, that their proposals will not be subject to VIE treatment. Bids that result in VIE treatment will be rejected after they are given an opportunity to provide an alternate structure that does not trigger a VIE.

Each Bidder must also agree to make available at any point in the bid evaluation process,

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[6] As defined in Appendix E (Power Purchase Agreement).

[7] "Capital Lease" and "Operating Lease" - shall have the meaning as set forth in the Statement of Financial Accounting Standards (SFAS) No. 13 as issued and amended from time to time by the Financial Accounting Standards Board.

[8] "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 (Revised December 2003) as issued and amended from time to time by the FASB.

any and all financial data associated with the Bidder PPA or BOT agreement that PacifiCorp requires to determine potential accounting impacts. Such information may include, but may not be limited to, data supporting the economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the Bidder's proposal. Financial data contained in the Bidder's financial statements (e.g., income statements, balance sheets, etc.) may also be required to provide additional information.

J. COST ASSOCIATED WITH DIRECT OR INFERRED DEBT

PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt (described below) as part of its economic analysis in the initial or Final Shortlist evaluation. However, after completing the Final Shortlist and before the final resource selections are made, PacifiCorp may take direct or inferred debt into consideration. In so doing, PacifiCorp may obtain a written advisory opinion from a rating agency to substantiate PacifiCorp's analysis and final decision regarding direct or inferred debt.

Direct debt results when a contract is deemed to be a Capital Lease pursuant to EITF 01-08 and SFAS No. 13 and the lower of the present value of the nonexecutory minimum lease payments or 100% of the fair market value of the asset must be added to PacifiCorp's balance sheet.

Inferred debt results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing PacifiCorp's credit standing.

SECTION 6. BID EVALUATION AND SELECTION

PacifiCorp will utilize a "first-price sealed bid format" in order to generate an Initial Shortlist. The Initial Shortlist constitutes the bids that will be evaluated with the IRP models, and from which the Final Shortlist bids will be selected for any post-bid negotiations.

Under this format, PacifiCorp will utilize the initial prices and pricing structure submitted by the Bidder in order to determine the initial short-listed entities. PacifiCorp will not ask for, or accept, updated pricing from Bidders during the evaluation period. **PacifiCorp will negotiate both price and non-price issues after the Initial Shortlist and during post-Shortlist negotiations**. PacifiCorp reserves the right not to engage in any post-bid or post-Shortlist negotiations with any Bidder that has not made the Initial Shortlist. Selection for the Initial Shortlist, the Final Shortlist and post-Shortlist negotiations does not constitute a "winning bid proposal." Only execution of a definitive agreement by both PacifiCorp and the Bidder on terms acceptable to PacifiCorp in its sole and absolute discretion will constitute a "winning bid proposal." Any definitive power purchase or build-own-transfer agreement will be in the form of the PPA or BOT contracts shown in **Appendices E** and **F**, respectively. If the Bidder alters the PPA or BOT or does not use it as the underlying agreement the bid evaluation will be effected. PacifiCorp has no legal obligation to enter into any agreement of any kind with any Bidder.

A. OVERVIEW OF THE EVALUATION PROCESS

The analysis for the RFP will determine which resources are in the public interest, and on a system-wide planning basis, provide the best value to customers to meet Oregon's solar PV generating capacity standard at a risk-adjusted, least cost basis. The evaluation process will utilize a screening process to derive an Initial Shortlist of bids (described in Step 1 below) and the Final Shortlist will be determined using the integrated resource planning models, and any residual value of the project to determine the Final Shortlist.

Bids submitted in this RFP will be evaluated in two steps:

STEP 1—PRICE AND NON-PRICE SCREEN WILL BE USED TO DETERMINE THE INITIAL SHORTLIST.

STEP 2—PACIFICORP'S PRODUCTION COST SIMULATION MODEL, USED FOR INTEGRATED RESOURCE PLANNING, WILL BE USED TO DETERMINE A LIST OF BIDS DEEMED AS THE FINAL SHORTLIST.

PacifiCorp intends to evaluate each bid received in a consistent manner by separately evaluating the non-price characteristics of the resource and the price characteristics. Each component will be evaluated separately and recombined to determine the bundled price and non-price score. The price factor will be weighted up to 80%, while the non-price factor will be weighted up to 20%. No proposal will receive a total weighting in excess of 100%. The price and non-price evaluation will be added together and used to determine the Initial Shortlist.

B. PRICE FACTOR EVALUATION (UP TO 80%)

PacifiCorp will utilize the RFP Base Model to screen the proposals and to evaluate and determine the price ranking.

The RFP Base Model is contained in a Microsoft Excel workbook that includes a number of proprietary Visual Basic macros, custom add-ins, and computational code written in C++.

RFP Base Model Inputs:
Market Quote Date: The model will pull corresponding forward price, volatilities, and correlation projections for electricity and fuel commodities. Treasury discount curves are also included. The same Market Quote Date will be used for all bids during each evaluation phase.

- Term: start and end date
- Transmission cost assumptions
- Rate base inputs, if applicable
- Point of delivery (POD) and Point of receipt (POR)
- Dispatch pattern
- Firm/unit contingent
- Resource type
- Product source

- Variable O&M payment ($/MWh)
- Variable O&M costs ($/MWh)
- Fixed energy payment ($/MWh, if applicable)
- Capacity charge ($/KW-mo, if applicable)
- Resource/POD availability by month
- Forward price curve multiplier by month
- Corporate financial inputs – inflation curve, WACC, etc.

Comparison Metric

The comparison metric will be the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The net PVRR component views the value of the energy and capacity as a positive, and the offsetting costs as negative. The more positive the net PVRR, the more valuable a given resource is to PacifiCorp's customers. The net PVRR/kW-mo metric is the annuity value which, when applied to the nominal kilowatts on a monthly basis and present-valued, will result in the same net PVRR as a straight NPV calculation.

Bid Cost Relative to Adjusted Price Curves	Price Factor Weighting
Less than or equal to 80% of adjusted price projections	80%
Greater than 80% of adjusted price projections but less than 140% of adjusted price curves	Linearly interpolated
Equal to or greater than 140% of the adjusted price projection	0%

C. NON-PRICE FACTORS (UP TO 20%)

The primary purpose of the non-price analysis is to help gauge the factors related to the proposal which are outside of price. A matrix will be established for each non-price factor and will be used to compare the bids with one another. Non-price factors will be weighted up to 20% (in combination with the price scores) in the determination of which proposals will be chosen for the Initial Shortlist. The non-price factor criteria are identified in Chart 4 below. Bids will be evaluated and scored in five discrete categories: (1) 100% of the percentage weight; (2) 75% of the percentage weight; (3) 50% of the percentage weight; (4) 25% of the percentage weight or (5) 0% of the percentage weight. Bids will be evaluated based on their ability to demonstrate the proposal is thorough, comprehensive and provides limited risk to PacifiCorp's customers prior to PacifiCorp performing due diligence on any given Bid. Bids which have a demonstrated track record or are mature proposals will be more highly evaluated. Chart 4 lists the key non-price criteria and the basis for weighting for each criterion. These Non-Price factors will be used in the evaluation of the Non-Price characteristics of the PPA or BOT proposals.

CHART 4 – NON-PRICE FACTORS

Non-Price Factor	Non-Price Factor Weighting
1) Conformity to RFP requirements - has the Bidder provided all the requirements pertaining to their proposals in **Appendix A, B, C-1, C-2, D and J**	4%
2) Conformity to pro forma PPA or BOT - has the Bidder required any additions or deletions that impose additional costs and or risks to customers. If any of the edits provided by the Bidder to the underlying agreements, PPA or BOT, shift or apply additional risks or costs to customers. If so, then the percentage will be adjusted. The percentage will not be adjusted if Bidders provide edits which either add value to customers or do not impose additional costs or shift risks to customers.	4%
3) Development and feasibility of proposal - Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstration of sufficient detail regarding the quality of their environmental compliance plan and any environmental impact of each proposal consistent with the proposed technology. Bids must demonstrate that the project can be reasonably developed within the appropriate timeframe to meet the proposed in service date and with limited risk to the customers. Bids which have achieved commercial operation will be awarded percentage weight consistent with the risk associated with each non-price category. For example, an existing project will be awarded 100% of the percentage weight associated with the Critical Path Schedule.	4%
4) Site control and permitting - Bidders must be able to 1) document they have obtained site control and necessary permits (maximum points in this category) or 2) demonstrate how site control and permits will be obtained. Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstration of sufficient detail on the status of permitting, and site control. Bids which can demonstrate little or no risk associated with these criteria will be more highly valued	4%
5) Operational Viability - Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstrate sufficient detail of their ability to comply with environmental permits and requirements and their operating experience with similar renewable projects and technology. Bidders should provide a description of the environmental management and compliance criterion for the renewable project and addresses the ability of such project, existing or to be constructed for a PPA or BOT, ability to meet all of the projects environmental compliance and permits. Second, Bidders should provide a description of any and all previous experience in operating and maintaining similar projects.	4%

Step 2 – IRP – Final Shortlist

The Company will use its current renewable energy resource valuation methodology for evaluating bids for inclusion in the Final Shortlist. This methodology, called the Alternative Compliance Cost (ACC) method, uses the Company's production cost simulation system and its Forward Price Curve to generate a market-based alternative comparison of the bid resources. In determining the alternative, the Company first runs the production cost simulation system (the Planning and Risk, or PaR model) in stochastic mode using the then-current IRP preferred portfolio. The PaR model is then run a second time with the uncommitted future Solar Resources removed from the

preferred portfolio. The resulting production costs from this second model run reflect the market-based energy costs incurred as a result of no longer adding Solar Resources to the IRP preferred portfolio. Next, other costs and benefits of the specific bid resource being considered are compared against the PaR model results. This comparison is in the form of a bid resource ACC value, which represents the resource cost, over the life of the project that yields a zero net PVRR difference with respect to the PaR model's market-based resource alternative. A negative ACC value, expressed on a dollar-per-MWh basis, indicates that the bid resource compares favorably to the market-based alternative, whereas a positive ACC value indicates that the bid resource compares unfavorably to the market-based alternative. The ACC value will also be examined on an "adjusted" basis with adjustments being made to account for (a) terminal value, (b) locational integration costs and (c) incremental capacity contribution. If the Final Shortlists have positive ACC values, the Company may perform additional analysis to assess the market value of renewable energy credits, compliance with RPS requirements, and potential regulations.

D. FINAL SELECTIONS; OTHER FACTORS

The two steps described above constitute the formal evaluation process and will lead to the compilation of the Final Shortlist of resources for further negotiation. After completing the formal evaluation process described above, but before making the final resource selections to be submitted for approval or acknowledgement, the Company will take into consideration certain other factors that are not expressly or adequately factored into the formal evaluation process, but that are required by applicable law or Commission order to be considered. In addition the Company may evaluate and include in its final finally and prudent costs associated with direct and or indirect debt directly related with the resource procurement consistent with the information outlined in Section 5(I) and (J).

SECTION 7. AWARDING OF CONTRACTS

A. INVITATION

This RFP is merely an invitation to make proposals to the Company. No proposal in and of itself shall constitute a binding contract. The Company may, in its sole and absolute discretion, perform any one or more of the following:

- Determine which proposals are eligible for consideration as proposals in response to this RFP.
- Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each Bidder.
- Disqualify proposals contemplating resources that do not meet the definition of Solar Resources in this RFP.
- Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
- Negotiate and request Bidders to amend any proposals.
- Select and enter into agreements with the Bidders who, in the Company's sole judgment, are most responsive to the RFP and whose proposals best satisfy the interest of the Company, its customers, and state legal and regulatory requirements, and not necessarily on the basis of any single factor alone.
- Issue additional subsequent solicitations for proposals.
- Reject any or all proposals in whole or in part.

- Vary any timetable.
- Conduct any briefing session or further RFP process on any terms and conditions.
- Withdraw any invitation to submit a response.

B. CONFIDENTIALITY AGREEMENT

All parties will be required to sign Confidentiality Agreements if they qualify for the Final Shortlist (**Appendix G**) prior to entering into negotiations with the Company.

C. NON-RELIANCE LETTER

All parties will be required to sign a non-reliance letter if they are qualify for the Final Shortlist (**Appendix H**) prior to entering into negotiations with the Company.

D. POST-BID NEGOTIATION

PacifiCorp will further negotiate both price and non-price factors during post-bid negotiations. PacifiCorp will also include in its evaluation any factor that may impact the total cost of a resource, including but not limited to all of the factors used in the Initial Shortlist cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable. Post-bid negotiation will be based on PacifiCorp's cost assessment. PacifiCorp will continually update its economic and risk evaluations until both parties execute a definitive agreement acceptable to PacifiCorp in its sole and absolute discretion.

PacifiCorp shall have no obligation to enter into any agreement with any Bidder to this RFP and PacifiCorp may terminate or modify this RFP at any time without liability or obligation to any Bidder. In addition, this RFP shall not be construed as preventing PacifiCorp from entering into any agreement that PacifiCorp deems prudent, in PacifiCorp's sole opinion, at any time before, during, or after this RFP process is complete. Finally, PacifiCorp reserves the right to negotiate only with those entities who propose transactions that PacifiCorp believes in its sole discretion to have a reasonable likelihood of being executed.

E. SUBSEQUENT REGULATORY ACTION

Unless mutually agreed between the parties or unless required by actual (or proposed) law or regulatory order, at the time of contract execution, PacifiCorp does not intend to include a contractual clause whereby PacifiCorp is allowed to adjust contract prices in the event that an entity who has regulatory jurisdiction over PacifiCorp does not fully recognize the contract prices in determining PacifiCorp's revenue requirement. As of the issuance date for this solicitation, PacifiCorp is unaware of any such actual law or regulatory order.

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/802
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Bruce W. Griswold

The 2010S Solar RFP Shortlist

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Preferred Transaction Structure

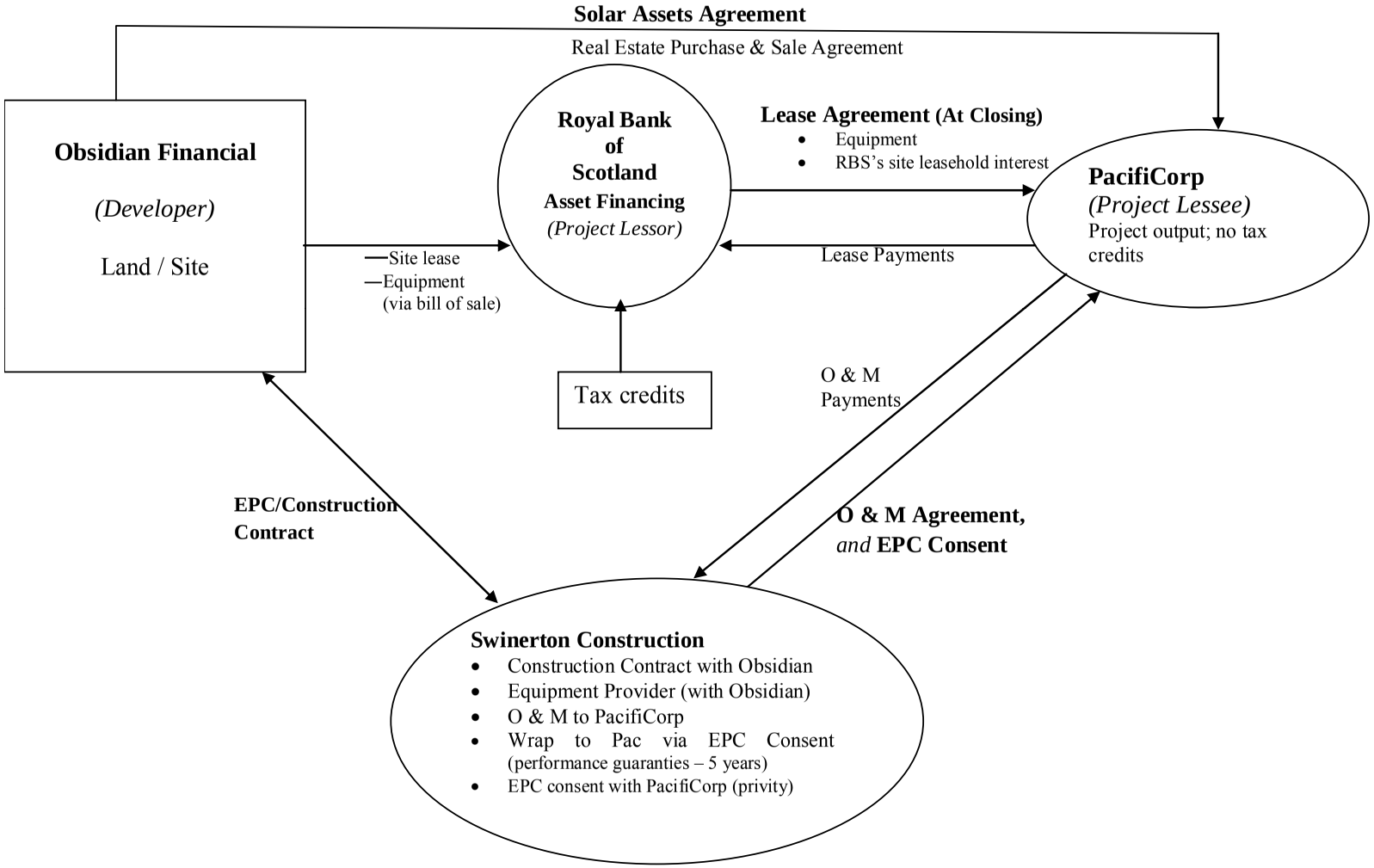

Exhibit PAC/803
Griswold/1

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/804
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Bruce W. Griswold

Economic Comparison of Alternatives

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

DIRECT TESTIMONY OF GREGORY N. DUVALL

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ATTACHED EXHIBITS

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

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

Qualifications

Q. Briefly describe your education and business experience.

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

Purpose and Summary of Testimony

Q. Please explain the purpose of your testimony.

A. My testimony addresses two subjects. In Section I, I explain how the Company developed the forecasts of the number of customers, kilowatt-hour sales at the meter ("sales"), system loads and system peak loads at the system input level ("loads"), and number of bills by rate schedule for the 12-month period ending, December 31, 2013. In Section II, I describe PacifiCorp's proposed Power Cost

Adjustment Mechanism ("PCAM"), including the need for a mechanism, costs that would be recovered by the mechanism, and how the proposed mechanism would be administered.

SECTION I – 2013 SALES AND LOAD FORECAST

Overview

Q. How is this section of your testimony organized?

A. First, I provide a general overview of the Company's 2013 sales and load forecast. Next, I compare this forecast to 2011 actual sales, the forecast used in the last Oregon general rate case, Docket UE 217 ("2010 GRC"), and the forecast used in the last Transition Adjustment Mechanism ("TAM"), Docket UE 227 ("2012 TAM"). I make these comparisons on a total Company and Oregon basis and discuss the results. Finally, I explain the details of the sales and load forecast methodology used to prepare the calendar year ("CY") 2013 forecast.

Q. How did the Company utilize the sales and load forecast in this filing and in the Company's concurrent 2013 TAM filing?

A. The 2013 load forecast was used to calculate net power costs in the 2013 TAM filing. The load forecast was also used by Company witness Mr. R. Bryce Dalley to calculate the jurisdictional allocation factors. The sales forecast by rate schedule was used by Company witnesses Mr. C. Craig Paice and Mr. William R. Griffith to allocate costs between customer classes and to design rates that correctly reflect the cost of service, respectively.

Q. Does this forecast employ the same methodology as presented to the Oregon Public Utility Commission in the 2010 GRC and 2012 TAM?

A. Yes. The updates to data and assumptions are detailed below.

Q. Please provide a general overview of the Company's sales and load forecast methodology.

A. In summary, this methodology consists of first developing a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, meaning kWh sales levels are grossed-up to a generation or "input" level. The monthly loads are then spread to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

Q. Please explain how the Company measures its sales and loads in its 2013 forecast.

A. Sales are measured at the customer meter and are forecast by customer class and by rate schedule. Loads are measured at system input and are forecast by jurisdiction. The difference between the sales and load forecast are system losses.

Q. Please provide a summary of the forecasted energy sales for 2013.

A. Table 1 provides the forecasted energy sales for the 2013 test period.

Table 1 - Test Period Sales Forecast (MWh)

	January 2013 to December 2013	
	Total Company	Oregon
Residential	15,866,151	5,403,215
Commercial	17,166,799	5,165,190
Industrial	20,363,476	2,274,055
Irrigation	1,214,725	217,560
Public Authority	406,610	-
Lighting	141,670	37,720
Total	55,159,430	13,097,740

Comparisons to Actual Sales and Prior Sales Forecasts

Q. On a total Company basis, how does the sales forecast for 2013 compare to actual, weather normalized MWh sales for the 12 months ended December 31, 2011?

A. Table 2 shows that the total Company sales forecast for 2013 is expected to exceed actual, weather normalized sales in 2011 by 1.6 percent. The majority of this growth (64 percent) is caused by sales to the commercial class. This reflects the addition and expansion of large data centers in Utah and Oregon, some of which are already operational.

Table 2 - Total Company Sales Comparison (MWh)

	2011 Actual	2012 GRC (CY 2013)	Percentage Change
Residential	15,872,865	15,866,151	0.0%
Commercial	16,619,000	17,166,799	3.3%
Industrial	20,057,428	20,363,476	1.5%
Irrigation	1,206,742	1,214,725	0.7%
Public Authority	401,860	406,610	1.2%
Lighting	144,334	141,670	-1.8%
Total	54,302,229	55,159,430	1.6%

Q. How does the Oregon sales forecast for 2013 compare to the actual, weather normalized MWh sales for the 12 months ended December 31, 2011?

A. Table 3 shows that Oregon test year sales are expected to exceed the weather-normalized sales in 2011 by 1.0 percent. Expected growth in sales to the commercial class accounts for 79 percent of the change, which reflects the expansion of a large data center in Oregon.

Table 3 - Oregon Sales Comparison (MWh)

	2011 Actual	2012 GRC (CY 2013)	Percentage Change
Residential	5,428,075	5,403,215	-0.5%
Commercial	5,065,481	5,165,190	2.0%
Industrial	2,228,424	2,274,055	2.0%
Irrigation	211,253	217,560	3.0%
Lighting	37,903	37,720	-0.5%
Total	12,971,136	13,097,740	1.0%

Q. Please describe the sales forecasts used in the Company's 2010 GRC, and the Company's 2012 TAM filing.

A. The 2011 sales forecast used in the 2010 GRC was prepared in October 2009. The 2012 sales forecast used in the Company's 2012 TAM filing was prepared in July 2011. The July 2011 forecast updated the sales forecast originally used in the 2012 TAM filing, which was prepared in November 2010.

Q. How does the total Company sales forecast for 2013 compare to the sales forecast for the 2010 GRC?

A. As shown in Table 4, total Company forecast sales for 2013 are 3.8 percent higher than the 2011 sales forecast used in the 2010 GRC. The difference in the forecasts is attributable to growth in the commercial and industrial classes. The growth in the commercial class is related to data centers. For the industrial class, additional growth is attributable to recovery by existing large industrial customers and an updated outlook for new loads by customers in the extractive industry in Utah and Wyoming. The growth in industrial sales is offset in part by a loss in sales from some industrial customers opting to use their on-site generation to serve their own load rather than sell the output of their generation to the Company.

Table 4 - Total Company Sales Comparison (MWh)

	2010 GRC (CY 2011)	2012 GRC (CY 2013)	Percentage Change
Residential	15,733,922	15,866,151	0.8%
Commercial	16,398,542	17,166,799	4.7%
Industrial	19,082,896	20,363,476	6.7%
Irrigation	1,357,020	1,214,725	-10.5%
Public Authority	438,660	406,610	-7.3%
Lighting	141,480	141,670	0.1%
Total	53,152,520	55,159,430	3.8%

Q. How does the Oregon sales forecast for 2013 compare to the sales forecast for 2011 used in the 2010 GRC?

A. As shown in Table 5, the Oregon sales forecast has increased by about 2.5 percent from the forecast used in the 2010 GRC. On an Oregon basis, almost all of this difference (86 percent) is attributable to sales to the commercial class and reflects the planned expansion of a large data center in Oregon.

Table 5 - Oregon Sales Comparison (MWh)

	2010 GRC (CY 2011)	2012 GRC (CY 2013)	Percentage Change
Residential	5,309,420	5,403,215	1.8%
Commercial	4,886,460	5,165,190	5.7%
Industrial	2,256,190	2,274,055	0.8%
Irrigation	285,110	217,560	-23.7%
Lighting	37,480	37,720	0.6%
Total	12,774,660	13,097,740	2.5%

Q. How does the total Company sales forecast for 2013 compare to the final sales forecast for 2012 used in the 2012 TAM?

A. Total Company sales have decreased by 0.6 percent for 2013 as compared to the final forecast used in the 2012 TAM for CY 2012, as shown in Table 6. The variance is driven by the following factors: (a) lower forecasted residential sales due to slower than expected economic recovery; (b) lower forecasted commercial sales due to lower residential growth and slippage in the timing of expected load

increases at data centers; and (c) higher industrial sales due to forecasted new loads in the oil and gas extraction sector. As previously noted, the growth in industrial sales is offset in part by a loss in sales from some industrial customers opting to use their on-site generation to serve their own load.

Table 6 - Total Company Sales Comparison (MWh)

	2012 TAM (CY2012)	2012 GRC (CY 2013)	Percentage Change
Residential	16,226,907	15,866,151	-2.2%
Commercial	17,208,915	17,166,799	-0.2%
Industrial	20,224,680	20,363,476	0.7%
Irrigation	1,247,329	1,214,725	-2.6%
Public Authority	432,710	406,610	-6.0%
Lighting	141,100	141,670	0.4%
Total	55,481,640	55,159,430	-0.6%

Q. How does the Oregon sales forecast for 2013 compare to the final sales forecast used in the 2012 TAM?

A. As shown in Table 7, the Oregon sales forecast has decreased by about 2.5 percent from the final forecast used in the 2012 TAM. The residential class causes 56 percent of this decrease, with the commercial and industrial classes each causing about 20 percent of the decrease. The reasons for the decreases in the Oregon sales forecast between the 2012 TAM and the 2013 GRC are generally the same as those discussed in the total Company comparison above.

Table 7 - Oregon Sales Comparison (MWh)

	2012 TAM (CY2012)	2012 GRC (CY 2013)	Percentage Change
Residential	5,590,592	5,403,215	-3.4%
Commercial	5,233,670	5,165,190	-1.3%
Industrial	2,338,417	2,274,055	-2.8%
Irrigation	235,770	217,560	-7.7%
Lighting	36,920	37,720	2.2%
Total	13,435,370	13,097,740	-2.5%

Q. What do you conclude from all of the comparisons in Tables 2-7?

A. Demand volatility associated with recent economic issues is reflected in the Company's sales forecasts over the last several years. The 2013 sales forecast is higher than both the Company's actual 2011 weather-adjusted sales and the forecasted 2011 sales in the 2010 GRC, primarily reflecting strong sales growth in the commercial class. However, the 2013 forecast is lower than the Company's 2012 forecast used in the 2012 TAM, primarily reflecting sales declines in the residential class. In summary, the 2013 forecast reflects overall year-to-year sales growth from 2011, albeit at a more moderated pace than that reflected in the Company's CY 2012 forecast in the 2012 TAM.

Forecast Methodology

Q. What aspects of the sales and load forecast methodology do you address?

A. First, I describe the updates to the data and assumptions used to produce the sales and load forecasts. Second, I describe the forecasting approach used to develop monthly sales for the residential, commercial, irrigation, and lighting customer classes, followed by a description of the forecasting approach for the industrial customer class. Third, I describe how the hourly load forecast is developed. Fourth, I describe how the forecast by rate schedule for sales and number of bills are developed.

Summary of Changes in Forecast Data and Assumptions

Q. Please summarize major updates used to produce the 2013 forecast as compared to the forecast used in the 2010 GRC.

A. The Company updated many of its data inputs and assumptions compared to the

forecast prepared for the 2010 GRC (October 2009 forecast). For each of these updates, the Company used the most recent information available.

1. The Company expanded the historical data period used to develop the monthly retail sales forecasts by adding 24 months of retail sales data (August 2009 through July 2011) to the existing data. The historical data period used to develop the model-driven portion of industrial monthly sales is from January 2002 through July 2011.
2. The Company expanded the historical data period used to develop the monthly peak forecasts to include January 1997 through December 2010.
3. The Company updated the economic drivers from IHS Global Insight using the most recent information available for each of the Company's jurisdictions.
4. The Company updated the forecast of individual industrial customer usage based on the best information available as of August 2011.
5. The time period used to define normal weather was rolled forward to the 20-year time period of 1991-2010.
6. The Company rolled forward the line loss calculation to the five-year period ended December 2010.
7. The data used to develop temperature splines was rolled forward based on available customer class hourly data (2006-2010).
8. The Company updated the residential use-per-customer-per-day model with appliance saturation and efficiency results released in June 2010.

Forecasts for Non-Industrial Customer Classes

Q. How are monthly sales forecasts developed by customer class?

A. The Company develops monthly sales forecasts as a product of two separate forecasts: (1) the number of customers; and (2) sales per customer. The Company uses this methodology for residential and commercial customer classes.

Q. How are the forecasts for number of customers developed?

A. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of number of households as the major driver. For the commercial class, the Company forecasts the number of customers using the forecasted number of residential customers as the major economic driver. For the industrial, irrigation and street lighting classes, the customer forecasts are fairly static and developed using time series or regression models without any economic drivers.

Q. How does the Company forecast sales per customer for each customer class?

A. The Company models sales per customer for the residential class through a Statistically Adjusted End-use ("SAE") model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

For the commercial class, the Company forecasts sales per customer using regression analysis techniques with non-manufacturing employment used as the major economic driver in addition to weather-related variables.

As already described, the sales forecast for the residential and commercial classes is the product of the number-of-customer forecast and the use-per-customer forecast. The development of the forecast of monthly commercial sales involves an additional step. To reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Customer Account Managers ("CAMs"). Although the scale is much smaller, the treatment of large commercial additions is similar to the methodology for industrial sales which is discussed below.

Monthly sales for irrigation and lighting are forecasted directly from historical sales volumes, not as a product of the use-per-customer and number of customers.

Industrial Class Forecasts

Q. How does the Company forecast sales for the industrial customer class?

A. The industrial customers are separated into three categories: (1) existing customers that are tracked by the CAMs; (2) new large customers or expansions by existing large customers; and (3) industrial customers that are not monitored by the CAMs. Customers are tracked by the CAMs if they have a peak load of one megawatt or more at a single site.

The Company develops the forecast for the first two categories through the data gathered by the CAM assigned to each customer. The CAMs have ongoing direct contact with large customers and are in the best position to know about any customer plans for changes in business processes that might change their energy consumption.

The Company develops the portion of the industrial forecast related to new large customers and expansion by existing large customers based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Smaller industrial customers (under one megawatt) are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver.

The Company develops the total industrial sales forecast by aggregating the forecast for the three industrial customer categories.

Q. Why does the Company forecast industrial sales using a different methodology than the other customer classes?

A. The Company forecasts this class differently because of the diverse makeup of the customers within the class. In the industrial class, there are no "typical" customers. Large customers have very diverse usage patterns and power requirements. In contrast, customer classes that are made up of mostly smaller, homogeneous customers are best forecasted by multiplying use per customer by the number of customers. Those customer classes are generally composed of many smaller customers that have similar behaviors and usage patterns. This difference is the reason for using a different approach for forecasting sales to industrial customers.

Hourly Load Forecast

Q. Please outline how the hourly load forecast is developed.

A. After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps.

First, monthly and seasonal peak forecasts for each state are developed. The monthly peak model uses historical peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. These weather variables include the average temperature on the peak day and lagged average temperatures. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period 1991-2010.

Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly and seasonal peaks from the first step above. Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Forecasts by Rate Schedule

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, Mr. Griffith and Mr. Paice require two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to

individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. The Company develops this forecast in two steps. First, the Company forecasts test year sales by rate schedule. Then the Company proportionally adjusts the rate schedule sales forecasts so that the total matches the customer class forecast.

Q. How does the Company forecast the number of bills for each rate schedule?

A. The forecast of the number of bills for each rate schedule follows the same process as the sales forecast for each rate schedule. First, the Company forecasts the number of bills by class and by rate schedule. Then, the Company proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills matches the customer class forecasted number of bills.

SECTION II – PACIFICORP'S OREGON PCAM PROPOSAL

Q. Please briefly describe the Company's proposed PCAM.

A. The proposed PCAM is a rate mechanism designed to allow the Company to collect or credit the differences between the actual net power costs ("NPC") incurred to serve Oregon customers and the amount of NPC collected from Oregon customers through rate in the TAM. On a monthly basis, the Company will compare the actual system net power costs ("Actual NPC") to the net power costs embedded in rates ("Base NPC"), and defer the differences in a balancing account. A PCAM rate will be calculated annually to collect from or credit to customers the accumulated balance over the subsequent year. The Company proposes to implement the PCAM to recover 2013 Actual NPC, with the first

PCAM reconciliation filing in May 2014.

The PCAM is designed to operate with the Company's current TAM, an annual filing to set Base NPC and determine the direct access transition adjustments, and the Renewable Adjustment Mechanism ("RAC"), a periodic filing designed to allow timely recovery of the fixed costs of renewable resources in rates.

Need for the Proposed PCAM

Q. Why is the Company proposing a PCAM?

A. The Company's NPC represent a large proportion of the Company's total revenue requirement. NPC are subject to a high degree of volatility largely outside of the Company's control; this volatility is increasing due to the high volume of wind generation on the Company's system. The Company is entitled to recover its prudently incurred costs both under general regulatory principles and under the specific provisions of Oregon's renewable portfolio standard ("RPS"), Senate Bill 838 ("SB 838"), which mandate recovery of the prudent costs of compliance, including the variable NPC impacts associated with integrating, firming, and shaping renewable energy sources. SB 838 specifically contemplates the use of an automatic adjustment mechanism, like a PCAM, to ensure timely and full recovery of prudent costs. As explained below, neither the Company's TAM nor its RAC currently provide for timely and full recovery of these costs.

Q. Why is the Company proposing a PCAM now, five years after the enactment of SB 838 in 2007?

A. There are two primary reasons. First, PacifiCorp now has significantly more

renewable resources in its generation portfolio than it did in 2007.

Second, a year prior to the enactment of SB 838, the Commission adopted PacifiCorp's TAM. Because the TAM permitted PacifiCorp to update its NPC forecast on an annual basis through a stream lined process, PacifiCorp expected that the TAM would result in rates that, over time, reflected PacifiCorp's actual NPC, including the variable costs of integrating, firming, and shaping renewable resources. In each of the five years since the passage of SB 838, however, the Company has significantly under-recovered its NPC through the TAM. The TAM has also proven to be more adversarial than anticipated, with significant controversies each year over NPC modeling and cost forecasts.

Q. What is the level of PacifiCorp's actual NPC as compared to NPC recovered in Oregon rates since the passage of SB 838?

A. Table 8 shows the Company's actual NPC for 2007 through 2011 and demonstrates that PacifiCorp has under-recovered more than a half billion in system NPC over the last five years.

Table 8

PacifiCorp NPC in Rates vs. Actual (000's)						
	2007 UE 179	**2008 UE 191**	**2009 UE 199**	**2010 UE 207**	**2011 UE 216**	
Initial Filing	$863,120	$1,004,083	$1,128,537	$1,100,534	$1,278,250	
Final Update	$874,951	$987,823	$1,134,565	$1,092,321	$1,288,694	
In Rates	$832,829	$980,211	$1,043,323	$1,028,768	$1,236,957	**Cumulative Total**
Actual NPC	$974,552	$1,120,616	$1,021,881	$1,149,945	$1,388,253	
Difference from In Rates*	$111,932	$120,863	$31,109	$137,109	$135,233	$536,245

*Difference from in rates is calculated based on the $/MWh difference between in-rates and actual NPC times the actual load.

Q. Why has the Company under-recovered such a high level of NPC over the last five years?

A. The Company's actual operations do not have the same certainty and perfect foresight as the Company's dispatch model used to estimate NPC in rates, which will always operate the system in an optimal manner without taking into account the realities of real-time system operation. While this is not a new issue, the addition of large amounts of wind generation has increased the gap between the costs captured in modeled and normalized NPC and the NPC that the Company actually experiences. In addition, to minimize the adversarial nature of the TAM, the Company has historically agreed to settle the TAM at NPC levels that have consistently understated the Company's actual costs.

Q. How is the variability of wind generation different than the variability created by changes in hydroelectric generation or loads?

A. Wind generation is intermittent or sporadic. Load, hydroelectric generation, and thermal generation all have some form of unexpected variability, but they are not intermittent or sporadic. Wind has no rational pattern due to its intermittency, and therefore creates a much more complex modeling challenge for the Company as compared to modeling the variability of hydroelectric resources and loads, which have a relatively more predictable pattern than wind generation. This is especially true when the TAM locks down assumptions on wind generation levels and hourly patterns eight to nine months prior to the beginning of the test year and 20 to 21 months prior to the last month of the test year. As a result, adding a significant amount of intermittent resources to the Company's system that will

allow it to comply with Oregon law lessens the Company's ability to produce reliable forecasts of NPC.

Q. Does the Company believe that using a different dispatch model or changing the model's input assumptions would allow it to more accurately forecast NPC?

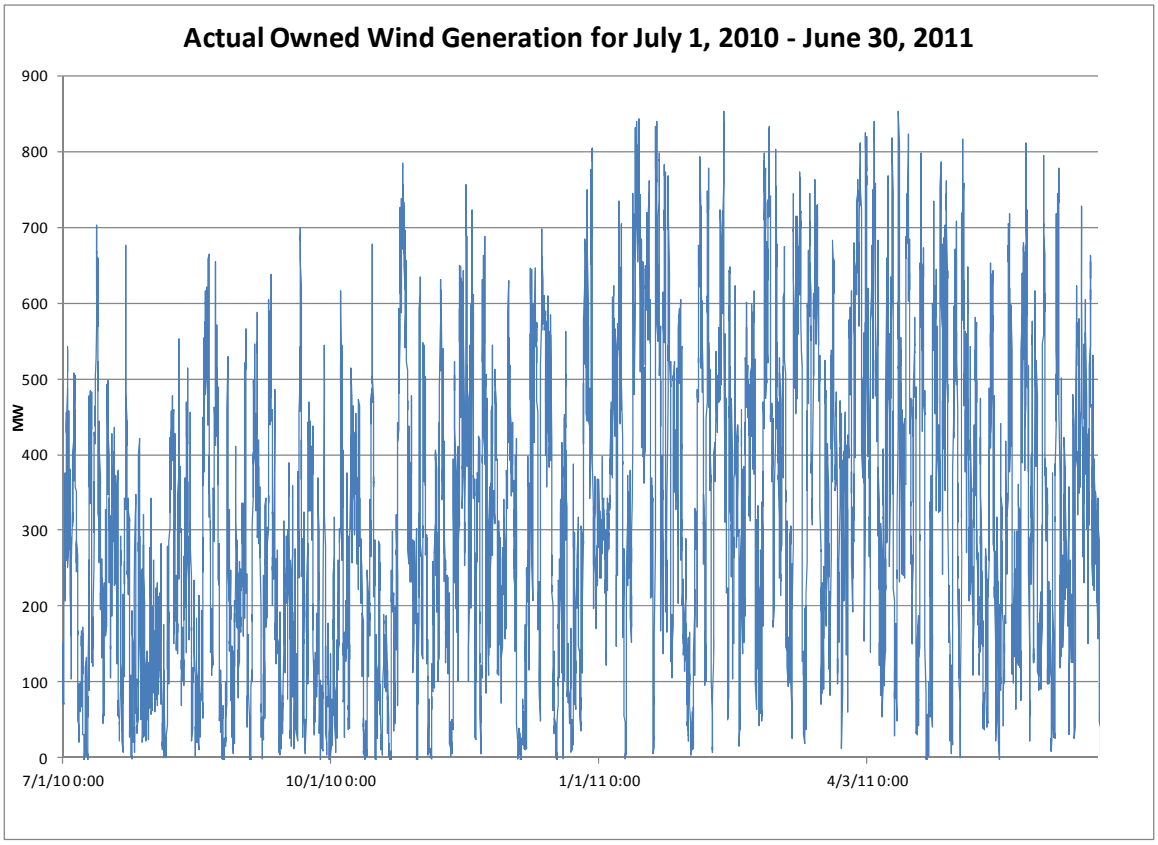
A. No. The inputs the Company uses for the NPC study from its Generation and Regulation Initiative Decision ("GRID") model are based on the best information the Company has at the time it creates a forecast of NPC. GRID reasonably simulates the operation of the Company's system consistent with this information and the optimization logic that is built into GRID. However, there is simply no way to perfectly forecast the changing variables and constraints that the Company experiences on a real-time basis, especially after the introduction of large amounts of wind resources into the Company's resource portfolio. This problem would exist regardless of which dispatch model the Company used to forecast NPC.

Q. Since the TAM uses a forecast test year and is filed annually, why is it necessary for the Company to also have a PCAM?

A. The TAM, by itself, can no longer adequately capture the costs associated with the increasing volatility on the Company's system. More specifically, the Company has seen an increase in wind generation on its system from 135 MW in 2006, just prior to the passage of SB 838, to over 2,375 MW at the end of 2011. The Company now projects wind generation on its system to grow to over 3,350 MW by 2025, not including additional Qualifying Facility ("QF") contracts. The 2,375 MW of wind on the Company's system directly impacts the day-to-day

system operations of the Company's existing fleet of thermal and hydro facilities (approximately 10,000 MW). To illustrate the volatility that a wind facility introduces to the Company's system, Table 9 below shows the hourly generation of a group of the Company's owned wind resources (approximately 900 MW) for the 12 months ending June 30, 2011.

Table 9

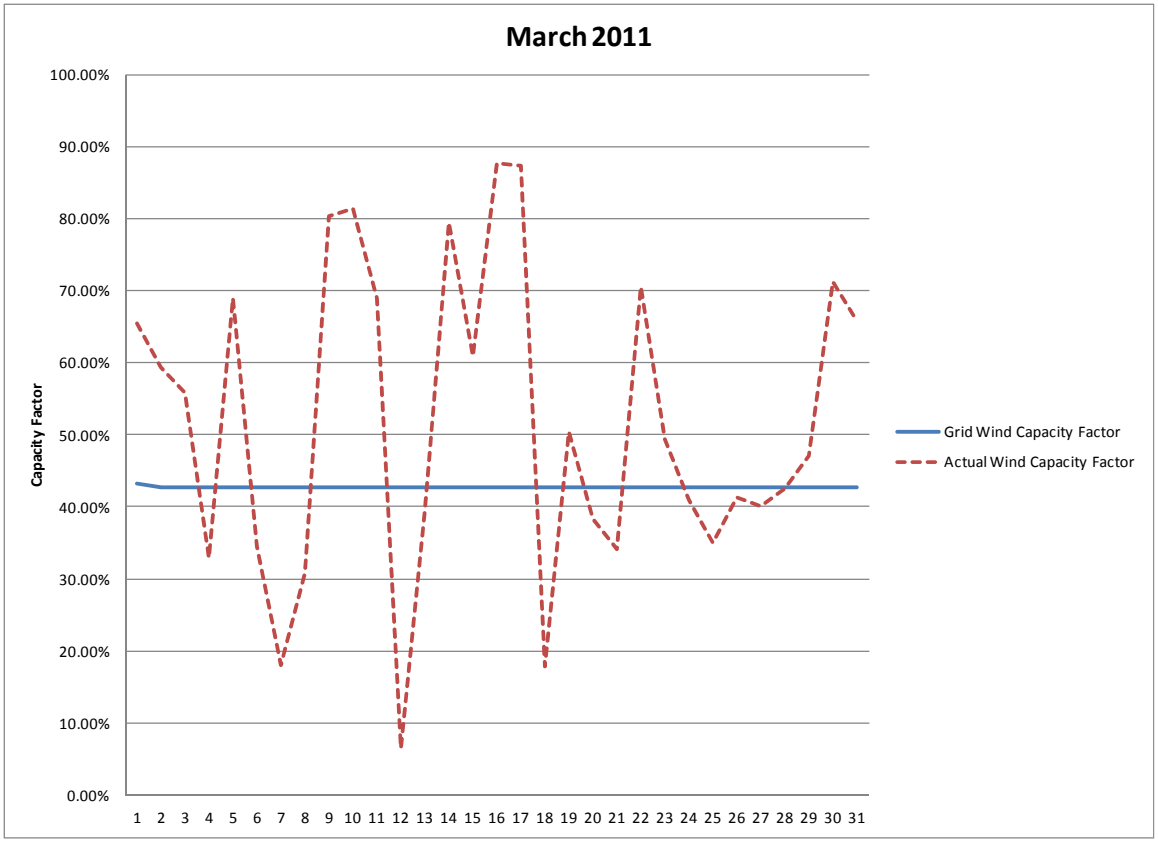


Q. Does the Company model wind generation in its TAM proceedings?

A. Yes. Using the GRID model, the Company models the generation of its wind facilities in four-hour blocks uniformly over the forecasted test period. This does not capture the operational volatility of these facilities, as demonstrated in Table 10 below, which shows the actual capacity factor of the Wyoming wind resources Glenrock (99 MW), Glenrock III (39 MW), Seven Mile Hill (99 MW), Seven

Mile Hill II (19.5 MW), Dunlap (111 MW), and Top of the World (200.2) compared to the GRID modeling of the six resources (568 MW).

Table 10



Q. Why does the Company model wind as a flattened product in its TAM proceedings?

A. The wind variability illustrated above cannot be reliably forecast. In other words, including a wind profile that varies from hour-to-hour is just as likely to be incorrect as an expectation that the wind facility would produce 40 percent of its generation in every hour of the month. In addition, power cost models are perfect foresight models, and the operation of the Company's system on a real-time basis cannot match the effectiveness of GRID and its ability to dispatch with 100 percent assurance that prices, load, and wind will be exactly what it expects them

to be the next day and the next hour for all 8,760 hours of the forecast year. Even if the Company were to include an actual generation profile of wind from the prior year, the GRID model would have perfect foresight of the energy within each hour and would optimize the dispatch accordingly without any error. The model would not capture the true costs associated with variable generation, including changes in market prices due to wind volatility, and the actions the Company must take to balance the system in real time without perfect foresight.

Q. The Company includes wind integration costs in its TAM filing. Are these costs representative of the total impact that wind has on the Company's system on a real-time basis?

A. No. The forecast wind integration costs are included in the TAM due to the fact that GRID is an hourly dispatch model and cannot take into consideration the intra-hour variations of wind on a real-time basis.[1] These charges do not adequately capture the multi-dimensional cost impacts associated with integrating large amounts of wind resources.

Q. In its current wind integration cost modeling, does the Company take into consideration the costs associated with ramping down a unit in its modeling of reserves for wind in the GRID model?

A. No. The Company models only the up reserves, or those reserves that are required to balance the system if the wind does not generate as compared to forecast or declines rapidly within the hour.

[1] The Company also includes a fixed cost inter-hour wind integration cost component to capture the day-ahead costs of scheduling and planning errors associated with expected dispatch errors of the Company's thermal generation units.

Q. Will the actual cost of holding reserves for intra-hour wind variations differ from what the Company models within GRID?

A. Yes. The Company includes an average level of reserves in the TAM that are held in each hour to take into consideration the different level of reserves that are required on a real-time basis for regulating and following wind facilities. By normalizing the cost of the additional intra-hour reserves across every hour of the year, there is the potential to under- or over-forecast the costs associated with holding these reserves on a real-time basis. In addition, as stated previously, GRID is a perfect foresight model and will hold reserves in the most cost effective manner for what it forecasts will occur. In real time, the Company strives to operate the system in the most cost effective manner, but the actual cost of reserves will vary with current market conditions and system constraints.

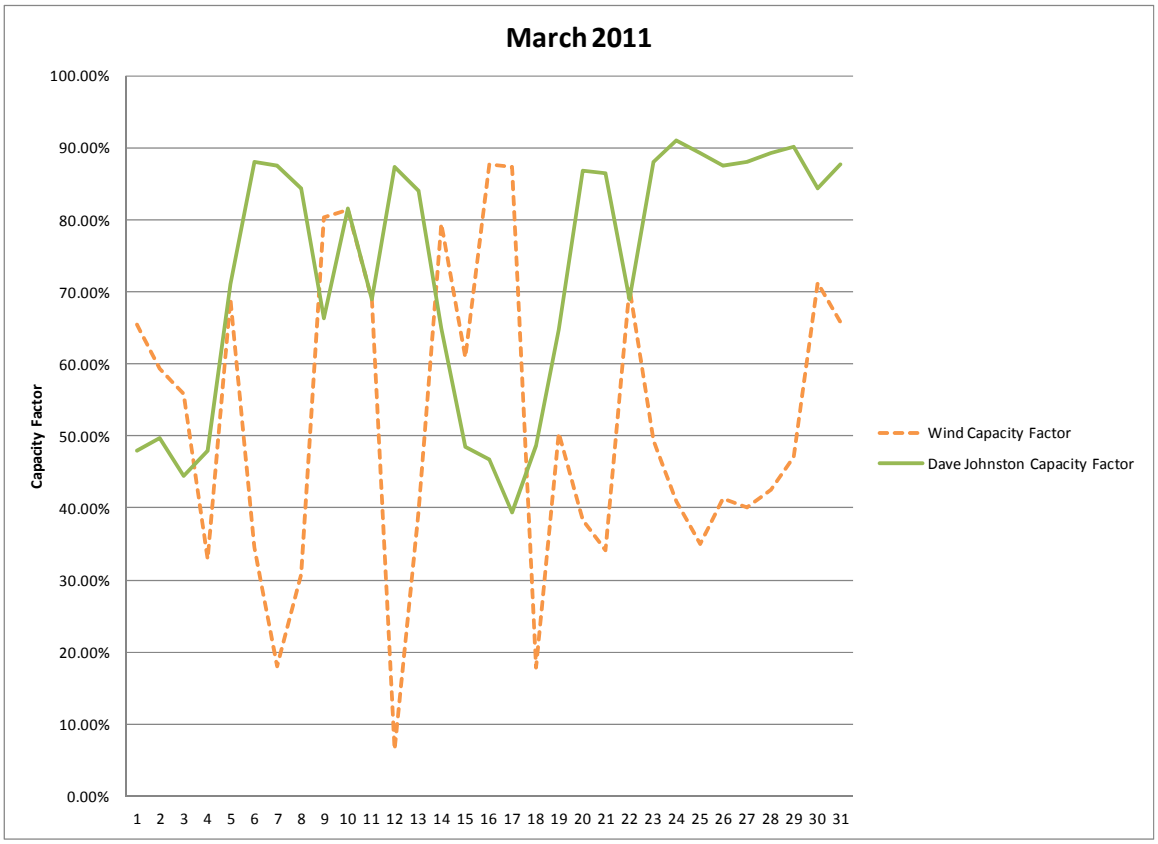
Q. Has the Company experienced a change in the operation of its coal-fired units due to the addition of wind on its system?

A. Yes. The operation of the Company's coal-fired units reflects the increased penetration of wind in eastern Wyoming,[2] and the transmission constraints that now occur when wind generates and there is no corresponding Wyoming load within the area. When the wind generates in eastern Wyoming during times of low load, the Company at times is required to ramp up or down its coal units in response to the changes in wind or its ability to make wholesale sales. Table 11 below illustrates the changes in the Company's wind generation in eastern

[2] The transmission constraints in eastern Wyoming are a function of not only the additional wind facilities that PacifiCorp has built or contracted for, but also the overall penetration of wind in that area from all wind developers and the development of new thermal generation.

Wyoming in March 2011, specifically Glenrock, Glenrock III, Seven Mile Hill, Seven Mile Hill II, Top of the World and Dunlap (568 MW), and the Company's response to the changing output of wind using the Dave Johnston coal-fired units 1-4 (758 MW).

Table 11



Q. Why do changes in the Company's actual coal generation that are directly related to the Company's wind generation cause actual NPC to be higher than forecasted NPC?

A. Coal is a relatively low cost resource, and when GRID optimizes the system, coal dispatches based on the marginal cost of each resource. GRID will typically not displace coal when wind resources are expected to generate; instead, it will displace a higher cost resource. Therefore, since GRID will always displace the

highest cost resource with the expected wind generation, the GRID model will invariably over predict the dispatch benefit of wind on a modeled basis reflecting an overall lower forecasted NPC. Table 12 below shows the capacity factors in March 2011 of the same GRID modeled eastern wind resources and GRID modeled Dave Johnston units 1-4, which is very different from the actual eastern wind and actual Dave Johnston units 1-4 demonstrated in Table 11.

Table 12

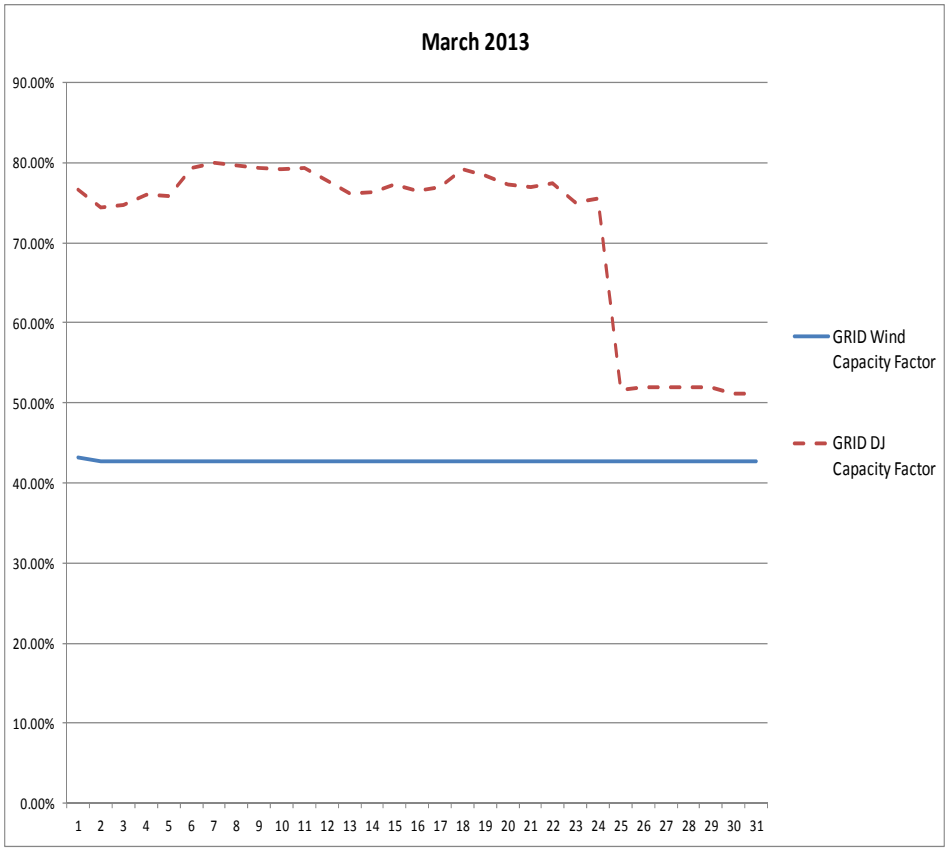


Table 12 shows that the GRID model does not capture the variations in wind nor does it capture the changes in coal generation as a result of actual wind generation.[3]

[3] The drop in expected coal generation in the GRID model line is due to a planned outage within the GRID model for Dave Johnston unit 4 in the 2013 GRID study.

Q. Are market prices also impacted by changes in wind generation?

A. Yes. When the wind generates, it affects a geographic region that is typically populated by numerous wind developers in one concentrated area, such as the Columbia River Gorge or eastern Wyoming. Similar to the price effect that excess hydro has in the wholesale market in the spring run-off period, wind also has a downward impact on market prices when all wind facilities are producing power simultaneously. The negative price impact[4] that wind has affects the overall wholesale sales revenue the Company is able to realize. Similarly, when wind is scheduled for the following day and it does not materialize, the price impact is the opposite, and the Company is in a position where it will incur higher wholesale purchase prices as the market reacts to changes in expected generation and the region's continued need to serve retail load.

Q. Does the Company's forward price curve take into consideration the impact that wind can have on actual market prices?

A. No. The Company's last update in the TAM filing is mid-November. The official forward price curve used at that time cannot take into consideration unexpected changes in wind over the course of the forecast test year.

[4] Wholesale market prices are a function of the marginal cost of the resources used to generate those sales in the market. Wind is a zero-cost resource, or lower if production tax credits and renewable energy credit sales are also taken into consideration. Therefore, all else held constant, when wind is generating it displaces the higher cost resources and lowers the overall marginal cost of producing power, thus lowering the wholesale market price.

Q. Is the Company able to isolate and quantify the precise impact of its renewable resources (wind, low-impact hydro, and solar), on its actual NPC as compared to the forecast NPC?

A. No. The operation of the Company's system on a real-time basis takes into consideration the operational conditions at the time, such as weather, load, market prices, transmission constraints, and thermal and transmission outages. A modeled redispatch of the Company's system cannot reasonably simulate what would have occurred if wind, low-impact hydro, or solar were not present in real-time. Attempting to model what might have occurred would again use a perfect foresight model and would model the wind and the Company's resources similar to how it is shown in Table 12 above. In addition, market prices would have been different than what occurred on a real-time basis due to the lack of electricity in the market generated by zero cost resources.

Relevant Provisions and Implementation of SB 838

Q. When the Oregon Legislature enacted SB 838 requiring the Company to comply with an RPS, did it allow the Company to recover its compliance costs?

A. Yes. Section 13 of SB 838, Cost Recovery by Electric Companies, codified at ORS 469A.120(1), specifically allows the Company to recover in rates all prudently incurred costs associated with compliance with the RPS, including "costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs

and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers."

Q. Did SB 838 define the meaning of the terms "integrate, firm or shape" as used in Section 13?

A. No. Similarly, the Commission's RPS implementation rules do not contain a definition of these terms. In this testimony, I use these terms consistently with their ordinary usage to refer to the actions the Company must take on a real-time basis to balance its system to address large amounts of new intermittent renewable resources.

Q. Did SB 838 specify the type of mechanism by which the Company could timely recover its prudently incurred compliance costs?

A. Yes. ORS 469A.120(3) provides that the Commission shall establish an automatic adjustment clause, or another method, that allows for the timely recovery of prudent costs.

Q. To implement SB 838, did the Commission establish an automatic adjustment clause that recovers the construction and acquisition costs of renewable resources?

A. Yes. The Commission established the RAC in Docket UM 1330, Order No. 07-572, which allows the Company to recover:

- The return of and on capital costs of the renewable energy source and associated transmission;
- Forecasted operation and maintenance costs;
- Forecasted property taxes;

- Forecasted energy tax credits; and
- Other forecasted costs and cost offsets authorized by SB 838 and not captured in the utility annual power cost update.[5]

Q. Does the RAC mechanism account for the NPC impact of renewable generation?

A. No. In 2007, when the Company entered into a stipulation on the RAC mechanism, it hoped that the annual TAM filing would allow for timely recovery of the NPC impact of its renewable generation resources. At that time, however, the Company's wind resource portfolio was a fraction of its current size, and the Company had limited experience integrating, shaping, and firming a large amount of wind resources into its system.

Q. Does the Company continue to believe that the TAM alone is an adequate mechanism for recovery of its prudently incurred costs associated with complying with SB 838?

A. No. As demonstrated in Table 8 above, in every year since the passage of SB 838 in 2007, the Company has significantly under recovered its NPC. The Company now believes that in addition to the TAM, a PCAM is necessary in order for the Company to recover its prudently incurred costs associated with complying with SB 838. The need for the PCAM is underscored by the fact that SB 838 increases the Company's renewable energy requirements to 25 percent of retail load in 2025.

[5] *See* Order No. 07-572 at 3.

Design of the Proposed PCAM

Q. Please describe the type of PCAM the Company is proposing in order to recover its prudently incurred NPC.

A. The Company proposes a PCAM under ORS 757.210(1) and ORS 469A.120(1) that is consistent with the design of the RAC mechanism the Commission adopted in Order No. 07-572. The mechanism would provide dollar-for-dollar recovery of prudent NPC and would not use sharing bands, deadbands, or an earnings review.

Q. How would the PCAM operate with the Company's current TAM and RAC mechanisms?

A. The Company would file the PCAM annually to collect or refund the difference between Base NPC, as set by the annual TAM filing, and Actual NPC. The Company would also continue to use the RAC to recover non-NPC-related costs of SB 838 compliance.

Q. How would customers benefit from a PCAM in the form that the Company has proposed?

A. Customers will benefit from the Company's proposed PCAM in the following manner:

- It will provide a more streamlined regulatory process focusing on the accuracy of the calculations and the prudence of the Company's NPC, rather than modeling issues, as been the case in TAM proceedings;
- It will provide a balanced outcome between the Company and its customers in the event of under- or over-recovery;
- Customers will pay the costs and receive the benefits associated with

the total actual wind generation on the Company's system as it varies from forecast year-to-year over the life of the resource;

- The PCAM should help moderate the amount of imputed debt and interest adjustments related to power purchase agreements that rating agencies make when determining their adjusted credit metrics. This may allow the Company to lower, over time, its common equity component of the capital structure.

Q. Does the PCAM shift all of the risk of increases or decreases in NPC completely away from the Company and onto the customers?

A. No. The proposed PCAM will recover from customers only actual NPC and will pass through to customers any actual NPC reductions. While this creates symmetry, a desirable feature of an adjustment mechanism, it does not shift from the Company to customers the risks of prudently managing its system. The Company retains that risk. The Commission, Staff and parties will have the opportunity to assess the prudence and reasonableness of actual NPC in its annual filing, which the Company proposes to make on May 15th of each year.

Q. Have parties criticized PCAMs that allow full recovery of NPC for allocating too little risk to the utility?

A. Yes. The Company is aware that parties have previously criticized PCAM proposals on the basis that they shift too much NPC risk to customers. Given the impact of SB 838 on NPC however, these criticisms are unpersuasive.

Q. Please explain.

A. In reviewing PCAM proposals, the Commission has typically required the electric

utility to continue to bear the business risk associated with normal changes in NPC. However, the Oregon Legislature recognized in SB 838 that the cost impacts of RPS compliance were not normal business risks assigned to the utility. Instead, it provided full and timely cost recovery through an automatic adjustment clause for a range of compliance costs, including wind variability. As discussed above, this variability cannot be captured in traditional NPC modeling and is now a major driver of NPC volatility and associated under recovery. Thus, the relevant discussion is timely recovery of prudent costs, not the assignment of risks.

Q. Are the risks associated with integrating, firming, and shaping wind resources "normal" utility business risks?

A. No. SB 838 has fundamentally changed the way utilities operate their generation systems. These challenges will increase as the Company adds additional intermittent renewable resources to meet SB 838's compliance requirements. Without a PCAM, the increasing cost impacts will continue to fall on the Company in a manner inconsistent with ORS 469A.120(1).

Q. Does the Company have less of an incentive to minimize actual NPC if a PCAM is in place?

A. No. The Company continues to be subject to annual prudence reviews in Oregon and in all of its six states. Implementing a PCAM in Oregon will not change the incentive that the Company has to minimize actual NPC.

Q. Are you familiar with PCAMs of other electric utilities across the country?

A. Yes. I have reviewed the PCAMs of the utilities in the comparable group of

companies that Company witness Dr. Samuel Hadaway uses for determining the Company's cost of equity. I am also familiar with PCAMs from some of the other states in which the Company operates. The large majority of utility PCAMs that I have reviewed do not contain deadbands, sharing mechanisms, or earnings review deadbands. For more detail on the PCAMs I reviewed, please refer to Exhibit PAC/901.

Q. Is the Company's proposed PCAM consistent with the power cost true-up mechanisms in place for other Oregon electric utilities?

A. No. Portland General Electric's ("PGE") and Idaho Power Company's ("Idaho Power") power cost true-up mechanisms contain a deadband around power costs, a sharing band after the application of the deadband, and an earnings review that includes a 100 basis point deadband around the authorized return on equity ("ROE").

Q. Did the Commission consider SB 838 in designing the PCAMs for PGE and Idaho Power?

A. No. The Commission adopted PGE's original PCAM prior to enactment of SB 838. The Commission also expressly noted that this PCAM was "narrowly tailored to suit PGE." While PGE's PCAM deadband was modified in 2010 by a stipulation with all parties in Docket UE 215, Order No. 10-410, SB 838 was not addressed. In addition, Idaho Power is not subject to SB 838.

Q. Can you demonstrate what the Company's power cost recovery would have been if a mechanism similar to PGE's PCAM had been in place since 2010?

A. Yes. Table 13 shows that under a PCAM like PGE's, the Company would have

recovered approximately 50 percent of its prudently incurred costs in 2010 and 2011.[6] The bulk of PacifiCorp's new investments to comply with SB 838 have come on line during this post-2010 time period. Applying a mechanism like PGE's to PacifiCorp would deny the Company recovery of a large share of its prudent costs, including costs covered by SB 838.

Table 13
PacifiCorp
NPC Recovery with PCAM

	2010 UE207	2011 UE216
Initial Filing	$1,100,534	$1,278,250
Final Update	$1,092,321	$1,288,694
In Rates	$1,028,768	$1,236,957
Actual NPC	$1,149,945	$1,388,253
Difference from In Rates	$137,109	$135,233
Oregon Allocation of Costs	$34,277	$33,808
Deadband	$14,000	$14,000
Allocation after deadband	$20,277	$19,808
Allocation after sharing	$18,250	$17,827
Percent recovery of costs	**53%**	**53%**

[6] This Table shows the actual NPC recovery of Oregon-allocated NPC (assuming a 25 percent allocation factor). The difference from in-rates NPC is calculated based on the $/MWh difference between in-rates and actual NPC times the actual load. PGE's current PCAM contains a fixed deadband of $15 million if PGE over-recovers NPC and a $30 million deadband if PGE under-recovers NPC. After application of the deadband, PGE is subject to a sharing mechanism that requires customers to pay 90 percent of the prudently incurred NPC and the Company must absorb an additional 10 percent of actual NPC variances. PGE is subject to an earnings review and must show that in the event of recovery from customers the company will not earn 100 basis points below its authorized ROE, and in the event of refund to customers the company will not earn 100 basis points above its authorized ROE. PacifiCorp's Oregon NPC are approximately half of PGE's Oregon NPC. Therefore, Table 13 assumes that a PacifiCorp PCAM similar to PGE's would have had deadbands that are approximately half of PGE's deadbands ($7 million in the event of over-recovery and $14 million in the event of under-recovery). The remaining assumptions in Table 13 are consistent with the current PGE mechanism.

Q. Does the Commission normally require a utility to absorb 50 percent of its excess power costs if they were prudently incurred?

A. No. It is my understanding that in the instances where the Commission has addressed recovery of excess NPC through deferred accounting, it has disallowed 50 percent of those costs only when it determined that the utility was imprudent.[7]

Q. Does SB 838 contemplate the Company absorbing 50 percent of the costs associated with differences in NPC due to the Company's RPS obligations?

A. No. As noted above, ORS 469A.120(1) mandates full recovery of prudent costs and does not discount this recovery when an automatic adjustment clause is the recovery mechanism used for timely cost recovery.

Q. Is a PGE-type PCAM for PacifiCorp a reasonable outcome and consistent with SB 838?

A. No. A PCAM that does not acknowledge the change in risk that the Oregon Legislature intended associated with the acquisition, integration, firming, and shaping of intermittent resources to comply with SB 838 is unreasonable.

Operation of Proposed PCAM

Q. What types of costs would be included in the PCAM?

A. The PCAM will be calculated using all components of NPC as traditionally defined in the Company's TAM proceedings and modeled by the Company's GRID model. Specifically, Base NPC and Actual NPC will include amounts typically booked to the following FERC accounts:

[7] *See* In the Matter of Portland General Electric Company Application to Amortize the Boardman Deferral, Docket UE 196, Order No. 10-051, (Feb. 11, 2010).

Account 447 – Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID
Account 501 – Fuel, steam generation; excluding fuel handling, start up fuel/gas[8], diesel fuel, residual disposal and other costs that are not modeled in GRID
Account 503 – Steam from other sources
Account 547 – Fuel, other generation
Account 555 – Purchased power, excluding BPA residential exchange credit pass-through if applicable
Account 565 – Transmission of electricity by others

The PCAM would address power cost expenses and would not include any costs associated with fixed cost recovery (*i.e.,* capital investment in rate base).

Q. Do Actual NPC include adjustments prior to the comparison with the Commission-approved NPC in the TAM proceeding (Base NPC)?

A. Yes. Adjustments will be made to Actual NPC as booked to be consistent with the Company's production dispatch model, to remove prior period accounting entries, and to include applicable Commission-adopted adjustments reflected in the most recent TAM filing. Actual NPC will not be adjusted for wind generation, hydro conditions, or forced outages because they give rise to the fluctuations in NPC that this mechanism is designed to capture. Actual NPC will be subject to review by the Commission and other parties annually.

Q. Please explain the balancing account and the calculation of the PCAM rate.

A. The balancing account and PCAM rate serve as a true-up mechanism to recover or credit the differences between Base NPC and Actual NPC. On a monthly basis, the Company will compare Actual NPC to Base NPC. Any differences in the system per-unit cost will be multiplied by actual Oregon MWh load in that

[8] Start up fuel is accounted for separately from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.

month and the product will be tracked in the balancing account. The monthly under- or over-recovery will accumulate in the balancing account and earn interest at the Company's most recently approved rate of return on rate base in Oregon.

On an annual basis, the cumulative balance in the balancing account will be recovered in Schedule 206, the Power Cost Adjustment Mechanism. Company witness Mr. Griffith discusses cost recovery through proposed Schedule 206 in his direct testimony.

Q. When will the Company reconcile the PCAM costs and recoveries and update the PCAM factors?

A. The Company proposes to file annual PCAM reconciliations and updated allocation factors on May 15 each year with a new PCAM rate effective date of January 1 of the following year. The Company proposes to file its first application on May 15, 2014, to true up 2013 Base NPC to 2013 Actual NPC.

Q. Does this conclude your testimony?

A. Yes.

Power Cost Adjustment Mechanism Comparison Chart

Summary				
	PCAM	**Deadband**	**Sharing**	**Earnings Review**
Total	55	7	7	2
Total Sharing and Deadband			4	
Total Sharing, Deadband and Earnings Review			1	

Utility	State	PCAM	Deadband	Sharing	Earnings Review	Description
AEP Texas Central, AEP Texas North	TX	Yes				Full recovery of fuel and purchased power costs. Over-or-under recoveries are deferred, with interest, for recovery over a subsequent 12 month period.
Alabama Power*	AL	Yes				Full recovery of the company's electric procurement costs and any previous under- or over-recovered costs through the Energy Cost Recovery mechanism.
Appalachian Power	VA	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Arizona Public Service	AZ	Yes		Yes		APS has a Power Supply Adjuster that allows 90/10 sharing on all fuel and purchased power costs that are in excess of base rate, however, it excludes from the sharing mechanism the demand element of long term PPA's that were established through competitive procurement and renewable energy purchases.
Avista*	WA	Yes	Yes	Yes		The Company and its customers share on an equal basis any positive or negative differences between actual and base power supply costs between $4 and $10 million. Avista is responsible for 10% of any excess power costs greater than $10 million with the customers bearing 90% of such excess costs.
Black Hills Power*	SD	Yes		Yes		Full recovery of projected fuel and purchased power costs subject to the following sharing mechanisms. Black Hills Power (BHP), through its fuel and purchased power adjustment clause (FPPAC), credits ratepayers 90% (and retains 10%) of the margins from renewable energy credit sales, and 65% of power marketing income (PMI) (retaining 35%), which is defined as the revenue from wholesale power and emission allowances sales, less certain expenses related to the operation of the wholesale business.
Cheyenne Light*	WY	Yes	Yes	Yes		If the Total Change from Base is more than $1,000,000 for the current period (either as an increase in costs or a decrease in costs), $1,000,000 is subtracted from the Total Change from Base, and the result is multiplied by 95 percent. This product is then the Delivered Power Cost to be Recovered from retail customers over the upcoming 12 months, or is the Delivered Power Cost to be Refunded to customers over the upcoming 12 months.
Cleveland Electric Illuminating, Ohio Edison, Toledo Edison	OH	Yes				Full recovery of all purchased power costs and any previous under- or over-recovered costs. (The company divested its generation assets following the implementation of retail competition.)
Colorado Electric*	CO	Yes				Black Hills Colorado Electric Utility Company (BHCE) is subject to an energy cost adjustment mechanism under which all fuel and purchased energy cost differences from the company's base energy cost rate are fully recovered from, or credited to, customers.
Columbus Southern, Ohio Power	OH	Yes				Full recovery of projected fuel and purchased power costs and any previous under-or over-recovered costs through quarterly fuel clauses established under the companies' Electric Security Plans.
Con. Edison, Orange & Rockland	NY	Yes				Full recovery of purchased power and any previous under- or over-recovered costs through Market Power Adjustment Clauses. (These subsidiaries no longer own generation.) In addition, each of the electric and gas utilities in New York operate under full revenue decoupling mechanisms.
Dayton Power & Light	OH	Yes				Full recovery of fuel and purchased power costs and any previous under- or over-recovered costs under the company's Electric Security Plan.
Detroit Edison*	MI	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Duke Energy Carolinas	NC	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Duke Energy Carolinas	SC	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs, implemented following hearings.

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Power Cost Adjustment Mechanism Comparison Chart

Utility	State	PCAM	Deadband	Sharing	Earnings Review	Description
Duke Energy Indiana	IN	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs, implemented following hearings.
Duke Energy Ohio	OH	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs through the company's Electric Security Plan.
Entergy Arkansas	AR	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Entergy Gulf States	LA	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Entergy Louisiana	LA	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Entergy Mississippi	MS	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Entergy New Orleans	LA	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Entergy Texas	TX	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs in rate cases and interim hearings.
Florida Power & Light	FL	Yes				Full recovery, with the exception of the reward or punishment associated with the Generating Performance Incentive Factor, which provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis-point ROE spread.
Georgia Power*	GA	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs, the capacity component is recovered in base rates.
Gulf Power*	FL	Yes				Full recovery, with the exception of the reward or punishment associated with the Generating Performance Incentive Factor, which provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis-point ROE spread.
Idaho Power*	ID	Yes		Yes		Recovery of 95% of projected fuel and purchased power costs and previous under- or over-recovered costs. No deadband.
Indiana Michigan Power	IN	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs through a summer reliability tracking mechanism.
Interstate Power & Light*	IA	Yes				Full recovery of projected fuel and purchased power costs and previous under- or over-recovered costs. In addition, all DSM, energy efficiency, and required renewable resource costs are permitted to be recovered contemporaneously with the expenditure, through a separate adjustment mechanism.
Jersey Central Power & Light	NJ	Yes				Full recovery of all purchased power costs and any previous under- or over-recovered costs. (The company divested its generation assets following the implementation of retail competition.)
Metropolitan Edison, Penn. Electric	PA	Yes				Full recovery of all purchased power costs and any previous under- or over-recovered costs. (The company divested its generation assets following the implementation of retail competition.)
Minnesota Power*	MN	Yes				Full recovery of projected fuel and purchased power costs and previous under- or over-recovered costs, with the exception of capacity or demand charges when such energy is purchased on an economic dispatch basis, revenues from the sale of SO_2 allowances, and the cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales.
Mississippi Power*	MS	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Northern States Power*	MN	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Northern States Power*	WI	Yes	Yes			Recovery of projected fuel and purchased power costs outside of a ±2% deadband.
Northern States Power*	ND	Yes				Automatic fuel and purchased power (energy only) adjustments are permitted. Fuel and purchased power cost adjustments are implemented monthly, and there is generally a two-month lag for recovery.
Northern States Power*	SD	Yes				Full recovery of projected fuel and purchased power costs.
NSTAR Electric	MA	Yes				Full recovery of fuel and purchased power costs and any previous under- or over-recovered costs. (Rates are completely market-based.)

Power Cost Adjustment Mechanism Comparison Chart

Utility	State	PCAM	Deadband	Sharing	Earnings Review	Description
Pacific Gas & Electric	CA	Yes				Full recovery of the company's electric procurement costs and any previous under- or over-recovered costs through the Energy Resource Recovery Account (ERRA).
Portland General Electric*	OR	Yes	Yes	Yes	Yes	Recovery of 90% of projected fuel and purchased power costs outside an asymmetric deadband. The asymmetric deadband is equal to plus or minus $15/$30 million. The Company is also subject to an earnings review
Progress Energy Carolina	NC	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs. The law limits the annual increase in rates related to the recovery of purchased power costs to 2% of a utility's total retail revenues. Interest is included only for over-collections.
Progress Energy Carolina	SC	Yes				Full recovery of fuel and purchased power costs and any previous under- or over-recovered costs, implemented following hearings.
Progress Energy Florida	FL	Yes				Full recovery, with the exception of the reward or punishment associated with the Generating Performance Incentive Factor, which provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis-point ROE spread.
Public Service Company of Colorado*	CO	Yes	Yes	Yes		Recovery of 50% of the first $15 million above the baseline included in rates, 75% of the next $15 million, and 100% of any fuel costs exceeding $30 million.
Public Service Company of Oklahoma	OK	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs, implemented following hearings.
Puget Sound Energy	WA	Yes	Yes	Yes		Puget has a deadband and sharing bands that are structured as follows: $20 million deadband 100 percent of costs to the Company, excess costs between $20-$40 million are split 50/50 between the Company and customers, excess costs between $40-$120 million are split 10 percent to the Company and 90 percent to customers, and any excess power costs above $120 million the Company is responsible for 5 percent of those costs. The Company's share of costs/benefits will not exceed $40 million (+/-) calculated per the sharing bands. If the cap is exceeded sharing thereafter is 99 percent of costs/benefits to customers and 1 percent to Company.
San Diego Gas & Electric*	CA	Yes				Full recovery of the company's electric procurement costs and any previous under- or over-recovered costs through the Energy Resource Recovery Account (ERRA).
Savannah Power*	GA	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs, the capacity component is recovered in base rates.
South Carolina Electricity & Gas*	SC	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs.
Southern California Edison*	CA	Yes				Full recovery of the company's electric procurement costs and any previous under- or over-recovered costs through the Energy Resource Recovery Account (ERRA).
Southern Indiana G&E*	IN	Yes			Yes	Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs, implemented following hearings. By law, the URC may not approve an FAC rate adjustment if it will result in the utility earning a net operating income (NOI) in excess of that authorized.
Southwestern Public Service*	TX	Yes				Full recovery of projected fuel and purchased power costs and any previous under- or over-recovered costs in rate cases and interim hearings.
Southwestern Public Service*	NM	Yes				Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause (FPPCAC) for an electric utility is calculated monthly (a variance from monthly reporting may be sought), and includes a balancing account in which there is approximately a two-month collection lag.
SWEPCO	TX	Yes				Full recovery of fuel and purchased power costs. Over-or-under recoveries are deferred, with interest, for recovery over a subsequent 12 month period.
Wisconsin Electric*	WI	Yes	Yes			Recovery of projected fuel and purchased power costs outside of a ±2% deadband.
Wisconsin Power & Light*	WI	Yes	Yes			Recovery of projected fuel and purchased power costs outside of a ±2% deadband.

*Utilities included in the current cost of capital peer group analysis (Dr. Samuel C. Hadaway Exhibit PAC/202).

Exhibit PAC/901
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DIRECT TESTIMONY OF ERICH D. WILSON

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ATTACHED EXHIBITS

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

A. My name is Erich D. Wilson. My business address is 825 N.E. Multnomah, Suite 1800, Portland, Oregon 97232. My position is Director of Human Resources.

Qualifications

Q. Please describe your education and business experience.

A. I received a Bachelor's degree in Economics (Business) from the University of California at San Diego in 1992. In addition, I achieved Certified Compensation Professional status from the American Compensation Association in 1999 and have kept this certification current by attending various educational programs and seminars. I joined the Company in 2001 as Director of Compensation. Before that, I held various positions in human resources (operations, benefits, and staffing), but for the majority of my career I have directed the design and administration of compensation programs. I assumed my current position as Director of Human Resources in 2006.

My primary responsibilities in my current position include managing the Company's human resource function, including compensation, benefits, compliance, staffing, training and development, employee and labor relations, and payroll. I focus on assisting the Company in attracting, retaining, and motivating qualified employees along with the administration of all associated human resource programs and employee experiences.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the compensation and benefit plans provided to employees at the Company and support the costs included in the test period for these areas. This overview focuses on the Company's base pay, annual incentive, pension, and health care benefit plans. These plans are designed to allow the Company to attract and retain the employee talent necessary to deliver safe and reliable service at a reasonable cost. I also demonstrate that the Company has prudently contained increases in labor costs since the last rate case and, in particular, has kept increases in benefit costs at a competitive level.

Q. How do the total labor costs in this case compare to the Company's last general rate case, Docket UE 217?

A. The current total labor costs demonstrate that overall labor and benefit costs are expected to decline slightly from calendar year 2011 to calendar year 2013. The table below shows that the total wage and benefit expense in this case for the 2013 test year has decreased by nearly 2 percent compared to labor costs included in the UE 217 filing for a 2011 test year. Moreover, on a dollar per megawatt-hour ("MWh") basis, wages and benefits have decreased over 5 percent since 2011, which is partially due to an increase in load.

	UE-217 Calendar Year 2011	Current Case Calendar Year 2013	Change
Wage & Benefit Expense	$537,618,832	$527,979,496	-1.79%
Total Load - MWh	58,023,556	60,066,295	3.52%
$/MWh	9.27	8.79	-5.13%

Q. Please briefly describe the Company's compensation philosophy.

A. Two fundamental principles underlie the Company's compensation philosophy. First, the Company's primary goal in determining employee compensation is to provide pay at the market average. Competitive compensation is critical to attracting and retaining qualified employees in a market that is becoming extremely competitive, and allows the Company to do so without incurring excessive or unreasonable costs. Thus, the Company endeavors to provide the same general pay levels and benefits in its total compensation package as those included in its competitors' packages.

Second, the Company believes that in order to encourage superior performance, a certain percentage of each employee's market compensation must be "at risk." Accordingly, under the Company's Annual Incentive Plan, each employee has the opportunity to receive total compensation at the market average, so long as the employee performs at an acceptable level. But employees will earn less than the average compensation when performance is less than acceptable and, conversely, will earn higher than the average compensation when performance is exceptional.

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. Before 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.

Total Compensation

Q. How does the Company determine the total cash compensation package for each position?

A. At least annually, the Company collects market data for comparable jobs and calculates the average data point for total cash compensation by position. To do so, the Company uses a variety of compensation studies put out by various experts/organizations, including AonHewitt, Towers Watson, and Mercer. The Company also uses an online tool called MarketPay.com. MarketPay.com provides electronic access to all of the compensation studies traditionally used and some additional surveys, allowing the Company to more efficiently perform information searches and job and pay comparisons.

After the Company determines the appropriate level of total cash compensation for a position, it then determines the portion of that compensation that will constitute the "at-risk" portion—that is, the "target" incentive pay. The Company sets the "at-risk" portion by reviewing market compensation using the various compensation studies described above. The "at-risk" portion is typically in the 10-25 percent range; however, incentive pay for a few employees is set as high as 75 percent. Generally speaking, the higher the position is within the Company, the higher the percentage of target incentive pay. The remaining

percentage of total compensation is referred to as "base compensation."

Annual Incentive Plan

Q. What is the objective of the Annual Incentive Plan?

A. The objective of the Annual Incentive Plan is to provide employees with incentive to perform at an above-average level. The plan is not a bonus but an incentive to achieve performance that in turn delivers competitive total compensation. This is achieved by putting a percentage of the competitive total compensation "at risk." If an employee performs at an acceptable level for the position, the employee will receive the target incentive amount which will allow the employee to earn compensation comparable to similar positions in the market. If an employee fails to perform at an acceptable level, the employee will receive less than the target incentive or no incentive at all. When this occurs, the employee will be paid less than the comparable total cash compensation in the market for that year. Conversely, for exceptional performance, an employee may receive above his or her target incentive level.

The ability to earn a higher-than-target incentive payment provides the employee with an incentive to exceed average performance. This opportunity is an essential counterbalance to the risk the employee faces that his or her performance in a particular year will be less than acceptable, with the consequence that total compensation will be less than market in that year. The symmetry of the incentive element provides the Company with the financial tool to encourage exceptional performance and discourage less than acceptable performance. As would be expected from a well-designed, symmetrical plan, the

average incentive element is approximately at the target incentive level.

Q. Is incentive compensation a greater benefit to customers than compensation consisting solely of base compensation?

A. Yes. In the Company's experience, a higher level of overall employee performance is achieved when a portion of pay is "at risk." In addition, the Company's incentive compensation plan enables the Company to attract and retain talented employees in the increasingly competitive market for skilled labor. Therefore, while the total cost of the Company's base-plus-incentive compensation program is equal to average total cash compensation (just as a salary-only program would be), the benefit to customers is greater.

Q. How is the incentive compensation plan implemented?

A. The Company's Annual Incentive Plan provides performance awards based on the following categories: (1) the employee's performance against individual goals; (2) the employee's performance against group goals including safety goals; and (3) success in addressing new issues and opportunities that may arise during the course of the year.

Q. What are the individual goals and how are they set?

A. Individual employee goals start with the goals set for the Company as a whole. Each year, the Company presidents, in conjunction with MidAmerican Energy Holdings Company, set the overall goals for the Company. All of these goals focus on delivering safe and reliable electricity to customers and providing excellent customer service. Goals include safety goals such as reducing lost time and reducing recordable, preventable, and restricted duty incidents. Customer

service goals include implementing local and regional customer service improvements, improving visibility and relations with industrial customers and consumer associations, and improving overall customer satisfaction. Some goals relate to operating within established budgets, including maintaining operating costs, controlling cost of capital expenditures, and achieving operational efficiencies/financial targets that allow the Company to remain a low-cost utility. Other key goals relate to operational performance, major project delivery, organizational planning and development, and quality of service and regulatory commitments. The achievement of each and every one of these goals will benefit customers.

Q. How do the Company goals relate to individual employee goals?

A. The Company-wide goals serve as the foundation for the goals set for each individual employee. Thus, when an individual employee sets his or her own individual goals for the year, they are set by reference to how that employee's position can advance the overall goals of the Company. The employee's performance on individual goals accounts for approximately 70 percent of his or her overall evaluation.

Q. What are the group goals?

A. In addition to performance against individual goals, all employees are evaluated against six common or "group" goals. These group goals describe the characteristics the Company believes are important to the success of all employees—customer focus, job knowledge, planning and decision making, productivity, building relationships, and leadership. Detailed descriptions of these

characteristics are attached as Exhibit PAC/1001. The employee's performance with respect to these group goals accounts for approximately 30 percent of the employee's overall evaluation.

Q. Explain the third category.

A. In the course of any one year, challenges will arise that were not contemplated by the goals set at the beginning of the year. For instance, the Company may become involved in a significant transaction, such as a purchase or sale, or the Company may contend with unexpected outage conditions. In these cases, some percentage of the employee's evaluation may reflect his or her performance under these unforeseen conditions.

Q. Are any of the employees judged on the financial performance of the Company?

A. No. While all employees are expected to operate within applicable budgets, corporate financial performance and returns are not a factor in determining the amount of incentive compensation awarded under the plan. The Company does maintain a separate plan for executives that awards bonuses based on overall corporate performance; however, the Company does not ask customers to absorb the costs associated with that plan.

Q. Please explain the level of incentive compensation that is included in this filing?

A. Recognizing that the pool of incentive compensation made available for distribution was reduced below 100 percent of the indicated market level in 2009, 2010 and 2011, the Company is proposing in this case to apply a percentage to the

market level reflecting the average of the last three full actual years (calendar years 2009 – 2011). As shown in Exhibit PAC/1102, Dalley/4.2.6, this application includes a request for total Company incentive compensation in the amount of $29.2 million ($20.7 million after capitalization). This amount is calculated using the pro forma wages in this case multiplied by a three-year average of the actual payment rate. The Oregon portion of this expense is approximately $5.9 million.

Q. Does the Company recommend including incentive compensation plus base compensation in rates?

A. Yes, for several reasons. First, customers should fully support the cost of incentive compensation because, as previously mentioned, it is an essential component of an overall market-based competitive compensation program. Reducing customer support for incentive pay would result in under-market salaries, making it impossible for the Company to recruit and maintain a qualified labor force, which would in turn make it impossible for the Company to provide safe and reliable service. Moreover, the goals of the plan are designed to encourage superior performance on the part of employees in pursuing the goals that directly benefit customers—safety, reliability, and customer service. This is precisely the type of prudently designed incentive plan program that provides direct benefits to customers and that customers should therefore support.

Retirement Plans

Q. Please describe the Company's retirement plan.

A. The Company strives to provide a competitive retirement plan offering with

reduced expense volatility for the benefit of employees and customers. In doing so, the Company provides non-represented employees hired before January 1, 2008, the ability to receive their retirement through either a cash balance or 401k only design. This choice was offered in 2008, and 41 percent of the eligible population elected the 401k design. All non-represented employees hired after January 1, 2008, receive retirement through the 401k design approach. Retirement plan benefits for represented employees are determined through the collective bargaining process, through which the Company has maintained its focus to shift the retirement approach from the traditional defined benefit to defined contribution (401k) approach.

Q. Are there increases in cost related to retirement program offerings?

A. Yes, the Company expects to see an increase of $10.7 million in pension expense during the test period versus actual expenses as of June 2011 for several reasons. The reasons for the PacifiCorp Retirement Plan ("PRP") differ from the reasons for the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57").

For Local 57, the Company has recently reached a period where it is obligated to fund more than the negotiated amount in order to meet minimum funding standards as set forth in the Employee Retirement Income Security Act ("ERISA") and the Internal Revenue Code ("additional required contributions"). The first additional required contribution of $0.1 million was due in April 2011. Thus the base year expense includes only $0.1 million for additional required contributions, but it is expected that the additional required contributions for the test year ending December 2013 will be significantly greater at $4.3 million. In

the case of the union, funding contributions are the same as expenses to the Company.

For PRP, the $4.5 million increase is the result of several changes. In addition to updating the census data to reflect actual demographic experience, the mortality table has been changed to project longer life expectancies. The most significant impact is due to the lower discount rate used to determine liabilities. The base year expenses were determined using the actual interest rates of 5.80 percent (as of December 31, 2009) for July to December 2010, and 5.35 percent (as of December 31, 2010) for January to June 2011. The discount rate assumed for the 2013 test year is 4.80 percent, based on rates as of September 30, 2011. Finally, there is an increase in expense due to the assumption that the plan's assets will earn zero percent during 2011, (greater than the actual returns through September 30, 2011) rather than the assumed long-term rate of return of 7.50 percent.

The Company is proactively managing benefit cost increases and their resulting impacts on customers through its actions to shift, as noted above, from a focus on defined benefit to defined contribution. Absent these actions by the Company, the increase would have been even greater.

Employee Health Benefits

Q. Please describe the Company's health care benefits.

A. As with all benefits, the Company attempts to provide employees with the same level of health care benefits provided by the employers with whom the Company competes for labor. For the Company, this means offering employees what may

be described as market average health benefits. The Company seeks to provide these benefits as economically as possible.

Q. How does the Company ensure that it is providing these competitive benefits as economically as possible?

A. The Company relies on the advice of its consultant, AonHewitt, to ensure that it is securing market competitive benefits at the best possible rate. AonHewitt are respected experts in their field, and the Company has relied on them for many years. With the help of AonHewitt, the Company periodically reviews and adjusts the sharing of health-care-related costs with employees in an effort to stabilize cost, manage volatility, and respond to changing market practices.

Q. Has the Company faced any particular challenges in the past several years relevant to its provision of health care benefits?

A. Yes. It is widely understood that health care costs have been rising over the past several years. As a result, the Company continued to experience increases in its health care benefit costs.

Q. Has the Company taken any action to contain these cost increases?

A. Yes. Beginning in 2008 the Company made adjustments to the cost sharing and plan design to reduce costs and to align with market practices. In particular, the Company established a base medical plan with a high deductible and a cost sharing of 90/10. The Company continues to offer other plan choices, however, and except for a $300 deductible plan that is offered in rural areas, these plans are set at a cost sharing of 70/30. All new hires as of January 1, 2008, have the option of selecting the high deductible plan or opting out of coverage. The

Company continued with this cost sharing approach in 2009 and further increases in cost sharing to the employee were implemented in subsequent years.

Q. What is the Company's rationale for sharing health-care-related costs with employees?

A. This structural shift adheres to the Company's goal of providing competitive benefits to its employees, while doing so in a manner that is fair and prudent for customers.

Q. Please explain the level of health care costs included in this filing and compare that to previous fiscal year expenses.

A. As discussed previously, there has been an upward trend in health care costs in recent years. For calendar years 2010 and 2011 actual total Company healthcare expenses totaled $57.9 million and $61.8 respectively. Consistent with this trend, the Company's calendar year 2013 estimates $64.4 million ($45.5 million after capitalization) in health care expenses on a total Company basis, as shown in the exhibits attached to Exhibit PAC/1102, Dalley/4.2.7. The Oregon allocated share of health care costs is $13.0 million.

Along with these increases, AonHewitt has informed the Company that current trends indicate the rates for the Company's health benefits are anticipated to increase further by a range of 8 and 10 percent. This is driven by the demographics and claims experience of our workforce. The company continues to work to mitigate these increases through the plan design and overall cost sharing with the employees.

Q. Has the Company made changes to the retiree medical plan that affect the FAS 106 post-retirement benefits other than pension costs included in this case?

A. Yes. The Company implemented benefit design changes to the post-retirement welfare plans that resulted in significant cost reductions of $12.1 million as shown in Exhibit PAC/1102, Dalley/4.2.7. These changes help to offset the other areas of cost increases that I have addressed, to the benefit of customers.

Q. Please explain the changes.

A. Health care reform legislation is causing many employers, including PacifiCorp, to change their approach to retiree health care benefits. With recent changes to Medicare, individual plans have become more widely available and affordable. These changes, which were effective January 1, 2012, will not only provide a savings to the customers through reduced expense, but will also provide more flexibility to the retiree to choose from a variety of plan options to select the coverage that works best for them. Instead of the monthly subsidy structure, the Company now will provide an annual contribution to a health reimbursement account that will then be managed by the retiree and used to pay for the care and services received.

Q. Does this conclude your direct testimony?

A. Yes.

Performance Factors (30%)

Customer Focus: Dedicated to meeting the expectations of internal and external customers, co-workers and stakeholders; obtains first-hand information from customers and uses it to improve processes and services; acts with customers in mind; establishes and maintains effective relationships with customers and gains their respect and trust. - Proactively meets internal or external customer expectations by anticipating needs and effectively addressing and resolving problems, issues and concerns in a timely manner - Develops and sustains productive customer relationships through appropriate communications - Shares information with customers to build their understanding of issues and capabilities -----WEIGHTING: 5%

Job Knowledge: Puts knowledge, understanding and skills to practical use on the job; demonstrates an understanding of key policies, skills and procedures in functional and related areas of work. Ensures all compliance aspects of position are known and followed; understands and complies with all policies, codes and regulations applicable to position and company. - Achieves a satisfactory level of skill and knowledge in position-related areas; demonstrates ability to learn new skills - Actively supports the company with all compliance related activities both assigned to the job as well as those encountered as an employee. This includes attending required training, understanding federal, state and local requirements applicable to the business, consulting with management and/or compliance officers on issues and completing all requirements while adhering to company policies and procedures. - Keeps up with current developments and trends in area of expertise as a part of personal development - Generates solutions in work situations; utilizes a variety of resources and tools - Demonstrates clear and effective communication in written and verbal formats -----WEIGHTING: 5%

Planning and Decision Making: Identifies and understands issues, problems and opportunities, demonstrates sound judgment while utilizing plan, execute, measure and correct process. - Develops plans using a disciplined planning approach taking into account a variety of creative alternatives for choosing a recommended course of action with a clearly defined desired outcome, risks, identification of key assumptions, cost benefit analysis, milestones and metrics; properly identifies all stakeholders - Executes in accordance with the plan by taking action that is timely and consistent with available facts, constraints and probable consequences - Uses metrics and milestones, and goal reassessment to measure execution and determine whether correction to plan is needed - Makes timely and thoughtful corrections to the plan when appropriate; takes responsibility for results; properly reports the plan's progress or corrections to the appropriate individuals - Not afraid to make decisions and ensure appropriate people are informed - Makes sound, logical, business decisions; shows good judgment in prioritizing work - Demonstrates high levels of personal accountability -----WEIGHTING: 5%

Productivity: Achieves a high level of relevant accomplishments for the benefit of the company and its customers. Uses appropriate methods to implement solutions; checks processes and tasks to ensure accuracy and efficiency; initiates action to correct problems or notifies others of quality issues as appropriate. - Takes initiative by generating new approaches to continuously improve efficiency and quality in every aspect of work - Performs well under pressure and does not create undue pressure for others; meets deadlines - Ensures job processes, tasks and work products are free from errors, omissions or defects - Work products are professional and clearly reflect a high level of attention to detail - Holds self and others accountable to quality results - Focuses on the desired outcomes and produces results -----WEIGHTING: 5%

Builds Relationships: Identifies opportunities and takes action to develop strategic relationships across the organization and externally. Relates well to all people and builds constructive and effective relationships for the improvement of the organization as a whole. - Adapts interpersonal style to accommodate tasks, situations and individuals involved - Effectively exchanges ideas and information with others - Accepts personal differences and values diversity - Acts with integrity by demonstrating professional, courteous, ethical and fair behavior at all times - Promotes cooperation by sharing information, encouraging contributions - Open to constructive feedback and provides it to others -----WEIGHTING: 5%

Leadership: Keeps the organization's vision and values at the forefront of decision-making and actions; demonstrates ability to guide individuals towards goal achievement by setting clear expectations, providing feedback and coaching. - Demonstrates passion; personal commitment and enthusiasm - Embraces change and motivates others to achieve goals - Enlists the active participation of appropriate resources to accomplish goals - Inspires employees to perform to their maximum potential - Provides opportunities for growth and development through delegation and succession planning - Provides candid and timely performance feedback - Clearly communicates expectations to teams and individuals; sets an example to others -----WEIGHTING: 5%

DIRECT TESTIMONY OF R. BRYCE DALLEY

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ATTACHED EXHIBITS

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

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon, 97232. I am currently employed as Director, Regulatory Affairs and Revenue Requirement.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Business Management with an emphasis in finance from Brigham Young University in 2003. I completed the Utility Management Certificate Program at Willamette University, and I have also attended various educational, professional, and electric industry-related seminars. I have been employed by PacifiCorp since 2002 in various positions within the regulation and finance organizations. I was appointed Manager of Revenue Requirement in 2008 and assumed my current position in 2012.

My primary responsibilities include oversight of regulatory proceedings and filings in California, Oregon, and Washington. I am also responsible for the calculation and reporting of the Company's regulated earnings and revenue requirement, application of the inter-jurisdictional cost allocation methodologies, and the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony in this case?

A. My direct testimony addresses the calculation of the Company's Oregon-allocated

revenue requirement, excluding net power costs ("NPC"), and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $38.4 million revenue increase requested in this general rate case representing the increase over current rates required for the Company to recover its Oregon non-NPC revenue requirement of $876.3 million. The Company currently recovers its NPC through the Transition Adjustment Mechanism ("TAM").
- The selection of the historical period of the 12 months ended June 2011 ("Base Period") as the basis for the test period in this proceeding.
- The development of the forecast test year in this case, which is the 12 months ending December 31, 2013 ("Test Period").
- Discussion of the 2010 Protocol inter-jurisdictional allocation methodology utilized to determine Oregon-allocated results.
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service prior to January 1, 2013, the beginning of the Test Period.
- The proposed accounting treatment to accelerate the depreciation of the Carbon plant in anticipation of retiring the facility in early 2015 in order to comply with recent Environmental Protection Agency ("EPA") standards.
- The calculation of the revenue requirement associated with the Mona-to-Oquirrh transmission investment, which the Company is proposing to

recover as a separate tariff once the project is complete and used and useful.

- The presentation of the adjusted results of operations for the Test Period demonstrating that under current rates the Company will earn an overall return on equity ("ROE") in Oregon of 8.5 percent, which is below the ROE requested in this case and the current authorized return.

Revenue Requirement

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

A. At current rate levels, the Company will earn an overall ROE in Oregon of 8.5 percent during the Test Period. This return is less than the 10.2 percent ROE the Company is requesting in this case, which produces a non-NPC revenue requirement of $876.3 million based on the 2010 Protocol allocation methodology. Exhibit PAC/1101 provides a summary of the Company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/1102 provides the supporting details and calculations and is discussed in greater detail later in my testimony.[1]

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

A. As noted above, the Company recovers its NPC through the TAM, which was filed on February 29, 2012 for calendar year 2013 NPC. To model the non-NPC revenue requirement for this case, the Company first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then

[1] The revenue requirement impact of the Mona-to-Oquirrh transmission investment is not included in Exhibits PAC/1101 or PAC/1102. As discussed later in my testimony, the revenue requirement associated with this investment is separately reflected in Exhibit PAC/1106 since the Company is not requesting rate recovery until the project is complete and used and useful.

removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as renewable energy tax credits, the hydro embedded cost differential ("Hydro ECD"), and the 2010 Protocol rate mitigation cap. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PAC/1101. Page 1.0 of Exhibit PAC/1102 also shows the division of revenue requirement between the TAM and general rate case components, and the resulting general rate case-related price change requested in this case.

Base Period

Q. Why did the Company use July 2010 through June 2011 as the historical basis, or Base Period, for the Test Period?

A. The Company selected the 12-month period ended June 2011 as the historical basis for this case because it was the most recent total company data available for inter-jurisdictional allocations to achieve a filing date of March 1, 2012. The Company audits and extracts total company accounting information with the data components necessary for state allocations on a semi-annual basis for the 12-month periods ending June and December each year. This semi-annual data extract and review procedure is a key control measure to ensure the accuracy and reliability of the data, which serves as the basis for each of the Company's results of operations and general rate case filings.

Q. Why was a March 1, 2012 filing date for this general rate case necessary?

A. In Order No. 09-274, the Commission adopted a stipulation establishing

guidelines for future TAM filings, including the following provision:

> In all future filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January 1 rate effective date*.[2]

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

Q. When will calendar year 2011 total company data become available on an inter-jurisdictional allocation basis?

A. Only once total company data is audited does it become available for analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total company financial data is finalized to ensure accurate state-allocated data. Due to these complex steps, calendar year 2011 data will not be available for use as the basis of a forecast test period until the end of April 2012, approximately two months after the general rate case filing commitment date of March 1.

Test Period

Q. What test period did the Company use to determine revenue requirement in this case?

A. The forecast Test Period used by the Company in this proceeding is the 12 months ending December 31, 2013.

Q. Why did the Company choose the year ending December 31, 2013, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during the

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

time the new rates will be in effect. Rates from this case will be effective no later than January 1, 2013, which matches the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this general rate case also matches the test period used in the development of the NPC filed in the TAM docket.

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

A. Revenue requirement preparation began with historical accounting information; in this case, the Company used the 12 months ended June 30, 2011. Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable and anticipated events.

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

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

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

A. Revenues are adjusted by applying the current Commission-approved tariff rates

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

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

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

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

A. The Company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified that needed to be adjusted in the rate case, the business units within the Company were asked to provide support for changes in the number, or frequency, of activities. An example of this type of adjustment is the Incremental O&M adjustment (adjustment page 4.9), which includes the cost of operating and maintaining new plants and transmission lines.

Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production, not changes in volume or processes.

Inter-Jurisdictional Allocations

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

A. The Company's Oregon-allocated revenue requirement is calculated using the 2010 Protocol inter-jurisdictional allocation method as described in the stipulation approved by the Commission in Order No. 11-244 in Docket UM 1050 ("MSP Docket") on July 5, 2011. This is the Company's first Oregon rate case filing since the Commission's approval of the 2010 Protocol. My testimony discusses how several aspects of the 2010 Protocol were dealt with in calculation of the Oregon revenue requirement, including the rate mitigation cap, the Hydro ECD, the Klamath Surcharge adjustment, and Class 1 Demand Side Management ("DSM") programs.

Q. Please explain the rate mitigation cap.

A. Included in the stipulation on the 2010 Protocol is an agreement to limit the impact of the 2010 Protocol on Oregon customers relative to the previously utilized Revised Protocol allocation method. The stipulation states:

> In order to mitigate risks associated with the potential rate impacts on Oregon customers, for all Company general rate case filings filed prior to December 31, 2016, the increase in the Oregon total revenue requirement (as finally determined by the Commission in each proceeding) as a result of the implementation of the 2010 Protocol shall be capped at 0.30 percent of the Company's Oregon

revenue requirement calculated under the Revised Protocol (as modified in Attachment 2 to this Stipulation).[3]

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

A. No. As shown on Page 1.1 of Exhibit PAC/1102, Oregon's revenue requirement under the Revised Protocol methodology plus 0.30 percent is $1,252.4 million, which is greater than the Oregon revenue requirement of $1,246.5 million calculated using the 2010 Protocol.[4] Consequently, the rate mitigation cap is not triggered and does not affect the Company's requested price change in this case.

Q. Please describe how the Hydro ECD is calculated in the Company's filing.

A. The Hydro ECD is calculated by comparing the cost per megawatt hour of the Company's west-side hydroelectric resources (including Mid-Columbia purchases) to the cost per megawatt hour of all other resources that were part of the Company's resource portfolio prior to the year 2005. The cost differential is then allocated to the Company's jurisdictions that were part of Pacific Power before the merger with Utah Power in 1989. In accordance with the 2010 Protocol stipulation, the costs of the hydroelectric and all other pre-2005 resources are updated to reflect Test Period cost elements. Details are provided on page 10.23 of Exhibit PAC/1102.

[3] *In the Matter of PacifiCorp Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket UM 1050, Order No. 11-244, Appendix A at 5 (July 5, 2011).

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

Q. Were any inter-jurisdictional allocation issues left unresolved by the stipulation and Commission order in the MSP Docket?

A. Yes. An on-going inter-jurisdictional allocation issue is the treatment of the Company's Class 1 DSM programs—the Idaho Irrigation Load Control program, the Utah Irrigation Load Control program, and the Utah Cool Keeper program. According to the Revised Protocol and the approved 2010 Protocol, Class 1 DSM programs are to be treated as situs resources; program costs are assigned directly to the host state, and program benefits in the form of reduced jurisdictional load are reflected in the host state's contribution to the monthly system coincident peaks. The Idaho Public Utilities Commission recently ordered that the Idaho Irrigation Load Control program would be system-allocated for purposes of setting rates in Idaho, and parties to the 2010 Protocol have been working to determine a path forward for the other states. The Oregon 2010 Protocol stipulation states:

> The Parties agree that the emerging issues related to the allocation of Class 1 DSM programs are not yet ripe for Commission action. The Parties agree that additional analysis and discussion of these issues should be undertaken in the MSP Standing Committee workgroup, and the Parties will endeavor to participate in the workgroup efforts to the extent possible. The Parties shall encourage the workgroup to develop a proposed resolution on these issues by the next MSP Commissioners' Forum. The Parties understand that the Company may make a subsequent filing with the Commission to address this discrete issue.[5]

Q. How are Class 1 DSM programs treated in this case?

A. Because no consensus has been reached among participants in the MSP Standing Committee workgroup regarding how to move this issue forward, the Company

[5] Order No. 11-244, Appendix A at 6.

has continued to treat Class 1 DSM programs as situs resources in this filing. This is the same treatment utilized in the 2010 general rate case. The MSP Standing Committee workgroup continues its work on this issue, and the Company may need to reflect the outcome of that process in this case if an agreement is reached that differs from current treatment.

Forecast Capital Additions

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

A. As mentioned in the direct testimony of Company witness Mr. Richard P. Reiten, the Company has included capital additions to plant in service through December 31, 2012, rather than through December 31, 2013, which is the end of the forecast Test Period and the rate effective period.

Q. Why has the Company limited forecast capital additions included in the revenue requirement to only those projects that will be placed in service prior to the beginning of the Test Period?

A. In the Company's 2009 general rate case, Docket UE 210, Commission Staff proposed the removal of approximately $116.6 million of capital investments forecast to be placed in service during the 2010 test year used in that case. These investments were proposed to be removed from rate base primarily under the premise that capital projects placed into service during the test period do not satisfy the used and useful standard under Oregon Revised Statute ("ORS") 757.355. The Company disagrees with Staff's interpretation of this statute and believes it is inconsistent with Commission precedent. But to

minimize controversy in this case and to mitigate the rate impact to customers, only capital projects with projected completion dates prior to January 1, 2013, the beginning of the Test Period in this filing, have been included in electric plant in service.

Carbon Plant Retirement

Q. Please describe the Company's proposed accounting treatment related to the anticipated closure of the Carbon plant.

A. As described in detail in the direct testimony of Company witness Mr. Chad A. Teply, the Company anticipates retiring the Carbon plant in early 2015 due to recent EPA standards. To ensure recovery of the remaining net plant and any associated decommissioning costs before the anticipated closure date, the Company is proposing to increase the depreciation rate used for the facility in order to fully depreciate the plant and recover any required decommissioning costs by April 15, 2015.

Q. How was the proposed depreciation rate developed?

A. As reflected in Confidential Exhibit PAC/1105, the depreciation rate was determined by using the net book value of the generation plant accounts, the projected decommissioning costs, and the number of remaining months of plant operation prior to the anticipated retirement date of April 15, 2015. Using these factors a Carbon plant composite accelerated depreciation rate was calculated.

Q. What is the Company's proposed start date of the revised Carbon plant depreciation rate?

A. The Company proposes the new depreciation rate become effective January 1,

2013, consistent with the beginning of the rate effective period in this case.

Q. Will the Company need to adjust this rate to accommodate plant additions, retirements, or changes in projected decommissioning costs associated with the facility?

A. Yes. The depreciation rate would require an update to accommodate any plant additions or retirements as well as any change to the projected decommissioning costs of the facility. The Company requests that as the net book value of the Carbon plant fluctuates each month due to capital additions, retirements, or if there is a change in the projected decommissioning costs, the associated depreciation rates be adjusted to fully depreciate the project by the end of the expected life. This requested treatment is similar to that approved for the depreciation of the Klamath hydroelectric project in Order No. 10-325 in Docket UE 219.

Q. Is a normalizing adjustment for the accelerated depreciation of the Carbon plant included as part of the Company's revenue requirement in these proceedings?

A. Yes. Adjustment page 8.15, discussed later in my testimony, describes the normalizing adjustment reflected in Exhibit PAC/1102 that incorporates the revenue requirement impacts of the accelerated depreciation of the Carbon plant into the Test Period.

Mona-to-Oquirrh Transmission Investment

Q. Please describe the revenue requirement associated with the Mona-to-Oquirrh transmission investment.

A. As discussed by Company witness Mr. Darrell T. Gerrard, the Company projects to complete the Mona-to-Oquirrh transmission investment in the second quarter of 2013. Exhibit PAC/1106 shows the projected capital investment, depreciation expense and reserve, O&M expense, and tax impacts associated with this project. Page two of this exhibit shows the overall Oregon revenue requirement of $13.1 million for this investment. The other pages in this exhibit provide supporting documentation for the figures used to determine the Oregon revenue requirement impact.

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

A. As discussed in the direct testimony of Company witness Mr. William R. Griffith, the Company is proposing to recover the revenue requirement associated with this investment through a separate tariff, following a prudence review in this case, once the project becomes used and useful.

Oregon Results of Operations

Q. Please describe Exhibit PAC/1102.

A. Exhibit PAC/1102, which was prepared under my direction, is the Company's Oregon results of operations report ("Report"). As previously explained, the Base Period for the Report is the 12 months ended June 30, 2011, which has been normalized and used to calculate the revenue requirement for the Test Period, the

12 months ending December 31, 2013. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base, and loads in the Test Period. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PAC/1102 is organized.

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

- Tab 1 Summary contains a summary of Oregon-allocated results according to the 2010 Protocol allocation methodology. Page 1.0 breaks out the non-NPC results and calculates the required price increase the Company is requesting as part of this general rate case (column 5). Page 1.2 contains a summary of the general rate case request.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by Federal Energy Regulatory Commission ("FERC") account and 2010 Protocol allocation factor.
- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company.
- Tab 9 is a restatement of Tab 2 with the Oregon allocation based on the Revised Protocol method, as required by Commission Order No. 11-244.

- Tab 10 contains the calculation of the 2010 Protocol allocation factors. Factors in this case are based on the load forecast through December 2013 and pro forma account balances.
- Tab 11 contains the Company's most recent lead lag study, which is based on calendar year 2010 data.
- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

Tab 3 – Revenue Adjustments

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

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

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

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

Wheeling Revenue (page 3.2) – This adjustment reflects the level of wheeling revenue for the Test Period by adjusting the actual revenue for normalizing, annualizing, and pro forma changes. Imbalance penalty revenue and expense is removed to avoid any impact on regulated results.

Sulfur Dioxide ("SO_2") Emission Allowances (page 3.3) – The EPA has established guidelines that govern the volume of SO_2 that can be emitted from power plants and granted the issuance of SO_2 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. This adjustment reflects the gain on sales of SO_2 allowances based on a four-year amortization period ending December 2013. This is the same methodology included in the Company's last three general rate cases, Dockets UE 179, UE 210, and UE 217.

Renewable Energy Credit ("REC") Revenues (page 3.4) – This adjustment removes all REC revenue as booked during the 12 months ended June 2011. Most of Oregon's share of the renewable energy credits ("RECs") is banked for compliance; however, not all RECs meet the Oregon Renewable Portfolio Standard ("RPS") qualifications. Oregon's revenue from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in Docket UP 260.

Ancillary Revenue (page 3.5) – In December 2011, the Company renewed its contract with Seattle City Light ("SCL") to receive real time output from SCL's share of the Stateline wind farm and return power two months later. The ancillary

revenue booked in the 12 months ended June 2011 is adjusted to reflect the Test Period revenue expected per the terms of the new contract. The impact on NPC is included in adjustment 5.1 and in the TAM.

Tab 4 – O&M Adjustments

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

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

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

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

Wage and Employee Benefits (page 4.2) – Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, and post-employment benefits for changes expected beyond the actual costs experienced in the period ended

June 2011. Company witness Mr. Erich D. Wilson's testimony provides an overview of the compensation and benefit plans provided to employees at the Company and supports the costs related to these areas included in the Test Period.

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

Page 4.2.1 of the Report provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual labor costs in the year ended June 2011 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Q. Please explain the treatment of workforce levels included in the Test Period.

A. The Test Period assumes no change to the level of workforce included in the Base Period. As noted in the direct testimony of Mr. Richard P. Reiten, this case reflects 194 fewer Full Time Equivalents ("FTEs") than the level included in the Company's last general rate case, Docket UE 217.

Q. Please continue with the description of O&M adjustments included in Tab 4.

A. **Idaho Irrigation Load Control (page 4.3) –** Incentive payments made to Idaho customers participating in the irrigation load control program and a portion of the program's administrative costs are initially system allocated in unadjusted accounting data. Consistent with the 2010 Protocol, DSM costs are situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in the inter-jurisdictional allocation factors. This adjustment corrects the booked allocation to assign these costs directly to Idaho. As previously discussed, allocation of Class 1 DSM programs continues to be reviewed by the MSP standing committee workgroup. If the MSP standing committee reaches agreement on proposed changes to the treatment of some or all of the Company's Class 1 DSM programs for purposes of allocations, then the Company may need to revise the treatment of Class 1 DSM programs in this case.

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

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

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

Insurance Expense (page 4.7) – This adjustment reflects the end of coverage by the captive insurance company on March 21, 2011. The Company has replaced captive insurance with self-insurance accruals for liability and property insurance per the stipulation approved by the Commission in Order No. 10-473 in Docket UE 217. This adjustment also removes the entries related to the set-up of a California regulatory asset.

Generation Overhaul Expense (page 4.8) – This adjustment normalizes generation overhaul expenses in the Base Period using a four-year average methodology. In this adjustment, overhaul expenses from June 2008 to June 2010 are restated to constant dollars to make them comparable prior to averaging. For new generating units, which include Lake Side and Chehalis, the four-year average is comprised of the overhaul expense for the first four full years these plants are operational.

Incremental O&M (page 4.9) – This adjustment adds incremental O&M to the Base Period to bring it to the projected O&M level for the 12 months ending December 2013, after accounting for Global Insight inflation escalation applied in adjustment page 4.12. See also the direct testimonies of Company witnesses Mr. Mark R. Tallman and Mr. Dana M. Ralston.

Intercompany Administrative Service Agreement ("IASA") Adjustment (page 4.10) – The portion of the IASA expenses related to the Supplemental Executive Retirement Plan ("SERP") and legislative activity are removed from the Test Period in this adjustment.

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

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

The IHS Global Insight indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The IHS Global Insight study used to prepare this filing was the fourth quarter 2011 forecast, released February 3, 2012. The IHS Global Insight data is proprietary and subject to copyright protection, therefore the

indices utilized in the Company's case are provided in Confidential Exhibit PAC/1107.

Tab 5 – Net Power Cost Adjustments

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

A. Tab 5 includes adjustments to items that are generally related to NPC, but may or may not be addressed separately in the Company's TAM filings. Specifically, adjustment page 5.1, Net Power Costs relates solely to NPC and recovery of these costs is being sought in the TAM docket rather than the general rate case. This adjustment is included for modeling and computational purposes only. For example, Test Period revenue requirement includes a tax credit for renewable energy generated from renewable facilities (adjustment page 7.3). This tax credit is calculated based on the generation output of these facilities as modeled in GRID (adjustment page 5.1) for the Test Period. Adjustment pages 5.2 through 5.6 include items that are not addressed in the Company's TAM filing with the exception of the Black Cap Solar, LLC Project (adjustment page 5.6), which includes revenue requirement components in both the TAM and the general rate case.

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

affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1) –** This adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling, and fuel in a manner consistent with the contractual terms of sales and purchase agreements, as well as normal hydro and temperature conditions for the 12-month period ending December 2013. The GRID study for this adjustment is based on forecasted loads for the period. As I previously described, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; NPC is not part of the revenue requirement for the general rate case.

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

Little Mountain (page 5.3) – The Company has provided both electricity and steam from its Little Mountain plant to the Great Salt Lake Minerals Company

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

Electric Lake Settlement (page 5.4) – Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake, Utah. Electric Lake is owned by the Company and provides water for the Huntington power plant. The two companies disputed the claim made by the Company that CFC's mining operations punctured the lake and caused water to flow into the Skyline mine. The two companies negotiated a settlement and release agreement for the claims made by the Company. Because the amortization for this settlement ended in January 2011, this adjustment removes the amortization of savings from actual results.

Bonneville Power Administration ("BPA") Residential Exchange (page 5.5) – The Company receives a monthly purchase power credit from BPA. This credit is treated as a 100 percent pass-through to eligible customers. Both a revenue credit

and a purchase power expense credit are posted to unadjusted results. This adjustment reverses the BPA purchase power expense credit recorded in unadjusted results. The revenue credit is removed from Test Period results in the Pro Forma Revenues adjustment, page 3.1.

Black Cap Solar LLC Project (page 5.6) – As described in the direct testimony of Company witness Mr. Bruce W. Griswold, this adjustment accounts for the Test Period costs related to the Black Cap Solar, LLC project, which is projected to become operational in October 2012. This adjustment adds the O&M expense, the lease payment expense, and the land balance associated with the project to the Test Period. The NPC benefit associated with this project is included in adjustment page 5.1, NPC and is reflected in the TAM. Confidential Exhibit PAC/1103 provides additional information related to the figures shown on page 5.6.

Because this project is being procured to satisfy the Company's obligation under ORS 757.370, it is classified as a state specific initiative under the 2010 Protocol allocation methodology. Accordingly, the costs and benefits associated with this project are situs assigned to Oregon customers.

Tab 6 – Depreciation and Amortization Expense Adjustments

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

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation

and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1)** – This adjustment reflects the incremental depreciation expense associated with the capital additions included in the filing in the plant additions adjustment, page 8.6. The annualized level of 2012 depreciation and amortization expense for the Test Period is calculated by applying composite depreciation and amortization rates to the December 2012 pro forma plant balances. Rates used are those approved by the Commission in Docket UM 1329, effective January 1, 2008. Details are provided on pages 6.1 through 6.1.13.

Depreciation and Amortization Reserve (page 6.2) – This adjustment steps forward the depreciation and amortization reserve from the Base Period to a December 2012 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to Base Period balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2011, to December 31, 2012. An incremental reserve amount has been added to the December 31, 2012 balances to reflect the annualized level of depreciation and

amortization expense included on page 6.1. The reserve balance calculations are detailed on pages 6.2 to 6.2.14.

Tab 7 – Tax Adjustments

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

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

Q. Please describe the adjustments included in Tab 7.

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

Property Tax Expense (page 7.2) – Property tax expense for the Test Period is computed by adjusting accruals from the Base Period for known or anticipated changes in the assessed values of the Company's operating property and the corresponding effect such changes will have on property tax expense for the Test Period. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1104.

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

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

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

Medicare Deferred Accounting (page 7.5) – As established in Dockets UM 1479 and UE 217, this adjustment recognizes the amortization of the Medicare deferral regulatory asset for the Test Period. This adjustment also normalizes the Base Period deferred income tax expense for a recent change in tax law. With the change in law, some of the costs related to other post-retirement benefits become non-deductible for income tax purposes.

Pro Forma Schedule M (page 7.6) – This adjustment normalizes the Schedule M to an estimated pro forma level of expense for the Test Period. The significant

change in tax depreciation is primarily driven by the reduced bonus depreciation available in the Test Period as compared to the Base Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

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

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

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

ADIT Corrections Adjustment (page 7.10) – This adjustment corrects allocation factors used to allocate accumulated deferred income tax balances and a schedule M.

Franchise and Resource Supplier Taxes (page 7.11) – This adjustment normalizes the Base Period Oregon Franchise Tax and the Oregon Energy Resource Supplier Assessment to the Test Period level based on pro forma revenues in adjustment page 3.1.

Tab 8 – Rate Base Adjustments

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

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components. The numerical summary (pages 8.0.2 – 8.0.3) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

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

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital balance included in rate base using the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net

lag days in this case are based on the lead lag study prepared by the Company using calendar year 2010 information. A complete copy of the 2010 study is provided in Tab 11 of the Report.

Trapper Mine Rate Base (page 8.2) – The Company owns a 21.4 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base and reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks the reclamation liability forward to December 2012. This adjustment was stipulated to and approved in Docket UE 111 and has been included in all Oregon rate case filings since.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the Company's portion of the pro forma December 31, 2012 net

plant balance to rate base. This adjustment was stipulated to and approved in Docket UE 111 and has been included in all Oregon rate case filings since.

Environmental Settlement (page 8.4) – The Company received an insurance settlement of $38 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company ("PERCO"). Any unspent cash proceeds from the insurance settlement are reflected as a reduction to rate base. The Company expects these cash proceeds to be exhausted prior to December 31, 2012. Accordingly, no reduction to rate base is reflected in the Test Period.

Customer Advances for Construction (page 8.5) – Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Plant Additions (page 8.6) – To reasonably represent the cost of system infrastructure required to serve customers, the Company has identified capital projects that will be used and useful by December 31, 2012.

Capital additions by FERC functional category are listed on pages 8.6.5 to 8.6.14, indicating the in-service date and amount by project. This adjustment is based on plant balances as of December 31, 2012. As described earlier in my testimony, the accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements. Projects over $5 million (total company basis) are described on pages 8.6.15 through 8.6.20 of the Report.

This adjustment does not include the impact of the Mona-to-Oquirrh

transmission investment, which is reflected in Exhibit PAC/1106. As discussed earlier in my testimony, the Company is requesting recovery of the revenue requirement associated with this project as a separate tariff rider.

Plant Retirements (page 8.7) – Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through December 31, 2012. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

Miscellaneous Rate Base (page 8.8) – This adjustment reflects the change in the fuel stock balance from the Base Period to the Test Period. This adjustment also reflects the working capital deposits that are offsets to fuel stock costs. In addition, balances for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural gas plants are walked forward to reflect payments and transfers of capital to electric plant in service through December 31, 2012.

Powerdale Hydro Removal (page 8.9) – This adjustment removes costs related to the Powerdale hydroelectric plant from results. Powerdale was decommissioned after it was damaged by a flood in November 2006. Deferred accounting for the unrecovered plant balance was authorized by the Commission in Docket UM 1298 and was fully amortized December 2010. Consistent with Dockets UE 210 and UE 217, the Company amortized the decommissioning regulatory asset beginning January 1, 2010. This regulatory asset will be fully

amortized before the beginning of the rate effective period in this case. Accordingly, this adjustment removes the O&M expense associated with the plant, the amortization expense related to the unrecovered plant regulatory asset, and the decommissioning regulatory asset balance.

Regulatory Asset Amortization (page 8.10) – This adjustment normalizes regulatory assets from the Base Period to the Test Period. In addition, in Docket UE 210, the Company agreed to set up tariff riders to collect the balance of the Grid West, the 2000 Transition Plan, and the MidAmerican Energy Holdings Company ("MEHC") Oregon Transition Plan regulatory assets. These separate tariff riders are credited to revenues when collected and removed from revenues in the Pro Forma Revenue adjustment page 3.1. These regulatory assets are amortized in unadjusted results by charging expense. This adjustment removes that expense.

Klamath Hydroelectric Settlement Agreement ("KHSA") (page 8.11) – This adjustment accounts for the total Test Period costs related to the KHSA. As approved by the Commission in Docket UE 219, effective January 1, 2011, the depreciation of existing Klamath facilities is being accelerated so that assets will be fully depreciated by December 31, 2019. Relicensing and settlement process costs are also amortized at a rate that will achieve a zero net book value by December 31, 2019.

In accordance with the 2010 Protocol methodology, the KHSA dam removal surcharge expense is initially system allocated, but it is then re-allocated to Oregon and California through the Klamath surcharge adjustment included in

the 2010 Protocol Hydro ECD. Additional Oregon and California general business revenues reflected in this adjustment are for purposes of the calculation of the 2010 Protocol allocation only. These revenues fully offset the facility removal costs included through this adjustment to FERC account 557 and the Klamath surcharge adjustment included in the 2010 Protocol Hydro ECD.

The testimony of Company witness Mr. Tallman provides detail regarding the Klamath O&M expense required for the Test Period.

Miscellaneous Asset Sales and Removals (page 8.12) – This adjusts the Company's Base Period for various assets that were sold or removed, including the sale of transmission assets to Black Hills Power, the sale of Snake Creek hydroelectric plant to Heber Light and Power Company, the removal of Deseret Power's portion of the Hunter unit two scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the removal of the Goose Creek switching station. Asset balances for Snake Creek and Condit are removed in the adjustment to plant retirements, page 8.7. The Oregon allocated proceeds related to the gain on the sale of Snake Creek will be placed in the property sales balancing account and passed through to customers in Schedule 96, Property Sales Balancing Account Adjustment, as outlined in Docket UP 275, Commission Order No. 11-331.

Remove Rolling Hills (page 8.13) – This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. This treatment is consistent with Commission Order No. 08-548.

Plant Held for Future Use ("PHFU") (page 8.14) – This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Commission Order No. 01-787.

Carbon Plant Retirement (page 8.15) – As discussed earlier in my testimony, this adjustment includes the impact of accelerated depreciation for the Carbon plant. Depreciation of the Carbon plant is accelerated so that assets are fully depreciated by April 15, 2015. The Carbon plant is depreciated using Commission-approved rates from the end of the Base Period through December 31, 2012. The level of expense reflected in the Test Period is based on an annualized level of depreciation expense using the proposed accelerated rate. Confidential Exhibit PAC/1105 provides supporting information for the figures shown on page 8.15 of the Report.

Tab 9 – Revised Protocol

Q. Please describe the information contained behind Tab 9.

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

Tab 10 – Allocation Factors

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

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

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

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

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

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

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

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

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

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

Tab 11 – 2010 Lead Lag Study

Q. Please describe the information contained behind Tab 11.

A. Tab 11 reflects a copy of the Company's most recent lead lag study, which was based on calendar year 2010 data. The Company relies on the lead lag study method to develop the cash working capital balance included in rate base as discussed in adjustment page 8.1.

The 2010 lead lag study is consistent with the methodology used by the Company in its 2007 lead lag study, which was used in the Company's last two rate case filings, Dockets UE 210 and UE 217. The Company's 2010 lead lag study shows net lag days in Oregon of 7.34, meaning that investors must infuse cash into the business for day-to-day operations. An electronic version of the study is also provided as part of the Company's workpapers.

Tabs B1 – B20

Q. Please describe the information contained behind Tabs B1 – B-20.

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

Q. Does this conclude your direct testimony?

A. Yes.

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

		(1)	(2) (3) - (1)	(3)	TAM	(4) GRC	(3) + (4) + (5)
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	360,255,677	837,942,989	1,198,198,666	9,902,753	38,356,265	1,246,457,684
3	Interdepartmental		-	-			-
4	Special Sales	118,916,679	1,018,526	119,935,205			119,935,205
5	Other Operating Revenues		39,568,077	39,568,077			39,568,077
6	Total Operating Revenues	479,172,356	878,529,592	1,357,701,948	9,902,753	38,356,265	1,405,960,966
7							
8	Operating Expenses:						
9	Steam Production	190,833,068	88,353,010	279,186,078			279,186,078
10	Nuclear Production		-	-			-
11	Hydro Production		12,991,451	12,991,451			12,991,451
12	Other Power Supply	264,379,285	33,429,429	297,808,714			297,808,714
13	Embedded Cost Differential (ECD)		5,971,123	5,971,123			5,971,123
14	Transmission	33,862,757	17,513,087	51,375,843			51,375,843
15	Distribution		70,646,415	70,646,415			70,646,415
16	Customer Accounting		35,339,085	35,339,085		249,290	35,588,375
17	Customer Service & Info		4,061,969	4,061,969			4,061,969
18	Sales		-	-			-
19	Administrative & General		45,484,898	45,484,898			45,484,898
20							
21	Total O&M Expenses	489,075,109	313,790,468	802,865,577	-	249,290	803,114,867
22							
23	Depreciation		178,458,250	178,458,250			178,458,250
24	Amortization		13,807,399	13,807,399			13,807,399
25	Taxes Other Than Income		65,230,076	65,230,076		1,148,565	66,378,640
26	Income Taxes - Federal	(3,308,609)	(749,100)	(4,057,709)	3,308,609	12,348,174	11,599,074
27	Income Taxes - State	(449,585)	1,999,113	1,549,528	449,585	1,677,912	3,677,025
28	Income Taxes - Def Net		71,514,522	71,514,522			71,514,522
29	Investment Tax Credit Adj.		-	-			-
30	Misc Revenue & Expense		(346,250)	(346,250)			(346,250)
31							
32	Total Operating Expenses:	485,316,915	643,704,479	1,129,021,394	3,758,194	15,423,941	1,148,203,529
33							
34	Operating Rev For Return:	(6,144,559)	234,825,114	228,680,554	6,144,559	22,932,324	257,757,438
35							
36	Rate Base:						
37	Electric Plant In Service		6,407,404,503	6,407,404,503			6,407,404,503
38	Plant Held for Future Use		-	-			-
39	Misc Deferred Debits		22,573,238	22,573,238			22,573,238
40	Elec Plant Acq Adj		11,260,952	11,260,952			11,260,952
41	Nuclear Fuel		-	-			-
42	Prepayments		7,666,103	7,666,103			7,666,103
43	Fuel Stock		50,782,521	50,782,521			50,782,521
44	Material & Supplies		54,123,489	54,123,489			54,123,489
45	Working Capital		27,888,103	27,888,103			27,888,103
46	Weatherization Loans		(1,210)	(1,210)			(1,210)
47	Misc Rate Base		-	-			-
48							
49	Total Electric Plant:	-	6,581,697,699	6,581,697,699			6,581,697,699
50							
51	Rate Base Deductions:						
52	Accum Prov For Deprec		(2,198,381,147)	(2,198,381,147)			(2,198,381,147)
53	Accum Prov For Amort		(140,097,658)	(140,097,658)			(140,097,658)
54	Accum Def Income Tax		(960,764,357)	(960,764,357)			(960,764,357)
55	Unamortized ITC		(1,115,967)	(1,115,967)			(1,115,967)
56	Customer Adv For Const		(11,392,393)	(11,392,393)			(11,392,393)
57	Customer Service Deposits		-	-			-
58	Misc Rate Base Deductions		(15,987,319)	(15,987,319)			(15,987,319)
59							
60	Total Rate Base Deductions	-	(3,327,738,840)	(3,327,738,840)			(3,327,738,840)
61							
62	Total Rate Base:	-	3,253,958,859	3,253,958,859			3,253,958,859
63							
64	Return on Rate Base			7.028%			7.921%
65							
66	Return on Equity			8.508%			10.200%

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) **GRC** Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	837,942,989	38,356,265	876,299,254
3	Interdepartmental	-		-
4	Special Sales	1,018,526		1,018,526
5	Other Operating Revenues	39,568,077		39,568,077
6	Total Operating Revenues	878,529,592	38,356,265	916,885,857
7				
8	Operating Expenses:			
9	Steam Production	88,353,010		88,353,010
10	Nuclear Production	-		-
11	Hydro Production	12,991,451		12,991,451
12	Other Power Supply	33,429,429		33,429,429
13	Embedded Cost Differential (ECD)	5,971,123		5,971,123
14	Transmission	17,513,087		17,513,087
15	Distribution	70,646,415		70,646,415
16	Customer Accounting	35,339,085	249,290	35,588,375
17	Customer Service & Info	4,061,969		4,061,969
18	Sales	-		-
19	Administrative & General	45,484,898		45,484,898
20				
21	Total O&M Expenses	313,790,468	249,290	314,039,758
22				
23	Depreciation	178,458,250		178,458,250
24	Amortization	13,807,399		13,807,399
25	Taxes Other Than Income	65,230,076	1,148,565	66,378,640
26	Income Taxes - Federal	(749,100)	12,348,174	11,599,074
27	Income Taxes - State	1,999,113	1,677,912	3,677,025
28	Income Taxes - Def Net	71,514,522		71,514,522
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(346,250)		(346,250)
31				
32	Total Operating Expenses:	643,704,479	15,423,941	659,128,419
33				
34	Operating Rev For Return:	234,825,114	22,932,324	257,757,438
35				
36	Rate Base:			
37	Electric Plant In Service	6,407,404,503		6,407,404,503
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	22,573,238		22,573,238
40	Elec Plant Acq Adj	11,260,952		11,260,952
41	Nuclear Fuel	-		-
42	Prepayments	7,666,103		7,666,103
43	Fuel Stock	50,782,521		50,782,521
44	Material & Supplies	54,123,489		54,123,489
45	Working Capital	27,888,103		27,888,103
46	Weatherization Loans	(1,210)		(1,210)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,581,697,699	-	6,581,697,699
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,198,381,147)		(2,198,381,147)
53	Accum Prov For Amort	(140,097,658)		(140,097,658)
54	Accum Def Income Tax	(960,764,357)		(960,764,357)
55	Unamortized ITC	(1,115,967)		(1,115,967)
56	Customer Adv For Const	(11,392,393)		(11,392,393)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(15,987,319)		(15,987,319)
59				
60	Total Rate Base Deductions	(3,327,738,840)	-	(3,327,738,840)
61				
62	Total Rate Base:	3,253,958,859	-	3,253,958,859
63				
64	Return on Rate Base	7.217%		7.921%
65				
66	Return on Equity	8.865%		10.200%
67				
68	TAX CALCULATION:			
69	Operating Revenue	307,589,649	36,958,410	344,548,059
70	Other Deductions			
71	Interest (AFUDC)	(14,012,032)	-	(14,012,032)
72	Interest	81,982,452	-	81,982,452
73	Schedule "M" Additions	221,999,907	-	221,999,907
74	Schedule "M" Deductions	415,357,745	-	415,357,745
75	Income Before Tax	46,261,391	36,958,410	83,219,801
76				
77	State Income Taxes	1,999,113	1,677,912	3,677,025
78	Taxable Income	44,262,278	35,280,499	79,542,776
79				
80	Federal Income Taxes + Other	(749,100)	12,348,174	11,599,074

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2013

TAM RESULTS

		(1) Total Adjusted Results	(2) **TAM** Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	360,255,677	9,902,753	370,158,430
3	Interdepartmental	-		-
4	Special Sales	118,916,679		118,916,679
5	Other Operating Revenues	-		-
6	Total Operating Revenues	479,172,356	9,902,753	489,075,109
7				
8	Operating Expenses:			
9	Steam Production	190,833,068		190,833,068
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	264,379,285		264,379,285
13	Embedded Cost Differential (ECD)	-		-
14	Transmission	33,862,757		33,862,757
15	Distribution	-		-
16	Customer Accounting	-	-	-
17	Customer Service & Info	-		-
18	Sales	-		-
19	Administrative & General	-		-
20				
21	Total O&M Expenses	489,075,109	-	489,075,109
22				
23	Depreciation	-		-
24	Amortization	-		-
25	Taxes Other Than Income	-	-	-
26	Income Taxes - Federal	(3,308,609)	3,308,609	(0)
27	Income Taxes - State	(449,585)	449,585	(0)
28	Income Taxes - Def Net	-		-
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	-		-
31				
32	Total Operating Expenses:	485,316,915	3,758,194	489,075,109
33				
34	Operating Rev For Return:	(6,144,559)	6,144,559	-
35				
36	Rate Base:			
37	Electric Plant In Service	-		-
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	-		-
40	Elec Plant Acq Adj	-		-
41	Nuclear Fuel	-		-
42	Prepayments	-		-
43	Fuel Stock	-		-
44	Material & Supplies	-		-
45	Working Capital	-		-
46	Weatherization Loans	-		-
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	-	-	-
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	-		-
53	Accum Prov For Amort	-		-
54	Accum Def Income Tax	-		-
55	Unamortized ITC	-		-
56	Customer Adv For Const	-		-
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	-		-
59				
60	Total Rate Base Deductions	-	-	-
61				
62	Total Rate Base:	-	-	-
63				
64	Return on Rate Base	N/A		N/A
65				
66	Return on Equity	N/A		N/A
67				
68	TAX CALCULATION:			
69	Operating Revenue	(9,902,753)	9,902,753	-
70	Other Deductions	-		
71	Interest (AFUDC)	-	-	-
72	Interest	-	-	-
73	Schedule "M" Additions	-	-	-
74	Schedule "M" Deductions	-	-	-
75	Income Before Tax	(9,902,753)	9,902,753	-
76				
77	State Income Taxes	(449,585)	449,585	(0)
78	Taxable Income	(9,453,168)	9,453,168	0
79				
80	Federal Income Taxes + Other	(3,308,609)	3,308,609	(0)

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,198,198,666	48,259,018	1,246,457,684
3	Interdepartmental	-		-
4	Special Sales	119,935,205		119,935,205
5	Other Operating Revenues	39,568,077		39,568,077
6	Total Operating Revenues	1,357,701,948	48,259,018	1,405,960,966
7				
8	Operating Expenses:			
9	Steam Production	279,186,078		279,186,078
10	Nuclear Production	-		-
11	Hydro Production	12,991,451		12,991,451
12	Other Power Supply	297,808,714		297,808,714
13	Embedded Cost Differential (ECD)	5,971,123		5,971,123
14	Transmission	51,375,843		51,375,843
15	Distribution	70,646,415		70,646,415
16	Customer Accounting	35,339,085	249,290	35,588,375
17	Customer Service & Info	4,061,969		4,061,969
18	Sales	-		-
19	Administrative & General	45,484,898		45,484,898
20				
21	Total O&M Expenses	802,865,577	249,290	803,114,867
22				
23	Depreciation	178,458,250		178,458,250
24	Amortization	13,807,399		13,807,399
25	Taxes Other Than Income	65,230,076	1,148,565	66,378,640
26	Income Taxes - Federal	(4,057,709)	15,656,783	11,599,074
27	Income Taxes - State	1,549,528	2,127,497	3,677,025
28	Income Taxes - Def Net	71,514,522		71,514,522
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(346,250)		(346,250)
31				
32	Total Operating Expenses:	1,129,021,394	19,182,135	1,148,203,529
33				
34	Operating Rev For Return:	228,680,554	29,076,883	257,757,438
35				
36	Rate Base:			
37	Electric Plant In Service	6,407,404,503		6,407,404,503
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	22,573,238		22,573,238
40	Elec Plant Acq Adj	11,260,952		11,260,952
41	Nuclear Fuel	-		-
42	Prepayments	7,666,103		7,666,103
43	Fuel Stock	50,782,521		50,782,521
44	Material & Supplies	54,123,489		54,123,489
45	Working Capital	27,888,103		27,888,103
46	Weatherization Loans	(1,210)		(1,210)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,581,697,699	-	6,581,697,699
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,198,381,147)		(2,198,381,147)
53	Accum Prov For Amort	(140,097,658)		(140,097,658)
54	Accum Def Income Tax	(960,764,357)		(960,764,357)
55	Unamortized ITC	(1,115,967)		(1,115,967)
56	Customer Adv For Const	(11,392,393)		(11,392,393)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(15,987,319)		(15,987,319)
59				
60	Total Rate Base Deductions	(3,327,738,840)	-	(3,327,738,840)
61				
62	Total Rate Base:	3,253,958,859	-	3,253,958,859
63				
64	Return on Rate Base	7.028%		7.921%
65				
66	Return on Equity	8.508%		10.200%
67				
68	TAX CALCULATION:			
69	Operating Revenue	297,686,895	46,861,164	344,548,059
70	Other Deductions			
71	Interest (AFUDC)	(14,012,032)	-	(14,012,032)
72	Interest	81,982,452	-	81,982,452
73	Schedule "M" Additions	221,999,907	-	221,999,907
74	Schedule "M" Deductions	415,357,745	-	415,357,745
75	Income Before Tax	36,358,638	46,861,164	83,219,801
76				
77	State Income Taxes	1,549,528	2,127,497	3,677,025
78	Taxable Income	34,809,110	44,733,667	79,542,776
79				
80	Federal Income Taxes + Other	(4,057,709)	15,656,783	11,599,074

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Exhibit PAC/1102		Exhibit PAC/1102			
				Tab 3	Tab 4	Tab 5	Tab 6
		TOTAL COMPANY ACTUAL RESULTS JUNE 2011	OREGON ALLOCATED ACTUAL RESULTS JUNE 2011	Revenue Adjustments	O&M Adjustments	NPC Adjustments	Deperciation & Amortization Adjustments
1	Operating Revenues:						
2	General Business Revenues	3,762,226,028	1,057,442,897	124,931,769	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	379,179,495	96,385,126	-	-	23,550,079	-
5	Other Operating Revenues	323,231,828	82,319,797	(21,566,614)	(21,405,215)	220,109	-
6	Total Operating Revenues	4,464,637,351	1,236,147,820	103,365,155	(21,405,215)	23,770,188	-
7							
8	Operating Expenses:						
9	Steam Production	991,002,147	245,482,444	-	5,069,635	28,633,999	-
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	43,249,454	11,148,479	-	1,847,203	-	-
12	Other Power Supply	900,802,841	211,830,165	-	(2,749,297)	84,763,922	-
13	Embedded Cost Differential (ECD)	0	5,971,123	-	-	-	-
13	Transmission	203,395,397	52,337,448	(226,615)	870,910	(1,591,989)	-
14	Distribution	211,900,030	67,278,537	-	3,367,878	-	-
15	Customer Accounting	95,209,362	33,934,000	-	1,797,065	-	-
16	Customer Service & Info	113,969,877	25,306,096	-	(21,244,127)	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	153,962,449	46,200,310	-	706,514	-	-
19							
20	Total O&M Expenses	2,713,491,556	699,488,603	(226,615)	(10,334,219)	111,805,932	-
21							
22	Depreciation	515,564,333	145,412,589	-	-	-	21,767,438
23	Amortization	48,399,074	13,236,640	-	-	-	189,821
24	Taxes Other Than Income	146,842,558	57,011,768	-	-	-	-
25	Income Taxes - Federal	(618,010,179)	(132,163,391)	34,560,516	(3,690,076)	(29,427,530)	(5,813,854)
26	Income Taxes - State	(76,306,062)	(15,981,563)	4,696,200	(501,420)	(3,998,713)	(790,006)
27	Income Taxes - Def Net	922,130,589	227,767,405	113,394	(3,712)	-	-
28	Investment Tax Credit Adj.	(1,874,204)	-	-	-	-	-
29	Misc Revenue & Expense	(1,689,284)	(217,418)	(164,185)	35,353	-	-
30							
31	Total Operating Expenses:	3,648,548,381	994,554,634	38,979,310	(14,494,074)	78,379,690	15,353,399
32							
33	Operating Rev For Return:	816,088,970	241,593,186	64,385,845	(6,911,141)	(54,609,502)	(15,353,399)
34							
35	Rate Base:						
36	Electric Plant In Service	22,157,283,708	6,037,881,175	-	-	75,000	-
37	Plant Held for Future Use	45,021,478	13,629,778	-	-	-	-
38	Misc Deferred Debits	213,788,714	20,003,579	-	-	-	-
39	Elec Plant Acq Adj	54,568,258	14,066,144	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-
41	Prepayments	28,443,124	7,666,103	-	-	-	-
42	Fuel Stock	218,254,887	53,065,443	-	-	-	-
43	Material & Supplies	190,997,513	54,123,489	-	-	-	-
44	Working Capital	71,478,693	22,808,093	785,355	(292,283)	1,577,139	(132,881)
45	Weatherization Loans	(35,682)	(1,210)	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	22,979,800,693	6,223,242,594	785,355	(292,283)	1,652,139	(132,881)
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	(6,903,348,317)	(2,012,312,865)	-	-	-	(174,810,209)
52	Accum Prov For Amort	(471,314,196)	(131,000,526)	-	-	-	(5,898,357)
53	Accum Def Income Tax	(3,103,714,231)	(836,216,537)	76,560	(1,774,653)	-	-
54	Unamortized ITC	(4,857,544)	(3,084,689)	-	-	-	-
55	Customer Adv For Const	(27,863,920)	(11,273,844)	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	(63,364,442)	(15,785,584)	(201,735)	-	-	-
58							
59	Total Rate Base Deductions	(10,574,462,650)	(3,009,674,046)	(125,174)	(1,774,653)	-	(180,708,566)
60							
61	Total Rate Base:	12,405,338,043	3,213,568,548				
62							
63	Return on Rate Base	6.579%	7.518%	2.002%	-0.209%	-1.704%	-0.053%
64							
65	Return on Equity	7.657%	9.436%	3.791%	-0.396%	-3.227%	-0.100%
66							
67	TAX CALCULATION:						
68	Operating Revenue		321,215,638	103,755,955	(11,106,348)	(88,035,744)	(21,957,259)
69	Other Deductions						
70	Interest (AFUDC)		(15,537,036)	-	-	-	-
71	Interest		80,964,831	16,633	(52,076)	41,625	(4,556,242)
72	Schedule "M" Additions		221,251,634	-	9,779	-	-
73	Schedule "M" Deductions		827,418,020	298,792	-	-	-
74	Income Before Tax		(350,378,544)	103,440,530	(11,044,493)	(88,077,369)	(17,401,017)
75							
76	State Income Taxes		(15,981,563)	4,696,200	(501,420)	(3,998,713)	(790,006)
77	Taxable Income		(334,396,981)	98,744,330	(10,543,073)	(84,078,657)	(16,611,011)
78							
79	Federal Income Taxes + Other		(132,163,391)	34,560,516	(3,690,076)	(29,427,530)	(5,813,854)
80							
81	PRICE CHANGE		21,517,720	(106,774,647)	11,198,706	90,852,814	1,706,702
82							
83	NET POWER COST		304,688,381	-	-	-	-

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Exhibit PAC/1102		
		Tab 7	Tab 8	
		Tax Adjustments	Rate Base Adjustments	Oregon Normalized Results December 2013
1	Operating Revenues:			
2	General Business Revenues	-	15,824,000	15,824,000
3	Interdepartmental	-	-	-
4	Special Sales	-	-	-
5	Other Operating Revenues	-	-	-
6	Total Operating Revenues	-	15,824,000	15,824,000
7				
8	Operating Expenses:			
9	Steam Production	-	-	-
10	Nuclear Production	-	-	-
11	Hydro Production	-	(4,231)	(4,231)
12	Other Power Supply	-	3,963,923	3,963,923
13	Embedded Cost Differential (ECD)	-	-	-
13	Transmission	-	(13,909)	(13,909)
14	Distribution	-	-	-
15	Customer Accounting	-	(391,980)	(391,980)
16	Customer Service & Info	-	-	-
17	Sales	-	-	-
18	Administrative & General	894,329	(2,316,256)	(1,421,927)
19				
20	Total O&M Expenses	894,329	1,237,548	2,131,877
21			-	-
22	Depreciation	-	11,278,223	11,278,223
23	Amortization	-	380,938	380,938
24	Taxes Other Than Income	8,218,308	-	8,218,308
25	Income Taxes - Federal	129,687,041	2,789,584	132,476,625
26	Income Taxes - State	17,745,972	379,058	18,125,030
27	Income Taxes - Def Net	(150,916,795)	(5,445,771)	(156,362,566)
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	-
30				
31	Total Operating Expenses:	5,628,855	10,619,580	16,248,435
32				
33	Operating Rev For Return:	(5,628,855)	5,204,420	(424,435)
34				
35	Rate Base:			
36	Electric Plant In Service	-	369,448,328	369,448,328
37	Plant Held for Future Use	-	(13,629,778)	(13,629,778)
38	Misc Deferred Debits	-	2,569,659	2,569,659
39	Elec Plant Acq Adj	-	(2,805,193)	(2,805,193)
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	-
42	Fuel Stock	-	(2,282,922)	(2,282,922)
43	Material & Supplies	-	-	-
44	Working Capital	3,149,978	(7,298)	3,142,681
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	3,149,978	353,292,796	356,442,775
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	(11,258,073)	(11,258,073)
52	Accum Prov For Amort	-	(3,198,774)	(3,198,774)
53	Accum Def Income Tax	(139,344,711)	16,494,984	(122,849,727)
54	Unamortized ITC	1,968,723	-	1,968,723
55	Customer Adv For Const	-	(118,548)	(118,548)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	-	-
58				
59	Total Rate Base Deductions	(137,375,989)	1,919,589	(135,456,400)
60				
61	Total Rate Base:			-
62				
63	Return on Rate Base	0.156%	-0.682%	-0.526%
64				
65	Return on Equity	0.295%	-1.291%	-0.996%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(9,112,637)	2,927,291	(6,185,346)
69	Other Deductions	-	-	
70	Interest (AFUDC)	1,525,003	-	1,525,003
71	Interest	(3,381,781)	8,949,462	5,567,681
72	Schedule "M" Additions	(8,055,058)	8,793,552	738,494
73	Schedule "M" Deductions	(406,781,149)	(5,577,917)	(412,359,067)
74	Income Before Tax	391,470,233	8,349,298	399,819,531
75				
76	State Income Taxes	17,745,972	379,058	18,125,030
77	Taxable Income	373,724,261	7,970,240	381,694,501
78				
79	Federal Income Taxes + Other	129,687,041	2,789,584	132,476,625
80				
81	PRICE CHANGE	(8,304,587)	38,062,310	29,757,723
82				
83	NET POWER COST	-	-	-

Docket No. UE-246
Exhibit PAC/1102
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Oregon Results of Operations
December 2013

March 2012

1. SUMMARY

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

		(1)	(2) (3) - (1)	(3) Ref. Page 1.4	(4) Ref. Page 1.3 TAM	(5) Ref. Page 1.2 GRC	(6) (3) + (4) + (5)
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	360,255,677	837,942,989	1,198,198,666	9,902,753	38,356,265	1,246,457,684
3	Interdepartmental		-	-			-
4	Special Sales	118,916,679	1,018,526	119,935,205			119,935,205
5	Other Operating Revenues		39,568,077	39,568,077			39,568,077
6	Total Operating Revenues	479,172,356	878,529,592	1,357,701,948	9,902,753	38,356,265	1,405,960,966
7							
8	Operating Expenses:						
9	Steam Production	190,833,068	88,353,010	279,186,078			279,186,078
10	Nuclear Production		-	-			-
11	Hydro Production		12,991,451	12,991,451			12,991,451
12	Other Power Supply	264,379,285	33,429,429	297,808,714			297,808,714
13	Embedded Cost Differential (ECD)		5,971,123	5,971,123			5,971,123
14	Transmission	33,862,757	17,513,087	51,375,843			51,375,843
15	Distribution		70,646,415	70,646,415			70,646,415
16	Customer Accounting		35,339,085	35,339,085		249,290	35,588,375
17	Customer Service & Info		4,061,969	4,061,969			4,061,969
18	Sales		-	-			-
19	Administrative & General		45,484,898	45,484,898			45,484,898
20							
21	Total O&M Expenses	489,075,109	313,790,468	802,865,577	-	249,290	803,114,867
22							
23	Depreciation		178,458,250	178,458,250			178,458,250
24	Amortization		13,807,399	13,807,399			13,807,399
25	Taxes Other Than Income		65,230,076	65,230,076		1,148,565	66,378,640
26	Income Taxes - Federal	(3,308,609)	(749,100)	(4,057,709)	3,308,609	12,348,174	11,599,074
27	Income Taxes - State	(449,585)	1,999,113	1,549,528	449,585	1,677,912	3,677,025
28	Income Taxes - Def Net		71,514,522	71,514,522			71,514,522
29	Investment Tax Credit Adj.		-	-			-
30	Misc Revenue & Expense		(346,250)	(346,250)			(346,250)
31							
32	Total Operating Expenses:	485,316,915	643,704,479	1,129,021,394	3,758,194	15,423,941	1,148,203,529
33							
34	Operating Rev For Return:	(6,144,559)	234,825,114	228,680,554	6,144,559	22,932,324	257,757,438
35							
36	Rate Base:						
37	Electric Plant In Service		6,407,404,503	6,407,404,503			6,407,404,503
38	Plant Held for Future Use		-	-			-
39	Misc Deferred Debits		22,573,238	22,573,238			22,573,238
40	Elec Plant Acq Adj		11,260,952	11,260,952			11,260,952
41	Nuclear Fuel		-	-			-
42	Prepayments		7,666,103	7,666,103			7,666,103
43	Fuel Stock		50,782,521	50,782,521			50,782,521
44	Material & Supplies		54,123,489	54,123,489			54,123,489
45	Working Capital		27,888,103	27,888,103			27,888,103
46	Weatherization Loans		(1,210)	(1,210)			(1,210)
47	Misc Rate Base		-	-			-
48							
49	Total Electric Plant:	-	6,581,697,699	6,581,697,699			6,581,697,699
50							
51	Rate Base Deductions:						
52	Accum Prov For Deprec		(2,198,381,147)	(2,198,381,147)			(2,198,381,147)
53	Accum Prov For Amort		(140,097,658)	(140,097,658)			(140,097,658)
54	Accum Def Income Tax		(960,764,357)	(960,764,357)			(960,764,357)
55	Unamortized ITC		(1,115,967)	(1,115,967)			(1,115,967)
56	Customer Adv For Const		(11,392,393)	(11,392,393)			(11,392,393)
57	Customer Service Deposits		-	-			-
58	Misc Rate Base Deductions		(15,987,319)	(15,987,319)			(15,987,319)
59							
60	Total Rate Base Deductions	-	(3,327,738,840)	(3,327,738,840)			(3,327,738,840)
61							
62	Total Rate Base:	-	3,253,958,859	3,253,958,859			3,253,958,859
63							
64	Return on Rate Base			7.028%			7.921%
65							
66	Return on Equity			8.508%			10.200%
				Ref. Page 2.2			Ref. Page 1.4

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
12 Months Ended December 31, 2013

(1) Test Period Revised Protocol Revenue Requirement	1,248,656,757	
(2) Rate Mitigation Cap	100.30%	
(3) Capped Revenue Requirement	1,252,402,727	
(4) Normalized General Business Revenues	1,198,198,666	Page 1.0
(5) Capped Revised Protocol Price Change*	**54,204,061**	

2010 Protocol

(6) Test Period 2010 Protocol Revenue Requirement	1,246,457,684	Page 1.0
(7) Normalized General Business Revenues	1,198,198,666	Page 1.0
(8) 2010 Protocol Price Change*	**48,259,018**	Page 1.0

*Includes TAM and GRC

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) GRC Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	837,942,989	38,356,265	876,299,254
3	Interdepartmental	-		-
4	Special Sales	1,018,526		1,018,526
5	Other Operating Revenues	39,568,077		39,568,077
6	Total Operating Revenues	878,529,592	38,356,265	916,885,857
7				
8	Operating Expenses:			
9	Steam Production	88,353,010		88,353,010
10	Nuclear Production	-		-
11	Hydro Production	12,991,451		12,991,451
12	Other Power Supply	33,429,429		33,429,429
13	Embedded Cost Differential (ECD)	5,971,123		5,971,123
14	Transmission	17,513,087		17,513,087
15	Distribution	70,646,415		70,646,415
16	Customer Accounting	35,339,085	249,290	35,588,375
17	Customer Service & Info	4,061,969		4,061,969
18	Sales	-		-
19	Administrative & General	45,484,898		45,484,898
20				
21	Total O&M Expenses	313,790,468	249,290	314,039,758
22				
23	Depreciation	178,458,250		178,458,250
24	Amortization	13,807,399		13,807,399
25	Taxes Other Than Income	65,230,076	1,148,565	66,378,640
26	Income Taxes - Federal	(749,100)	12,348,174	11,599,074
27	Income Taxes - State	1,999,113	1,677,912	3,677,025
28	Income Taxes - Def Net	71,514,522		71,514,522
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(346,250)		(346,250)
31				
32	Total Operating Expenses:	643,704,479	15,423,941	659,128,419
33				
34	Operating Rev For Return:	234,825,114	22,932,324	257,757,438
35				
36	Rate Base:			
37	Electric Plant In Service	6,407,404,503		6,407,404,503
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	22,573,238		22,573,238
40	Elec Plant Acq Adj	11,260,952		11,260,952
41	Nuclear Fuel	-		-
42	Prepayments	7,666,103		7,666,103
43	Fuel Stock	50,782,521		50,782,521
44	Material & Supplies	54,123,489		54,123,489
45	Working Capital	27,888,103		27,888,103
46	Weatherization Loans	(1,210)		(1,210)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,581,697,699	-	6,581,697,699
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,198,381,147)		(2,198,381,147)
53	Accum Prov For Amort	(140,097,658)		(140,097,658)
54	Accum Def Income Tax	(960,764,357)		(960,764,357)
55	Unamortized ITC	(1,115,967)		(1,115,967)
56	Customer Adv For Const	(11,392,393)		(11,392,393)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(15,987,319)		(15,987,319)
59				
60	Total Rate Base Deductions	(3,327,738,840)	-	(3,327,738,840)
61				
62	Total Rate Base:	3,253,958,859	-	3,253,958,859
63				
64	Return on Rate Base	7.217%		7.921%
65				
66	Return on Equity	8.865%		10.200%
67				
68	TAX CALCULATION:			
69	Operating Revenue	307,589,649	36,958,410	344,548,059
70	Other Deductions			
71	Interest (AFUDC)	(14,012,032)	-	(14,012,032)
72	Interest	81,982,452	-	81,982,452
73	Schedule "M" Additions	221,999,907	-	221,999,907
74	Schedule "M" Deductions	415,357,745	-	415,357,745
75	Income Before Tax	46,261,391	36,958,410	83,219,801
76				
77	State Income Taxes	1,999,113	1,677,912	3,677,025
78	Taxable Income	44,262,278	35,280,499	79,542,776
79				
80	Federal Income Taxes + Other	(749,100)	12,348,174	11,599,074

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec 31, 2013

TAM RESULTS

		(1) Total Adjusted Results	(2) TAM Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	360,255,677	9,902,753	370,158,430
3	Interdepartmental	-		-
4	Special Sales	118,916,679		118,916,679
5	Other Operating Revenues	-		-
6	Total Operating Revenues	479,172,356	9,902,753	489,075,109
7				
8	Operating Expenses:			
9	Steam Production	190,833,068		190,833,068
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	264,379,285		264,379,285
13	Embedded Cost Differential (ECD)	-		-
14	Transmission	33,862,757		33,862,757
15	Distribution	-		-
16	Customer Accounting	-	-	-
17	Customer Service & Info	-		-
18	Sales	-		-
19	Administrative & General	-		-
20				
21	Total O&M Expenses	489,075,109	-	489,075,109
22				
23	Depreciation	-		-
24	Amortization	-		-
25	Taxes Other Than Income	-	-	-
26	Income Taxes - Federal	(3,308,609)	3,308,609	(0)
27	Income Taxes - State	(449,585)	449,585	(0)
28	Income Taxes - Def Net	-		-
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	-		-
31				
32	Total Operating Expenses:	485,316,915	3,758,194	489,075,109
33				
34	Operating Rev For Return:	(6,144,559)	6,144,559	-
35				
36	Rate Base:			
37	Electric Plant In Service	-		-
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	-		-
40	Elec Plant Acq Adj	-		-
41	Nuclear Fuel	-		-
42	Prepayments	-		-
43	Fuel Stock	-		-
44	Material & Supplies	-		-
45	Working Capital	-		-
46	Weatherization Loans	-		-
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	-	-	-
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	-		-
53	Accum Prov For Amort	-		-
54	Accum Def Income Tax	-		-
55	Unamortized ITC	-		-
56	Customer Adv For Const	-		-
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	-		-
59				
60	Total Rate Base Deductions	-	-	-
61				
62	Total Rate Base:	-	-	-
63				
64	Return on Rate Base	N/A		N/A
65				
66	Return on Equity	N/A		N/A
67				
68	TAX CALCULATION:			
69	Operating Revenue	(9,902,753)	9,902,753	-
70	Other Deductions	-		
71	Interest (AFUDC)	-	-	-
72	Interest	-	-	-
73	Schedule "M" Additions	-	-	-
74	Schedule "M" Deductions	-	-	-
75	Income Before Tax	(9,902,753)	9,902,753	-
76				
77	State Income Taxes	(449,585)	449,585	(0)
78	Taxable Income	(9,453,168)	9,453,168	0
79				
80	Federal Income Taxes + Other	(3,308,609)	3,308,609	(0)

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,198,198,666	48,259,018	1,246,457,684
3	Interdepartmental	-		-
4	Special Sales	119,935,205		119,935,205
5	Other Operating Revenues	39,568,077		39,568,077
6	Total Operating Revenues	1,357,701,948	48,259,018	1,405,960,966
7				
8	Operating Expenses:			
9	Steam Production	279,186,078		279,186,078
10	Nuclear Production	-		-
11	Hydro Production	12,991,451		12,991,451
12	Other Power Supply	297,808,714		297,808,714
13	Embedded Cost Differential (ECD)	5,971,123		5,971,123
14	Transmission	51,375,843		51,375,843
15	Distribution	70,646,415		70,646,415
16	Customer Accounting	35,339,085	249,290	35,588,375
17	Customer Service & Info	4,061,969		4,061,969
18	Sales	-		-
19	Administrative & General	45,484,898		45,484,898
20				
21	Total O&M Expenses	802,865,577	249,290	803,114,867
22				
23	Depreciation	178,458,250		178,458,250
24	Amortization	13,807,399		13,807,399
25	Taxes Other Than Income	65,230,076	1,148,565	66,378,640
26	Income Taxes - Federal	(4,057,709)	15,656,783	11,599,074
27	Income Taxes - State	1,549,528	2,127,497	3,677,025
28	Income Taxes - Def Net	71,514,522		71,514,522
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(346,250)		(346,250)
31				
32	Total Operating Expenses:	1,129,021,394	19,182,135	1,148,203,529
33				
34	Operating Rev For Return:	228,680,554	29,076,883	257,757,438
35				
36	Rate Base:			
37	Electric Plant In Service	6,407,404,503		6,407,404,503
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	22,573,238		22,573,238
40	Elec Plant Acq Adj	11,260,952		11,260,952
41	Nuclear Fuel	-		-
42	Prepayments	7,666,103		7,666,103
43	Fuel Stock	50,782,521		50,782,521
44	Material & Supplies	54,123,489		54,123,489
45	Working Capital	27,888,103		27,888,103
46	Weatherization Loans	(1,210)		(1,210)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,581,697,699	-	6,581,697,699
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,198,381,147)		(2,198,381,147)
53	Accum Prov For Amort	(140,097,658)		(140,097,658)
54	Accum Def Income Tax	(960,764,357)		(960,764,357)
55	Unamortized ITC	(1,115,967)		(1,115,967)
56	Customer Adv For Const	(11,392,393)		(11,392,393)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(15,987,319)		(15,987,319)
59				
60	Total Rate Base Deductions	(3,327,738,840)	-	(3,327,738,840)
61				
62	Total Rate Base:	3,253,958,859	-	3,253,958,859
63				
64	Return on Rate Base	7.028%		7.921%
65				
66	Return on Equity	8.508%		10.200%
67				
68	TAX CALCULATION:			
69	Operating Revenue	297,686,895	46,861,164	344,548,059
70	Other Deductions			
71	Interest (AFUDC)	(14,012,032)	-	(14,012,032)
72	Interest	81,982,452	-	81,982,452
73	Schedule "M" Additions	221,999,907	-	221,999,907
74	Schedule "M" Deductions	415,357,745	-	415,357,745
75	Income Before Tax	36,358,638	46,861,164	83,219,801
76				
77	State Income Taxes	1,549,528	2,127,497	3,677,025
78	Taxable Income	34,809,110	44,733,667	79,542,776
79				
80	Federal Income Taxes + Other	(4,057,709)	15,656,783	11,599,074
81		Ref. Page 2.2		

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

Net Rate Base	$	3,253,958,859	Ref. Page 2.2
Return on Rate Base Requested		7.921%	Ref. Page 2.1
Revenues Required to Earn Requested Return		257,757,438	
Less Current Operating Revenues		(228,680,554)	
Increase to Current Revenues		29,076,883	
Net to Gross Bump-up		165.97%	
Price Change Required for Requested Return	$	48,259,018	
Requested Price Change	$	48,259,018	
Uncollectible Percent		0.517%	Ref. Page 1.6
Increased Uncollectible Expense	$	249,290	
Requested Price Change	$	48,259,018	
Franchise Tax		2.300%	Ref. Page 1.6
Revenue Tax		0.000%	Ref. Page 1.6
Resource Supplier Tax		0.080%	Ref. Page 1.6
Gross Receipts		0.000%	Ref. Page 1.6
Increase Taxes Other Than Income	$	1,148,565	
Requested Price Change	$	48,259,018	
Uncollectible Expense		(249,290)	
Taxes Other Than Income		(1,148,565)	
Income Before Taxes	$	46,861,164	
State Effective Tax Rate		4.54%	Ref. Page 2.1
State Income Taxes	$	2,127,497	
Taxable Income	$	44,733,667	
Federal Income Tax Rate		35.00%	Ref. Page 2.1
Federal Income Taxes	$	15,656,783	
Operating Income		100.000%	
Net Operating Income		60.252%	Ref. Page 1.6
Net to Gross Bump-Up		165.97%	

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
Twelve Months Ending Dec 31, 2013

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.517%	See Note (1) Below
Taxes Other - Franchise Tax	2.300%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.080%	
Taxes Other - Gross Receipts	0.000%	
Sub-Total	97.103%	
State Income Tax @ 4.54%	4.408%	
Sub-Total	92.695%	
Federal Income Tax @ 35.00%	32.443%	
Net Operating Income	60.252%	

(1) Uncollectible Accounts = 5,462,397 Pg. 4.5.1
1,057,442,897 Pg. 2.2, General Business Revenues

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2013

		TOTAL COMPANY ACTUAL RESULTS JUNE 2011	OREGON ALLOCATED ACTUAL RESULTS JUNE 2011	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 NPC Adjustments	Tab 6 Deperciation & Amortization Adjustments	Tab 7 Tax Adjustments
1	Operating Revenues:							
2	General Business Revenues	3,762,226,028	1,057,442,897	124,931,769	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	379,179,495	96,385,126	-	-	23,550,079	-	-
5	Other Operating Revenues	323,231,828	82,319,797	(21,566,614)	(21,405,215)	220,109	-	-
6	Total Operating Revenues	4,464,637,351	1,236,147,820	103,365,155	(21,405,215)	23,770,188	-	-
7								
8	Operating Expenses:							
9	Steam Production	991,002,147	245,482,444	-	5,069,635	28,633,999	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	43,249,454	11,148,479	-	1,847,203	-	-	-
12	Other Power Supply	900,802,841	211,830,165	-	(2,749,297)	84,763,922	-	-
13	Embedded Cost Differential (ECD)	0	5,971,123	-	-	-	-	-
13	Transmission	203,395,397	52,337,448	(226,615)	870,910	(1,591,989)	-	-
14	Distribution	211,900,030	67,278,537	-	3,367,878	-	-	-
15	Customer Accounting	95,209,362	33,934,000	-	1,797,065	-	-	-
16	Customer Service & Info	113,969,877	25,306,096	-	(21,244,127)	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	153,962,449	46,200,310	-	706,514	-	-	894,329
19								
20	Total O&M Expenses	2,713,491,556	699,488,603	(226,615)	(10,334,219)	111,805,932	-	894,329
21								
22	Depreciation	515,564,333	145,412,589	-	-	-	21,767,438	-
23	Amortization	48,399,074	13,236,640	-	-	-	189,821	-
24	Taxes Other Than Income	146,842,558	57,011,768	-	-	-	-	8,218,308
25	Income Taxes - Federal	(618,010,179)	(132,163,391)	34,560,516	(3,690,076)	(29,427,530)	(5,813,854)	129,687,041
26	Income Taxes - State	(76,306,062)	(15,981,563)	4,696,200	(501,420)	(3,998,713)	(790,006)	17,745,972
27	Income Taxes - Def Net	922,130,589	227,767,405	113,394	(3,712)	-	-	(150,916,795)
28	Investment Tax Credit Adj.	(1,874,204)	-	-	-	-	-	-
29	Misc Revenue & Expense	(1,689,284)	(217,418)	(164,185)	35,353	-	-	-
30								
31	Total Operating Expenses:	3,648,548,381	994,554,634	38,979,310	(14,494,074)	78,379,690	15,353,399	5,628,855
32								
33	Operating Rev For Return:	816,088,970	241,593,186	64,385,845	(6,911,141)	(54,609,502)	(15,353,399)	(5,628,855)
34								
35	Rate Base:							
36	Electric Plant In Service	22,157,283,708	6,037,881,175	-	-	75,000	-	-
37	Plant Held for Future Use	45,021,478	13,629,778	-	-	-	-	-
38	Misc Deferred Debits	213,788,714	20,003,579	-	-	-	-	-
39	Elec Plant Acq Adj	54,568,258	14,066,144	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-
41	Prepayments	28,443,124	7,666,103	-	-	-	-	-
42	Fuel Stock	218,254,887	53,065,443	-	-	-	-	-
43	Material & Supplies	190,997,513	54,123,489	-	-	-	-	-
44	Working Capital	71,478,693	22,808,093	785,355	(292,283)	1,577,139	(132,881)	3,149,978
45	Weatherization Loans	(35,682)	(1,210)	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	22,979,800,693	6,223,242,594	785,355	(292,283)	1,652,139	(132,881)	3,149,978
49								
50	Rate Base Deductions:							
51	Accum Prov For Deprec	(6,903,348,317)	(2,012,312,865)	-	-	-	(174,810,209)	-
52	Accum Prov For Amort	(471,314,196)	(131,000,526)	-	-	-	(5,898,357)	-
53	Accum Def Income Tax	(3,103,714,231)	(836,216,537)	76,560	(1,774,653)	-	-	(139,344,711)
54	Unamortized ITC	(4,857,544)	(3,084,689)	-	-	-	-	1,968,723
55	Customer Adv For Const	(27,863,920)	(11,273,844)	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	(63,364,442)	(15,785,584)	(201,735)	-	-	-	-
58								
59	Total Rate Base Deductions	(10,574,462,650)	(3,009,674,046)	(125,174)	(1,774,653)	-	(180,708,566)	(137,375,989)
60								
61	Total Rate Base:	12,405,338,043	3,213,568,548					
62								
63	Return on Rate Base	6.579%	7.518%	2.002%	-0.209%	-1.704%	-0.053%	0.156%
64								
65	Return on Equity	7.657%	9.436%	3.791%	-0.396%	-3.227%	-0.100%	0.295%
66								
67	TAX CALCULATION:							
68	Operating Revenue		321,215,638	103,755,955	(11,106,348)	(88,035,744)	(21,957,259)	(9,112,637)
69	Other Deductions							-
70	Interest (AFUDC)		(15,537,036)	-	-	-	-	1,525,003
71	Interest		80,964,831	16,633	(52,076)	41,625	(4,556,242)	(3,381,781)
72	Schedule "M" Additions		221,251,634	-	9,779	-	-	(8,055,058)
73	Schedule "M" Deductions		827,418,020	298,792	-	-	-	(406,781,149)
74	Income Before Tax		(350,378,544)	103,440,530	(11,044,493)	(88,077,369)	(17,401,017)	391,470,233
75								
76	State Income Taxes		(15,981,563)	4,696,200	(501,420)	(3,998,713)	(790,006)	17,745,972
77	Taxable Income		(334,396,981)	98,744,330	(10,543,073)	(84,078,657)	(16,611,011)	373,724,261
78								
79	Federal Income Taxes + Other		(132,163,391)	34,560,516	(3,690,076)	(29,427,530)	(5,813,854)	129,687,041
80								
81	PRICE CHANGE		21,517,720	(106,774,647)	11,198,706	90,852,814	1,706,702	(8,304,587)

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2013

Tab 8

		Rate Base Adjustments	Oregon Normalized Results December 2013
1	Operating Revenues:		
2	General Business Revenues	15,824,000	1,198,198,666
3	Interdepartmental	-	-
4	Special Sales	-	119,935,205
5	Other Operating Revenues	-	39,568,077
6	Total Operating Revenues	15,824,000	1,357,701,948
7			
8	Operating Expenses:		
9	Steam Production	-	279,186,078
10	Nuclear Production	-	-
11	Hydro Production	(4,231)	12,991,451
12	Other Power Supply	3,963,923	297,808,714
13	Embedded Cost Differential (ECD)	-	5,971,123
13	Transmission	(13,909)	51,375,843
14	Distribution	-	70,646,415
15	Customer Accounting	(391,980)	35,339,085
16	Customer Service & Info	-	4,061,969
17	Sales	-	-
18	Administrative & General	(2,316,256)	45,484,898
19			
20	Total O&M Expenses	1,237,548	802,865,577
21		-	-
22	Depreciation	11,278,223	178,458,250
23	Amortization	380,938	13,807,399
24	Taxes Other Than Income	-	65,230,076
25	Income Taxes - Federal	2,789,584	(4,057,709)
26	Income Taxes - State	379,058	1,549,528
27	Income Taxes - Def Net	(5,445,771)	71,514,522
28	Investment Tax Credit Adj.	-	-
29	Misc Revenue & Expense	-	(346,250)
30			
31	Total Operating Expenses:	10,619,580	1,129,021,394
32			
33	Operating Rev For Return:	5,204,420	228,680,554
34			
35	Rate Base:		
36	Electric Plant In Service	369,448,328	6,407,404,503
37	Plant Held for Future Use	(13,629,778)	-
38	Misc Deferred Debits	2,569,659	22,573,238
39	Elec Plant Acq Adj	(2,805,193)	11,260,952
40	Nuclear Fuel	-	-
41	Prepayments	-	7,666,103
42	Fuel Stock	(2,282,922)	50,782,521
43	Material & Supplies	-	54,123,489
44	Working Capital	(7,298)	27,888,103
45	Weatherization Loans	-	(1,210)
46	Misc Rate Base	-	-
47			
48	Total Electric Plant:	353,292,796	6,581,697,699
49			
50	Rate Base Deductions:		
51	Accum Prov For Deprec	(11,258,073)	(2,198,381,147)
52	Accum Prov For Amort	(3,198,774)	(140,097,658)
53	Accum Def Income Tax	16,494,984	(960,764,357)
54	Unamortized ITC	-	(1,115,967)
55	Customer Adv For Const	(118,548)	(11,392,393)
56	Customer Service Deposits	-	-
57	Misc Rate Base Deductions	-	(15,987,319)
58			
59	Total Rate Base Deductions	1,919,589	(3,327,738,840)
60			
61	Total Rate Base:		3,213,568,548
62			
63	Return on Rate Base	-0.682%	7.028%
64			
65	Return on Equity	-1.291%	8.508%
66			
67	TAX CALCULATION:		
68	Operating Revenue	2,927,291	297,686,895
69	Other Deductions	-	
70	Interest (AFUDC)	-	(14,012,032)
71	Interest	8,949,462	81,982,452
72	Schedule "M" Additions	8,793,552	221,999,907
73	Schedule "M" Deductions	(5,577,917)	415,357,745
74	Income Before Tax	8,349,298	36,358,638
75			
76	State Income Taxes	379,058	1,549,528
77	Taxable Income	7,970,240	34,809,110
78			
79	Federal Income Taxes + Other	2,789,584	(4,057,709)
80			
81	PRICE CHANGE	38,062,310	48,259,018

	Description of Account Summary:	December 2010 (1) UNADJUSTED RESULTS TOTAL	December 2010 (1) UNADJUSTED RESULTS OREGON	June 2011 (2) UNADJUSTED RESULTS TOTAL	June 2011 (2) UNADJUSTED RESULTS OREGON
1	Operating Revenues				
2	General Business Revenues	3,574,583,105	944,131,898	3,762,226,028	1,057,442,897
3	Interdepartmental	0	0	0	0
4	Special Sales	501,563,210	130,068,295	379,179,495	96,385,126
5	Other Operating Revenues	326,069,070	81,402,219	323,231,828	82,319,797
6	Total Operating Revenues	4,402,215,385	1,155,602,412	4,464,637,351	1,236,147,820
7					
8	Operating Expenses:				
9	Steam Production	957,497,818	244,305,189	991,002,147	245,482,444
10	Nuclear Production	0	0	0	0
11	Hydro Production	40,481,667	10,607,249	43,249,454	11,148,479
12	Other Power Supply	922,755,661	218,505,849	900,802,841	211,830,165
	Embedded Cost Differential (ECD)	0	(6,984,115)	0	5,971,123
13	Transmission	195,628,269	51,189,765	203,395,397	52,337,448
14	Distribution	208,550,302	68,092,067	211,900,030	67,278,537
15	Customer Accounting	92,750,645	32,181,036	95,209,362	33,934,000
16	Customer Service & Infor	128,944,905	22,403,261	113,969,877	25,306,096
17	Sales	0	0	0	0
18	Administrative & General	146,076,485	44,614,004	153,962,449	46,200,310
19					
20	Total O & M Expenses	2,692,685,751	684,914,306	2,713,491,556	699,488,603
21					
22	Depreciation	491,643,870	140,519,726	515,564,333	145,412,589
23	Amortization	44,975,946	12,513,121	48,399,074	13,236,640
24	Taxes Other Than Income	136,512,728	53,587,853	146,842,558	57,011,768
25	Income Taxes - Federal	(483,829,694)	(131,083,381)	(618,010,179)	(132,163,391)
26	Income Taxes - State	(55,297,825)	(14,987,832)	(76,306,062)	(15,981,563)
27	Income Taxes - Def Net	761,444,172	202,071,623	922,130,589	227,767,405
28	Investment Tax Credit Adj.	(1,874,204)	0	(1,874,204)	0
29	Misc Revenue & Expense	(5,388,606)	(724,548)	(1,689,284)	(217,418)
30					
31	Total Operating Expenses	3,580,872,139	946,810,867	3,648,548,381	994,554,634
32					
33	Operating Revenue for Return	821,343,245	208,791,545	816,088,970	241,593,186
34					
35	Rate Base:				
36	Electric Plant in Service	20,347,033,834	5,639,740,511	22,157,283,708	6,037,881,175
37	Plant Held for Future Use	15,175,403	5,107,396	45,021,478	13,629,778
38	Misc Deferred Debits	164,786,435	19,861,626	213,788,714	20,003,579
39	Elec Plant Acq Adj	59,786,774	15,665,690	54,568,258	14,066,144
40	Nuclear Fuel	0	0	0	0
41	Prepayments	36,569,894	10,005,108	28,443,124	7,666,103
42	Fuel Stock	179,989,733	45,211,568	218,254,887	53,065,443
43	Material & Supplies	182,198,510	52,932,959	190,997,513	54,123,489
44	Working Capital	64,522,918	17,669,973	71,478,693	22,808,093
45	Weatherization Loans	18,524,395	(1,234)	(35,682)	(1,210)
46	Miscellaneous Rate Base	972,508	265,506	0	0
47					
48	Total Electric Plant	21,069,560,405	5,806,459,103	22,979,800,693	6,223,242,594
49					
50	Rate Base Deductions:				
51	Accum Prov For Depr	(6,753,405,676)	(1,978,858,659)	(6,903,348,317)	(2,012,312,865)
52	Accum Prov For Amort	(441,232,410)	(126,590,332)	(471,314,196)	(131,000,526)
53	Accum Def Income Taxes	(2,482,347,796)	(686,402,568)	(3,103,714,231)	(836,216,537)
54	Unamortized ITC	(6,606,954)	(4,255,967)	(4,857,544)	(3,084,689)
55	Customer Adv for Const	(22,100,039)	(4,934,581)	(27,863,920)	(11,273,844)
56	Customer Service Deposits	0	0	0	0
57	Misc. Rate Base Deductions	(65,686,584)	(14,658,698)	(63,364,442)	(15,785,584)
58					
59	Total Rate Base Deductions	(9,771,379,459)	(2,815,700,805)	(10,574,462,650)	(3,009,674,046)
60					
61	Total Rate Base	11,298,180,946	2,990,758,298	12,405,338,043	3,213,568,548
62					
63	Return on Rate Base	7.270%	6.981%	6.579%	7.518%
64					
65	Return on Equity	8.558%	8.004%	7.657%	9.436%
66	Net Power Costs	1,125,770,120	284,093,477	1,242,802,122	304,688,381
67	100 Basis Points in Equity:				
68	Revenue Requirement Impact	94,684,106	25,063,971	105,562,031	27,345,553
69	Rate Base Decrease	(754,208,531)	(207,325,398)	(921,690,031)	(210,885,310)

Notes:
(1) Allocation methodology = Revised Protocol; Rate Base method = 13-Month Average
(2) Allocation methodology = 2010 Protocol; Rate Base method = Year End

2. RESULTS OF OPERATIONS

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DEC 31, 2013
FILE:	OR JAM Dec 2013 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/27/2012
TIME:	8:20:55 AM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	**2010 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	1.660
FEDERAL/STATE COMBINED RATE	37.951%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	46.90%	5.372%	2.519%
PREFERRED	0.30%	5.427%	0.016%
COMMON	52.80%	10.200%	5.386%
	100.00%		7.921%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see the testimony of Mr. Bruce N. Williams.
For information and support regarding return on common equity, see the testimony of Dr. Samuel C. Hadaway.

2010 PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1	Operating Revenues					
2	General Business Revenues	2.3	3,762,226,028	1,057,442,897	4,261,379,301	1,198,198,666
3	Interdepartmental	2.3	0	0	0	0
4	Special Sales	2.3	379,179,495	96,385,126	470,484,400	119,935,205
5	Other Operating Revenues	2.4	323,231,828	82,319,797	146,133,018	39,568,077
6	Total Operating Revenues	2.4	4,464,637,351	1,236,147,820	4,877,996,718	1,357,701,948
7						
8	Operating Expenses:					
9	Steam Production	2.5	991,002,147	245,482,444	1,128,949,413	279,186,078
10	Nuclear Production	2.6	0	0	0	0
11	Hydro Production	2.7	43,249,454	11,148,479	50,399,087	12,991,451
12	Other Power Supply	2.9	900,802,841	211,830,165	1,187,016,092	297,808,714
13	Embedded Cost Differential (ECD)		0	5,971,123	0	5,971,123
14	Transmission	2.10	203,395,397	52,337,448	199,472,285	51,375,843
15	Distribution	2.12	211,900,030	67,278,537	222,653,494	70,646,415
16	Customer Accounting	2.12	95,209,362	33,934,000	99,289,759	35,339,085
17	Customer Service & Infor	2.13	113,969,877	25,306,096	20,536,835	4,061,969
18	Sales	2.13	0	0	0	0
19	Administrative & General	2.14	153,962,449	46,200,310	143,057,189	45,484,898
20						
21	Total O & M Expenses	2.14	2,713,491,556	699,488,603	3,051,374,154	802,865,577
22						
23	Depreciation	2.16	515,564,333	145,412,589	648,623,871	178,458,250
24	Amortization	2.17	48,399,074	13,236,640	51,678,159	13,807,399
25	Taxes Other Than Income	2.17	146,842,558	57,011,768	167,755,580	65,230,076
26	Income Taxes - Federal	2.20	(618,010,179)	(132,163,391)	(88,481,875)	(4,057,709)
27	Income Taxes - State	2.20	(76,306,062)	(15,981,563)	(3,872,841)	1,549,528
28	Income Taxes - Def Net	2.19	922,130,589	227,767,405	284,396,170	71,514,522
29	Investment Tax Credit Adj.	2.17	(1,874,204)	0	(1,874,204)	0
30	Misc Revenue & Expense	2.4	(1,689,284)	(217,418)	(2,364,567)	(346,250)
31						
32	Total Operating Expenses	2.20	3,648,548,381	994,554,634	4,107,234,448	1,129,021,394
33						
34	Operating Revenue for Return		816,088,970	241,593,186	770,762,271	228,680,554
35						
36	Rate Base:					
37	Electric Plant in Service	2.30	22,157,283,708	6,037,881,175	23,586,997,425	6,407,404,503
38	Plant Held for Future Use	2.31	45,021,478	13,629,778	0	0
39	Misc Deferred Debits	2.33	213,788,714	20,003,579	224,219,332	22,573,238
40	Elec Plant Acq Adj	2.31	54,568,258	14,066,144	43,685,781	11,260,952
41	Nuclear Fuel	2.31	0	0	0	0
42	Prepayments	2.32	28,443,124	7,666,103	28,443,124	7,666,103
43	Fuel Stock	2.32	218,254,887	53,065,443	208,865,369	50,782,521
44	Material & Supplies	2.32	190,997,513	54,123,489	190,997,513	54,123,489
45	Working Capital	2.33	71,478,693	22,808,093	85,388,633	27,888,103
46	Weatherization Loans	2.31	(35,682)	(1,210)	(35,682)	(1,210)
47	Miscellaneous Rate Base	2.34	0	0	0	0
48						
49	Total Electric Plant		22,979,800,693	6,223,242,594	24,368,561,496	6,581,697,699
50						
51	Rate Base Deductions:					
52	Accum Prov For Depr	2.38	(6,903,348,317)	(2,012,312,865)	(7,548,558,148)	(2,198,381,147)
53	Accum Prov For Amort	2.39	(471,314,196)	(131,000,526)	(506,182,675)	(140,097,658)
54	Accum Def Income Taxes	2.35	(3,103,714,231)	(836,216,537)	(3,627,014,527)	(960,764,357)
55	Unamortized ITC	2.35	(4,857,544)	(3,084,689)	(1,899,596)	(1,115,967)
56	Customer Adv for Const	2.34	(27,863,920)	(11,273,844)	(27,863,920)	(11,392,393)
57	Customer Service Deposits	2.34	0	0	0	0
58	Misc. Rate Base Deductions	2.34	(63,364,442)	(15,785,584)	(64,194,166)	(15,987,319)
59						
60	Total Rate Base Deductions		(10,574,462,650)	(3,009,674,046)	(11,775,713,032)	(3,327,738,840)
61						
62	Total Rate Base		12,405,338,043	3,213,568,548	12,592,848,464	3,253,958,859
63						
64	Return on Rate Base		6.579%	7.518%	6.121%	7.028%
65						
66	Return on Equity		7.657%	9.436%	6.790%	8.508%
67	Net Power Costs		1,242,802,122	304,688,381	1,504,095,928	370,158,430
68	100 Basis Points in Equity:					
69	Revenue Requirement Impact		105,562,031	27,345,553	107,157,633	27,689,250
70	Rate Base Decrease		(921,690,031)	(210,885,310)	(1,000,058,530)	(227,388,024)

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
71	Sales to Ultimate Customers								
72	440	Residential Sales							
73			0	S		1,437,482,984	525,297,185	1,594,603,193	580,219,963
74									
75					B1	1,437,482,984	525,297,185	1,594,603,193	580,219,963
76									
77	442	Commercial & Industrial Sales							
78			0	S		2,284,357,284	526,413,455	2,626,335,543	612,827,521
79			P	SE		-	-	-	-
80			PT	SG		-	-	-	-
81									
82									
83					B1	2,284,357,284	526,413,455	2,626,335,543	612,827,521
84									
85	444	Public Street & Highway Lighting							
86			0	S		20,614,685	5,732,257	19,191,288	5,151,182
87			0	SO		-	-	-	-
88					B1	20,614,685	5,732,257	19,191,288	5,151,182
89									
90	445	Other Sales to Public Authority							
91			0	S		19,771,075	-	21,249,276	-
92									
93					B1	19,771,075	-	21,249,276	-
94									
95	448	Interdepartmental							
96			DPW	S		-	-	-	-
97			GP	SO		-	-	-	-
98					B1	-	-	-	-
99									
100	**Total Sales to Ultimate Customers**				**B1**	**3,762,226,028**	**1,057,442,897**	**4,261,379,301**	**1,198,198,666**
101									
102									
103									
104	447	Sales for Resale-Non NPC							
105			P	S		9,158,552	1,018,526	9,158,552	1,018,526
106						9,158,552	1,018,526	9,158,552	1,018,526
107									
108	447NPC	Sales for Resale-NPC							
109			P	SG		369,045,839	95,129,518	461,325,848	118,916,679
110			P	SE		975,104	237,082	-	-
111			P	SG		-	-	-	-
112						370,020,943	95,366,600	461,325,848	118,916,679
113									
114		Total Sales for Resale			B1	379,179,495	96,385,126	470,484,400	119,935,205
115									
116	449	Provision for Rate Refund							
117			P	S		-	-	-	-
118			P	SG		-	-	-	-
119									
120									
121					B1	-	-	-	-
122									
123	**Total Sales from Electricity**				**B1**	**4,141,405,523**	**1,153,828,023**	**4,731,863,701**	**1,318,133,871**
124	450	Forfeited Discounts & Interest							
125			CUST	S		8,064,749	3,149,119	8,064,749	3,149,119
126			CUST	SO		-	-	-	-
127					B1	8,064,749	3,149,119	8,064,749	3,149,119
128									
129	451	Misc Electric Revenue							
130			CUST	S		5,941,041	1,140,452	5,941,041	1,140,452
131			CUST	SG		-	-	-	-
132			CUST	SO		1,151	313	1,151	313
133					B1	5,942,192	1,140,764	5,942,192	1,140,764
134									
135	453	Water Sales							
136			P	SG		85,842	22,128	85,842	22,128
137					B1	85,842	22,128	85,842	22,128
138									
139	454	Rent of Electric Property							
140			DPW	S		10,629,119	5,103,258	10,629,119	5,103,258
141			T	SG		5,697,494	1,468,652	5,697,494	1,468,652
142			GP	SO		3,501,221	951,106	3,501,221	951,106
143					B1	19,827,834	7,523,016	19,827,834	7,523,016
144									
145									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
146									
147	456	Other Electric Revenue							
148			DMSC	S		98,316,742	21,405,134	4,021,198	(81)
149			CUST	CN		-	-	-	-
150			OTHSE	SE		10,745,276	2,612,555	10,894,140	2,648,749
151			OTHSO	SO		285,872	77,657	285,872	77,657
152			OTHSGR	SG		179,963,321	46,389,424	97,011,191	25,006,725
153									
154									
155					B1	289,311,211	70,484,770	112,212,401	27,733,050
156									
157	**Total Other Electric Revenues**				**B1**	**323,231,828**	**82,319,797**	**146,133,018**	**39,568,077**
158									
159	**Total Electric Operating Revenues**				**B1**	**4,464,637,351**	**1,236,147,820**	**4,877,996,718**	**1,357,701,948**
160									
161	Summary of Revenues by Factor								
162		S				3,894,336,230	1,089,259,385	4,299,193,959	1,208,609,940
163		CN				-	-	-	-
164		SE				11,720,380	2,849,637	10,894,140	2,648,749
165		SO				3,788,245	1,029,076	3,788,245	1,029,076
166		SG				554,792,496	143,009,722	564,120,374	145,414,183
167		DGP				-	-	-	-
168									
169	Total Electric Operating Revenues					4,464,637,351	1,236,147,820	4,877,996,718	1,357,701,948
170	Miscellaneous Revenues								
171	41160	Gain on Sale of Utility Plant - CR							
172			DPW	S		-	-	-	-
173			T	SG		-	-	-	-
174			G	SO		-	-	-	-
175			T	SG		-	-	-	-
176			P	SG		-	-	-	-
177					B1	-	-	-	-
178									
179	41170	Loss on Sale of Utility Plant							
180			DPW	S		-	-	-	-
181			T	SG		-	-	-	-
182					B1	-	-	-	-
183									
184	4118	Gain from Emission Allowances							
185			P	S		-	-	-	-
186			P	SE		(559,750)	(136,095)	(1,235,033)	(300,280)
187					B1	(559,750)	(136,095)	(1,235,033)	(300,280)
188									
189	41181	Gain from Disposition of NOX Credits							
190			P	SE		-	-	-	-
191					B1	-	-	-	-
192									
193	4194	Impact Housing Interest Income							
194			P	SG		-	-	-	-
195					B1	-	-	-	-
196									
197	421	(Gain) / Loss on Sale of Utility Plant							
198			DPW	S		233,226	275,201	77,137	265,014
199			T	SG		(761,976)	(196,416)	(761,976)	(196,416)
200			T	SG		(170,995)	(44,078)	(170,995)	(44,078)
201			CUST	CN		899	264	899	264
202			PTD	SO		(380,083)	(103,249)	2,099	570
203			P	SG		(50,606)	(13,045)	(276,699)	(71,325)
204					B1	(1,129,534)	(81,323)	(1,129,534)	(45,970)
205									
206	**Total Miscellaneous Revenues**					**(1,689,284)**	**(217,418)**	**(2,364,567)**	**(346,250)**
207	Miscellaneous Expenses								
208	4311	Interest on Customer Deposits							
209			CUST	S		-	-	-	-
210					B1	-	-	-	-
211	**Total Miscellaneous Expenses**					-	-	-	-
212									
213	**Net Misc Revenue and Expense**				**B1**	**(1,689,284)**	**(217,418)**	**(2,364,567)**	**(346,250)**
214									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
215	500	Operation Supervision & Engineering							
216			P	SG		17,434,919	4,494,226	18,163,498	4,682,033
217			P	SG		2,217,593	571,632	2,403,391	619,526
218					B2	19,652,512	5,065,859	20,566,889	5,301,559
219									
220	501	Fuel Related-Non NPC							
221			P	SE		18,028,765	4,383,427	19,539,898	4,750,837
222			P	SE		-	-	-	-
223			P	SE		-	-	-	-
224			P	SE		-	-	-	-
225			P	SE		3,225,441	784,218	3,495,680	849,923
226					B2	21,254,205	5,167,645	23,035,578	5,600,760
227									
228	501NPC	Fuel Related-NPC							
229			P	S		(409,282)	-	-	-
230			P	SE		614,495,568	149,405,496	724,243,273	176,089,025
231			P	SE		-	-	-	-
232			P	SE		-	-	-	-
233			P	SE		-	-	-	-
234			P	SE		49,297,564	11,985,973	56,457,816	13,726,882
235					B2	663,383,851	161,391,468	780,701,089	189,815,907
236									
237		Total Fuel Related				684,638,056	166,559,114	803,736,667	195,416,666
238									
239	502	Steam Expenses							
240			P	SG		31,637,199	8,155,170	33,473,246	8,628,451
241			P	SG		7,646,027	1,970,928	8,286,640	2,136,060
242					B2	39,283,226	10,126,098	41,759,887	10,764,511
243									
244	503	Steam From Other Sources-Non-NPC							
245			P	SE		-	-	(3,411)	(829)
246					B2	-	-	(3,411)	(829)
247									
248	503NPC	Steam From Other Sources-NPC							
249			P	SE		3,321,608	807,600	4,183,520	1,017,161
250					B2	3,321,608	807,600	4,183,520	1,017,161
251									
252	505	Electric Expenses							
253			P	SG		3,108,226	801,212	3,282,389	846,106
254			P	SG		1,137,586	293,237	1,232,897	317,806
255					B2	4,245,811	1,094,449	4,515,286	1,163,912
256									
257	506	Misc. Steam Expense							
258			P	SG		48,802,848	12,579,986	50,795,673	13,093,679
259			P	SE		-	-	-	-
260			P	SG		1,904,602	490,952	2,064,357	532,133
261					B2	50,707,450	13,070,938	52,860,030	13,625,812
262									
263	507	Rents							
264			P	SG		286,514	73,855	310,520	80,043
265			P	SG		623	161	675	174
266					B2	287,138	74,016	311,195	80,217
267									
268	510	Maint Supervision & Engineering							
269			P	SG		4,593,089	1,183,968	2,210,861	569,897
270			P	SG		1,999,843	515,503	2,174,725	560,582
271					B2	6,592,932	1,699,470	4,385,586	1,130,479
272									
273									
274									
275	511	Maintenance of Structures							
276			P	SG		23,720,364	6,114,435	24,725,131	6,373,435
277			P	SG		424,329	109,380	443,447	114,308
278					B2	24,144,693	6,223,815	25,168,578	6,487,743
279									
280	512	Maintenance of Boiler Plant							
281			P	SG		101,673,678	26,208,582	108,957,994	28,086,271
282			P	SG		4,835,272	1,246,396	8,690,223	2,240,092
283					B2	106,508,950	27,454,977	117,648,217	30,326,363
284									
285	513	Maintenance of Electric Plant							
286			P	SG		38,873,335	10,020,440	40,521,249	10,445,225
287			P	SG		643,842	165,964	672,834	173,437
288					B2	39,517,177	10,186,404	41,194,083	10,618,663
289									
290	514	Maintenance of Misc. Steam Plant							
291			P	SG		10,067,965	2,595,235	10,496,512	2,705,702
292			P	SG		2,034,629	524,470	2,126,376	548,119
293					B2	12,102,595	3,119,705	12,622,887	3,253,821
294									
295	**Total Steam Power Generation**				**B2**	**991,002,147**	**245,482,444**	**1,128,949,413**	**279,186,078**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
296	517	Operation Super & Engineering							
297			P	SG		-	-	-	-
298					B2	-	-	-	-
299									
300	518	Nuclear Fuel Expense							
301			P	SE		-	-	-	-
302									
303					B2	-	-	-	-
304									
305	519	Coolants and Water							
306			P	SG		-	-	-	-
307					B2	-	-	-	-
308									
309	520	Steam Expenses							
310			P	SG		-	-	-	-
311					B2	-	-	-	-
312									
313									
314									
315	523	Electric Expenses							
316			P	SG		-	-	-	-
317					B2	-	-	-	-
318									
319	524	Misc. Nuclear Expenses							
320			P	SG		-	-	-	-
321					B2	-	-	-	-
322									
323	528	Maintenance Super & Engineering							
324			P	SG		-	-	-	-
325					B2	-	-	-	-
326									
327	529	Maintenance of Structures							
328			P	SG		-	-	-	-
329					B2	-	-	-	-
330									
331	530	Maintenance of Reactor Plant							
332			P	SG		-	-	-	-
333					B2	-	-	-	-
334									
335	531	Maintenance of Electric Plant							
336			P	SG		-	-	-	-
337					B2	-	-	-	-
338									
339	532	Maintenance of Misc Nuclear							
340			P	SG		-	-	-	-
341					B2	-	-	-	-
342									
343	**Total Nuclear Power Generation**				**B2**	-	-	-	-
344									
345	535	Operation Super & Engineering							
346			P	DGP		-	-	-	-
347			P	SG		5,436,999	1,401,504	9,912,764	2,555,228
348			P	SG		(924,196)	(238,231)	(505,379)	(130,272)
349									
350					B2	4,512,803	1,163,272	9,407,384	2,424,956
351									
352	536	Water For Power							
353			P	DGP		-	-	-	-
354			P	SG		199,930	51,536	212,164	54,690
355			P	SG		-	-	-	-
356									
357					B2	199,930	51,536	212,164	54,690
358									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
359	537	Hydraulic Expenses							
360			P	DGP		-	-	-	-
361			P	SG		3,376,626	870,398	4,143,554	1,068,090
362			P	SG		259,907	66,997	277,962	71,651
363									
364					B2	3,636,533	937,395	4,421,516	1,139,741
365									
366	538	Electric Expenses							
367			P	DGP		-	-	-	-
368			P	SG		-	-	-	-
369			P	SG		-	-	-	-
370									
371					B2	-	-	-	-
372									
373	539	Misc. Hydro Expenses							
374			P	DGP		-	-	-	-
375			P	SG		19,787,089	5,100,549	20,640,604	5,320,560
376			P	SG		7,388,753	1,904,610	7,670,423	1,977,217
377									
378									
379					B2	27,175,842	7,005,159	28,311,027	7,297,777
380									
381	540	Rents (Hydro Generation)							
382			P	DGP		-	-	-	-
383			P	SG		158,963	40,976	178,124	45,915
384			P	SG		983	253	1,060	273
385									
386					B2	159,947	41,230	179,184	46,188
387									
388	541	Maint Supervision & Engineering							
389			P	DGP		-	-	-	-
390			P	SG		1,691	436	1,755	452
391			P	SG		-	-	-	-
392									
393					B2	1,691	436	1,755	452
394									
395	542	Maintenance of Structures							
396			P	DGP		-	-	-	-
397			P	SG		1,028,908	265,223	1,071,488	276,199
398			P	SG		22,386	5,770	22,567	5,817
399									
400					B2	1,051,293	270,994	1,094,055	282,016
401									
402									
403									
404									
405	543	Maintenance of Dams & Waterways							
406			P	DGP		-	-	-	-
407			P	SG		1,391,013	358,564	1,451,174	374,071
408			P	SG		637,041	164,211	661,402	170,491
409									
410					B2	2,028,054	522,775	2,112,576	544,562
411									
412	544	Maintenance of Electric Plant							
413			P	DGP		-	-	-	-
414			P	SG		1,280,143	329,985	1,330,455	342,953
415			P	SG		361,514	93,188	375,294	96,740
416									
417					B2	1,641,657	423,172	1,705,749	439,693
418									
419	545	Maintenance of Misc. Hydro Plant							
420			P	DGP		-	-	-	-
421			P	SG		1,978,265	509,940	2,053,304	529,283
422			P	SG		863,439	222,570	900,373	232,090
423									
424					B2	2,841,704	732,511	2,953,677	761,374
425									
426	**Total Hydraulic Power Generation**				**B2**	**43,249,454**	**11,148,479**	**50,399,087**	**12,991,451**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
427									
428	546	Operation Super & Engineering							
429			P	SG		398,439	102,706	430,688	111,019
430			P	SG		-	-	-	-
431					B2	398,439	102,706	430,688	111,019
432									
433	547	Fuel-Non-NPC							
434			P	SE		-	-	-	-
435			P	SE		-	-	-	-
436					B2	-	-	-	-
437									
438	547NPC	Fuel-NPC							
439			P	SE		365,731,151	88,922,112	349,046,222	84,865,419
440			P	SE		16,065,664	3,906,128	17,197,901	4,181,415
441					B2	381,796,815	92,828,241	366,244,123	89,046,834
442									
443	548	Generation Expense							
444			P	SG		12,707,631	3,275,666	12,387,370	3,193,112
445			P	SG		1,195,095	308,061	1,247,708	321,624
446					B2	13,902,725	3,583,727	13,635,078	3,514,735
447									
448	549	Miscellaneous Other							
449			P	S		-	-	-	-
450			P	SG		21,482,053	5,537,462	21,654,734	5,581,974
451			P	SG		-	-	-	-
452					B2	21,482,053	5,537,462	21,654,734	5,581,974
453									
454									
455									
456									
457	550	Rents							
458			P	S		-	-	502,584	502,584
459			P	SG		3,846,936	991,631	4,158,849	1,072,033
460			P	SG		-	-	-	-
461					B2	3,846,936	991,631	4,661,433	1,574,617
462									
463	551	Maint Supervision & Engineering							
464			P	SG		-	-	-	-
465					B2	-	-	-	-
466									
467	552	Maintenance of Structures							
468			P	SG		2,539,068	654,499	2,667,827	687,690
469			P	SG		141,863	36,568	145,949	37,621
470					B2	2,680,930	691,068	2,813,776	725,311
471									
472	553	Maint of Generation & Electric Plant							
473			P	SG		9,506,139	2,450,412	9,729,443	2,507,974
474			P	SG		517,185	133,315	536,452	138,282
475					B2	10,023,323	2,583,728	10,265,896	2,646,256
476									
477	554	Maintenance of Misc. Other							
478			P	SG		2,583,613	665,982	2,718,026	700,630
479			P	SG		133,251	34,348	136,469	35,178
480					B2	2,716,865	700,330	2,854,495	735,808
481									
482	**Total Other Power Generation**				**B2**	**436,848,086**	**107,018,892**	**422,560,223**	**103,936,555**
483									
484									
485	555	Purchased Power-Non NPC							
486			DMSC	S		(30,986,809)	(22,356,044)	-	-
487						(30,986,809)	(22,356,044)	-	-
488									
489	555NPC	Purchased Power-NPC							
490			P	S		-	-	(145,921)	(145,921)
491			P	SG		402,775,436	103,824,048	644,944,800	166,248,421
492			P	SE		23,644,780	5,748,878	37,962,219	9,229,951
493		Seasonal Co	P	SG		-	-	-	-
494				DGP		-	-	-	-
495						426,420,216	109,572,927	682,761,098	175,332,451
496									
497		Total Purchased Power			B2	395,433,407	87,216,882	682,761,098	175,332,451
498									
499	556	System Control & Load Dispatch							
500			P	SG		1,200,430	309,437	1,272,275	327,956
501									
502					B2	1,200,430	309,437	1,272,275	327,956
503									
504									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
505									
506	557	Other Expenses							
507			P	S		(183,792)	(53,813)	9,566,674	(53,813)
508			P	SG		62,079,483	16,002,325	69,733,396	17,975,286
509			P	SGCT		1,122,425	290,280	1,122,425	290,280
510			P	SE		4,302,803	1,046,163	-	-
511			P	SG		-	-	-	-
512			P	TROJP		-	-	-	-
513									
514					B2	67,320,919	17,284,954	80,422,496	18,211,752
515									
516	**Total Other Power Supply**				**B2**	**463,954,755**	**104,811,273**	**764,455,869**	**193,872,159**
517									
518	**Total Production Expense**				**B2**	**1,935,054,442**	**468,461,088**	**2,366,364,592**	**589,986,243**
519									
520	Embedded Cost Differentials								
521		Company Owned Hyc	P	DGP		-	-	-	-
522		Company Owned Hyc	P	SG		-	-	-	-
523		Mid-C Contract	P	MC		-	-	-	-
524		Mid-C Contract	P	SG		-	-	-	-
525		Existing QF Contracts	P	S		-	-	-	-
526		Existing QF Contracts	P	SG		-	-	-	-
527									
528					**B2**	-	-	-	-
529									
530	2010 Protocol Stipulated Embedded Cost Differential and Adjustment								
531		Company Owned Hyc	P	DGP		(10,473,926)	(5,690,345)	(10,473,926)	(5,690,345)
532		Company Owned Hyc	P	SG		10,473,926	2,699,880	10,473,926	2,699,880
533		Mid-C Contract	P	MC		(15,540,530)	(6,434,648)	(15,540,530)	(6,434,648)
534		Mid-C Contract	P	SG		15,540,530	4,005,906	15,540,530	4,005,906
535		Klamath Dam Remov	P	S		0	11,390,329	0	11,390,329
536						0	5,971,123	0	5,971,123
537									
538									
539	Summary of Production Expense by Factor								
540			S			(31,579,884)	(11,019,528)	9,923,337	11,693,179
541			SG			893,413,013	230,296,457	1,169,210,167	301,389,117
542			SE			1,098,113,343	266,989,995	1,212,123,118	294,709,783
543			SNPPH			-	-	-	-
544			TROJP			-	-	-	-
545			SGCT			1,122,425	290,280	1,122,425	290,280
546			DGP			(10,473,926)	(5,690,345)	(10,473,926)	(5,690,345)
547			DEU			-	-	-	-
548			DEP			-	-	-	-
549			SNPPS			-	-	-	-
550			SNPPO			-	-	-	-
551			DGU			-	-	-	-
552			MC			(15,540,530)	(6,434,648)	(15,540,530)	(6,434,648)
553			SSGCT			-	-	-	-
554			SSECT			-	-	-	-
555			SSGC			-	-	-	-
556			SSGCH			-	-	-	-
557			SSECH			-	-	-	-
558	Total Production Expense by Factor					1,935,054,442	474,432,211	2,366,364,592	595,957,366
559	560	Operation Supervision & Engineering							
560			T	SG		6,080,103	1,567,278	6,260,781	1,613,851
561									
562					B2	6,080,103	1,567,278	6,260,781	1,613,851
563									
564	561	Load Dispatching							
565			T	SG		10,809,557	2,786,396	11,237,083	2,896,600
566									
567					B2	10,809,557	2,786,396	11,237,083	2,896,600
568	562	Station Expense							
569			T	SG		2,821,129	727,207	2,965,446	764,408
570									
571					B2	2,821,129	727,207	2,965,446	764,408
572									
573	563	Overhead Line Expense							
574			T	SG		117,236	30,220	122,245	31,511
575									
576					B2	117,236	30,220	122,245	31,511
577									
578	564	Underground Line Expense							
579			T	SG		-	-	-	-
580									
581					B2	-	-	-	-
582									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
583	565	Transmission of Electricity by Others							
584			T	SG		-	-	-	-
585			T	SE		-	-	-	-
586						-	-	-	-
587									
588	565NPC	Transmission of Electricity by Others-NPC							
589			T	SG		131,608,086	33,924,820	128,632,545	33,157,810
590			T	SE		6,292,490	1,529,926	2,899,400	704,946
591						137,900,576	35,454,746	131,531,945	33,862,757
592									
593		Total Transmission of Electricity by Others			B2	137,900,576	35,454,746	131,531,945	33,862,757
594									
595	566	Misc. Transmission Expense							
596			T	SG		4,256,727	1,097,263	3,583,415	923,703
597									
598					B2	4,256,727	1,097,263	3,583,415	923,703
599									
600	567	Rents - Transmission							
601			T	SG		1,837,478	473,649	1,949,783	502,599
602									
603					B2	1,837,478	473,649	1,949,783	502,599
604									
605	568	Maint Supervision & Engineering							
606			T	SG		2,286,817	589,476	2,376,593	612,618
607									
608					B2	2,286,817	589,476	2,376,593	612,618
609									
610	569	Maintenance of Structures							
611			T	SG		4,806,788	1,239,053	5,030,496	1,296,719
612									
613					B2	4,806,788	1,239,053	5,030,496	1,296,719
614									
615	570	Maintenance of Station Equipment							
616			T	SG		11,187,555	2,883,833	11,668,160	3,007,720
617									
618					B2	11,187,555	2,883,833	11,668,160	3,007,720
619									
620	571	Maintenance of Overhead Lines							
621			T	SG		20,881,692	5,382,706	22,314,037	5,751,924
622									
623					B2	20,881,692	5,382,706	22,314,037	5,751,924
624									
625	572	Maintenance of Underground Lines							
626			T	SG		140,683	36,264	147,248	37,956
627									
628					B2	140,683	36,264	147,248	37,956
629									
630	573	Maint of Misc. Transmission Plant							
631			T	SG		269,056	69,355	285,051	73,478
632									
633					B2	269,056	69,355	285,051	73,478
634									
635	**Total Transmission Expense**				**B2**	**203,395,397**	**52,337,448**	**199,472,285**	**51,375,843**
636									
637	Summary of Transmission Expense by Factor								
638		SE				6,292,490	1,529,926	2,899,400	704,946
639		SG				197,102,907	50,807,522	196,572,884	50,670,897
640		SNPT				-	-	-	-
641	Total Transmission Expense by Factor					203,395,397	52,337,448	199,472,285	51,375,843
642	580	Operation Supervision & Engineering							
643			DPW	S		42,004	-	44,700	(22)
644			DPW	SNPD		13,876,912	3,733,700	14,375,480	3,867,843
645					B2	13,918,916	3,733,700	14,420,180	3,867,822
646									
647	581	Load Dispatching							
648			DPW	S		-	-	0	0
649			DPW	SNPD		13,794,410	3,711,502	14,295,255	3,846,258
650					B2	13,794,410	3,711,502	14,295,255	3,846,258
651									
652	582	Station Expense							
653			DPW	S		4,039,699	1,101,897	4,231,352	1,151,914
654			DPW	SNPD		33,605	9,042	34,972	9,410
655					B2	4,073,304	1,110,939	4,266,324	1,161,324
656									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
657	583	Overhead Line Expenses							
658			DPW	S		5,982,127	2,969,038	6,218,589	3,085,147
659			DPW	SNPD		30,145	8,111	31,400	8,449
660					B2	6,012,272	2,977,149	6,249,990	3,093,596
661									
662	584	Underground Line Expense							
663			DPW	S		278	-	295	-
664			DPW	SNPD		-	-	-	-
665					B2	278	-	295	-
666									
667	585	Street Lighting & Signal Systems							
668			DPW	S		-	-	-	-
669			DPW	SNPD		221,438	59,580	229,230	61,676
670					B2	221,438	59,580	229,230	61,676
671									
672	586	Meter Expenses							
673			DPW	S		5,747,285	2,841,470	5,975,389	2,954,255
674			DPW	SNPD		1,338,372	360,100	1,392,549	374,677
675					B2	7,085,657	3,201,570	7,367,938	3,328,932
676									
677	587	Customer Installation Expenses							
678			DPW	S		12,706,959	4,336,385	13,210,598	4,507,068
679			DPW	SNPD		-	-	-	-
680					B2	12,706,959	4,336,385	13,210,598	4,507,068
681									
682	588	Misc. Distribution Expenses							
683			DPW	S		1,163,371	271,373	1,218,437	285,912
684			DPW	SNPD		4,035,067	1,085,669	4,242,428	1,141,461
685					B2	5,198,437	1,357,042	5,460,866	1,427,373
686									
687	589	Rents							
688			DPW	S		3,105,864	1,725,844	3,294,557	1,830,943
689			DPW	SNPD		64,337	17,311	68,316	18,381
690					B2	3,170,201	1,743,154	3,362,873	1,849,324
691									
692	590	Maint Supervision & Engineering							
693			DPW	S		822,461	318,747	856,965	332,395
694			DPW	SNPD		3,963,420	1,066,391	4,105,506	1,104,621
695					B2	4,785,882	1,385,139	4,962,471	1,437,016
696									
697	591	Maintenance of Structures							
698			DPW	S		1,693,542	482,824	1,812,437	516,721
699			DPW	SNPD		81,577	21,949	87,304	23,490
700					B2	1,775,119	504,773	1,899,740	540,210
701									
702	592	Maintenance of Station Equipment							
703			DPW	S		13,321,109	4,794,255	13,967,934	5,031,020
704			DPW	SNPD		1,453,956	391,199	1,506,447	405,322
705					B2	14,775,064	5,185,454	15,474,381	5,436,343
706	593	Maintenance of Overhead Lines							
707			DPW	S		87,567,530	28,822,221	92,850,975	30,523,061
708			DPW	SNPD		935,245	251,635	993,680	267,358
709					B2	88,502,774	29,073,856	93,844,655	30,790,419
710									
711	594	Maintenance of Underground Lines							
712			DPW	S		23,367,197	5,828,439	24,519,542	6,102,548
713			DPW	SNPD		202	54	216	58
714					B2	23,367,399	5,828,493	24,519,758	6,102,606
715									
716	595	Maintenance of Line Transformers							
717			DPW	S		-	-	-	-
718			DPW	SNPD		863,979	232,461	902,135	242,727
719					B2	863,979	232,461	902,135	242,727
720									
721	596	Maint of Street Lighting & Signal Sys.							
722			DPW	S		4,084,095	1,172,787	4,301,512	1,223,327
723			DPW	SNPD		-	-	-	-
724					B2	4,084,095	1,172,787	4,301,512	1,223,327
725									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
726	597	Maintenance of Meters							
727			DPW	S		4,756,900	1,020,485	4,955,527	1,062,137
728			DPW	SNPD		1,013,733	272,753	1,053,667	283,498
729					B2	5,770,633	1,293,239	6,009,193	1,345,635
730									
731	598	Maint of Misc. Distribution Plant							
732			DPW	S		2,085,687	450,008	2,227,633	479,343
733			DPW	SNPD		(292,473)	(78,692)	(351,531)	(94,582)
734					B2	1,793,214	371,316	1,876,101	384,760
735									
736	**Total Distribution Expense**				**B2**	**211,900,030**	**67,278,537**	**222,653,494**	**70,646,415**
737									
738									
739	Summary of Distribution Expense by Factor								
740		S				170,486,107	56,135,774	179,686,441	59,085,769
741		SNPD				41,413,923	11,142,764	42,967,053	11,560,646
742									
743	Total Distribution Expense by Factor					211,900,030	67,278,537	222,653,494	70,646,415
744									
745	901	Supervision							
746			CUST	S		2,542	1,014	2,671	1,054
747			CUST	CN		2,624,795	770,715	2,729,363	801,419
748					B2	2,627,337	771,729	2,732,034	802,473
749									
750	902	Meter Reading Expense							
751			CUST	S		20,676,876	9,820,883	21,488,525	10,203,950
752			CUST	CN		2,206,147	647,788	2,295,146	673,921
753					B2	22,883,023	10,468,671	23,783,671	10,877,871
754									
755	903	Customer Receipts & Collections							
756			CUST	S		7,837,725	2,224,477	8,168,746	2,318,208
757			CUST	CN		48,674,989	14,292,370	50,746,013	14,900,482
758					B2	56,512,714	16,516,847	58,914,759	17,218,690
759									
760	904	Uncollectible Accounts							
761			CUST	S		12,598,658	5,996,810	13,239,348	6,250,186
762			P	SG		-	-	-	-
763			CUST	CN		390,827	114,758	413,756	121,491
764					B2	12,989,486	6,111,568	13,653,105	6,371,676
765									
766	905	Misc. Customer Accounts Expense							
767			CUST	S		10,473	10,473	11,087	11,087
768			CUST	CN		186,329	54,712	195,103	57,288
769					B2	196,802	65,184	206,190	68,375
770									
771	**Total Customer Accounts Expense**				**B2**	**95,209,362**	**33,934,000**	**99,289,759**	**35,339,085**
772									
773	Summary of Customer Accts Exp by Factor								
774		S				41,126,274	18,053,658	42,910,378	18,784,485
775		CN				54,083,088	15,880,343	56,379,381	16,554,600
776		SG				-	-	-	-
777	Total Customer Accounts Expense by Factor					95,209,362	33,934,000	99,289,759	35,339,085
778									
779	907	Supervision							
780			CUST	S		-	-	-	-
781			CUST	CN		279,527	82,077	289,796	85,093
782					B2	279,527	82,077	289,796	85,093
783									
784	908	Customer Assistance							
785			CUST	S		106,251,795	22,984,962	12,474,522	1,637,007
786			CUST	CN		2,500,498	734,218	2,591,349	760,894
787									
788									
789					B2	108,752,293	23,719,180	15,065,871	2,397,902
790									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
791	909	Informational & Instructional Adv							
792			CUST	S		546,516	215,357	575,866	226,726
793			CUST	CN		4,158,696	1,221,112	4,359,846	1,280,175
794					B2	4,705,212	1,436,469	4,935,711	1,506,902
795									
796	910	Misc. Customer Service							
797			CUST	S		-	-	-	-
798			CUST	CN		232,845	68,370	245,457	72,073
799									
800					B2	232,845	68,370	245,457	72,073
801									
802	**Total Customer Service Expense**				**B2**	**113,969,877**	**25,306,096**	**20,536,835**	**4,061,969**
803									
804									
805	Summary of Customer Service Exp by Factor								
806		S				106,798,311	23,200,319	13,050,387	1,863,734
807		CN				7,171,566	2,105,777	7,486,448	2,198,235
808									
809	Total Customer Service Expense by Factor				B2	113,969,877	25,306,096	20,536,835	4,061,969
810									
811									
812	911	Supervision							
813			CUST	S		-	-	-	-
814			CUST	CN		-	-	-	-
815					B2	-	-	-	-
816									
817	912	Demonstration & Selling Expense							
818			CUST	S		-	-	-	-
819			CUST	CN		-	-	-	-
820					B2	-	-	-	-
821									
822	913	Advertising Expense							
823			CUST	S		-	-	-	-
824			CUST	CN		-	-	-	-
825					B2	-	-	-	-
826									
827	916	Misc. Sales Expense							
828			CUST	S		-	-	-	-
829			CUST	CN		-	-	-	-
830					B2	-	-	-	-
831									
832	**Total Sales Expense**				**B2**	-	-	-	-
833									
834									
835	Total Sales Expense by Factor								
836		S				-	-	-	-
837		CN				-	-	-	-
838	Total Sales Expense by Factor					-	-	-	-
839									
840	**Total Customer Service Exp Including Sales**				**B2**	**113,969,877**	**25,306,096**	**20,536,835**	**4,061,969**
841	920	Administrative & General Salaries							
842			PTD	S		(5,902,057)	1,274,323	(8,510,215)	(821,591)
843			CUST	CN		-	-	-	-
844			PTD	SO		76,070,259	20,664,475	78,936,527	21,443,096
845					B2	70,168,202	21,938,799	70,426,313	20,621,505
846									
847	921	Office Supplies & expenses							
848			PTD	S		818,712	302,041	863,989	318,745
849			CUST	CN		-	-	-	-
850			PTD	SO		8,822,483	2,396,626	9,243,641	2,511,034
851					B2	9,641,195	2,698,667	10,107,629	2,829,778
852									
853	922	A&G Expenses Transferred							
854			PTD	S		-	-	-	-
855			CUST	CN		-	-	-	-
856			PTD	SO		(31,726,905)	(8,618,609)	(34,862,827)	(9,470,482)
857					B2	(31,726,905)	(8,618,609)	(34,862,827)	(9,470,482)
858									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
859	923	Outside Services							
860			PTD	S		20,106	12,958	21,290	13,721
861			CUST	CN		-	-	-	-
862			PTD	SO		14,126,182	3,837,375	14,861,865	4,037,223
863					B2	14,146,288	3,850,333	14,883,154	4,050,944
864									
865	924	Property Insurance							
866			DPW	S		2,036,678	1,307,800	5,994,676	5,265,799
867			PT	SG		-	-	-	-
868			PTD	SO		23,348,780	6,342,693	9,748,399	2,648,151
869					B2	25,385,458	7,650,493	15,743,075	7,913,950
870									
871	925	Injuries & Damages							
872			PTD	S		-	-	248,469	248,469
873			PTD	SO		8,314,977	2,258,762	7,013,752	1,905,285
874					B2	8,314,977	2,258,762	7,262,221	2,153,754
875									
876	926	Employee Pensions & Benefits							
877			LABOR	S		-	-	-	-
878			CUST	CN		-	-	-	-
879			LABOR	SO		-	-	-	-
880					B2	-	-	-	-
881									
882	927	Franchise Requirements							
883			DMSC	S		-	-	-	-
884			DMSC	SG		-	-	-	-
885					B2	-	-	-	-
886									
887	928	Regulatory Commission Expense							
888			DMSC	S		14,959,078	3,046,402	15,795,520	3,255,051
889			CUST	CN		-	-	-	-
890			DMSC	SO		1,799,757	488,904	1,862,611	505,978
891			FERC	SG		1,657,049	427,140	1,755,117	452,419
892					B2	18,415,884	3,962,445	19,413,248	4,213,448
893									
894	929	Duplicate Charges							
895			LABOR	S		-	-	-	-
896			LABOR	SO		(6,811,639)	(1,850,381)	(7,736,639)	(2,101,657)
897					B2	(6,811,639)	(1,850,381)	(7,736,639)	(2,101,657)
898									
899	930	Misc General Expenses							
900			PTD	S		1,654,367	1,359,479	2,197,149	2,031,324
901			CUST	CN		-	-	-	-
902			LABOR	SO		14,551,845	3,953,007	14,311,679	3,887,765
903					B2	16,206,212	5,312,486	16,508,828	5,919,090
904									
905	931	Rents							
906			PTD	S		1,085,852	1,056,225	1,172,227	1,140,243
907			PTD	SO		5,322,451	1,445,843	5,745,828	1,560,853
908					B2	6,408,304	2,502,068	6,918,055	2,701,096
909									
910	935	Maintenance of General Plant							
911			G	S		235,679	90,071	241,201	92,331
912			CUST	CN		-	-	-	-
913			G	SO		23,578,792	6,405,176	24,152,930	6,561,140
914					B2	23,814,472	6,495,246	24,394,131	6,653,471
915									
916	**Total Administrative & General Expense**				**B2**	**153,962,449**	**46,200,310**	**143,057,189**	**45,484,898**
917									
918	Summary of A&G Expense by Factor								
919		S				14,908,416	8,449,299	18,024,307	11,544,092
920		SO				137,396,984	37,323,871	123,277,765	33,488,387
921		SG				1,657,049	427,140	1,755,117	452,419
922		CN				-	-	-	-
923	Total A&G Expense by Factor					153,962,449	46,200,310	143,057,189	45,484,898
924									
925	**Total O&M Expense**				**B2**	**2,713,491,556**	**699,488,603**	**3,051,374,154**	**802,865,577**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
926	403SP	Steam Depreciation							
927			P	SG		21,699,385	5,593,484	30,086,982	7,755,568
928			P	SG		25,254,801	6,509,969	30,498,129	7,861,550
929			P	SG		71,555,236	18,444,904	161,045,747	41,513,012
930			P	SG		7,849,360	2,023,342	11,577,816	2,984,431
931					B3	126,358,782	32,571,699	233,208,674	60,114,561
932									
933	403NP	Nuclear Depreciation							
934			P	SG		-	-	-	-
935					B3	-	-	-	-
936									
937	403HP	Hydro Depreciation							
938			P	SG		3,614,050	931,599	6,185,025	1,594,324
939			P	SG		1,004,089	258,826	931,287	240,059
940			P	SG		9,959,593	2,567,300	14,361,224	3,701,915
941			P	SG		3,695,335	952,552	4,616,029	1,189,881
942					B3	18,273,067	4,710,277	26,093,565	6,726,179
943									
944	403OP	Other Production Depreciation							
945			P	S		-	-	-	-
946			P	SG		123,593	31,859	(3,312)	(854)
947			P	SG		109,925,386	28,335,637	104,654,323	26,976,907
948			P	SG		2,625,250	676,715	2,692,774	694,120
949			P	SG		-	-	-	-
950					B3	112,674,229	29,044,211	107,343,785	27,670,174
951									
952	403TP	Transmission Depreciation							
953			T	S		-	-	-	-
954			T	SG		11,173,740	2,880,272	10,788,283	2,780,912
955			T	SG		12,421,176	3,201,826	12,398,498	3,195,980
956			T	SG		55,933,484	14,418,061	66,201,741	17,064,925
957					B3	79,528,400	20,500,159	89,388,522	23,041,818
958									
959									
960									
961	403	Distribution Depreciation							
962	360	Land & Land Rights	DPW	S		314,458	68,465	442,878	90,290
963	361	Structures	DPW	S		1,224,317	290,449	1,415,294	322,906
964	362	Station Equipment	DPW	S		12,591,896	4,332,463	14,573,663	4,669,271
965	363	Storage Battery Eq	DPW	S		1,854	-	1,854	-
966	364	Poles & Towers	DPW	S		34,968,334	12,562,380	37,265,769	12,952,836
967	365	OH Conductors	DPW	S		19,443,714	6,903,560	21,017,653	7,171,056
968	366	UG Conduit	DPW	S		7,883,127	2,153,638	8,616,519	2,278,280
969	367	UG Conductor	DPW	S		17,848,103	3,737,039	19,590,683	4,033,197
970	368	Line Trans	DPW	S		28,003,627	11,077,108	30,671,681	11,530,553
971	369	Services	DPW	S		12,028,084	4,494,872	13,454,704	4,737,331
972	370	Meters	DPW	S		6,354,816	2,175,541	6,785,873	2,248,801
973	371	Inst Cust Prem	DPW	S		489,912	118,152	511,107	121,754
974	372	Leased Property	DPW	S		-	-	-	-
975	373	Street Lighting	DPW	S		2,156,362	666,810	2,302,721	691,685
976					B3	143,308,604	48,580,477	156,650,401	50,847,961
977									
978	403GP	General Depreciation							
979			G-SITUS	S		12,138,484	3,740,188	13,476,566	4,019,896
980			G-DGP	SG		248,887	64,156	110,098	28,380
981			G-DGU	SG		376,406	97,027	138,646	35,739
982			P	SE		21,246	5,166	16,878	4,104
983			CUST	CN		1,706,446	501,062	1,516,791	445,373
984			G-SG	SG		6,152,699	1,585,991	6,639,755	1,711,540
985			PTD	SO		14,631,939	3,974,764	13,932,877	3,784,864
986			P	SG		6,010	1,549	6,328	1,631
987			P	SG		139,134	35,865	100,984	26,031
988					B3	35,421,251	10,005,767	35,938,924	10,057,558
989									
990	403GV0	General Vehicles							
991			G-SG	SG		-	-	-	-
992					B3	-	-	-	-
993									
994	403MP	Mining Depreciation							
995			P	SE		-	-	-	-
996					B3	-	-	-	-
997									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
998	403EP	Experimental Plant Depreciation							
999			P	SG		-	-	-	-
1000			P	SG		-	-	-	-
1001					B3	-	-	-	-
1002	4031	ARO Depreciation							
1003			P	S		-	-	-	-
1004					B3	-	-	-	-
1005									
1006									
1007	**Total Depreciation Expense**				**B3**	**515,564,333**	**145,412,589**	**648,623,871**	**178,458,250**
1008									
1009	Summary	S				155,447,088	52,320,665	170,126,967	54,867,856
1010		DGP				-	-	-	-
1011		DGU				-	-	-	-
1012		SG				343,757,613	88,610,933	463,030,357	119,356,053
1013		SO				14,631,939	3,974,764	13,932,877	3,784,864
1014		CN				1,706,446	501,062	1,516,791	445,373
1015		SE				21,246	5,166	16,878	4,104
1016		SSGCH				-	-	-	-
1017		SSGCT				-	-	-	-
1018	Total Depreciation Expense By Factor					515,564,333	145,412,589	648,623,871	178,458,250
1019									
1020	404GP	Amort of LT Plant - Capital Lease Gen							
1021			I-SITUS	S		1,672,595	777,880	1,108,765	248,068
1022			I-SG	SG		-	-	-	-
1023			PTD	SO		1,265,577	343,794	1,259,258	342,077
1024			I-DGU	SG		-	-	-	-
1025			CUST	CN		270,082	79,304	273,367	80,268
1026			I-DGP	SG		-	-	-	-
1027					B4	3,208,254	1,200,978	2,641,390	670,413
1028									
1029	404SP	Amort of LT Plant - Cap Lease Steam							
1030			P	SG		-	-	-	-
1031			P	SG		-	-	-	-
1032					B4	-	-	-	-
1033									
1034	404IP	Amort of LT Plant - Intangible Plant							
1035			I-SITUS	S		195,942	14,532	185,661	8,962
1036			P	SE		13,653	3,320	336,447	81,802
1037			I-SG	SG		9,025,509	2,326,519	5,317,923	1,370,809
1038			PTD	SO		15,076,510	4,095,532	20,971,360	5,696,867
1039			CUST	CN		5,695,883	1,672,474	5,801,059	1,703,357
1040			I-SG	SG		6,752,316	1,740,555	10,780,267	2,778,846
1041			I-SG	SG		307,800	79,342	302,172	77,891
1042			I-DGP	SG		-	-	-	-
1043			I-SG	SG		-	-	-	-
1044			I-SG	SG		77,056	19,863	-	-
1045			I-DGU	SG		16,758	4,320	16,151	4,163
1046					B4	37,161,427	9,956,457	43,711,041	11,722,699
1047									
1048	404MP	Amort of LT Plant - Mining Plant							
1049			P	SE		-	-	-	-
1050					B4	-	-	-	-
1051									
1052	404OP	Amort of LT Plant - Other Plant							
1053			P	SG		-	-	-	-
1054					B4	-	-	-	-
1055									
1056									
1057	404HP	Amortization of Other Electric Plant							
1058			P	SG		168,315	43,387	249,015	64,189
1059			P	SG		46,417	11,965	44,532	11,479
1060			P	SG		-	-	-	-
1061					B4	214,732	55,352	293,548	75,668
1062									
1063	**Total Amortization of Limited Term Plant**				**B4**	**40,584,413**	**11,212,786**	**46,645,979**	**12,468,780**
1064									
1065									
1066	405	Amortization of Other Electric Plant							
1067			GP	S		-	-	-	-
1068									
1069					B4	-	-	-	-
1070									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1071	406	Amortization of Plant Acquisition Adj							
1072			P	S		-	-	-	-
1073			P	SG		-	-	-	-
1074			P	SG		-	-	-	-
1075			P	SG		5,523,970	1,423,922	5,193,044	1,338,619
1076			P	SO		-	-	-	-
1077					B4	5,523,970	1,423,922	5,193,044	1,338,619
1078	407	Amort of Prop Losses, Unrec Plant, etc							
1079			DPW	S		(200,504)	(39,640)	(160,864)	-
1080			GP	SO		-	-	-	-
1081			P	SG		1,327,321	342,146	(0)	(0)
1082			P	SE		-	-	-	-
1083			P	SG		-	-	-	-
1084			P	TROJP		1,163,874	297,426	(0)	(0)
1085					B4	2,290,691	599,931	(160,864)	(0)
1086									
1087	**Total Amortization Expense**				**B4**	**48,399,074**	**13,236,640**	**51,678,159**	**13,807,399**
1088									
1089									
1090									
1091	Summary of Amortization Expense by Factor								
1092		S				1,668,033	752,772	1,133,562	257,030
1093		SE				13,653	3,320	336,447	81,802
1094		TROJP				1,163,874	297,426	(0)	(0)
1095		DGP				-	-	-	-
1096		SG-P				-	-	-	-
1097		SO				16,342,088	4,439,326	22,230,619	6,038,944
1098		SSGCT				-	-	-	-
1099		SSGCH				-	-	-	-
1100		CN				5,965,965	1,751,778	6,074,426	1,783,625
1101		SG				23,245,461	5,992,019	21,903,105	5,645,997
1102	Total Amortization Expense by Factor					48,399,074	13,236,640	51,678,159	13,807,399
1103	408	Taxes Other Than Income							
1104			DMSC	S		27,545,791	24,628,661	31,057,647	28,140,517
1105			GP	GPS		108,846,556	29,567,899	124,768,000	33,892,921
1106			GP	SO		9,622,896	2,614,058	9,622,896	2,614,058
1107			P	SE		827,316	201,150	827,316	201,150
1108			P	SG		-	-	1,479,722	381,430
1109			DMSC	OPRV-ID		-	-	-	-
1110			GP	EXCTAX		-	-	-	-
1111			GP	SG		-	-	-	-
1112									
1113									
1114									
1115	**Total Taxes Other Than Income**				**B5**	**146,842,558**	**57,011,768**	**167,755,580**	**65,230,076**
1116									
1117									
1118	41140	Deferred Investment Tax Credit - Fed							
1119			PTD	DGU		(1,874,204)	-	(1,874,204)	-
1120									
1121					B7	(1,874,204)	-	(1,874,204)	-
1122									
1123	41141	Deferred Investment Tax Credit - Idaho							
1124			PTD	DGU		-	-	-	-
1125									
1126					B7	-	-	-	-
1127									
1128	**Total Deferred ITC**				**B7**	**(1,874,204)**	**-**	**(1,874,204)**	**-**
1129									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1130									
1131	427	Interest on Long-Term Debt							
1132			GP	S		312,146,753	80,964,831	317,137,259	81,982,452
1133			GP	SNP		-	-	-	-
1134					B6	312,146,753	80,964,831	317,137,259	81,982,452
1135									
1136	428	Amortization of Debt Disc & Exp							
1137			GP	SNP		-	-	-	-
1138					B6	-	-	-	-
1139									
1140	429	Amortization of Premium on Debt							
1141			GP	SNP		-	-	-	-
1142					B6	-	-	-	-
1143									
1144	431	Other Interest Expense							
1145			NUTIL	OTH		-	-	-	-
1146			GP	SO		-	-	-	-
1147			GP	SNP		-	-	-	-
1148					B6	-	-	-	-
1149									
1150	432	AFUDC - Borrowed							
1151			GP	SNP		-	-	-	-
1152						-	-	-	-
1153									
1154		Total Elec. Interest Deductions for Tax			B6	312,146,753	80,964,831	317,137,259	81,982,452
1155									
1156		Non-Utility Portion of Interest							
1157		427	NUTIL	NUTIL		-	-	-	-
1158		428	NUTIL	NUTIL		-	-	-	-
1159		429	NUTIL	NUTIL		-	-	-	-
1160		431	NUTIL	NUTIL		-	-	-	-
1161									
1162		Total Non-utility Interest				-	-	-	-
1163									
1164		Total Interest Deductions for Tax			B6	312,146,753	80,964,831	317,137,259	81,982,452
1165									
1166									
1167	419	Interest & Dividends							
1168			GP	S		-	-	-	-
1169			GP	SNP		(59,310,129)	(15,537,036)	(53,488,675)	(14,012,032)
1170		Total Operating Deductions for Tax			B6	(59,310,129)	(15,537,036)	(53,488,675)	(14,012,032)
1171									
1172									
1173	41010	Deferred Income Tax - Federal-DR							
1174			GP	S		47,440,799	339,759	1,292,220	20,423
1175			P	SCHMDEXP		-	-	-	-
1176			PT	SG		31,324	8,074	31,324	8,074
1177			LABOR	SO		7,830,895	2,127,262	(15,554)	(4,225)
1178			GP	SNP		33,713,788	8,831,752	32,439,546	8,497,948
1179			P	SE		18,367,716	4,465,838	1,130,007	274,745
1180			PT	SG		23,560,496	6,073,226	45,491,826	11,726,499
1181			GP	GPS		26,018,718	7,067,921	21,164,533	5,749,293
1182			TAXDEPR	TAXDEPR		1,080,616,640	282,568,931	503,656,213	131,700,357
1183			CUST	BADDEBT		-	-	-	-
1184			CUST	CN		18,276	5,366	0	0
1185			IBT	IBT		-	-	-	-
1186			DPW	SNPD		-	-	-	-
1187					B7	1,237,598,652	311,488,128	605,190,115	157,973,114
1188									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1189									
1190									
1191	41110	Deferred Income Tax - Federal-CR							
1192			GP	S		(26,227,663)	(5,015,484)	(10,150,074)	(1,773,344)
1193			P	SE		(12,433,468)	(3,023,014)	-	-
1194			CUST	BADDEBT		(499,023)	(232,886)	-	-
1195			GP	SNP		(19,232,707)	(5,038,250)	(27,638,492)	(7,240,251)
1196			PT	SG		(8,206,952)	(2,115,519)	(15,642,792)	(4,032,267)
1197			DPW	CIAC		(10,561,420)	(2,841,639)	(19,266,440)	(5,183,797)
1198			LABOR	SO		(17,184,714)	(4,668,225)	(4,237,506)	(1,151,118)
1199			PT	SNPD		(3,638,499)	(978,969)	-	-
1200			P	SG		-	-	-	-
1201			P	SGCT		(425,972)	(110,164)	(425,972)	(110,164)
1202			GP	SCHMDEXP		(215,825,162)	(59,380,764)	(242,921,943)	(66,836,000)
1203			P	TROJD		(721,757)	(184,160)	-	-
1204			IBT	IBT		-	-	-	-
1205			0	SG		-	-	-	-
1206			0	SG		-	-	-	-
1207			0	SG		-	-	-	-
1208			0	SG		(510,725)	(131,650)	(510,725)	(131,650)
1209			0	SG		-	-	-	-
1210					B7	(315,468,063)	(83,720,723)	(320,793,945)	(86,458,591)
1211									
1212	**Total Deferred Income Taxes**				**B7**	**922,130,589**	**227,767,405**	**284,396,170**	**71,514,522**
1213	SCHMAF	Additions - Flow Through							
1214			SCHMAF	S		-	-	-	-
1215			SCHMAF	SNP		-	-	-	-
1216			SCHMAF	SO		-	-	-	-
1217			SCHMAF	SE		-	-	-	-
1218			SCHMAF	TROJP		-	-	-	-
1219			SCHMAF	SG		-	-	-	-
1220					B6	-	-	-	-
1221									
1222	SCHMAP	Additions - Permanent							
1223			P	S		28,808	-	-	-
1224			P	SE		130,031	31,615	16,000	3,890
1225			LABOR	SNP		-	-	-	-
1226			SCHMAP-SO	SO		14,206,873	3,859,295	(2,502,079)	(679,689)
1227			SCHMAP	SG		-	-	-	-
1228			DPW	SCHMDEXP		(535,912)	(147,447)	(240,884)	(66,275)
1229					B6	13,829,800	3,743,463	(2,726,963)	(742,075)
1230									
1231	SCHMAT	Additions - Temporary							
1232			SCHMAT-SITUS	S		52,139,597	11,691,014	3,084,839	(36,000)
1233			P	SG		-	-	-	-
1234			DPW	CIAC		27,829,092	7,487,651	50,766,618	13,659,185
1235			SCHMAT-SNP	SNP		50,677,736	13,275,672	72,826,783	19,077,894
1236			P	TROJD		1,901,813	485,258	-	-
1237			CUST	BADDEBT		1,314,913	613,648	-	-
1238			SCHMAT-SE	SE		32,761,900	7,965,571	-	-
1239			P	SG		16,882,886	4,351,928	41,145,553	10,606,153
1240			SCHMAT-GPS	CN		-	-	-	-
1241			SCHMAT-SO	SO		45,281,318	12,300,664	11,165,730	3,033,169
1242			SCHMAT-SNP	SNPD		9,587,358	2,579,559	-	-
1243			P	SGCT		1,122,425	290,280	1,122,425	290,280
1244			TAXDEPR	SG		-	-	-	-
1245			BOOKDEPR	SCHMDEXP		568,694,270	156,466,928	640,093,658	176,111,302
1246			0	SG		-	-	-	-
1247			0	SG		-	-	-	-
1248			0	SG		-	-	-	-
1249			0	SG		-	-	-	-
1250					B6	808,193,308	217,508,171	820,205,606	222,741,982
1251									
1252	TOTAL SCHEDULE - M ADDITIONS				B6	822,023,108	221,251,634	817,478,643	221,999,907
1253									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1254	SCHMDF	Deductions - Flow Through							
1255			SCHMDF	S		-	-	-	-
1256			SCHMDF	SG		-	-	-	-
1257			SCHMDF	SG		-	-	-	-
1258					B6	-	-	-	-
1259	SCHMDP	Deductions - Permanent							
1260			SCHMDP	S		-	-	-	-
1261			P	SE		574,264	139,624	477,991	116,216
1262			PTD	SNP		361,498	94,699	381,062	99,824
1263			SCHMDEXP	SCHMDEXP		109,247	30,058	-	-
1264			P	SG		-	-	-	-
1265			SCHMDP-SO	SO		20,811,550	5,653,455	(4,100,000)	(1,113,764)
1266					B6	21,856,559	5,917,835	(3,240,947)	(897,724)
1267									
1268	SCHMDT	Deductions - Temporary							
1269			GP	S		125,005,401	895,255	3,404,965	53,813
1270			CUST	BADDEBT		-	-	-	-
1271			SCHMDT-SNP	SNP		88,835,043	23,271,459	85,477,445	22,391,894
1272			SCHMDT	CN		48,156	14,140	0	0
1273			SCHMDT	SG		82,539	21,276	82,539	21,276
1274			P	SG		-	-	-	-
1275			P	SE		48,398,501	11,767,379	2,977,542	723,945
1276			SCHMDT-SG	SG		62,081,357	16,002,808	119,869,900	30,899,050
1277			SCHMDT-GPS	GPS		68,558,717	18,623,807	55,768,052	15,149,254
1278			SCHMDT-SO	SO		23,344,458	6,341,519	(40,985)	(11,134)
1279			TAXDEPR	TAXDEPR		2,847,399,647	744,562,543	1,327,122,376	347,027,370
1280			DPW	SNPD		-	-	-	-
1281					B6	3,263,753,819	821,500,185	1,594,661,834	416,255,469
1282									
1283	TOTAL SCHEDULE - M DEDUCTIONS				B6	3,285,610,378	827,418,020	1,591,420,887	415,357,745
1284									
1285	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(2,463,587,270)**	**(606,166,386)**	**(773,942,244)**	**(193,357,838)**
1286									
1287									
1288									
1289	40911	State Income Taxes							
1290			IBT	S		(76,017,523)	(15,907,186)	(3,480,423)	1,650,682
1291			IBT	IBT		-	-	-	-
1292		REC	P	SG		(288,539)	(74,377)	(392,418)	(101,154)
1293			IBT	IBT		-	-	-	-
1294	**Total State Tax Expense**					**(76,306,062)**	**(15,981,563)**	**(3,872,841)**	**1,549,528**
1295									
1296									
1297	Calculation of Taxable Income:								
1298		Operating Revenues				4,464,637,351	1,236,147,820	4,877,996,718	1,357,701,948
1299		Operating Deductions:							
1300		O & M Expenses				2,713,491,556	699,488,603	3,051,374,154	802,865,577
1301		Depreciation Expense				515,564,333	145,412,589	648,623,871	178,458,250
1302		Amortization Expense				48,399,074	13,236,640	51,678,159	13,807,399
1303		Taxes Other Than Income				146,842,558	57,011,768	167,755,580	65,230,076
1304		Interest & Dividends (AFUDC-Equity)				(59,310,129)	(15,537,036)	(53,488,675)	(14,012,032)
1305		Misc Revenue & Expense				(1,689,284)	(217,418)	(2,364,567)	(346,250)
1306		Total Operating Deductions				3,363,298,107	899,395,146	3,863,578,523	1,046,003,020
1307		Other Deductions:							
1308		Interest Deductions				312,146,753	80,964,831	317,137,259	81,982,452
1309		Interest on PCRBS				-	-	-	-
1310		Schedule M Adjustments				(2,463,587,270)	(606,166,386)	(773,942,244)	(193,357,838)
1311									
1312		Income Before State Taxes				(1,674,394,779)	(350,378,544)	(76,661,308)	36,358,638
1313									
1314		State Income Taxes				(76,306,062)	(15,981,563)	(3,872,841)	1,549,528
1315									
1316	Total Taxable Income					(1,598,088,717)	(334,396,981)	(72,788,466)	34,809,110
1317									
1318	Tax Rate					35.0%	35.0%	35.0%	35.0%
1319									
1320	Federal Income Tax - Calculated					(559,331,051)	(117,038,943)	(25,475,963)	12,183,188
1321									
1322	Adjustments to Calculated Tax:								
1323	40910	PMI	P	SE		(120,409)	(29,276)	(16,000)	(3,890)
1324	40910	REC	P	SG		(58,529,911)	(15,087,346)	(62,989,912)	(16,237,007)
1325	40911	State Energy Cr	P	SO		(28,808)	(7,826)	-	-
1326	40910	IRS Settle	LABOR	S		-	-	-	-
1327	**Federal Income Tax Expense**					**(618,010,179)**	**(132,163,391)**	**(88,481,875)**	**(4,057,709)**
1328									
1329	**Total Operating Expenses**					**3,648,548,381**	**994,554,634**	**4,107,234,448**	**1,129,021,394**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1330	310	Land and Land Rights							
1331			P	SG		2,328,228	600,151	2,328,228	600,151
1332			P	SG		34,798,446	8,970,049	34,798,446	8,970,049
1333			P	SG		56,303,435	14,513,424	56,303,435	14,513,424
1334			P	S		-	-	-	-
1335			P	SG		2,468,743	636,372	2,468,743	636,372
1336					B8	95,898,852	24,719,996	95,898,852	24,719,996
1337									
1338	311	Structures and Improvements							
1339			P	SG		233,585,247	60,211,631	233,585,247	60,211,631
1340			P	SG		324,837,488	83,733,863	324,837,488	83,733,863
1341			P	SG		306,366,663	78,972,610	306,366,663	78,972,610
1342			P	SG		58,737,692	15,140,906	58,737,692	15,140,906
1343					B8	923,527,091	238,059,010	923,527,091	238,059,010
1344									
1345	312	Boiler Plant Equipment							
1346			P	SG		635,449,135	163,800,708	605,259,570	156,018,697
1347			P	SG		586,564,644	151,199,678	565,104,934	145,667,975
1348			P	SG		2,138,721,828	551,301,641	2,864,452,289	738,374,307
1349			P	SG		325,216,222	83,831,490	305,234,138	78,680,677
1350					B8	3,685,951,829	950,133,516	4,340,050,930	1,118,741,656
1351									
1352	314	Turbogenerator Units							
1353			P	SG		127,038,148	32,746,820	127,038,148	32,746,820
1354			P	SG		143,662,395	37,032,078	143,662,395	37,032,078
1355			P	SG		591,402,331	152,446,696	583,723,978	150,467,435
1356			P	SG		63,736,456	16,429,445	63,736,456	16,429,445
1357					B8	925,839,330	238,655,039	918,160,977	236,675,778
1358									
1359	315	Accessory Electric Equipment							
1360			P	SG		86,928,888	22,407,794	86,928,888	22,407,794
1361			P	SG		137,455,589	35,432,140	137,455,589	35,432,140
1362			P	SG		126,540,752	32,618,606	126,540,752	32,618,606
1363			P	SG		66,647,509	17,179,832	66,647,509	17,179,832
1364					B8	417,572,737	107,638,372	417,572,737	107,638,372
1365									
1366									
1367									
1368	316	Misc Power Plant Equipment							
1369			P	SG		4,715,664	1,215,564	4,715,664	1,215,564
1370			P	SG		5,085,197	1,310,819	5,085,197	1,310,819
1371			P	SG		19,517,661	5,031,098	19,517,661	5,031,098
1372			P	SG		4,036,539	1,040,505	4,036,539	1,040,505
1373					B8	33,355,061	8,597,986	33,355,061	8,597,986
1374									
1375	317	Steam Plant ARO							
1376			P	S		-	-	-	-
1377					B8	-	-	-	-
1378									
1379	SP	Unclassified Steam Plant - Account 300							
1380			P	SG		5,221,058	1,345,840	5,221,058	1,345,840
1381					B8	5,221,058	1,345,840	5,221,058	1,345,840
1382									
1383									
1384	**Total Steam Production Plant**				**B8**	**6,087,365,959**	**1,569,149,759**	**6,733,786,706**	**1,735,778,637**
1385									
1386									
1387	Summary of Steam Production Plant by Factor								
1388		S				-	-	-	-
1389		DGP				-	-	-	-
1390		DGU				-	-	-	-
1391		SG				6,087,365,959	1,569,149,759	6,733,786,706	1,735,778,637
1392		SSGCH				-	-	-	-
1393	Total Steam Production Plant by Factor					6,087,365,959	1,569,149,759	6,733,786,706	1,735,778,637
1394	320	Land and Land Rights							
1395			P	SG		-	-	-	-
1396			P	SG		-	-	-	-
1397					B8	-	-	-	-
1398									
1399	321	Structures and Improvements							
1400			P	SG		-	-	-	-
1401			P	SG	B8	-	-	-	-
1402						-	-	-	-

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1403									
1404	322	Reactor Plant Equipment							
1405			P	SG		-	-	-	-
1406			P	SG		-	-	-	-
1407					B8	-	-	-	-
1408									
1409	323	Turbogenerator Units							
1410			P	SG		-	-	-	-
1411			P	SG		-	-	-	-
1412					B8	-	-	-	-
1413									
1414	324	Land and Land Rights							
1415			P	SG		-	-	-	-
1416			P	SG		-	-	-	-
1417					B8	-	-	-	-
1418									
1419	325	Misc. Power Plant Equipment							
1420			P	SG		-	-	-	-
1421			P	SG		-	-	-	-
1422					B8	-	-	-	-
1423									
1424									
1425	NP	Unclassified Nuclear Plant - Acct 300							
1426			P	SG		-	-	-	-
1427					B8	-	-	-	-
1428									
1429									
1430	**Total Nuclear Production Plant**				**B8**	-	-	-	-
1431									
1432									
1433									
1434	Summary of Nuclear Production Plant by Factor								
1435		DGP				-	-	-	-
1436		DGU				-	-	-	-
1437		SG				-	-	-	-
1438									
1439	Total Nuclear Plant by Factor					-	-	-	-
1440									
1441	330	Land and Land Rights							
1442			P	SG		10,537,839	2,716,355	10,537,839	2,716,355
1443			P	SG		5,269,427	1,358,308	5,269,427	1,358,308
1444			P	SG		9,571,216	2,467,187	9,571,216	2,467,187
1445			P	SG		672,873	173,448	672,873	173,448
1446					B8	26,051,355	6,715,298	26,051,355	6,715,298
1447									
1448	331	Structures and Improvements							
1449			P	SG		20,799,391	5,361,491	20,799,391	5,361,491
1450			P	SG		5,274,527	1,359,623	5,274,527	1,359,623
1451			P	SG		80,369,624	20,717,003	80,369,624	20,717,003
1452			P	SG		8,245,496	2,125,454	8,245,496	2,125,454
1453					B8	114,689,039	29,563,571	114,689,039	29,563,571
1454									
1455	332	Reservoirs, Dams & Waterways							
1456			P	SG		150,783,539	38,867,706	146,431,209	37,745,800
1457			P	SG		19,969,848	5,147,659	18,011,998	4,642,981
1458			P	SG		115,440,304	29,757,226	339,922,585	87,622,372
1459			P	SG		49,681,299	12,806,426	72,068,456	18,577,198
1460					B8	335,874,990	86,579,017	576,434,248	148,588,350
1461									
1462	333	Water Wheel, Turbines, & Generators							
1463			P	SG		31,234,511	8,051,368	31,234,511	8,051,368
1464			P	SG		8,597,048	2,216,074	8,597,048	2,216,074
1465			P	SG		45,210,605	11,654,008	45,210,605	11,654,008
1466			P	SG		30,461,484	7,852,104	30,461,484	7,852,104
1467					B8	115,503,647	29,773,554	115,503,647	29,773,554
1468									
1469	334	Accessory Electric Equipment							
1470			P	SG		4,342,020	1,119,249	4,342,020	1,119,249
1471			P	SG		3,626,864	934,902	3,626,864	934,902
1472			P	SG		45,034,974	11,608,735	45,034,974	11,608,735
1473			P	SG		7,348,480	1,894,229	7,348,480	1,894,229
1474					B8	60,352,339	15,557,116	60,352,339	15,557,116
1475									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1476									
1477									
1478	335	Misc. Power Plant Equipment							
1479			P	SG		1,145,813	295,358	1,145,813	295,358
1480			P	SG		161,332	41,587	161,332	41,587
1481			P	SG		992,216	255,765	992,216	255,765
1482			P	SG		12,582	3,243	12,582	3,243
1483					B8	2,311,942	595,953	2,311,942	595,953
1484									
1485	336	Roads, Railroads & Bridges							
1486			P	SG		4,632,223	1,194,055	4,632,223	1,194,055
1487			P	SG		822,839	212,104	822,839	212,104
1488			P	SG		10,344,503	2,666,519	10,344,503	2,666,519
1489			P	SG		674,244	173,801	674,244	173,801
1490					B8	16,473,809	4,246,479	16,473,809	4,246,479
1491									
1492	337	Hydro Plant ARO							
1493			P	S		-	-	-	-
1494					B8	-	-	-	-
1495									
1496	HP	Unclassified Hydro Plant - Acct 300							
1497			P	S		-	-	-	-
1498			P	SG		-	-	-	-
1499			P	SG		-	-	-	-
1500			P	SG		-	-	-	-
1501					B8	-	-	-	-
1502									
1503	**Total Hydraulic Production Plant**				**B8**	**671,257,121**	**173,030,989**	**911,816,379**	**235,040,321**
1504									
1505	Summary of Hydraulic Plant by Factor								
1506		S				-	-	-	-
1507		SG				671,257,121	173,030,989	911,816,379	235,040,321
1508		DGP				-	-	-	-
1509		DGU				-	-	-	-
1510	Total Hydraulic Plant by Factor					671,257,121	173,030,989	911,816,379	235,040,321
1511									
1512	340	Land and Land Rights							
1513			P	S		-	-	75,000	75,000
1514			P	SG		28,912,692	7,452,870	28,912,692	7,452,870
1515			P	SG		-	-	-	-
1516			P	SG		-	-	-	-
1517					B8	28,912,692	7,452,870	28,987,692	7,527,870
1518									
1519	341	Structures and Improvements							
1520			P	SG		158,822,988	40,940,048	155,777,248	40,154,943
1521			P	SG		163,512	42,149	163,512	42,149
1522			P	SG		4,240,304	1,093,030	4,240,304	1,093,030
1523					B8	163,226,804	42,075,226	160,181,064	41,290,121
1524									
1525	342	Fuel Holders, Producers & Accessories							
1526			P	SG		8,424,526	2,171,603	8,424,526	2,171,603
1527			P	SG		121,339	31,278	121,339	31,278
1528			P	SG		2,284,126	588,783	2,284,126	588,783
1529					B8	10,829,991	2,791,664	10,829,991	2,791,664
1530									
1531	343	Prime Movers							
1532			P	S		-	-	-	-
1533			P	SG		754,440	194,473	(485,616)	(125,178)
1534			P	SG		2,438,440,767	628,560,656	2,252,911,880	580,736,588
1535			P	SG		53,648,952	13,829,174	55,775,187	14,377,256
1536					B8	2,492,844,159	642,584,303	2,308,201,451	594,988,666
1537									
1538	344	Generators							
1539			P	S		-	-	-	-
1540			P	SG		-	-	-	-
1541			P	SG		338,102,743	87,153,268	332,252,370	85,645,208
1542			P	SG		15,873,643	4,091,774	15,873,643	4,091,774
1543					B8	353,976,386	91,245,042	348,126,013	89,736,982

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1544									
1545	345	Accessory Electric Plant							
1546			P	SG		244,333,275	62,982,167	232,284,593	59,876,360
1547			P	SG		156,586	40,363	156,586	40,363
1548			P	SG		2,919,649	752,602	2,919,649	752,602
1549					B8	247,409,510	63,775,133	235,360,828	60,669,326
1550									
1551									
1552									
1553	346	Misc. Power Plant Equipment							
1554			P	SG		12,359,491	3,185,925	11,699,994	3,015,925
1555			P	SG		11,813	3,045	11,813	3,045
1556					B8	12,371,304	3,188,970	11,711,807	3,018,971
1557									
1558	347	Other Production ARO							
1559			P	S		-	-	-	-
1560					B8	-	-	-	-
1561									
1562	OP	Unclassified Other Prod Plant-Acct 300							
1563			P	S		-	-	-	-
1564			P	SG		-	-	-	-
1565						-	-	-	-
1566									
1567	**Total Other Production Plant**				**B8**	**3,309,570,847**	**853,113,207**	**3,103,398,847**	**800,023,598**
1568									
1569	Summary of Other Production Plant by Factor								
1570		S				-	-	75,000	75,000
1571		DGU				-	-	-	-
1572		SG				3,309,570,847	853,113,207	3,103,323,847	799,948,598
1573		SSGCT				-	-	-	-
1574	Total of Other Production Plant by Factor					3,309,570,847	853,113,207	3,103,398,847	800,023,598
1575									
1576	Experimental Plant								
1577	103	Experimental Plant							
1578			P	SG		-	-	-	-
1579	**Total Experimental Production Plant**				**B8**	-	-	-	-
1580									
1581	**Total Production Plant**				**B8**	**10,068,193,926**	**2,595,293,955**	**10,749,001,932**	**2,770,842,557**
1582	350	Land and Land Rights							
1583			T	SG		21,116,232	5,443,164	21,116,232	5,443,164
1584			T	SG		48,488,152	12,498,866	48,488,152	12,498,866
1585			T	SG		117,882,430	30,386,737	117,459,550	30,277,730
1586					B8	187,486,813	48,328,766	187,063,933	48,219,760
1587									
1588	352	Structures and Improvements							
1589			T	S		-	-	-	-
1590			T	SG		7,437,017	1,917,051	7,437,017	1,917,051
1591			T	SG		18,158,628	4,680,778	18,158,628	4,680,778
1592			T	SG		111,471,491	28,734,179	111,471,491	28,734,179
1593					B8	137,067,135	35,332,008	137,067,135	35,332,008
1594									
1595	353	Station Equipment							
1596			T	SG		124,774,520	32,163,321	124,774,520	32,163,321
1597			T	SG		183,031,133	47,180,219	183,031,133	47,180,219
1598			T	SG		1,286,199,080	331,545,531	1,286,199,080	331,545,531
1599					B8	1,594,004,732	410,889,071	1,594,004,732	410,889,071
1600									
1601	354	Towers and Fixtures							
1602			T	SG		155,436,532	40,067,116	155,436,532	40,067,116
1603			T	SG		133,296,819	34,360,128	133,296,819	34,360,128
1604			T	SG		663,705,120	171,084,298	663,705,120	171,084,298
1605					B8	952,438,471	245,511,541	952,438,471	245,511,541
1606									
1607	355	Poles and Fixtures							
1608			T	S		-	-	-	-
1609			T	SG		66,359,912	17,105,697	58,930,153	15,190,517
1610			T	SG		116,744,670	30,093,455	111,390,489	28,713,299
1611			T	SG		442,373,423	114,031,283	711,672,158	183,448,835
1612					B8	625,478,004	161,230,435	881,992,800	227,352,651
1613									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1614	356	Clearing and Grading							
1615			T	SG		185,514,669	47,820,404	185,514,669	47,820,404
1616			T	SG		157,672,314	40,643,437	157,672,314	40,643,437
1617			T	SG		540,276,301	139,267,859	540,276,301	139,267,859
1618					B8	883,463,283	227,731,700	883,463,283	227,731,700
1619									
1620	357	Underground Conduit							
1621			T	SG		6,371	1,642	6,371	1,642
1622			T	SG		91,651	23,625	91,651	23,625
1623			T	SG		3,161,431	814,927	3,161,431	814,927
1624					B8	3,259,452	840,194	3,259,452	840,194
1625									
1626	358	Underground Conductors							
1627			T	SG		-	-	-	-
1628			T	SG		1,087,552	280,340	1,087,552	280,340
1629			T	SG		6,387,543	1,646,527	6,387,543	1,646,527
1630					B8	7,475,095	1,926,867	7,475,095	1,926,867
1631									
1632	359	Roads and Trails							
1633			T	SG		1,863,032	480,237	1,863,032	480,237
1634			T	SG		440,513	113,552	440,513	113,552
1635			T	SG		9,295,159	2,396,027	9,295,159	2,396,027
1636					B8	11,598,703	2,989,816	11,598,703	2,989,816
1637									
1638	TP	Unclassified Trans Plant - Acct 300							
1639			T	SG		52,813,167	13,613,732	52,813,167	13,613,732
1640					B8	52,813,167	13,613,732	52,813,167	13,613,732
1641									
1642	TS0	Unclassified Trans Sub Plant - Acct 300							
1643			T	SG		-	-	-	-
1644					B8	-	-	-	-
1645									
1646	**Total Transmission Plant**				**B8**	**4,455,084,856**	**1,148,394,129**	**4,711,176,773**	**1,214,407,339**
1647	Summary of Transmission Plant by Factor								
1648		DGP				-	-	-	-
1649		DGU				-	-	-	-
1650		SG				4,455,084,856	1,148,394,129	4,711,176,773	1,214,407,339
1651	Total Transmission Plant by Factor					4,455,084,856	1,148,394,129	4,711,176,773	1,214,407,339
1652	360	Land and Land Rights							
1653			DPW	S		53,310,709	12,659,445	55,631,353	13,257,962
1654					B8	53,310,709	12,659,445	55,631,353	13,257,962
1655									
1656	361	Structures and Improvements							
1657			DPW	S		79,280,201	19,644,752	82,731,310	20,534,828
1658					B8	79,280,201	19,644,752	82,731,310	20,534,828
1659									
1660	362	Station Equipment							
1661			DPW	S		822,686,594	201,249,126	858,498,574	210,485,397
1662					B8	822,686,594	201,249,126	858,498,574	210,485,397
1663									
1664	363	Storage Battery Equipment							
1665			DPW	S		-	-	-	-
1666					B8	-	-	-	-
1667									
1668	364	Poles, Towers & Fixtures							
1669			DPW	S		953,729,554	322,560,427	995,245,904	333,267,914
1670					B8	953,729,554	322,560,427	995,245,904	333,267,914
1671									
1672	365	Overhead Conductors							
1673			DPW	S		653,386,179	231,283,187	681,828,424	238,618,730
1674					B8	653,386,179	231,283,187	681,828,424	238,618,730
1675									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1676	366	Underground Conduit							
1677			DPW	S		304,451,586	83,119,613	317,704,524	86,537,680
1678					B8	304,451,586	83,119,613	317,704,524	86,537,680
1679									
1680									
1681									
1682									
1683	367	Underground Conductors							
1684			DPW	S		723,393,642	154,354,890	754,883,348	162,476,403
1685					B8	723,393,642	154,354,890	754,883,348	162,476,403
1686									
1687	368	Line Transformers							
1688			DPW	S		1,107,583,957	387,652,357	1,155,797,670	400,087,161
1689					B8	1,107,583,957	387,652,357	1,155,797,670	400,087,161
1690									
1691	369	Services							
1692			DPW	S		592,230,200	221,950,830	618,010,293	228,599,776
1693					B8	592,230,200	221,950,830	618,010,293	228,599,776
1694									
1695	370	Meters							
1696			DPW	S		178,944,014	59,949,532	186,733,541	61,958,530
1697					B8	178,944,014	59,949,532	186,733,541	61,958,530
1698									
1699	371	Installations on Customers' Premises							
1700			DPW	S		8,798,701	2,469,615	9,181,713	2,568,397
1701					B8	8,798,701	2,469,615	9,181,713	2,568,397
1702									
1703	372	Leased Property							
1704			DPW	S		-	-	-	-
1705					B8	-	-	-	-
1706									
1707	373	Street Lights							
1708			DPW	S		60,757,949	21,964,678	63,402,774	22,646,805
1709					B8	60,757,949	21,964,678	63,402,774	22,646,805
1710									
1711	DP	Unclassified Dist Plant - Acct 300							
1712			DPW	S		23,844,586	4,850,420	23,844,586	4,850,420
1713					B8	23,844,586	4,850,420	23,844,586	4,850,420
1714									
1715	DS0	Unclassified Dist Sub Plant - Acct 300							
1716			DPW	S		-	-	-	-
1717					B8	-	-	-	-
1718									
1719									
1720	**Total Distribution Plant**				**B8**	**5,562,397,875**	**1,723,708,872**	**5,803,494,015**	**1,785,890,003**
1721									
1722	Summary of Distribution Plant by Factor								
1723		S				5,562,397,875	1,723,708,872	5,803,494,015	1,785,890,003
1724									
1725	Total Distribution Plant by Factor					5,562,397,875	1,723,708,872	5,803,494,015	1,785,890,003

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1726	389	Land and Land Rights							
1727			G-SITUS	S		9,472,275	3,046,462	9,472,275	3,046,462
1728			CUST	CN		1,128,506	331,362	1,128,506	331,362
1729			G-DGU	SG		332	86	332	86
1730			G-SG	SG		1,228	316	1,228	316
1731			PTD	SO		5,596,700	1,520,343	5,596,700	1,520,343
1732					B8	16,199,041	4,898,568	16,199,041	4,898,568
1733									
1734	390	Structures and Improvements							
1735			G-SITUS	S		112,740,950	33,831,192	112,740,950	33,831,192
1736			G-DGP	SG		356,327	91,851	356,327	91,851
1737			G-DGU	SG		1,638,043	422,241	1,638,043	422,241
1738			CUST	CN		12,312,990	3,615,446	12,312,990	3,615,446
1739			G-SG	SG		5,341,588	1,376,909	5,341,588	1,376,909
1740			PTD	SO		103,941,406	28,235,668	103,941,406	28,235,668
1741					B8	236,331,305	67,573,309	236,331,305	67,573,309
1742									
1743	391	Office Furniture & Equipment							
1744			G-SITUS	S		10,991,809	3,251,346	10,991,809	3,251,346
1745			G-DGP	SG		-	-	-	-
1746			G-DGU	SG		5,295	1,365	5,295	1,365
1747			CUST	CN		8,316,863	2,442,069	8,316,863	2,442,069
1748			G-SG	SG		4,603,865	1,186,746	4,603,865	1,186,746
1749			P	SE		68,033	16,541	68,033	16,541
1750			PTD	SO		54,794,019	14,884,788	54,794,019	14,884,788
1751			P	SG		89,734	23,131	89,734	23,131
1752			P	SG		-	-	-	-
1753					B8	78,869,618	21,805,985	78,869,618	21,805,985
1754									
1755	392	Transportation Equipment							
1756			G-SITUS	S		72,819,065	21,181,722	72,819,065	21,181,722
1757			PTD	SO		7,289,686	1,980,242	7,289,686	1,980,242
1758			G-SG	SG		17,294,590	4,458,053	17,266,336	4,450,770
1759			CUST	CN		-	-	-	-
1760			G-DGU	SG		779,129	200,837	779,129	200,837
1761			P	SE		404,148	98,263	404,148	98,263
1762			G-DGP	SG		120,286	31,006	120,286	31,006
1763			P	SG		343,984	88,669	343,984	88,669
1764			P	SG		44,655	11,511	44,655	11,511
1765					B8	99,095,543	28,050,304	99,067,289	28,043,021
1766									
1767	393	Stores Equipment							
1768			G-SITUS	S		8,443,634	2,672,691	8,443,634	2,672,691
1769			G-DGP	SG		69,750	17,980	69,750	17,980
1770			G-DGU	SG		268,272	69,153	268,272	69,153
1771			PTD	SO		324,919	88,264	324,919	88,264
1772			G-SG	SG		4,127,356	1,063,915	4,127,356	1,063,915
1773			P	SG		53,971	13,912	53,971	13,912
1774					B8	13,287,902	3,925,915	13,287,902	3,925,915

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1775									
1776	394	Tools, Shop & Garage Equipment							
1777			G-SITUS	S		31,738,287	10,248,972	31,738,287	10,248,972
1778			G-DGP	SG		1,339,090	345,179	1,339,090	345,179
1779			G-SG	SG		20,900,830	5,387,639	20,900,830	5,387,639
1780			PTD	SO		3,801,735	1,032,741	3,801,735	1,032,741
1781			P	SE		7,106	1,728	7,106	1,728
1782			G-DGU	SG		907,807	234,007	907,807	234,007
1783			P	SG		1,697,140	437,475	1,697,140	437,475
1784			P	SG		89,913	23,177	89,913	23,177
1785					B8	60,481,908	17,710,918	60,481,908	17,710,918
1786									
1787	395	Laboratory Equipment							
1788			G-SITUS	S		23,516,426	9,316,206	23,516,426	9,316,206
1789			G-DGP	SG		1,518	391	1,518	391
1790			G-DGU	SG		5,371	1,384	5,371	1,384
1791			PTD	SO		5,705,503	1,549,899	5,705,503	1,549,899
1792			P	SE		7,593	1,846	7,593	1,846
1793			G-SG	SG		6,322,239	1,629,693	6,322,239	1,629,693
1794			P	SG		253,001	65,216	253,001	65,216
1795			P	SG		14,022	3,614	14,022	3,614
1796					B8	35,825,672	12,568,251	35,825,672	12,568,251
1797									
1798	396	Power Operated Equipment							
1799			G-SITUS	S		94,699,232	29,310,166	94,699,232	29,310,166
1800			G-DGP	SG		845,108	217,845	845,108	217,845
1801			G-SG	SG		31,187,550	8,039,263	31,187,550	8,039,263
1802			PTD	SO		1,137,422	308,980	1,137,422	308,980
1803			G-DGU	SG		1,634,205	421,252	1,634,205	421,252
1804			P	SE		45,031	10,949	45,031	10,949
1805			P	SG		-	-	-	-
1806			P	SG		999,837	257,730	999,837	257,730
1807					B8	130,548,386	38,566,184	130,548,386	38,566,184
1808	397	Communication Equipment							
1809			DPW	S		110,422,697	36,498,469	173,122,987	57,049,520
1810			G-DGP	SG		1,471,243	379,245	558,348	143,926
1811			G-DGU	SG		2,381,434	613,866	343,497	88,544
1812			PTD	SO		57,841,983	15,712,766	45,909,819	12,471,396
1813			CUST	CN		2,855,125	838,346	237,650	69,781
1814			G-SG	SG		96,581,869	24,896,058	107,962,913	27,829,767
1815			P	SE		126,615	30,784	31,041	7,547
1816			G-SG	SG		619,180	159,607	80,679	20,797
1817			G-SG	SG		1,590	410	(10,062)	(2,594)
1818					B8	272,301,737	79,129,552	328,236,873	97,678,684
1819									
1820	398	Misc. Equipment							
1821			G-SITUS	S		1,521,391	670,085	1,521,391	670,085
1822			G-DGP	SG		-	-	-	-
1823			G-DGU	SG		-	-	-	-
1824			CUST	CN		212,837	62,495	212,837	62,495
1825			PTD	SO		2,924,199	794,358	2,924,199	794,358
1826			P	SE		1,668	405	1,668	405
1827			G-SG	SG		1,910,599	492,498	1,910,599	492,498
1828			G-SG	SG		-	-	-	-
1829					B8	6,570,694	2,019,842	6,570,694	2,019,842
1830									
1831	399	Coal Mine							
1832			P	SE		286,661,904	69,697,596	488,304,005	118,723,886
1833	MP		P	SE		-	-	-	-
1834					B8	286,661,904	69,697,596	488,304,005	118,723,886
1835									
1836	399L	WIDCO Capital Lease							
1837			P	SE	Tab 8	-	-	-	-
1838						-	-	-	-
1839									
1840		Remove Capital Leases				-	-	-	-
1841					Tab 8	-	-	-	-
1842									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1843	1011390	General Capital Leases							
1844			G-SITUS	S		18,984,156	5,882,166	18,984,156	5,882,166
1845			P	SG		33,744,912	8,698,478	33,744,912	8,698,478
1846			PTD	SO		12,664,054	3,440,188	12,664,054	3,440,188
1847					B9	65,393,121	18,020,833	65,393,121	18,020,833
1848									
1849		Remove Capital Leases				(65,393,121)	(18,020,833)	(65,393,121)	(18,020,833)
1850						-	-	-	-
1851									
1852	1011346	General Gas Line Capital Leases							
1853			P	SG		-	-	-	-
1854					B9	-	-	-	-
1855									
1856		Remove Capital Leases				-	-	-	-
1857						-	-	-	-
1858									
1859	GP	Unclassified Gen Plant - Acct 300							
1860			G-SITUS	S		-	-	-	-
1861			PTD	SO		1,548,788	420,728	1,548,788	420,728
1862			CUST	CN		-	-	-	-
1863			G-SG	SG		(53,522)	(13,796)	(53,522)	(13,796)
1864			G-DGP	SG		-	-	-	-
1865			G-DGU	SG		-	-	-	-
1866					B8	1,495,266	406,932	1,495,266	406,932
1867									
1868	399G	Unclassified Gen Plant - Acct 300							
1869			G-SITUS	S		-	-	-	-
1870			PTD	SO		-	-	-	-
1871			G-SG	SG		-	-	-	-
1872			G-DGP	SG		-	-	-	-
1873			G-DGU	SG		-	-	-	-
1874					B8	-	-	-	-
1875									
1876	**Total General Plant**				**B8**	**1,237,668,975**	**346,353,354**	**1,495,217,958**	**413,921,494**
1877									
1878	Summary of General Plant by Factor								
1879		S				495,349,922	155,909,477	558,050,211	176,460,528
1880		DGP				-	-	-	-
1881		DGU				-	-	-	-
1882		SG				237,993,341	61,347,912	245,845,146	63,371,884
1883		SO				257,570,415	69,968,967	245,638,251	66,727,596
1884		SE				287,322,098	69,858,112	488,868,625	118,861,165
1885		CN				24,826,321	7,289,718	22,208,846	6,521,153
1886		DEU				-	-	-	-
1887		SSGCT				-	-	-	-
1888		SSGCH				-	-	-	-
1889		Less Capital Leases				(65,393,121)	(18,020,833)	(65,393,121)	(18,020,833)
1890	Total General Plant by Factor					1,237,668,975	346,353,354	1,495,217,958	413,921,494
1891	301	Organization							
1892			I-SITUS	S		-	-	-	-
1893			PTD	SO		-	-	-	-
1894			I-SG	SG		-	-	-	-
1895					B8	-	-	-	-
1896	302	Franchise & Consent							
1897			I-SITUS	S		1,000,000	-	1,000,000	-
1898			I-SG	SG		10,265,665	2,646,196	4,304,740	1,109,640
1899			I-SG	SG		173,622,224	44,754,870	169,528,812	43,699,705
1900			I-SG	SG		9,189,363	2,368,756	9,051,536	2,333,228
1901			I-DGP	SG		-	-	-	-
1902			I-DGU	SG		600,993	154,919	600,993	154,919
1903					B8	194,678,245	49,924,741	184,486,081	47,297,491
1904									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1905	303	Miscellaneous Intangible Plant							
1906			I-SITUS	S		7,507,698	1,853,709	6,798,360	1,320,629
1907			I-SG	SG		131,131,608	33,801,998	131,109,838	33,796,386
1908			PTD	SO		375,888,954	102,110,181	381,477,170	103,628,219
1909			P	SE		3,654,416	888,517	3,538,192	860,259
1910			CUST	CN		121,077,156	35,551,719	120,697,107	35,440,125
1911			P	SG		-	-	-	-
1912			I-DGP	SG		-	-	-	-
1913					B8	639,259,832	174,206,124	643,620,666	175,045,618
1914	303	Less Non-Utility Plant							
1915			I-SITUS	S		-	-	-	-
1916						639,259,832	174,206,124	643,620,666	175,045,618
1917	IP	Unclassified Intangible Plant - Acct 300							
1918			I-SITUS	S		-	-	-	-
1919			I-SG	SG		-	-	-	-
1920			I-DGU	SG		-	-	-	-
1921			PTD	SO		-	-	-	-
1922						-	-	-	-
1923									
1924	**Total Intangible Plant**				**B8**	**833,938,076**	**224,130,866**	**828,106,747**	**222,343,110**
1925									
1926	Summary of Intangible Plant by Factor								
1927		S				8,507,698	1,853,709	7,798,360	1,320,629
1928		DGP				-	-	-	-
1929		DGU				-	-	-	-
1930		SG				324,809,853	83,726,739	314,595,919	81,093,878
1931		SO				375,888,954	102,110,181	381,477,170	103,628,219
1932		CN				121,077,156	35,551,719	120,697,107	35,440,125
1933		SSGCT				-	-	-	-
1934		SSGCH				-	-	-	-
1935		SE				3,654,416	888,517	3,538,192	860,259
1936	Total Intangible Plant by Factor					833,938,076	224,130,866	828,106,747	222,343,110
1937	Summary of Unclassified Plant (Account 106)								
1938		DP				23,844,586	4,850,420	23,844,586	4,850,420
1939		DS0				-	-	-	-
1940		GP				1,495,266	406,932	1,495,266	406,932
1941		HP				-	-	-	-
1942		NP				-	-	-	-
1943		OP				-	-	-	-
1944		TP				52,813,167	13,613,732	52,813,167	13,613,732
1945		TS0				-	-	-	-
1946		IP				-	-	-	-
1947		MP							
1948		SP				5,221,058	1,345,840	5,221,058	1,345,840
1949	Total Unclassified Plant by Factor					83,374,078	20,216,924	83,374,078	20,216,924
1950									
1951	**Total Electric Plant In Service**				**B8**	**22,157,283,708**	**6,037,881,175**	**23,586,997,425**	**6,407,404,503**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1952	Summary of Electric Plant by Factor								
1953		S				6,066,255,494	1,881,472,059	6,369,417,586	1,963,746,160
1954		SE				290,976,514	70,746,630	492,406,816	119,721,424
1955		DGU				-	-	-	-
1956		DGP				-	-	-	-
1957		SG				15,086,081,976	3,888,762,735	16,020,544,770	4,129,640,658
1958		SO				633,459,369	172,079,148	627,115,421	170,355,815
1959		CN				145,903,477	42,841,437	142,905,953	41,961,278
1960		DEU				-	-	-	-
1961		SSGCH				-	-	-	-
1962		SSGCT				-	-	-	-
1963		Less Capital Leases				(65,393,121)	(18,020,833)	(65,393,121)	(18,020,833)
1964						22,157,283,708	6,037,881,175	23,586,997,425	6,407,404,503
1965	105	Plant Held For Future Use							
1966			DPW	S		7,174,343	4,254,106	-	-
1967			P	SG		-	-	-	-
1968			P	SG		2,944,517	759,013	-	-
1969			P	SG		8,923,302	2,300,173	-	-
1970			P	SE		25,979,316	6,316,486	-	-
1971			G	SG		-	-	-	-
1972									
1973									
1974	**Total Plant Held For Future Use**				**B10**	**45,021,478**	**13,629,778**	**-**	**-**
1975									
1976	114	Electric Plant Acquisition Adjustments							
1977			P	S		-	-	-	-
1978			P	SG		144,614,797	37,277,580	144,614,797	37,277,580
1979			P	SG		14,560,711	3,753,337	14,560,711	3,753,337
1980	**Total Electric Plant Acquisition Adjustment**				**B15**	**159,175,508**	**41,030,917**	**159,175,508**	**41,030,917**
1981									
1982	115	Accum Provision for Asset Acquisition Adjustments							
1983			P	S		-	-	-	-
1984			P	SG		(91,388,309)	(23,557,306)	(102,270,785)	(26,362,499)
1985			P	SG		(13,218,942)	(3,407,467)	(13,218,942)	(3,407,467)
1986					B15	(104,607,250)	(26,964,773)	(115,489,727)	(29,769,966)
1987									
1988	120	Nuclear Fuel							
1989			P	SE		-	-	-	-
1990	**Total Nuclear Fuel**				**B15**	**-**	**-**	**-**	**-**
1991									
1992	124	Weatherization							
1993			DMSC	S		1,969,468	0	1,969,468	0
1994			DMSC	SO		(4,454)	(1,210)	(4,454)	(1,210)
1995					B16	1,965,015	(1,210)	1,965,015	(1,210)
1996									
1997	182W	Weatherization							
1998			DMSC	S		(2,000,697)	-	(2,000,697)	-
1999			DMSC	SG		-	-	-	-
2000			DMSC	SG		-	-	-	-
2001			DMSC	SO		-	-	-	-
2002					B16	(2,000,697)	-	(2,000,697)	-
2003									
2004	186W	Weatherization							
2005			DMSC	S		-	-	-	-
2006			DMSC	CN		-	-	-	-
2007			DMSC	CNP		-	-	-	-
2008			DMSC	SG		-	-	-	-
2009			DMSC	SO		-	-	-	-
2010					B16	-	-	-	-
2011									
2012	**Total Weatherization**				**B16**	**(35,682)**	**(1,210)**	**(35,682)**	**(1,210)**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2013									
2014	151	Fuel Stock							
2015			P	DEU		-	-	-	-
2016			P	SE		212,462,887	51,657,204	208,232,339	50,628,609
2017			P	SE		-	-	-	-
2018			P	SE		10,592,137	2,575,321	6,673,661	1,622,602
2019	**Total Fuel Stock**				**B13**	**223,055,023**	**54,232,525**	**214,906,000**	**52,251,211**
2020									
2021	152	Fuel Stock - Undistributed							
2022			P	SE		-	-	-	-
2023						-	-	-	-
2024									
2025	25316	DG&T Working Capital Deposit							
2026			P	SE		(2,777,000)	(675,186)	(3,417,000)	(830,793)
2027					B13	(2,777,000)	(675,186)	(3,417,000)	(830,793)
2028									
2029	25317	DG&T Working Capital Deposit							
2030			P	SE		(2,023,136)	(491,896)	(2,623,631)	(637,897)
2031					B13	(2,023,136)	(491,896)	(2,623,631)	(637,897)
2032									
2033	25319	Provo Working Capital Deposit							
2034			P	SE		-	-	-	-
2035						-	-	-	-
2036									
2037		Total Fuel Stock			B13	218,254,887	53,065,443	208,865,369	50,782,521
2038	154	Materials and Supplies							
2039			MSS	S		88,641,997	27,856,546	88,641,997	27,856,546
2040			MSS	SG		4,703,417	1,212,407	4,703,417	1,212,407
2041			MSS	SE		6,159,125	1,497,500	6,159,125	1,497,500
2042			MSS	SO		51,819	14,077	51,819	14,077
2043			MSS	SG		87,220,162	22,482,876	87,220,162	22,482,876
2044			MSS	SG		(1,860)	(479)	(1,860)	(479)
2045			MSS	SNPD		(2,478,050)	(666,740)	(2,478,050)	(666,740)
2046			MSS	SG		-	-	-	-
2047			MSS	SG		-	-	-	-
2048			MSS	SG		-	-	-	-
2049			MSS	SG		-	-	-	-
2050			MSS	SG		6,973,902	1,797,674	6,973,902	1,797,674
2051			MSS	SG		-	-	-	-
2052	**Total Materials and Supplies**				**B13**	**191,270,513**	**54,193,860**	**191,270,513**	**54,193,860**
2053									
2054	163	Stores Expense Undistributed							
2055			MSS	SO		-	-	-	-
2056									
2057					B13	-	-	-	-
2058									
2059	25318	Provo Working Capital Deposit							
2060			MSS	SG		(273,000)	(70,372)	(273,000)	(70,372)
2061									
2062					B13	(273,000)	(70,372)	(273,000)	(70,372)
2063									
2064		Total Materials & Supplies			B13	190,997,513	54,123,489	190,997,513	54,123,489
2065									
2066	165	Prepayments							
2067			DMSC	S		7,868,243	2,209,516	7,868,243	2,209,516
2068			GP	GPS		283,539	77,023	283,539	77,023
2069			PT	SG		2,643,389	681,391	2,643,389	681,391
2070			P	SE		3,362,821	817,620	3,362,821	817,620
2071			PTD	SO		14,285,132	3,880,554	14,285,132	3,880,554
2072	**Total Prepayments**				**B15**	**28,443,124**	**7,666,103**	**28,443,124**	**7,666,103**
2073									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2074	182M	Misc Regulatory Assets							
2075			DDS2	S		121,949,207	(61,893)	121,791,362	(219,737)
2076			DEFSG	SG		-	-	-	-
2077			P	SGCT		6,828,086	1,765,867	4,583,236	1,185,308
2078			DEFSG	SG		-	-	-	-
2079			P	SE		-	-	-	-
2080			P	SG		-	-	-	-
2081			DDSO2	SO		8,841,299	2,401,738	8,841,299	2,401,738
2082					B11	137,618,592	4,105,712	135,215,897	3,367,309
2083									
2084	186M	Misc Deferred Debits							
2085			LABOR	S		13,749,962	-	13,749,962	-
2086			P	SG		-	-	-	-
2087			P	SG		-	-	-	-
2088			DEFSG	SG		49,283,351	12,703,846	62,116,663	16,011,908
2089			LABOR	SO		-	-	-	-
2090			P	SE		13,136,810	3,194,021	13,136,810	3,194,021
2091			P	SG		-	-	-	-
2092			GP	EXCTAX		-	-	-	-
2093	**Total Misc. Deferred Debits**				**B11**	**76,170,123**	**15,897,867**	**89,003,435**	**19,205,929**
2094									
2095	Working Capital								
2096	CWC	Cash Working Capital							
2097			CWC	S		33,991,603	12,241,198	48,296,213	17,417,166
2098			CWC	SO		-	-	-	-
2099			CWC	SE		-	-	-	-
2100					B14	33,991,603	12,241,198	48,296,213	17,417,166
2101									
2102	OWC	Other Work. Cap.							
2103	131	Cash	GP	SNP		-	-	-	-
2104	135	Working Funds	P	SG		-	-	-	-
2105	141	Notes Receivabl	GP	SO		-	-	-	-
2106	143	Other A/R	GP	SO		55,756,133	15,146,146	55,756,133	15,146,146
2107	232	A/P	PTD	S		-	-	-	-
2108	232	A/P	PTD	SO		(4,730,325)	(1,284,992)	(4,730,325)	(1,284,992)
2109	232	A/P	P	SE		(3,588,481)	(872,486)	(3,588,481)	(872,486)
2110	232	A/P	T	SG		(172,140)	(44,373)	(172,140)	(44,373)
2111	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2112	2533	Other Msc. Df. Crd.	P	SE		(6,363,956)	(1,547,302)	(6,758,625)	(1,643,260)
2113	230	Asset Retir. Oblig.	P	SE		(2,516,092)	(611,750)	(2,516,092)	(611,750)
2114	230	Asset Retir. Oblig.	P	S		-	-	-	-
2115	254105	ARO Reg Liability	P	S		-	-	-	-
2116	254105	ARO Reg Liability	P	SE		(898,049)	(218,347)	(898,049)	(218,347)
2117	2533	Cholla Reclamation	P	SE		-	-	-	-
2118					B14	37,487,090	10,566,895	37,092,420	10,470,937
2119									
2120	**Total Working Capital**				**B14**	**71,478,693**	**22,808,093**	**85,388,633**	**27,888,103**
2121	Miscellaneous Rate Base								
2122	18221	Unrec Plant & Reg Study Costs							
2123			P	S		-	-	-	-
2124									
2125					B15	-	-	-	-
2126									
2127	18222	Nuclear Plant - Trojan							
2128			P	S		-	-	-	-
2129			P	TROJP		-	-	-	-
2130			P	TROJD		-	-	-	-
2131					B15	-	-	-	-
2132									
2133									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2134									
2135	1869	Misc Deferred Debits-Trojan							
2136			P	S		-	-	-	-
2137			P	SG		-	-	-	-
2138					B15	-	-	-	-
2139									
2140	**Total Miscellaneous Rate Base**				**B15**	-	-	-	-
2141									
2142	**Total Rate Base Additions**				**B15**	**822,516,985**	**185,361,419**	**781,564,071**	**174,293,196**
2143	235	Customer Service Deposits							
2144			CUST	S		-	-	-	-
2145			CUST	CN		-	-	-	-
2146	**Total Customer Service Deposits**				B15	-	-	-	-
2147									
2148	2281	Prop Ins	PTD	SO		-	-	-	-
2149	2282	Inj & Dam	PTD	SO		(6,485,000)	(1,761,649)	(6,485,000)	(1,761,649)
2150	2283	Pen & Ben	PTD	SO		(25,325,928)	(6,879,785)	(25,325,928)	(6,879,785)
2151	254	Ins Prov	PTD	SO		-	-	-	-
2152	254	Reg Liabilitie	P	SE		-	-	-	-
2153					B15	(31,810,928)	(8,641,434)	(31,810,928)	(8,641,434)
2154									
2155	22844	Accum Hydro Relicensing Obligation							
2156			P	S		-	-	-	-
2157			P	SG		-	-	-	-
2158					B15	-	-	-	-
2159									
2160	22841	Chehalis Rat	P	SG		(1,500,000)	(386,657)	(1,500,000)	(386,657)
2161	230	ARO	P	TROJP		(1,660,934)	(424,449)	(1,660,934)	(424,449)
2162	254105	ARO	P	TROJP		(3,463,650)	(885,130)	(3,463,650)	(885,130)
2163	254		P	S		(9,715,443)	(1,313,427)	(9,715,443)	(1,313,427)
2164					B15	(16,340,028)	(3,009,663)	(16,340,028)	(3,009,663)
2165									
2166	252	Customer Advances for Construction							
2167			DPW	S		(11,658,859)	(7,096,641)	(12,562,616)	(7,448,152)
2168			DPW	SE		-	-	-	-
2169			T	SG		(16,205,061)	(4,177,204)	(15,301,304)	(3,944,241)
2170			DPW	SO		-	-	-	-
2171			CUST	CN		-	-	-	-
2172	**Total Customer Advances for Construction**				**B19**	**(27,863,920)**	**(11,273,844)**	**(27,863,920)**	**(11,392,393)**
2173									
2174	25398	SO2 Emissions							
2175			P	SE		-	-	(829,723)	(201,735)
2176					B19	-	-	(829,723)	(201,735)
2177									
2178	25399	Other Deferred Credits							
2179			P	S		(1,300,240)	(621,782)	(1,300,240)	(621,782)
2180			LABOR	SO		-	-	-	-
2181			P	SG		(8,875,492)	(2,287,849)	(8,875,492)	(2,287,849)
2182			P	SE		(5,037,754)	(1,224,855)	(5,037,754)	(1,224,855)
2183					B19	(15,213,487)	(4,134,487)	(15,213,487)	(4,134,487)

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2184									
2185	190	Accumulated Deferred Income Taxes							
2186			P	S		19,032,602	962,923	32,739,158	2,194,422
2187			CUST	CN		47,212	13,863	28,936	8,496
2188			LABOR	SO		78,987,023	21,456,814	83,158,212	22,589,916
2189			P	GPS		-	-	-	-
2190			IBT	IBT		-	-	-	-
2191			P	SG		-	-	-	-
2192			P	SG		-	-	-	-
2193			CUST	BADDEBT		3,844,157	1,794,004	5,515,134	2,573,821
2194			P	TROJD		1,912,922	488,093	-	-
2195			P	SG		39,603,970	10,208,777	7,372,994	1,900,548
2196			P	SE		(15,479,212)	(3,763,541)	(13,979,690)	(3,398,954)
2197			PTD	SNP		-	-	-	-
2198			DPW	SNPD		1,793,564	482,573	806,637	217,032
2199			P	SG		-	-	-	-
2200	**Total Accum Deferred Income Taxes**				**B19**	**129,742,238**	**31,643,505**	**115,641,381**	**26,085,282**
2201									
2202	281	Accumulated Deferred Income Taxes							
2203			P	S		-	-	-	-
2204			PT	SG		(121,387,549)	(31,290,257)	-	-
2205			T	SG		-	-	-	-
2206					B19	(121,387,549)	(31,290,257)	-	-
2207									
2208	282	Accumulated Deferred Income Taxes							
2209			GP	S		-	-	(3,658,835,895)	(985,558,965)
2210			GP	CN		-	-	-	-
2211			TAXDEPR	SG		-	-	-	-
2212			ACCMDIT	DITBAL		(3,031,107,795)	(832,740,314)	2	1
2213			P	SG		-	-	-	-
2214			DPW	SG-P		-	-	-	-
2215			P	SG		-	-	-	-
2216			PT	SG-U		-	-	-	-
2217			LABOR	SO		26,404,262	7,172,714	23,436,640	6,366,560
2218			GP	SG		-	-	-	-
2219			P	SE		(5,491,795)	(1,335,249)	(5,083,668)	(1,236,019)
2220			P	SG		(4,961,751)	(1,278,998)	14,715,157	3,793,149
2221					B19	(3,015,157,079)	(828,181,847)	(3,625,767,764)	(976,635,274)
2222									
2223	283	Accumulated Deferred Income Taxes							
2224			GP	S		(56,399,874)	2,046,121	(78,631,297)	(339,034)
2225			P	SG		(9,100,661)	(2,345,891)	(1,946,183)	(501,671)
2226			P	SE		(12,837,744)	(3,121,307)	(15,145,533)	(3,682,412)
2227			LABOR	SO		(3,864,666)	(1,049,836)	(9,931,871)	(2,697,991)
2228			GP	GPS		(7,560,429)	(2,053,772)	(5,821,397)	(1,581,368)
2229			PTD	SNP		(4,344,154)	(1,138,006)	(3,672,481)	(962,053)
2230			P	TROJD		-	-	-	-
2231			P	SG		-	-	-	-
2232			P	SGCT		(2,804,313)	(725,246)	(1,739,383)	(449,836)
2233			P	IBT		-	-	-	-
2234					B19	(96,911,841)	(8,387,938)	(116,888,144)	(10,214,365)
2235									
2236	**Total Accum Deferred Income Tax**				**B19**	**(3,103,714,231)**	**(836,216,537)**	**(3,627,014,527)**	**(960,764,357)**
2237	255	Accumulated Investment Tax Credit							
2238			PTD	S		-	-	-	-
2239			PTD	ITC84		(872,621)	(619,351)	-	-
2240			PTD	ITC85		(2,026,144)	(1,371,497)	(668,689)	(452,636)
2241			PTD	ITC86		(1,109,823)	(717,034)	(616,575)	(398,357)
2242			PTD	ITC88		(177,804)	(108,816)	(118,548)	(72,551)
2243			PTD	ITC89		(398,410)	(224,527)	(280,594)	(158,131)
2244			PTD	ITC90		(272,742)	(43,463)	(215,190)	(34,292)
2245			PTD	DGU		-	-	-	-
2246	**Total Accumlated ITC**				**B19**	(4,857,544)	(3,084,689)	(1,899,596)	(1,115,967)
2247									
2248	**Total Rate Base Deductions**					**(3,199,800,137)**	**(866,360,655)**	**(3,720,972,208)**	**(989,260,035)**
2249									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2250									
2251									
2252	108SP	Steam Prod Plant Accumulated Depr							
2253			P	S		-	-	-	-
2254			P	SG		(764,758,175)	(197,132,900)	(780,055,729)	(201,076,174)
2255			P	SG		(855,622,229)	(220,555,068)	(878,481,702)	(226,447,590)
2256			P	SG		(634,543,934)	(163,567,373)	(928,281,792)	(239,284,636)
2257			P	SG		(168,303,056)	(43,383,740)	(167,834,615)	(43,262,989)
2258					B17	(2,423,227,394)	(624,639,081)	(2,754,653,837)	(710,071,390)
2259									
2260	108NP	Nuclear Prod Plant Accumulated Depr							
2261			P	SG		-	-	-	-
2262			P	SG		-	-	-	-
2263			P	SG		-	-	-	-
2264					B17	-	-	-	-
2265									
2266									
2267	108HP	Hydraulic Prod Plant Accum Depr							
2268			P	S		-	-	-	-
2269			P	SG		(154,767,475)	(39,894,652)	(162,043,005)	(41,770,076)
2270			P	SG		(29,241,674)	(7,537,672)	(28,697,021)	(7,397,276)
2271			P	SG		(67,412,046)	(17,376,908)	(54,558,705)	(14,063,682)
2272			P	SG		(17,589,885)	(4,534,172)	(21,810,471)	(5,622,119)
2273					B17	(269,011,080)	(69,343,403)	(267,109,202)	(68,853,153)
2274									
2275	108OP	Other Production Plant - Accum Depr							
2276			P	S		-	-	-	-
2277			P	SG		(1,548,574)	(399,178)	(366,724)	(94,531)
2278			P	SG		-	-	-	-
2279			P	SG		(412,359,088)	(106,294,441)	(506,567,557)	(130,578,704)
2280			P	SG		(21,791,105)	(5,617,127)	(24,540,740)	(6,325,905)
2281					B17	(435,698,768)	(112,310,747)	(531,475,021)	(136,999,140)
2282									
2283	108EP	Experimental Plant - Accum Depr							
2284			P	SG		-	-	-	-
2285			P	SG		-	-	-	-
2286						-	-	-	-
2287									
2288	**Total Production Plant Accum Depreciation**				**B17**	**(3,127,937,242)**	**(806,293,231)**	**(3,553,238,060)**	**(915,923,682)**
2289									
2290	Summary of Prod Plant Depreciation by Factor								
2291		S				-	-	-	-
2292		DGP				-	-	-	-
2293		DGU				-	-	-	-
2294		SG				(3,127,937,242)	(806,293,231)	(3,553,238,060)	(915,923,682)
2295		SSGCH				-	-	-	-
2296		SSGCT				-	-	-	-
2297	Total of Prod Plant Depreciation by Factor					(3,127,937,242)	(806,293,231)	(3,553,238,060)	(915,923,682)
2298									
2299									
2300	108TP	Transmission Plant Accumulated Depr							
2301			T	S		-	-	-	-
2302			T	SG		(369,436,693)	(95,230,269)	(378,249,324)	(97,501,915)
2303			T	SG		(398,038,617)	(102,603,031)	(411,324,484)	(106,027,750)
2304			T	SG		(428,771,884)	(110,525,193)	(490,402,478)	(126,411,807)
2305	**Total Trans Plant Accum Depreciation**				**B17**	**(1,196,247,194)**	**(308,358,493)**	**(1,279,976,286)**	**(329,941,471)**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2306	108360	Land and Land Rights							
2307			DPW	S		(7,602,613)	(2,374,363)	(9,030,795)	(2,950,952)
2308					B17	(7,602,613)	(2,374,363)	(9,030,795)	(2,950,952)
2309									
2310	108361	Structures and Improvements							
2311			DPW	S		(15,035,110)	(3,599,321)	(17,159,008)	(4,456,786)
2312					B17	(15,035,110)	(3,599,321)	(17,159,008)	(4,456,786)
2313									
2314	108362	Station Equipment							
2315			DPW	S		(214,712,020)	(58,097,426)	(236,751,601)	(66,995,304)
2316					B17	(214,712,020)	(58,097,426)	(236,751,601)	(66,995,304)
2317									
2318	108363	Storage Battery Equipment							
2319			DPW	S		-	-	-	-
2320					B17	-	-	-	-
2321									
2322	108364	Poles, Towers & Fixtures							
2323			DPW	S		(514,475,720)	(209,418,127)	(540,025,911)	(219,733,317)
2324					B17	(514,475,720)	(209,418,127)	(540,025,911)	(219,733,317)
2325									
2326	108365	Overhead Conductors							
2327			DPW	S		(277,148,700)	(127,166,293)	(294,652,762)	(134,233,080)
2328					B17	(277,148,700)	(127,166,293)	(294,652,762)	(134,233,080)
2329									
2330	108366	Underground Conduit							
2331			DPW	S		(127,942,936)	(35,884,487)	(136,099,123)	(39,177,324)
2332					B17	(127,942,936)	(35,884,487)	(136,099,123)	(39,177,324)
2333									
2334	108367	Underground Conductors							
2335			DPW	S		(295,078,722)	(59,114,033)	(314,458,268)	(66,937,995)
2336					B17	(295,078,722)	(59,114,033)	(314,458,268)	(66,937,995)
2337									
2338	108368	Line Transformers							
2339			DPW	S		(382,284,169)	(168,090,440)	(411,956,083)	(180,069,664)
2340					B17	(382,284,169)	(168,090,440)	(411,956,083)	(180,069,664)
2341									
2342	108369	Services							
2343			DPW	S		(179,783,834)	(67,712,510)	(195,649,542)	(74,117,855)
2344					B17	(179,783,834)	(67,712,510)	(195,649,542)	(74,117,855)
2345									
2346	108370	Meters							
2347			DPW	S		(74,912,498)	(32,858,656)	(79,706,366)	(34,794,049)
2348					B17	(74,912,498)	(32,858,656)	(79,706,366)	(34,794,049)
2349									
2350									
2351									
2352	108371	Installations on Customers' Premises							
2353			DPW	S		(7,778,672)	(2,493,265)	(8,014,388)	(2,588,428)
2354					B17	(7,778,672)	(2,493,265)	(8,014,388)	(2,588,428)
2355									
2356	108372	Leased Property							
2357			DPW	S		-	-	-	-
2358					B17	-	-	-	-
2359									
2360	108373	Street Lights							
2361			DPW	S		(27,338,303)	(8,583,788)	(28,965,994)	(9,240,924)
2362					B17	(27,338,303)	(8,583,788)	(28,965,994)	(9,240,924)
2363									
2364	108D00	Unclassified Dist Plant - Acct 300							
2365			DPW	S		-	-	-	-
2366					B17	-	-	-	-
2367									
2368	108DS	Unclassified Dist Sub Plant - Acct 300							
2369			DPW	S		-	-	-	-
2370					B17	-	-	-	-
2371									
2372	108DP	Unclassified Dist Sub Plant - Acct 300							
2373			DPW	S		1,183,546	(224,187)	1,183,546	(224,187)
2374					B17	1,183,546	(224,187)	1,183,546	(224,187)
2375									
2376									
2377	**Total Distribution Plant Accum Depreciation**				**B17**	**(2,122,909,752)**	**(775,616,895)**	**(2,271,286,293)**	**(835,519,865)**
2378									
2379	Summary of Distribution Plant Depr by Factor								
2380		S				(2,122,909,752)	(775,616,895)	(2,271,286,293)	(835,519,865)
2381									
2382	Total Distribution Depreciation by Factor					(2,122,909,752)	(775,616,895)	(2,271,286,293)	(835,519,865)

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2383	108GP	General Plant Accumulated Depr							
2384			G-SITUS	S		(154,405,355)	(45,213,577)	(153,946,618)	(43,367,585)
2385			G-DGP	SG		(2,773,800)	(715,007)	(2,097,281)	(540,619)
2386			G-DGU	SG		(4,558,040)	(1,174,933)	(2,969,084)	(765,345)
2387			G-SG	SG		(53,387,293)	(13,761,725)	(55,301,048)	(14,255,037)
2388			CUST	CN		(7,761,004)	(2,278,853)	(7,506,237)	(2,204,046)
2389			PTD	SO		(74,737,799)	(20,302,512)	(63,288,399)	(17,192,285)
2390			P	SE		(309,947)	(75,359)	(281,847)	(68,527)
2391			P	SG		(44,066)	(11,359)	(46,139)	(11,893)
2392			P	SG		(1,930,396)	(497,601)	(1,672,452)	(431,111)
2393					B17	(299,907,700)	(84,030,926)	(287,109,106)	(78,836,448)
2394									
2395									
2396	108MP	Mining Plant Accumulated Depr.							
2397			P	S		-	-	-	-
2398			P	SE		(156,346,430)	(38,013,319)	(156,948,403)	(38,159,679)
2399					B17	(156,346,430)	(38,013,319)	(156,948,403)	(38,159,679)
2400	108MP	Less Centralia Situs Depreciation							
2401			P	S		-	-	-	-
2402					B17	(156,346,430)	(38,013,319)	(156,948,403)	(38,159,679)
2403									
2404	1081390	Accum Depr - Capital Lease							
2405			PTD	SO	B17	-	-	-	-
2406						-	-	-	-
2407									
2408		Remove Capital Leases				-	-	-	-
2409					B17	-	-	-	-
2410									
2411	1081399	Accum Depr - Capital Lease							
2412			P	S		-	-	-	-
2413			P	SE	B17	-	-	-	-
2414						-	-	-	-
2415									
2416		Remove Capital Leases				-	-	-	-
2417					B17	-	-	-	-
2418									
2419									
2420	**Total General Plant Accum Depreciation**				**B17**	**(456,254,130)**	**(122,044,245)**	**(444,057,508)**	**(116,996,128)**
2421									
2422									
2423									
2424	Summary of General Depreciation by Factor								
2425		S				(154,405,355)	(45,213,577)	(153,946,618)	(43,367,585)
2426		DGP				-	-	-	-
2427		DGU				-	-	-	-
2428		SE				(156,656,378)	(38,088,678)	(157,230,250)	(38,228,206)
2429		SO				(74,737,799)	(20,302,512)	(63,288,399)	(17,192,285)
2430		CN				(7,761,004)	(2,278,853)	(7,506,237)	(2,204,046)
2431		SG				(62,693,595)	(16,160,625)	(62,086,005)	(16,004,006)
2432		DEU				-	-	-	-
2433		SSGCT				-	-	-	-
2434		SSGCH				-	-	-	-
2435		Remove Capital Leases				-	-	-	-
2436	Total General Depreciation by Factor					(456,254,130)	(122,044,245)	(444,057,508)	(116,996,128)
2437									
2438									
2439	**Total Accum Depreciation - Plant In Service**				**B17**	**(6,903,348,317)**	**(2,012,312,865)**	**(7,548,558,148)**	**(2,198,381,147)**
2440	111SP	Accum Prov for Amort-Steam							
2441			P	SG		-	-	-	-
2442			P	SG		-	-	-	-
2443					B18	-	-	-	-
2444									
2445									
2446	111GP	Accum Prov for Amort-General							
2447			G-SITUS	S		(16,369,840)	(6,518,199)	(18,032,987)	(6,890,301)
2448			CUST	CN		(2,861,226)	(840,138)	(3,271,277)	(960,540)
2449			I-SG	SG		-	-	-	-
2450			PTD	SO		(11,320,920)	(3,075,326)	(13,209,808)	(3,588,443)
2451			P	SE		-	-	-	-
2452					B18	(30,551,986)	(10,433,663)	(34,514,072)	(11,439,284)
2453									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2454									
2455	111HP	Accum Prov for Amort-Hydro							
2456			P	SG		-	-	-	-
2457			P	SG		-	-	-	-
2458			P	SG		(240,880)	(62,092)	(614,404)	(158,376)
2459			P	SG		(460,259)	(118,642)	(527,058)	(135,860)
2460					B18	(701,139)	(180,734)	(1,141,461)	(294,236)
2461									
2462									
2463	111IP	Accum Prov for Amort-Intangible Plant							
2464			I-SITUS	S		(1,127,555)	(51,762)	(698,196)	466,390
2465			I-DGP	SG		-	-	-	-
2466			I-DGU	SG		(357,775)	(92,224)	(360,485)	(92,923)
2467			P	SE		(1,452,677)	(353,197)	(1,845,722)	(448,760)
2468			I-SG	SG		(49,291,670)	(12,705,990)	(41,781,003)	(10,769,954)
2469			I-SG	SG		(19,514,437)	(5,030,267)	(31,636,160)	(8,154,902)
2470			I-SG	SG		(3,523,610)	(908,286)	(3,840,958)	(990,090)
2471			CUST	CN		(97,854,280)	(28,732,817)	(106,183,429)	(31,178,494)
2472			P	SG		-	-	-	-
2473			P	SG		(171,088)	(44,102)	(171,088)	(44,102)
2474			PTD	SO		(266,767,979)	(72,467,484)	(284,010,102)	(77,151,304)
2475					B18	(440,061,070)	(120,386,129)	(470,527,143)	(128,364,138)
2476	111IP	Less Non-Utility Plant							
2477			NUTIL	OTH		-	-	-	-
2478						(440,061,070)	(120,386,129)	(470,527,143)	(128,364,138)
2479									
2480	111390	Accum Amtr - Capital Lease							
2481			G-SITUS	S		(5,492,566)	(2,003,233)	(5,492,566)	(2,003,233)
2482			P	SG		(4,390,814)	(1,131,827)	(4,390,814)	(1,131,827)
2483			PTD	SO		1,055,993	286,860	1,055,993	286,860
2484						(8,827,387)	(2,848,199)	(8,827,387)	(2,848,199)
2485									
2486		Remove Capital Lease Amtr				8,827,387	2,848,199	8,827,387	2,848,199
2487									
2488	**Total Accum Provision for Amortization**				B18	**(471,314,196)**	**(131,000,526)**	**(506,182,675)**	**(140,097,658)**
2489									
2490									
2491									
2492									
2493	Summary of Amortization by Factor								
2494		S				(22,989,961)	(8,573,194)	(24,223,749)	(8,427,143)
2495		DGP				-	-	-	-
2496		DGU				-	-	-	-
2497		SE				(1,452,677)	(353,197)	(1,845,722)	(448,760)
2498		SO				(277,032,906)	(75,255,950)	(296,163,917)	(80,452,886)
2499		CN				(100,715,506)	(29,572,955)	(109,454,706)	(32,139,035)
2500		SSGCT				-	-	-	-
2501		SSGCH				-	-	-	-
2502		SG				(77,950,533)	(20,093,430)	(83,321,969)	(21,478,033)
2503		Less Capital Lease				8,827,387	2,848,199	8,827,387	2,848,199
2504	Total Provision For Amortization by Factor					(471,314,196)	(131,000,526)	(506,182,675)	(140,097,658)

3. REVENUE ADJUSTMENTS

The Company used actual revenue for the twelve months ended June 30, 2011 as the starting point for the calculation of pro forma revenue. Actual revenue was adjusted using the normalizing and pro forma adjustments below to calculate the revenue for the December 2013 test period.

PacifiCorp
Normalized Results of Operations
Tab 3 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Total Adjustments	3.1 Pro Forma Revenue	3.2 Wheeling Revenue	3.3 SO2 Emission Allowances	3.4 REC Revenue	3.5 Ancillary Revenue
1	Operating Revenues:						
2	General Business Revenues	124,931,769	124,931,769	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-
5	Other Operating Revenues	(21,566,614)	-	873,205	-	(23,520,882)	1,081,062
6	Total Operating Revenues	103,365,155	124,931,769	873,205	-	(23,520,882)	1,081,062
7							
8	Operating Expenses:						
9	Steam Production	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-
12	Other Power Supply	-	-	-	-	-	-
13	Embedded Cost Differential (ECD)	-	-	-	-	-	-
13	Transmission	(226,615)	-	(226,615)	-	-	-
14	Distribution	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	-	-	-	-	-	-
19							
20	Total O&M Expenses	(226,615)	-	(226,615)	-	-	-
21							
22	Depreciation	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-
25	Income Taxes - Federal	34,560,516	41,732,924	367,429	(43,911)	(7,857,050)	361,124
26	Income Taxes - State	4,696,200	5,670,811	49,927	(5,967)	(1,067,643)	49,071
27	Income Taxes - Def Net	113,394	-	-	113,394	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-
29	Misc Revenue & Expense	(164,185)	-	-	(164,185)	-	-
30							
31	Total Operating Expenses:	38,979,310	47,403,735	190,741	(100,669)	(8,924,693)	410,195
32							
33	Operating Rev For Return:	64,385,845	77,528,034	682,465	100,669	(14,596,189)	670,867
34							
35	Rate Base:						
36	Electric Plant In Service	-	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-
44	Working Capital	785,355	953,848	3,838	(1,004)	(179,581)	8,254
45	Weatherization Loans	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	785,355	953,848	3,838	(1,004)	(179,581)	8,254
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-
53	Accum Def Income Tax	76,560	-	-	76,560	-	-
54	Unamortized ITC	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	(201,735)	-	-	(201,735)	-	-
58							
59	Total Rate Base Deductions	(125,174)	-	-	(125,174)	-	-
60							
61	Total Rate Base:	660,181	953,848	3,838	(126,178)	(179,581)	8,254
62							
63	Return on Rate Base	2.002%	2.410%	0.021%	0.004%	-0.454%	0.021%
64							
65	Return on Equity	3.791%	4.564%	0.040%	0.007%	-0.859%	0.039%
66							
67	TAX CALCULATION:						
68	Operating Revenue	103,755,955	124,931,769	1,099,821	164,185	(23,520,882)	1,081,062
69	Other Deductions						
70	Interest (AFUDC)	-	-	-	-	-	-
71	Interest	16,633	24,032	97	(3,179)	(4,524)	208
72	Schedule "M" Additions	-	-	-	-	-	-
73	Schedule "M" Deductions	298,792	-	-	298,792	-	-
74	Income Before Tax	103,440,530	124,907,737	1,099,724	(131,428)	(23,516,358)	1,080,854
75							
76	State Income Taxes	4,696,200	5,670,811	49,927	(5,967)	(1,067,643)	49,071
77	Taxable Income	98,744,330	119,236,926	1,049,797	(125,461)	(22,448,715)	1,031,783
78							
79	Federal Income Taxes + Other	34,560,516	41,732,924	367,429	(43,911)	(7,857,050)	361,124
80							
81	PRICE CHANGE	(106,774,647)	(128,548,181)	(1,132,185)	(183,669)	24,201,743	(1,112,356)

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Income:							
Residential	440	3	39,098,778	OR	100.000%	39,098,778	
Commercial	442	3	48,378,959	OR	100.000%	48,378,959	
Industrial	442	3	25,953,785	OR	100.000%	25,953,785	
Irrigation	442	3	12,081,321	OR	100.000%	12,081,321	
Public Street & Hwy	444	3	(581,075)	OR	100.000%	(581,075)	
			124,931,769			124,931,769	3.1.1
Adjustment to Income - All States Other Than Oregon							
Residential	440	3	100,821,431	Situs	0.000%	-	3.1.3
Commercial/Industrial	442	3	255,564,193	Situs	0.000%	-	3.1.3
Public Street & Hwy	444	3	(842,322)	Situs	0.000%		3.1.3
Other Sales to Public Auth	445	3	1,478,201	Situs	0.000%	-	3.1.3
			357,021,503			-	

Description of Adjustment:

This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the twelve-months ending December 2013 based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Revenue Adjustment
Actual 12 Months Ended June 2011
Forecast 12 Months Ending December 2013

	A	B	C	D	E	F	G	H	I	J	K
	Actual Booked Revenue	Remove Tariff Riders[2]	Base Rate Revenues	Normalizing Adjustments[3]	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change[4]	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change[5]	Total Oregon Forecast Revenue	**Total Adjustment Column J - A**
Residential	$525,297,185	$12,756,743	$538,053,927	($9,988,374)	($6,134,964)	$521,930,589	$36,441,158	$558,371,747	$6,024,216	$564,395,963	**$39,098,778**
Commercial	$379,624,419	($6,018,888)	$373,605,531	($2,341,291)	$1,487,649	$372,751,889	$33,503,973	$406,255,862	$21,747,517	$428,003,379	**$48,378,959**
Industrial [1]	$133,674,876	($3,091,632)	$130,583,244	$6,456,752	$0	$137,039,996	$13,081,784	$150,121,780	$9,506,882	$159,628,662	**$25,953,785**
Irrigation	$13,114,162	$395,310	$13,509,472	$2,540,721	$0	$16,050,193	$1,497,058	$17,547,251	$7,648,232	$25,195,484	**$12,081,321**
Public St & Hwy	$5,732,257	$46,474	$5,778,731	($650,935)	$0	$5,127,796	($50,726)	$5,077,070	$74,111	$5,151,182	**($581,075)**
Total Oregon	**$1,057,442,899**	$4,088,007	$1,061,530,906	($3,983,126)	($4,647,316)	$1,052,900,464	$84,473,246	$1,137,373,710	$45,000,958	**$1,182,374,668**	**$124,931,769**
Source / Formula	**Ref Pg 2.2, Line 2** 305 Report	Table 2	A + B	Table 2	Table 2	C + D + E	Table 2	F + G	Table 2	H + I	**Ref # 3.1** J-A

[1] Includes Schedules 28 and 48 which were booked under Irrigation Class.
[2] Removal of SB408 Recovery, SB838 Recovery, Gain on Sale of Asset, Merger Credit, BPA, Revenue Accounting Adjustments, Independent Evaluator Adj (Sch 93), Property Sales Adj (Sch 96), Transition Plan-Oregon Reg Asset Adj (Sch 193), MEHC Change-in-Control Severance Reg Asset Adj (Sch 194), Grid West Reg Asset Adj (Sch 195), and RAC Deferral (Sch 203).
[3] Removal of SMUD Revenue Imputations, Demand Charge Accrual, RMA and Out of Period adjustment.
[4] GRC (UE-217) and TAM rate changes effective January 1, 2011; Klamath rate change Effective April 17, 2011 (Schedule 33).
[5] Klamath rate change Effective April 17, 2012 (Schedule 33 and Schedule 92); TAM rate change effective January 1, 2012.

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Revenue Adjustment
Actual 12 Months Ended June 2011
Forecast 12 Months Ending December 2013

	A	B	C	D	E	F	G	H
	Booked MWhs	Normalizing Adjustments MWhs[2]	Temperature Adjustment MWhs	Type 1 Adjusted MWhs	Type 2 Adjustments MWhs[3]	Total Oregon Adjusted Actual MWhs	Type 3 Adjustment MWhs[4]	Total Oregon Forecast MWhs
Residential	5,603,196	736	(62,636)	5,541,296	(82)	5,541,213	(137,998)	5,403,215
Commercial	4,906,001	(8,687)	28,353	4,925,667	93,198	5,018,865	146,325	5,165,190
Industrial [1]	2,247,267	(1,510)	0	2,245,756	9,209	2,254,966	26,307	2,281,273
Irrigation	200,081	493	0	200,573	0	200,573	9,769	210,342
Public St & Hwy	37,139	984	0	38,123	1	38,124	(404)	37,720
Total Oregon	12,993,683	(7,985)	(34,283)	12,951,415	102,326	13,053,741	43,999	13,097,740
Source / Formula	305 Report	Table 2	Table 2	A + B + C	Table 2	D + E	Table 2	F + G

[1] Includes Schedules 28 and 48 which were booked under Irrigation Class.
[2] Out of period adjustment.
[3] Adjustment made to reconcile booked kWh's with blocking kWh's. Includes adjustment to incorporate direct access kWh.
[4] Difference between actual and forecast.

PacifiCorp
Summary of Revenue Adjustments
Oregon General Rate Case - December 2013
All States Other Than Oregon

Unadjusted Revenue - 12 ME June 2011	Residential 440	Commercial/Industrial 442	Public Street & Hwy 444	OSPA 445	TOTAL REVENUE
California	49,497,735	45,088,118	397,217		94,983,070
Idaho	65,182,277	148,293,575	481,849		213,957,700
Utah	590,286,231	953,431,963	10,749,256	19,771,075	1,574,238,524
Washington	114,387,974	148,483,176	1,189,585		264,060,735
Wyoming	92,831,582	462,646,998	2,064,521		557,543,102
TOTAL	912,185,799	1,757,943,830	14,882,429	19,771,075	2,704,783,132

Pro Forma Revenue - 12 ME December 2013	Residential 440	Commercial/Industrial 442	Public Street & Hwy 444	OSPA 445	TOTAL REVENUE
California	49,702,802	46,052,573	440,404		96,195,778
Idaho	70,337,576	171,600,407	578,170		242,516,153
Utah	654,262,859	1,119,519,053	9,690,515	21,249,276	1,804,721,704
Washington	131,372,754	165,875,163	1,167,667		298,415,585
Wyoming	107,331,238	510,460,826	2,163,350		619,955,415
TOTAL	1,013,007,230	2,013,508,022	14,040,106	21,249,276	3,061,804,635

Adjustment to Revenue	Residential 440	Commercial/Industrial 442	Public Street & Hwy 444	OSPA 445	TOTAL REVENUE
California	205,067	964,454	43,187	-	1,212,708
Idaho	5,155,300	23,306,832	96,321	-	28,558,453
Utah	63,976,628	166,087,091	(1,058,741)	1,478,201	230,483,179
Washington	16,984,781	17,391,987	(21,918)	-	34,354,850
Wyoming	14,499,656	47,813,828	98,828	-	62,412,313
TOTAL	**100,821,431**	**255,564,193**	**(842,322)**	**1,478,201**	**357,021,503**
	Ref 3.1	**Ref 3.1**	**Ref 3.1**	**Ref 3.1**	**Ref 3.1**

PacifiCorp
Oregon General Rate Case - December 2013
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2013	TAM/ NPC	NON-TAM / NON NPC
$1,182,374,668	$360,255,677	$822,118,991
Ref # 3.1.1	Ref # 3.1.5	

The above calculation shows the split of proforma revenue between TAM and the General Rate Case.

PacifiCorp
Oregon General Rate Case - December 2013
Present Net Power Costs In Rates
Forecast 12 Months Ended December 31, 2013

Base Rate Schedule	MWH	Net Power Costs Collection (Schedule 201 Revenue)
4	5,400,866	$151,277,059
23	1,093,926	$30,685,325
28	1,986,600	$55,467,511
30	1,303,689	$35,793,556
33	0	$0
41	210,342	$5,607,039
47	50,204	$1,256,773
48	3,003,510	$79,046,852
15	9,710	$258,367
50	8,845	$193,380
51	18,680	$645,497
52	599	$15,861
53	9,579	$108,240
54	1,189	$23,156
Total	13,097,740	$360,378,616
Employee Discount		($122,939)
	13,097,740	$360,255,677

Comparison to UE 227	MWH	Approved NPC
2012 Test Period	13,435,370	$366,682,292
Difference resulting from change in test period	(337,630)	($6,426,615)
Percentage Change	-3%	-2%

Table 2 - Page 1 of 2
PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2011; Forecast 12 Months Ended December 2013
Customer, kWh and Revenue Adjustments

	CUSTOMERS			KWH								
					Type 1				Type 2		Type 3	
	305 Average Customers	Adjustment Customers	Forecast Customers	305 Booked kWh	Normalization Adjustment kWh	Temperature Adjustments kWh	Type 1 Adjustments kWh	Total Type 1 Adjusted kWh	Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh
Residential												
15	2,841	-139	2,702	2,443,927	94,932		94,932	2,538,859	1,073	2,539,932	(191,617)	2,348,315
4	474,569	4,888	479,457	5,606,874,100	640,678	(62,636,116)	(61,995,438)	5,544,878,662	(83,363)	5,544,795,299	(143,928,826)	5,400,866,473
BPA Balancing Account	0			0				0		0		0
SMUD Revenue Imputations	0			0				0		0		0
SB408 Recovery	0			0				0		0		0
SB838 Recovery	0			0				0		0		0
Gain on Sale of Asset	0			0				0		0		0
Revenue Accounting Adjustment	0			0				0		0		0
Unbilled	0			(6,122,000)				(6,122,000)		(6,122,000)	6,122,000	0
AGA	0			0				0		0		0
Total Residential	**477,410**	**4,749**	**482,159**	**5,603,196,027**	**735,610**	**(62,636,116)**	**(61,900,506)**	**5,541,295,521**	**(82,290)**	**5,541,213,231**	**(137,998,443)**	**5,403,214,788**
Commercial												
15	4,171	-168	4,003	7,228,993	271,114		271,114	7,500,107	5,668	7,505,775	(484,263)	7,021,512
23	73,347	762	74,108	1,104,499,378	(241,818)	3,015,593	2,773,775	1,107,273,153	838,133	1,108,111,286	(37,241,685)	1,070,869,601
28	9,463	-107	9,356	1,926,533,649	(1,312,247)	7,944,696	6,632,449	1,933,166,098	4,040,728	1,937,206,826	(51,088,823)	1,886,118,003
30	692	-16	676	1,055,751,504	(2,774,489)	8,765,769	5,991,280	1,061,742,784	75,634,043	1,137,376,827	(40,167,194)	1,097,209,633
47	3	0	3	27,453,200	(530,728)		(530,728)	26,922,472	(20,672)	26,901,800	(4,917,565)	21,984,235
48	103	0	103	776,910,872	(4,093,000)	8,626,634	4,533,634	781,444,506	12,700,400	794,144,906	286,653,133	1,080,798,039
54	104	-1	103	1,144,374	(5,800)		(5,800)	1,138,574	0	1,138,574	50,764	1,189,338
BPA Balancing Account	0			0				0		0		0
SMUD Revenue Imputations	0			0				0		0		0
SB408 Recovery	0			0				0		0		0
SB838 Recovery	0			0				0		0		0
Gain on Sale of Asset	0			0				0		0		0
Revenue Accounting Adjustment	0			0				0		0		0
Merger Credit	0			0				0		0		0
Unbilled	0			6,479,000				6,479,000		6,479,000	(6,479,000)	0
AGA	0			0				0		0		0
Total Commercial	**87,882**	**470**	**88,352**	**4,906,000,970**	**(8,686,968)**	**28,352,693**	**19,665,725**	**4,925,666,695**	**93,198,300**	**5,018,864,995**	**146,325,366**	**5,165,190,361**
Industrial												
15	146	-9	137	325,468	12,538		12,538	338,006	(4)	338,002	(14,810)	323,192
23	1,235	-9	1,226	21,655,188	8,959		8,959	21,664,147	290	21,664,437	1,391,893	23,056,330
28	496	-35	461	93,894,779	(246,199)		(246,199)	93,648,580	62,406	93,710,986	6,771,098	100,482,084
30	154	-15	139	190,238,309	58,741		58,741	190,297,050	28	190,297,078	16,182,246	206,479,324
47	3	-1	2	169,570,280	0		0	169,570,280	0	169,570,280	(141,350,461)	28,219,819
48	111	-6	105	1,776,206,487	(1,344,200)		(1,344,200)	1,774,862,287	9,146,600	1,784,008,887	138,702,907	1,922,711,794
BPA Balancing Account	0			0				0		0		0
SMUD Revenue Imputations	0			0				0		0		0
SB408 Recovery	0			0				0		0		0
SB838 Recovery	0			0				0		0		0
Gain on Sale of Asset	0			0				0		0		0
Revenue Accounting Adjustment	0			0				0		0		0
Unbilled	0			(4,624,000)				(4,624,000)		(4,624,000)	4,624,000	0
AGA	0			0				0		0		0
Total Industrial	**2,144**	**(74)**	**2,070**	**2,247,266,511**	**(1,510,161)**	**0**	**(1,510,161)**	**2,245,756,350**	**9,209,320**	**2,254,965,670**	**26,306,873**	**2,281,272,543**
Irrigation												
41	6,125	-31	6,094	110,219,596	73,726		73,726	110,293,322	23	110,293,345	4,357,113	114,650,458
33 (Klamath)	2,017	-21	1,996	89,336,996	418,987		418,987	89,755,983	0	89,755,983	5,935,856	95,691,839
BPA Balancing Account	0			0				0		0		0
SB408 Recovery	0			0				0		0		0
SB838 Recovery	0			0				0		0		0
BPA Adjustment	0			0				0		0		0
Demand Charge Accrual	0			0				0		0		0
Gain on Sale of Asset	0			0				0		0		0
Merger Credit	0			0				0		0		0
Revenue Accounting Adjustment	0			0				0		0		0
Unbilled	0			524,000				524,000		524,000	(524,000)	0
AGA	0			0				0		0		0
Total Irrigation	**8,141**	**(51)**	**8,090**	**200,080,592**	**492,713**	**0**	**492,713**	**200,573,305**	**23**	**200,573,328**	**9,768,969**	**210,342,297**
Lighting												
15	8	0	8	14,026	555		555	14,581	(3)	14,578	2,226	16,804
50	253	-3	250	9,111,793	161,762		161,762	9,273,555	329	9,273,884	(428,410)	8,845,474
51	700	33	733	17,808,202	742,941		742,941	18,551,143	23	18,551,166	128,569	18,679,735
52	55	-5	50	735,792	52,003		52,003	787,795	285	788,080	(188,877)	599,203
53	255	5	260	9,521,405	26,861		26,861	9,548,266	(30)	9,548,236	30,544	9,578,780
SB408 Recovery	0			0				0		0		0
SB838 Recovery	0			0				0		0		0
Gain on Sale of Asset	0			0				0		0		0
Revenue Accounting Adjustment	0			0				0		0		0
Unbilled	0			(52,000)				(52,000)		(52,000)	52,000	0
AGA	0			0				0		0		0
Total Lighting	**1,271**	**31**	**1,301**	**37,139,218**	**984,122**	**0**	**984,122**	**38,123,340**	**604**	**38,123,944**	**(403,948)**	**37,719,996**
TOTAL COMPANY	**576,849**	**5,124**	**581,972**	**12,993,683,318**	**(7,984,684)**	**(34,283,423)**	**(42,268,107)**	**12,951,415,211**	**102,325,957**	**13,053,741,168**	**43,998,817**	**13,097,739,985**

Table 2 - Page 2 of 2
PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2011; Forecast 12 Months Ended December 2013
Customer, kWh and Revenue Adjustments

	REVENUES									
		Type 1					Type 2		Type 3	
	305 Booked Revenues	Remove Tariff Riders $	Actual Base Rate Revenues	Normalizing Adjustments $	Temperature Adjustment $	Total Type 1 Adjusted $	Type 2 Adjustments $	Total Type 2 Adjusted $	Type 3 Adjustments $	Total Forecast Revenues
Residential										
15	$389,327	$10,964	$400,291	($43,860)	$0	$356,432	($7,457)	$348,975	($18,201)	$330,774
4	$512,142,099	$22,781,273	$534,923,372	($9,424,969)	($6,134,964)	$519,363,439	$36,448,614	$555,812,053	$8,234,417	$564,046,470
BPA Balancing Account	$5,269,745	($5,269,745)	$0	$0	$0	$0	$0	$0	$0	$0
SMUD Revenue Imputations	$519,545	$0	$519,545	($519,545)	$0	$0	$0	$0	$0	$0
SB408 Recovery	$5,794,105	($5,794,105)	$0	$0	$0	$0	$0	$0	$0	$0
SB838 Recovery	($1,066,647)	$1,066,647	$0	$0	$0	$0	$0	$0	$0	$0
Gain on Sale of Asset	$85,873	($85,873)	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Accounting Adjustment	($47,581)	$47,581	$0	$0	$0	$0	$0	$0	$0	$0
Unbilled	$2,192,000	$0	$2,192,000	$0	$0	$2,192,000	$0	$2,192,000	($2,192,000)	$0
AGA	$18,719	$0	$18,719	$0	$0	$18,719	$0	$18,719	$0	$18,719
Total Residential	**$525,297,185**	**$12,756,743**	**$538,053,927**	**($9,988,374)**	**($6,134,964)**	**$521,930,589**	**$36,441,158**	**$558,371,747**	**$6,024,216**	**$564,395,963**
Commercial										
15	$1,091,100	$4,415	$1,095,515	($127,329)	$0	$968,186	($6,267)	$961,918	($38,020)	$923,899
23	$105,731,349	($235,871)	$105,495,478	$2,840,808	$209,085	$108,545,371	$8,474,391	$117,019,762	$516,204	$117,535,966
28	$143,202,307	($514,794)	$142,687,513	($6,078,843)	$407,172	$137,015,843	$12,054,246	$149,070,089	$3,426,710	$152,496,799
30	$72,398,923	($401,929)	$71,996,994	($1,093,833)	$453,923	$71,357,084	$8,031,104	$79,388,188	$1,402,658	$80,790,846
47	$2,048,731	($15,577)	$2,033,155	$68,416	$417,468	$2,519,039	($246,890)	$2,272,149	($498,744)	$1,773,405
48	$44,937,119	($417,697)	$44,519,422	$2,522,679	$0	$47,042,101	$5,197,791	$52,239,892	$19,761,653	$72,001,545
54	$111,458	($432)	$111,026	($13,861)	$0	$97,165	($401)	$96,764	$7,056	$103,820
BPA Balancing Account	$253,227	($253,227)	$0	$0	$0	$0	$0	$0	$0	$0
SMUD Revenue Imputations	$459,329	$0	$459,329	($459,329)	$0	$0	$0	$0	$0	$0
SB408 Recovery	$5,079,948	($5,079,948)	$0	$0	$0	$0	$0	$0	$0	$0
SB838 Recovery	($933,139)	$933,139	$0	$0	$0	$0	$0	$0	$0	$0
Gain on Sale of Asset	$74,203	($74,203)	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Accounting Adjustment	($37,235)	$37,235	$0	$0	$0	$0	$0	$0	$0	$0
Merger Credit	($1)	$1	$0	$0	$0	$0	$0	$0	$0	$0
Unbilled	$2,830,000	$0	$2,830,000	$0	$0	$2,830,000	$0	$2,830,000	($2,830,000)	$0
AGA	$2,377,099	$0	$2,377,099	$0	$0	$2,377,099	$0	$2,377,099	$0	$2,377,099
Total Commercial	**$379,624,419**	**($6,018,888)**	**$373,605,531**	**($2,341,291)**	**$1,487,649**	**$372,751,889**	**$33,503,973**	**$406,255,862**	**$21,747,517**	**$428,003,379**
Industrial										
15	$46,648	($119)	$46,530	($5,895)	$0	$40,635	$115	$40,750	($679)	$40,070
23	$2,113,467	($10,623)	$2,102,845	$56,256	$0	$2,159,101	$162,514	$2,321,615	$211,724	$2,533,339
28	$7,614,191	($52,406)	$7,561,785	($315,231)	$0	$7,246,554	$598,790	$7,845,344	$924,012	$8,769,356
30	$14,437,099	($111,348)	$14,325,750	($147,876)	$0	$14,177,874	$1,143,083	$15,320,957	$2,006,588	$17,327,545
47	$8,583,920	($96,213)	$8,487,707	$650,026	$0	$9,137,733	$1,065,858	$10,203,591	($8,392,071)	$1,811,520
48	$97,740,597	($961,947)	$96,778,650	$6,443,110	$0	$103,221,761	$10,111,423	$113,333,184	$15,749,308	$129,082,492
BPA Balancing Account	$800	($800)	$0	$0	$0	$0	$0	$0	$0	$0
SMUD Revenue Imputations	$223,638	$0	$223,638	($223,638)	$0	$0	$0	$0	$0	$0
SB408 Recovery	$2,344,591	($2,344,591)	$0	$0	$0	$0	$0	$0	$0	$0
SB838 Recovery	($518,535)	$518,535	$0	$0	$0	$0	$0	$0	$0	$0
Gain on Sale of Asset	$47,022	($47,022)	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Accounting Adjustment	($14,901)	$14,901	$0	$0	$0	$0	$0	$0	$0	$0
Unbilled	$992,000	$0	$992,000	$0	$0	$992,000	$0	$992,000	($992,000)	$0
AGA	$64,339	$0	$64,339	$0	$0	$64,339	$0	$64,339	$0	$64,339
Total Industrial	**$133,674,876**	**($3,091,632)**	**$130,583,244**	**$6,456,752**	**$0**	**$137,039,996**	**$13,081,784**	**$150,121,780**	**$9,506,882**	**$159,628,662**
Irrigation										
41	$9,449,617	$401,510	$9,851,127	$2,500,847	$0	$12,351,974	$494,924	$12,846,898	$899,192	$13,746,090
33 (Klamath)	$2,958,286	$280,653	$3,238,939	$18,774	$0	$3,257,713	$1,002,134	$4,259,847	$6,934,040	$11,193,887
BPA Balancing Account	$119,358	($119,358)	$0	$0	$0	$0	$0	$0	$0	$0
SB408 Recovery	$215,595	($215,595)	$0	$0	$0	$0	$0	$0	$0	$0
SB838 Recovery	($82,523)	$82,523	$0	$0	$0	$0	$0	$0	$0	$0
BPA Adjustment	$39,137	($39,137)	$0	$0	$0	$0	$0	$0	$0	$0
Demand Charge Accrual	($21,100)	$0	($21,100)	$21,100	$0	$0	$0	$0	$0	$0
Gain on Sale of Asset	$3,666	($3,666)	$0	$0	$0	$0	$0	$0	$0	$0
Merger Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Accounting Adjustment	($8,380)	$8,380	$0	$0	$0	$0	$0	$0	$0	$0
Unbilled	$185,000	$0	$185,000	$0	$0	$185,000	$0	$185,000	($185,000)	$0
AGA	$255,507	$0	$255,507	$0	$0	$255,507	$0	$255,507	$0	$255,507
Total Irrigation	**$13,114,162**	**$395,310**	**$13,509,472**	**$2,540,721**	**$0**	**$16,050,193**	**$1,497,058**	**$17,547,251**	**$7,648,232**	**$25,195,484**
Lighting										
15	$2,452	$7	$2,460	($261)	$0	$2,199	($70)	$2,129	$398	$2,527
50	$1,216,331	($3,671)	$1,212,660	($156,334)	$0	$1,056,326	($9,926)	$1,046,399	($24,833)	$1,021,566
51	$3,744,723	($9,397)	$3,735,326	($382,657)	$0	$3,352,669	($31,744)	$3,320,925	$111,763	$3,432,688
52	$105,201	($331)	$104,870	($11,668)	$0	$93,202	$97	$93,299	($20,194)	$73,105
53	$716,013	($2,597)	$713,416	($100,015)	$0	$613,401	($9,083)	$604,318	$16,979	$621,297
SB408 Recovery	$40,424	($40,424)	$0	$0	$0	$0	$0	$0	$0	$0
SB838 Recovery	($5,249)	$5,249	$0	$0	$0	$0	$0	$0	$0	$0
Gain on Sale of Asset	$740	($740)	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Accounting Adjustment	($98,379)	$98,379	$0	$0	$0	$0	$0	$0	$0	$0
Unbilled	$10,000	$0	$10,000	$0	$0	$10,000	$0	$10,000	($10,000)	$0
AGA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Lighting	**$5,732,257**	**$46,474**	**$5,778,731**	**($650,935)**	**$0**	**$5,127,796**	**($50,726)**	**$5,077,070**	**$74,111**	**$5,151,182**
TOTAL COMPANY	**$1,057,442,899**	**$4,088,007**	**$1,061,530,906**	**($3,983,126)**	**($4,647,316)**	**$1,052,900,464**	**$84,473,246**	**$1,137,373,710**	**$45,000,958**	**$1,182,374,668**

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PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2011; Forecast 12 Months Ended December 2013
Revenue Adjustments

		Remove Tariff Riders													
	305 Booked Revenues	SB408 Recovery Adjust	SB838 Recovery Adjust	Revenue Accounting Adjust	Gain on Sale of Asset Adjust	Merger Credit Adjust	Sch98 BPA Adjust	Sch93 Ind. Evaluator Adjust	Sch96 Property Sales Adjust	Sch193 Trans. Plan Adjust	Sch194 MEHC Sev Adjust	Sch195 Grid West Adjust	Sch203 RAC Deferral Adjust	Total Remove Tariff Riders	Actual Base Rate Revenues
Residential															
15	$389,327						$12,019	($163)	$377	($97)	($391)	($73)	($706)	$10,964	$400,291
4	$512,142,099						$25,926,179	($378,531)	$790,413	($91,316)	($897,099)	($168,207)	($2,400,166)	$22,781,273	$534,923,372
BPA Balancing Account	$5,269,745						($5,269,745)							($5,269,745)	$0
SMUD Revenue Imputations	$519,545													$0	$519,545
SB408 Recovery	$5,794,105	($5,794,105)												($5,794,105)	$0
SB838 Recovery	($1,066,647)		$1,066,647											$1,066,647	$0
Gain on Sale of Asset	$85,873				($85,873)									($85,873)	$0
Revenue Accounting Adjustment	($47,581)			$47,581										$47,581	$0
Unbilled	$2,192,000													$0	$2,192,000
AGA	$18,719													$0	$18,719
Total Residential	**$525,297,185**	**($5,794,105)**	**$1,066,647**	**$47,581**	**($85,873)**	**$0**	**$20,668,453**	**($378,694)**	**$790,790**	**($91,413)**	**($897,490)**	**($168,280)**	**($2,400,872)**	**$12,756,743**	**$538,053,927**
Commercial															
15	$1,091,100						$7,534	($483)	$1,115	($288)	($1,157)	($217)	($2,089)	$4,415	$1,095,515
23	$105,731,349						$405,071	($74,437)	$149,401	($21,676)	($176,718)	($33,136)	($484,376)	($235,871)	$105,495,478
28	$143,202,307						$606,433	($130,235)	$255,704	($40,213)	($308,864)	($57,912)	($839,708)	($514,794)	$142,687,513
30	$72,398,923						$216,013	($75,694)	$146,875	($24,416)	($179,174)	($33,595)	($451,939)	($401,929)	$71,996,994
47	$2,048,731						$0	($1,920)	$3,339	($768)	($4,393)	($823)	($11,011)	($15,577)	$2,033,155
48	$44,937,119						$14,931	($53,415)	$102,281	($19,248)	($125,371)	($23,507)	($313,368)	($417,697)	$44,519,422
54	$111,458						$0	($76)	$138	($22)	($184)	($34)	($254)	($432)	$111,026
BPA Balancing Account	$253,227						($253,227)							($253,227)	$0
SMUD Revenue Imputations	$459,329													$0	$459,329
SB408 Recovery	$5,079,948	($5,079,948)												($5,079,948)	$0
SB838 Recovery	($933,139)		$933,139											$933,139	$0
Gain on Sale of Asset	$74,203				($74,203)									($74,203)	$0
Revenue Accounting Adjustment	($37,235)			$37,235										$37,235	$0
Merger Credit	($1)					$1								$1	$0
Unbilled	$2,830,000													$0	$2,830,000
AGA	$2,377,099													$0	$2,377,099
Total Commercial	**$379,624,419**	**($5,079,948)**	**$933,139**	**$37,235**	**($74,203)**	**$1**	**$996,755**	**($336,259)**	**$658,853**	**($106,631)**	**($795,862)**	**($149,223)**	**($2,102,745)**	**($6,018,888)**	**$373,605,531**
Industrial															
15	$46,648						$22	($22)	$50	($13)	($52)	($10)	($94)	($119)	$46,530
23	$2,113,467						$1,944	($1,459)	$2,929	($425)	($3,465)	($650)	($9,497)	($10,623)	$2,102,845
28	$7,614,191						$2,240	($6,347)	$12,462	($1,960)	($15,053)	($2,822)	($40,925)	($52,406)	$7,561,785
30	$14,437,099						$0	($13,639)	$26,466	($4,399)	($32,286)	($6,053)	($81,436)	($111,348)	$14,325,750
47	$8,583,920						$0	($11,861)	$20,621	($4,747)	($27,132)	($5,086)	($68,009)	($96,213)	$8,487,707
48	$97,740,597						$27,146	($122,118)	$233,839	($44,006)	($286,630)	($53,743)	($716,435)	($961,947)	$96,778,650
BPA Balancing Account	$800						($800)							($800)	$0
SMUD Revenue Imputations	$223,638													$0	$223,638
SB408 Recovery	$2,344,591	($2,344,591)												($2,344,591)	$0
SB838 Recovery	($518,535)		$518,535											$518,535	$0
Gain on Sale of Asset	$47,022				($47,022)									($47,022)	$0
Revenue Accounting Adjustment	($14,901)			$14,901										$14,901	$0
Unbilled	$992,000													$0	$992,000
AGA	$64,339													$0	$64,339
Total Industrial	**$133,674,876**	**($2,344,591)**	**$518,535**	**$14,901**	**($47,022)**	**$0**	**$30,551**	**($155,447)**	**$296,368**	**($55,550)**	**($364,618)**	**($68,364)**	**($916,397)**	**($3,091,632)**	**$130,583,244**
Irrigation															
41	$9,449,617						$477,326	($7,227)	$10,143	($5,930)	($17,636)	($3,307)	($51,859)	$401,510	$9,851,127
33 (Klamath)	$2,958,286						$341,442	($5,650)	$8,718	($5,075)	($14,294)	($2,679)	($41,809)	$280,653	$3,238,939
BPA Balancing Account	$119,358						($119,358)							($119,358)	$0
SB408 Recovery	$215,595	($215,595)												($215,595)	$0
SB838 Recovery	($82,523)		$82,523											$82,523	$0
BPA Adjustment	$39,137						($39,137)							($39,137)	$0
Demand Charge Accrual	($21,100)													$0	($21,100)
Gain on Sale of Asset	$3,666				($3,666)									($3,666)	$0
Merger Credit	$0					$0								$0	$0
Revenue Accounting Adjustment	($8,380)			$8,380										$8,380	$0
Unbilled	$185,000													$0	$185,000
AGA	$255,507													$0	$255,507
Total Irrigation	**$13,114,162**	**($215,595)**	**$82,523**	**$8,380**	**($3,666)**	**$0**	**$660,273**	**($12,877)**	**$18,861**	**($11,005)**	**($31,930)**	**($5,986)**	**($93,668)**	**$395,310**	**$13,509,472**
Lighting															
15	$2,452						$14	($1)	$2	($1)	($2)	($0)	($4)	$7	$2,460
50	$1,216,331						$0	($612)	$1,384	($398)	($1,458)	($274)	($2,313)	($3,671)	$1,212,660
51	$3,744,723						$0	($1,216)	$2,741	($610)	($2,848)	($536)	($6,928)	($9,397)	$3,735,326
52	$105,201						$0	($50)	$90	($15)	($119)	($20)	($217)	($331)	$104,870
53	$716,013						$0	($642)	$1,278	($198)	($1,524)	($286)	($1,225)	($2,597)	$713,416
SB408 Recovery	$40,424	($40,424)												($40,424)	$0
SB838 Recovery	($5,249)		$5,249											$5,249	$0
Gain on Sale of Asset	$740				($740)									($740)	$0
Revenue Accounting Adjustment	($98,379)			$98,379										$98,379	$0
Unbilled	$10,000													$0	$10,000
AGA	$0													$0	$0
Total Lighting	**$5,732,257**	**($40,424)**	**$5,249**	**$98,379**	**($740)**	**$0**	**$14**	**($2,521)**	**$5,495**	**($1,222)**	**($5,951)**	**($1,116)**	**($10,687)**	**$46,474**	**$5,778,731**
TOTAL COMPANY	**$1,057,442,899**	**($13,474,662)**	**$2,606,093**	**$206,476**	**($211,503)**	**$1**	**$22,356,044**	**($885,798)**	**$1,770,367**	**($265,821)**	**($2,095,851)**	**($392,970)**	**($5,524,369)**	**$4,088,007**	**$1,061,530,906**

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PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2011; Forecast 12 Months Ended December 2013
Revenue Adjustments

	Normalization Adjustments							Type 2						Type 3			
	SMUD Rev. Imputations Adjust	Demand Charge Accrual	Sch 299 RMA Adjust	Out of Period Adjust	Subtotal Normalization Adjustments	Temperature Adjustment	Total Type 1 Adjusted Revenues	GRC Price Change January 1, 2011	TAM Price Change January 1, 2011	Klamath Price Change April 17, 2011	Blocking Adjustment	Total Type 2 Adj.	Total Type 2 Adjusted Revenues	Type 3 Price Changes	Forecast Price Change	Total Type 3 Adj.	Total Type 3 Adjusted Revenues
Residential																	
15			($44,195)	$335	($43,860)		$356,432	($20,825)	$16,236	$0	($2,868)	($7,457)	$348,975	$8,774	($26,975)	($18,201)	$330,774
4			($8,193,413)	($1,231,556)	($9,424,969)	($6,134,964)	$519,363,439	$19,952,220	$13,943,130	$0	$2,553,264	$36,448,614	$555,812,053	$21,550,066	($13,315,649)	$8,234,417	$564,046,470
BPA Balancing Account					$0		$0						$0				$0
SMUD Revenue Imputations	($519,545)				($519,545)		$0						$0				$0
SB408 Recovery					$0		$0						$0				$0
SB838 Recovery					$0		$0						$0				$0
Gain on Sale of Asset					$0		$0						$0				$0
Revenue Accounting Adjustment					$0		$0						$0				$0
Unbilled					$0		$2,192,000						$2,192,000		($2,192,000)	($2,192,000)	$0
AGA					$0		$18,719						$18,719				$18,719
Total Residential	**($519,545)**	**$0**	**($8,237,608)**	**($1,231,221)**	**($9,988,374)**	**($6,134,964)**	**$521,930,589**	**$19,931,395**	**$13,959,366**	**$0**	**$2,550,397**	**$36,441,158**	**$558,371,747**	**$21,558,840**	**($15,534,624)**	**$6,024,216**	**$564,395,963**
Commercial																	
15			($130,385)	$3,056	($127,329)		$968,186	($56,567)	$44,103	$0	$6,197	($6,267)	$961,918	$25,705	($63,725)	($38,020)	$923,899
23			$2,850,639	($9,831)	$2,840,808	$209,085	$108,545,371	$4,954,429	$2,856,988	$0	$662,974	$8,474,391	$117,019,762	$4,320,127	($3,803,923)	$516,204	$117,535,966
28			($6,008,692)	($70,151)	($6,078,843)	$407,172	$137,015,843	$6,235,026	$4,640,502	$0	$1,178,718	$12,054,246	$149,070,089	$7,528,947	($4,102,237)	$3,426,710	$152,496,799
30			($957,605)	($136,228)	($1,093,833)	$453,923	$71,357,084	$2,894,167	$2,540,902	$0	$2,596,035	$8,031,104	$79,388,188	$4,344,762	($2,942,104)	$1,402,658	$80,790,846
47			$96,101	($27,685)	$68,416	$417,468	$2,519,039	$116,021	$100,647	$0	($463,558)	($246,890)	$2,272,149	$91,613	($590,357)	($498,744)	$1,773,405
48			$2,734,810	($212,131)	$2,522,679		$47,042,101	$2,166,644	$1,879,542	$0	$1,151,605	$5,197,791	$52,239,892	$2,964,611	$16,797,042	$19,761,653	$72,001,545
54			($13,400)	($461)	($13,861)		$97,165	($6,250)	$4,964	$0	$885	($401)	$96,764	$3,085	$3,971	$7,056	$103,820
BPA Balancing Account					$0		$0						$0				$0
SMUD Revenue Imputations	($459,329)				($459,329)		$0						$0				$0
SB408 Recovery					$0		$0						$0				$0
SB838 Recovery					$0		$0						$0				$0
Gain on Sale of Asset					$0		$0						$0				$0
Revenue Accounting Adjustment					$0		$0						$0				$0
Merger Credit					$0		$0						$0				$0
Unbilled					$0		$2,830,000						$2,830,000		($2,830,000)	($2,830,000)	$0
AGA					$0		$2,377,099						$2,377,099				$2,377,099
Total Commercial	**($459,329)**	**$0**	**($1,428,531)**	**($453,431)**	**($2,341,291)**	**$1,487,649**	**$372,751,889**	**$16,303,470**	**$12,067,648**	**$0**	**$5,132,855**	**$33,503,973**	**$406,255,862**	**$19,278,850**	**$2,468,667**	**$21,747,517**	**$428,003,379**
Industrial																	
15			($5,875)	($20)	($5,895)		$40,635	($2,374)	$1,851	$0	$638	$115	$40,750	$1,159	($1,838)	($679)	$40,070
23			$55,734	$522	$56,256		$2,159,101	$98,550	$56,829	$0	$7,135	$162,514	$2,321,615	$84,339	$127,385	$211,724	$2,533,339
28			($292,169)	($23,062)	($315,231)		$7,246,554	$329,761	$245,429	$0	$23,600	$598,790	$7,845,344	$363,078	$560,934	$924,012	$8,769,356
30			($160,847)	$12,971	($147,876)		$14,177,874	$575,039	$504,850	$0	$63,194	$1,143,083	$15,320,957	$731,092	$1,275,496	$2,006,588	$17,327,545
47			$650,026	$0	$650,026		$9,137,733	$420,862	$365,093	$0	$279,903	$1,065,858	$10,203,591	$591,097	($8,983,168)	($8,392,071)	$1,811,520
48			$6,515,508	($72,398)	$6,443,110		$103,221,761	$4,754,141	$4,124,170	$0	$1,233,112	$10,111,423	$113,333,184	$6,511,964	$9,237,344	$15,749,308	$129,082,492
BPA Balancing Account					$0		$0						$0				$0
SMUD Revenue Imputations	($223,638)				($223,638)		$0						$0				$0
SB408 Recovery					$0		$0						$0				$0
SB838 Recovery					$0		$0						$0				$0
Gain on Sale of Asset					$0		$0						$0				$0
Revenue Accounting Adjustment					$0		$0						$0				$0
Unbilled					$0		$992,000						$992,000		($992,000)	($992,000)	$0
AGA					$0		$64,339						$64,339				$64,339
Total Industrial	**($223,638)**	**$0**	**$6,762,377**	**($81,987)**	**$6,456,752**	**$0**	**$137,039,996**	**$6,175,979**	**$5,298,222**	**$0**	**$1,607,583**	**$13,081,784**	**$150,121,780**	**$8,282,729**	**$1,224,153**	**$9,506,882**	**$159,628,662**
Irrigation																	
41			$2,484,938	$15,908	$2,500,847		$12,351,974	$34,154	$216,624	$0	$244,146	$494,924	$12,846,898	$409,135	$490,057	$899,192	$13,746,090
33 (Klamath)			$0	$18,774	$18,774		$3,257,713	$0	$0	$1,049,991	($47,857)	$1,002,134	$4,259,847	$6,275,001	$659,039	$6,934,040	$11,193,887
BPA Balancing Account					$0		$0						$0				$0
SB408 Recovery					$0		$0						$0				$0
SB838 Recovery					$0		$0						$0				$0
BPA Adjustment					$0		$0						$0				$0
Demand Charge Accrual		$21,100			$21,100		$0						$0				$0
Gain on Sale of Asset					$0		$0						$0				$0
Merger Credit					$0		$0						$0				$0
Revenue Accounting Adjustment					$0		$0						$0				$0
Unbilled					$0		$185,000						$185,000		($185,000)	($185,000)	$0
AGA					$0		$255,507						$255,507				$255,507
Total Irrigation	**$0**	**$21,100**	**$2,484,938**	**$34,682**	**$2,540,721**	**$0**	**$16,050,193**	**$34,154**	**$216,624**	**$1,049,991**	**$196,289**	**$1,497,058**	**$17,547,251**	**$6,684,136**	**$964,096**	**$7,648,232**	**$25,195,484**
Lighting																	
15			($261)	$0	($261)		$2,199	($128)	$100	$0	($42)	($70)	$2,129	$49	$349	$398	$2,527
50			($158,894)	$2,559	($156,334)		$1,056,326	($61,538)	$45,975	$0	$5,637	($9,926)	$1,046,399	$24,633	($49,466)	($24,833)	$1,021,566
51			($510,783)	$128,126	($382,657)		$3,352,669	($194,560)	$142,666	$0	$20,150	($31,744)	$3,320,925	$88,134	$23,629	$111,763	$3,432,688
52			($12,993)	$1,325	($11,668)		$93,202	($5,524)	$4,947	$0	$674	$97	$93,299	$2,893	($23,088)	($20,194)	$73,105
53			($100,626)	$611	($100,015)		$613,401	($35,666)	$24,080	$0	$2,503	($9,083)	$604,318	$14,993	$1,986	$16,979	$621,297
SB408 Recovery					$0		$0						$0				$0
SB838 Recovery					$0		$0						$0				$0
Gain on Sale of Asset					$0		$0						$0				$0
Revenue Accounting Adjustment					$0		$0						$0				$0
Unbilled					$0		$10,000						$10,000		($10,000)	($10,000)	$0
AGA					$0		$0						$0				$0
Total Lighting	**$0**	**$0**	**($783,557)**	**$132,622**	**($650,935)**	**$0**	**$5,127,796**	**($297,416)**	**$217,768**	**$0**	**$28,922**	**($50,726)**	**$5,077,070**	**$130,701**	**($56,590)**	**$74,111**	**$5,151,182**
TOTAL COMPANY	**($1,202,512)**	**$21,100**	**($1,202,380)**	**($1,599,335)**	**($3,983,126)**	**($4,647,316)**	**$1,052,900,464**	**$42,147,582**	**$31,759,628**	**$1,049,991**	**$9,516,045**	**$84,473,246**	**$1,137,373,710**	**$55,935,256**	**($10,934,298)**	**$45,000,958**	**$1,182,374,668**

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Oregon General Rate Case - December 2013
Wheeling Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
Other Electric Revenues	456	1	(1,888,339)	SG	25.777%	(486,760)	3.2.3
Other Electric Revenues	456	1	(2,635)	SE	24.314%	(641)	3.2.3
Other Electric Revenues	456	2	255,775	SG	25.777%	65,932	3.2.3
Other Electric Revenues	456	3	4,879,669	SG	25.777%	1,257,840	3.2.3
Other Electric Revenues	456	3	151,499	SE	24.314%	36,835	3.2.3
			3,395,969			873,205	3.2.3
Wheeling Imbalance Expense	566	1	(879,133)	SG	25.777%	(226,615)	

Adjustment Detail:		
Actual Wheeling Revenues 12 ME June 2011	72,045,788	B1
Total Adjustments	3,395,969	3.2.3
Normalized Wheeling Revenues	75,441,758	3.2.3

Description of Adjustment:

This adjustment reflects the level of wheeling revenues the Company expects in the 12 months ending December 31, 2013 by adjusting the actual revenues for the 12 months ended June 30, 2011 for normalizing, annualizing and pro forma changes. Imbalance penalty revenue and expense is removed to avoid any impact on regulated results.

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Wheeling Revenue

Customer	Network 301912	Pt-to-Pt 302980	Legacy Contracts 301916	Legacy Contracts 301917	Non-Firm Wheeling 301922	ST Firm Wheeling 301926	Use of Facilities 302901	Ancillary C&T:Spin/Sup 301970	Ancillary Spin/Sup 301973	Ancillary Spin/Sup 302902	Ancillary Spin/Sup 301972	Delivery/ Distribution Metering 301966	Schedule 1 Scheduling 301967	Schedule 3 Regulation/ Trans. 301968	Schedule 3 Regulation/ C&t 301969	Penalties 505961	Penalties 505963		Total
Bonneville Power Administration	-	-	(4,526,848)	-	-	-	-	-	-	-	-	-	-	-	-	-	-		(4,526,848)
WAPA Folsom	-	-	(1,000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-		(1,000)
Powder River Energy Corp	-	-	-	-	-	-	(190)	-	-	-	-	-	-	-	-	-	-		(190)
Basin Electric Power Cooperative	(9,416)	-	-	-	(98,315)	(5,580)	-	463	-	13,620	-	(35,679)	-	(370)	(1,053)	-	-		(136,330)
Black Hills, Inc.	(105,649)	(1,822,500)	-	-	(138,018)	(258,480)	-	-	-	-	-	-	-	-	-	-	-		(2,324,646)
Bonneville Power Administration	(265,202)	(1,676,700)	-	(984,794)	(1,437)	-	(1,171,506)	13,251	(47,304)	191,866	-	(312,987)	(37,800)	(12,469)	(179,183)	(7,607)	-		(4,491,872)
Cargill Power Markets, LLC	-	-	-	-	(1,466,864)	(67,550)	-	-	-	-	-	-	-	-	-	-	-		(1,534,413)
Constellation	(41,655)	-	-	-	(71,315)	-	-	-	-	-	-	-	-	-	-	-	(2,069)		(115,038)
Coral Power/Shell	-	-	-	-	(29,369)	-	-	-	-	-	-	-	-	-	-	-	-		(29,369)
Deseret Generation & Transmission Cooperative	-	-	-	(2,281,973)	-	(3,720)	-	(484,667)	(887,646)	(149,865)	(308,853)	(46,080)	(24,966)	(71,263)	(230,809)	-	-		(4,489,844)
Fall River Rural Electric Cooperative	-	-	-	-	-	-	(151,308)	-	-	-	-	-	-	-	-	-	-		(151,308)
Foot Creek III, LLC	-	-	-	-	-	-	(36,182)	-	-	-	-	-	-	-	-	-	-		(36,182)
Idaho Power Company	-	(756,740)	-	-	(45,694)	(708,750)	(90,108)	-	-	-	-	-	-	-	-	-	-		(1,601,292)
Morgan Stanley Capital Group, Inc.	-	-	-	-	(1,344,560)	(75,437)	-	-	-	-	-	-	-	-	-	-	-		(1,419,997)
Pacific Gas & Electric Company	-	-	-	-	-	-	(20,310,869)	-	-	-	-	-	-	-	-	-	-		(20,310,869)
Portland General Electric	-	-	-	-	-	(47,858)	-	-	-	-	-	-	-	-	-	-	-		(47,858)
Powerex Corporation	956,198	(2,916,000)	-	-	(2,926,839)	(42,677)	-	(13,615)	11,946	(4,784)	4,197	-	-	-	-	-	(1,445)		(4,933,019)
Iberdrola Renewables Inc.	311,906	(1,093,500)	-	-	(44,136)	-	-	(92,918)	(133,865)	(32,647)	(47,034)	-	-	-	-	-	(14,392)		(1,146,585)
Public Service Company of Colorado	-	-	-	-	(53,591)	(104,052)	-	-	-	-	-	-	-	-	-	-	-		(157,643)
Rainbow Energy Marketing	-	-	-	-	(161,012)	(107,988)	-	-	-	-	-	-	-	-	-	-	-		(268,999)
Sierra Pacific Power	-	-	-	-	(31,747)	-	(106,511)	-	-	-	-	-	-	-	-	-	-		(138,258)
State of South Dakota	48,600	(145,800)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		(97,200)
TransAlta Energy	-	-	-	-	(128,565)	-	-	-	-	-	-	-	-	-	-	-	-		(128,565)
Tri-State Generation and Trans.	(199,691)	-	(134,620)	-	(11,727)	-	-	-	-	-	-	-	-	(3,252)	(9,256)	(11,722)	-		(370,268)
UAMPS	-	-	-	(7,537,101)	-	-	-	(98,705)	(154,574)	(1,405)	(54,310)	(108,112)	(99,900)	-	(288,720)	-	-		(8,342,826)
Utah Municipal Power Agency	-	-	-	(2,200,244)	-	-	-	35,670	-	18,000	-	-	(54,000)	-	(107,010)	-	-		(2,307,584)
Warm Springs	59,850	-	-	-	-	-	(179,550)	-	-	-	-	-	-	-	-	-	-		(119,700)
Western Area Power Administration	(19,922)	-	-	-	-	-	-	-	-	21,450	-	(61,564)	-	-	-	-	-		(60,036)
Western Area Power Administration	-	-	-	(2,863,457)	(550,625)	(11,420)	-	-	-	-	-	-	-	-	-	-	-		(3,425,503)
NextEra Energy Resources, LLC	805,902	(2,662,875)	-	-	(338,575)	-	-	(70,933)	(102,906)	(24,922)	(36,156)	-	-	-	-	-	(588,051)		(3,018,516)
Southern Calif Edison Com Direct	(702,089)	-	-	-	(1,135,492)	(40,799)	(310,869)	(3,959)	(717)	(1,391)	(252)	-	-	-	-	-	(179,231)		(2,374,800)
PPL Energy Plus, LLC	-	-	-	-	(93,415)	(33,009)	-	-	-	-	-	-	-	-	-	-	-		(126,424)
US Bureau of Reclamation	(4,411)	-	(11,840)	(22,628)	-	-	-	-	-	(11,775)	-	2,038	-	(73)	(208)	-	-		(48,896)
Moon Lake Electric Association	-	-	-	(19,695)	-	-	-	-	-	-	-	-	-	-	-	-	-		(19,695)
Seattle City Light	303,750	(911,250)	-	-	(1,460)	-	-	(18,311)	(18,433)	(6,433)	(6,476)	-	-	-	-	-	(25,869)		(684,482)
Eugene Water & Electric Board	-	-	-	-	(38,489)	-	-	-	-	-	-	-	-	-	-	-	-		(38,489)
Sempra Energy Solutions LLC	(155,213)	-	-	-	-	-	-	7,273	-	2,555	-	-	-	(7,117)	(20,257)	(45,459)	-		(218,219)
Enel	-	(50,625)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		(50,625)
Citigroup Energy	-	-	-	-	(6)	-	-	-	-	-	-	-	-	-	-	-	-		(6)
JPM Ventures Energy	(5,653)	-	-	-	(893,312)	-	-	3,131	-	1,100	-	-	-	-	-	-	(2,572)		(897,305)
Barclays Bank	-	-	-	-	(146)	-	-	-	-	-	-	-	-	-	-	-	-		(146)
Municipal Energy Agency of Nebraska	-	-	-	-	(12,474)	-	-	-	-	-	-	-	-	-	-	-	-		(12,474)
Raser Power Systems LLC	133,650	(400,950)	-	-	-	-	-	(13,630)	(14,765)	(4,789)	(5,188)	-	-	-	-	-	(1,151)		(306,822)
Macquarie Energy, LLC	-	-	-	-	(9,268)	-	-	-	-	-	-	-	-	-	-	-	-		(9,268)
Salt River Project	-	-	-	-	(113,303)	-	-	-	-	-	-	-	-	-	-	-	-		(113,303)
Gila River Power, LP	-	-	-	-	(1,831)	-	-	-	-	-	-	-	-	-	-	-	-		(1,831)
Black Hills/Colorado Electric Utility Company, L.P	-	-	-	-	(1,986)	(8,398)	-	-	-	-	-	-	-	-	-	-	-		(10,384)
Eagle Energy Partners	-	-	-	-	(3,733)	-	-	-	-	-	-	-	-	-	-	-	-		(3,733)
Enel Cove Fort, LLC	-	81,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		81,000
Tenaska Power Services Co	-	-	-	-	(21,235)	-	-	-	-	-	-	-	-	-	-	-	-		(21,235)
Los Angeles Dept Water & Power	-	-	-	-	(788,501)	-	-	-	-	-	-	-	-	-	-	-	-		(788,501)
Cowlitz County PUD	-	-	-	-	-	-	(115,281)	-	-	-	-	-	-	-	-	-	-		(115,281)
Accruals and Adjustments	135,126	(417,150)	5,473	(146,763)	(188,238)	154,979	28,703	-	-	(910)	(111,988)	(12,801)	-	459		-	-		(553,110)
Actual Totals	1,246,082	(12,773,090)	(4,668,834)	(16,056,656)	(10,745,276)	(1,360,738)	(22,443,670)	(736,950)	(1,348,265)	9,669	(566,059)	(575,185)	(216,666)	(94,086)	(836,497)	(64,789)	(814,779)		**(72,045,788)**

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PacifiCorp
Oregon General Rate Case - December 2013
Wheeling Revenue

Adj Type	Customer	Network 301912	Pt-to-Pt 302980	Legacy Contracts 301916	Legacy Contracts 301917	Non-Firm Wheeling 301922	ST Firm Wheeling 301926	Use of Facilities 302901	Ancillary C&T:Spin/Sup 301970	Ancillary Spin/Sup 301973	Ancillary Spin/Sup 302902	Ancillary Spin/Sup 301972	Delivery/ Distribution Metering 301966	Schedule 1 Scheduling 301967	Schedule 3 Regulation/ Trans. 301968	Schedule 3 Regulation/ C&t 301969	Penalties 505961	Penalties 505963		Total
1	Remove network accruals as changes covered in adjustments to usage based on 2009 for forecasting to the test period.	(135,126)																		(135,126)
1	Remove point-to-point accruals as changes covered in adjustments for the test period.		417,150																	417,150
1	Reverse unreserved use charges: Black Hills.	13,578																		13,578
1	Reverse unreserved use charges: Constellation.	41,655																		41,655
1	Reverse unreserved use charges: Iberdrola.	52,594																		52,594
1	Reverse unreserved use charges: NextEra.	130,703																		130,703
1	Reverse unreserved use charges: Southern California Edison.	702,089																		702,089
1	Reverse unreserved use charges: JP Morgan.	5,653																		5,653
1	Eliminate re-assignments-Idaho.		(2,635)			2,635														-
1	Add back reclass entry for transfer of meter charge for BPA.												(6,900)							(6,900)
1	Remove refunds to Bonneville Power Administration primary delivery and distribution substation charges.												(143,406)							(143,406)
1	Remove refunds to US Bureau of Reclamation for primary delivery and distribution substation charges.												(16,912)							(16,912)
2	Annualize revisions to Basin network, "load", based on 2010 usage.	(2,868)																		(2,868)
2	Annualize revisions to Black Hills network, "load", based on 2010 usage.	(9,689)																		(9,689)
2	Annualize revisions to Bonneville Power Administration, "BPA", network, "load", based on 2010 usage.	25,760																		25,760
3	Annualize revisions for Tri-State load based on 2010 usage and estimates for added load.	(75,838)																		(75,838)
3	Estimated reduction in Noble Americas network usage based on 2011 usage.	45,476																		45,476
2	Annualize regulation and frequency response - Tri-State based on projected usage.														(1,780)	(5,067)				(6,847)
2	Annualize conversion of BPA contract from legacy to tariff.		(340,200)																	(340,200)
2	Remove legacy BPA revenue caused by revenue conversion to tariff.			78,069																78,069
3	Estimated load increase; BPA GTA based on historical usage			(78,000)																(78,000)
3	Decrease in use of facilities charge for PG&E - Malin per contract reduction. Estimated revenue for non-firm for 150mw available in 2012.					-		5,500,004												5,500,004
3	Estimated decrease in use of facilities charge for PG&E and SCE.							62,264												62,264
1	Remove reclass of Nevada/Sierra Pacific for amounts over 1 year							31,327												31,327
3	Estimate annual non-firm transmission with SCE for new generation added in October 2010.					(940,000)														(940,000)
3	Reverse Non-firm usage from LDWP as customer usage is usual and possibly one-time.					788,501														788,501
3	New contract: Long-term pt-to-pt, 3 MW deferral fee		(6,075)																	(6,075)
3	New contract: 150mw pt-to-pt effective 1/1/12 deferred to 1/1/13. Assume start of 1/1/2013		(3,645,000)																	(3,645,000)
3	New contract:150 mw pt-to-pt effective 4/1/12. Annualize full year.		(3,645,000)																	(3,645,000)
3	New Contract: 60mw pt-to-pt effective 4/1/12. Annualize for one year of revenue for 2013.		(1,458,000)																	(1,458,000)
3	New Contract: 50mw pt-to-pt effective 1/1/13. Since deferral of 150 mw, this agreement deferred to 1/1/2014.		(101,250)																	(101,250)
3	New Contract: 50mw pt-to-pt effective 1/1/13.		(1,215,000)																	(1,215,000)

PacifiCorp
Oregon General Rate Case - December 2013
Wheeling Revenue

	Customer	Network 301912	Pt-to-Pt 302980	Legacy Contracts 301916	Legacy Contracts 301917	Non-Firm Wheeling 301922	ST Firm Wheeling 301926	Use of Facilities 302901	Ancillary C&T:Spin/Sup 301970	Ancillary Spin/Sup 301973	Ancillary Spin/Sup 302902	Ancillary Spin/Sup 301972	Delivery/ Distribution Metering 301966	Schedule 1 Scheduling 301967	Schedule 3 Regulation/ Trans. 301968	Schedule 3 Regulation/ C&t 301969	Penalties 505961	Penalties 505963		Total
1	Reverse Enel Cove Fort Refund. Deferral deposit through March 2013 as contract extended to start Nov. 2013.		(81,000)																	(81,000)
3	New contract: 65mw start of 11/2013		(263,250)																	(263,250)
1	Removal of imbalance penalties as penalties incurred are accrued and refunded to non-offending customers.																64,789	814,779		879,568
	Test Period Incremental Adjustments	793,987	(10,340,260)	69	-	(148,864)	-	5,593,595	-	-	-	-	(167,218)	-	(1,780)	(5,067)	64,789	814,779		**(3,395,969)**
	Accum Test Period Totals	2,040,069	(23,113,350)	(4,668,765)	(16,056,656)	(10,894,140)	(1,360,738)	(16,850,075)	(736,950)	(1,348,265)	9,669	(566,059)	(742,402)	(216,666)	(95,866)	(841,564)	-	-		**(75,441,758)**
1	Type 1 adjustments (Normalize for out of period and one-time adj's)	811,146	333,515	-	-	2,635	-	31,327	-	-	-	-	(167,218)	-	-	-	64,789	814,779		1,890,974
2	Type 2 adjustments (Annualize changes that occur during the test period)	13,203	(340,200)	78,069	-	-	-	-	-	-	-	-	-	-	(1,780)	(5,067)	-	-		(255,775)
3	Type 3 adjustments (Proforma known and measurable changes or estimated changes)	(30,362)	(10,333,575)	(78,000)	-	(151,499)	-	5,562,268	-	-	-	-	-	-	-	-	-	-		(5,031,168)
	Total	793,987	(10,340,260)	69	-	(148,864)	-	5,593,595	-	-	-	-	(167,218)	-	(1,780)	(5,067)	64,789	814,779		**(3,395,969)**

Ref. 3.2

PacifiCorp PAGE 3.3
Oregon General Rate Case - December 2013
SO2 Emission Allowances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove 12 ME Jun 2011 Allowance Sales	4118	3	559,750	SE	24.314%	136,095	3.3.1
Add 12 ME Dec 2013 Amortization	4118	3	(1,235,033)	SE	24.314%	(300,280)	3.3.1
			(675,283)			(164,185)	
Adjustment to Rate Base:							
Regulatory Deferred Sales	25398	3	(829,723)	SE	24.314%	(201,735)	3.3.1
Adjustment to Taxes:							
Accumulated Deferred Income Taxes	190	3	314,888	SE	24.314%	76,560	3.3.1
Schedule M Deduction	SCHMDT	3	1,228,912	SE	24.314%	298,792	3.3.1
DIT Expense	41010	3	466,384	SE	24.314%	113,394	3.3.1

Description of Adjustment:

The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("SO2") that can be emitted from power plants and granted the issuance of SO2 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. This adjustment reflects the gain on sales of SO2 allowances based on a four-year amortization period ending December 2013. This is the same methodology included in the Company's last three general rate cases, Dockets UE-179, UE-210, and UE-217.

PacifiCorp **Beginning of the Period** **Dec-12**
Oregon General Rate Case - December 2013 **Ending of the Period** **Dec-13**
SO2 Emission Allowance Sales

Description	Date Booked	Sales To Date	Accumulated Amortization	End Unamort Balance	Current Period Amortization	Beg Unamor Balance	Unrealized Gain SCHMAT	Realized Gain SCHMDT	D.I.T. Expense	Accumulated Deferred Income Tax	Accumulated Deferred Income Tax
		Dec-13	Dec-13	Dec-13	12 Months Ended	Dec-12	12 Months Ended	12 Months Ended	12 Months Ended	Dec-12	Dec-13
Mar 2007 Sale	Mar-07	2,322,500	2,322,500	0	0	0	0	0	0	(0)	(0)
Apr 2007 Sale	Apr-07	3,727,548	3,727,548	0	0	0	0	0	0	(0)	(0)
May 2007 Sale	May-07	2,897,500	2,897,500	0	0	0	0	0	0	(0)	(0)
Oct 2007 Sale	Oct-07	2,872,500	2,872,500	0	0	0	0	0	0	(0)	(0)
Dec 2007 Sale	Dec-07	2,843,450	2,843,450	0	0	0	0	0	0	(0)	(0)
Apr 2008 Sale	Apr-08	1,192,027	1,192,027	0	0	0	0	0	0	(0)	(0)
Oct 2008 Sale	Oct-08	149,500	149,500	0	0	0	0	0	0	0	0
Nov 2008 Sale	Nov-08	1,393,500	1,393,500	0	0	0	0	0	0	0	0
Dec 2008 Sale	Dec-08	2,154,000	2,154,000	0	0	0	0	0	0	0	0
Jan 2009 Sale	Jan-09	194,500	194,500	0	0	0	0	0	0	0	0
Apr 2009 Sale	Apr-09	173,141	173,141	0	10,826	10,826	0	10,826	4,109	4,109	0
Jun 2009 Sale	Jun-09	1,017,500	1,017,500	0	105,986	105,986	0	105,986	40,223	40,223	(0)
Aug 2009 Sale	Aug-09	1,455,000	1,455,000	0	212,167	212,167	0	212,167	80,519	80,519	0
Sep 2009 Sale	Sep-09	950,750	950,750	0	158,470	158,470	0	158,470	60,141	60,141	(0)
Feb 2010 Sale	Feb-10	402,500	394,095	8,405	100,620	109,025	0	100,620	38,186	41,376	3,190
Mar 2010 Sale	Mar-10	1,647,551	1,578,904	68,647	411,888	480,535	0	411,888	156,316	182,368	26,052
Apr 2010 Sale	Apr-10	372,500	349,200	23,300	93,120	116,420	0	93,120	35,340	44,183	8,843
Aug 2010 Sale	Aug-10	395,000	337,389	57,611	98,748	156,359	0	98,748	37,476	59,340	21,864
Feb 2011 Sale	Feb-11	78,000	56,875	21,125	19,500	40,625	0	19,500	7,400	15,418	8,017
Mar 2011 Sale	Mar-11	41,737	29,580	12,157	10,440	22,597	0	10,440	3,962	8,576	4,614
Apr 2011 Sale	Apr-11	4,505	3,102	1,403	1,128	2,531	0	1,128	428	961	533
June 2011 Sale	Jun-11	40,509	26,164	14,345	10,128	24,473	0	10,128	3,844	9,288	5,444
Forecast Sale	Jan-12	387	192	195	96	291	0	96	36	110	74
Forecast Sale	Feb-12	387	184	203	96	299	0	96	36	113	77
Forecast Sale	Mar-12	387	176	211	96	307	0	96	36	116	80
Forecast Sale	Apr-12	387	168	219	96	315	0	96	36	119	83
Forecast Sale	May-12	568	240	328	144	472	0	144	55	179	124
Forecast Sale	Jun-12	387	152	235	96	331	0	96	36	125	89
Forecast Sale	Jul-12	387	144	243	96	339	0	96	36	129	92
Forecast Sale	Aug-12	387	136	251	96	347	0	96	36	132	95
Forecast Sale	Sep-12	387	128	259	96	355	0	96	36	135	98
Forecast Sale	Oct-12	387	120	267	96	363	0	96	36	138	101
Forecast Sale	Nov-12	387	112	275	96	371	0	96	36	141	104
Forecast Sale	Dec-12	387	104	283	96	379	0	96	36	144	107
Forecast Sale	Jan-13	495	120	375	120	0	495	120	(142)	0	142
Forecast Sale	Feb-13	495	110	385	110	0	495	110	(146)	0	146
Forecast Sale	Mar-13	495	100	395	100	0	495	100	(150)	0	150
Forecast Sale	Apr-13	495	90	405	90	0	495	90	(154)	0	154
Forecast Sale	May-13	676	112	564	112	0	676	112	(214)	0	214
Forecast Sale	Jun-13	495	70	425	70	0	495	70	(161)	0	161
Forecast Sale	Jul-13	495	60	435	60	0	495	60	(165)	0	165
Forecast Sale	Aug-13	495	50	445	50	0	495	50	(169)	0	169
Forecast Sale	Sep-13	495	40	455	40	0	495	40	(173)	0	173
Forecast Sale	Oct-13	495	30	465	30	0	495	30	(176)	0	176
Forecast Sale	Nov-13	495	20	475	20	0	495	20	(180)	0	180
Forecast Sale	Dec-13	495	10	485	10	0	495	10	(184)	0	184
Totals		26,336,661	26,121,394	215,267	**1,235,033**	1,444,179	**6,121**	**1,235,033**	466,384	548,080	81,696
					Ref # 3.3		**Ref # 3.3**	**Ref # 3.3**			

SO2 Credit Unamortized Balance

Beginning Balance	1,444,179
Ending Balance	215,267
Average Balance	**829,723**
	Ref # 3.3

SO2 Sales 12 ME June 2011: **559,750** **Ref # 3.3**

	DIT Expense	DIT Unamortized Balance
		548,080
Ditexp @ current rate	**468,707**	
Tax rate Adjustment	0	81,696
410 Adjusted total	468,707	**314,888**
Ref # 3.3	**(2,323)**	**Ref # 3.3**
	466,384	

PacifiCorp
Oregon General Rate Case - December 2013
SO2 Emission Allowance Sales
SAP Account 301947 - Actuals for 12 Months Ended Jun 2011

Year	Month	Amount	Accumulated Amount	
2010	7	-	-	
2010	8	(395,000)	(395,000)	
2010	9	-	(395,000)	
2010	10	-	(395,000)	
2010	11	-	(395,000)	
2010	12	-	(395,000)	
2011	1	-	(395,000)	
2011	2	(78,000)	(473,000)	
2011	3	(41,737)	(514,737)	
2011	4	(4,504)	(519,241)	
2011	5	(1)	(519,242)	
2011	6	(40,509)	**(559,750)**	**Pg. 3.3.1**

PacifiCorp
Oregon General Rate Case - December 2013
REC Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove 12 ME June-11 Booked Revenues	456	1	(91,247,006)	SG	25.777%	(23,520,882)	3.4.1

Description of Adjustment:

This adjustment removes all REC revenue as booked during the 12-months ended June 2011. Most of Oregon's share of the renewable energy credits (RECs) are banked for compliance; however, not all RECs meet the Oregon RPS qualifications. Oregon's revenue from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in Docket UP 260.

PacifiCorp
Oregon General Rate Case - December 2013
REC Revenue
Actuals as Booked

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	SAP Total
SAP Acct	301944	301944	301945	
July-10	(2,980,492)	8,105,532	(8,125,032)	(2,999,992)
August-10	(2,634,505)	2,980,492	(2,980,492)	(2,634,505)
September-10	(2,539,446)	2,634,505	(2,631,733)	(2,536,674)
October-10	(11,511,605)	2,539,446	(2,539,446)	(11,511,605)
November-10	(13,112,173)	11,511,605	(11,551,983)	(13,152,551)
December-10	(15,086,780)	13,112,173	(13,065,327)	(15,039,934)
January-11	(5,706,530)	15,086,780	(14,141,780)	(4,761,530)
February-11	(6,840,580)	5,706,530	(4,780,270)	(5,914,320)
March-11	(8,722,315)	6,840,580	(6,836,128)	(8,717,863)
April-11	(8,055,200)	8,722,315	(8,721,097)	(8,053,982)
May-11	(8,760,908)	8,055,200	(8,045,174)	(8,750,882)
June-11	(7,186,024)	8,760,908	(8,748,052)	(7,173,168)
12 ME June 2011 Total	(93,136,559)	94,056,067	(92,166,514)	**(91,247,006)**

Ref 3.4

PacifiCorp
Oregon General Rate Case - December 2013
Ancillary Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Ancillary Contract Renewal	456	3	4,193,877	SG	25.777%	1,081,062	3.5.1

Description of Adjustment:

This adjusts revenue to account for the contract the Company entered into with Seattle City Light (SCL) to receive real time output from SCL's share of the Stateline wind farm and return power two months later, which was renewed in December 2011. The ancillary revenue booked in the twelve-months ended June 2011 is adjusted to reflect the Test Period revenue expected per the terms of the new contract, consistent with net power costs treatment in adjustment 5.1.

PacifiCorp
Oregon General Rate Case - December 2013
Ancillary Revenue

Ancillary Revenue Adjustment Calculation

Revenue

FERC Acct	Account	Acc.Text	Locatn	Factor	YE Jun 2011	YE Dec 2013	Adjustment
4562300	301959	Wind-based Ancl Rev	70	SG	5,283,000	9,476,878	**4,193,877**
							Ref 3.5

The Company's June 2011 actual O&M expenses are the basis for the test period O&M expenses. These actual expenses are adjusted for various normalizing items including labor costs, non-labor operation and maintenance, and inflation to reflect the appropriate level of on-going costs that the Company expects to incur during the December 2013 test period. The following adjustments are included:

PacifiCorp
Normalized Results of Operations
Tab 4 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		4.1	4.2	4.3	4.4	4.5	4.6	4.7
	Total Adjustments	Miscellaneous General Expense & Revenue	Wage & Employee Benefit Adjustment	Irrigation Load Control Program	Remove Non-Recurring Entries	Uncollectible Accounts	DSM Revenue and Expense Removal	Insurance Expense
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-	-
5 Other Operating Revenues	(21,405,215)	-	-	-	-	-	(21,405,215)	-
6 Total Operating Revenues	(21,405,215)	-	-	-	-	-	(21,405,215)	-
7								
8 Operating Expenses:								
9 Steam Production	5,069,635	-	1,154,815	-	12,402	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	1,847,203	-	169,594	-	-	-	-	-
12 Other Power Supply	(2,749,297)	(761)	408,203	(2,320,689)	(1,827,984)	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-	-	-
13 Transmission	870,910	-	242,797	-	(155)	-	-	-
14 Distribution	3,367,878	(96)	1,339,136	-	200	-	-	-
15 Customer Accounting	1,797,065	(3,247)	736,688	-	-	316,534	-	-
16 Customer Service & Info	(21,244,127)	(4,561)	86,063	-	-	-	(21,405,215)	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	706,514	(82,446)	1,027,113	-	60,516	-	-	158,449
19								
20 Total O&M Expenses	(10,334,219)	(91,111)	5,164,407	(2,320,689)	(1,755,021)	316,534	(21,405,215)	158,449
21								
22 Depreciation	-	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	(3,690,076)	18,641	(1,726,023)	775,609	586,554	(105,790)	17,083	(48,212)
26 Income Taxes - State	(501,420)	2,533	(234,538)	105,392	79,703	(14,375)	2,321	(6,551)
27 Income Taxes - Def Net	(3,712)	-	-	-	-	-	(3,712)	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	35,353	35,353	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(14,494,074)	(34,584)	3,203,847	(1,439,687)	(1,088,763)	196,369	(21,389,522)	103,686
32								
33 Operating Rev For Return:	(6,911,141)	34,584	(3,203,847)	1,439,687	1,088,763	(196,369)	(15,693)	(103,686)
34								
35 Rate Base:								
36 Electric Plant In Service	-	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-	-
44 Working Capital	(292,283)	(1,407)	64,467	(28,969)	(21,908)	3,951	(430,321)	2,086
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(292,283)	(1,407)	64,467	(28,969)	(21,908)	3,951	(430,321)	2,086
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	-	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-	-
53 Accum Def Income Tax	(1,774,653)	-	-	-	-	-	(1,210,936)	(563,717)
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	(1,774,653)	-	-	-	-	-	(1,210,936)	(563,717)
60								
61 Total Rate Base:	(2,066,936)	(1,407)	64,467	(28,969)	(21,908)	3,951	(1,641,257)	(561,631)
62								
63 Return on Rate Base	-0.209%	0.001%	-0.100%	0.045%	0.034%	-0.006%	0.004%	-0.002%
64								
65 Return on Equity	-0.396%	0.002%	-0.189%	0.085%	0.064%	-0.012%	0.008%	-0.003%
66								
67 TAX CALCULATION:								
68 Operating Revenue	(11,106,348)	55,758	(5,164,407)	2,320,689	1,755,021	(316,534)	-	(158,449)
69 Other Deductions								
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	(52,076)	(35)	1,624	(730)	(552)	100	(41,351)	(14,150)
72 Schedule "M" Additions	9,779	-	-	-	-	-	9,779	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-	-
74 Income Before Tax	(11,044,493)	55,794	(5,166,031)	2,321,418	1,755,573	(316,634)	51,130	(144,299)
75								
76 State Income Taxes	(501,420)	2,533	(234,538)	105,392	79,703	(14,375)	2,321	(6,551)
77 Taxable Income	(10,543,073)	53,261	(4,931,494)	2,216,026	1,675,870	(302,259)	48,809	(137,748)
78								
79 Federal Income Taxes + Other	(3,690,076)	18,641	(1,726,023)	775,609	586,554	(105,790)	17,083	(48,212)
80								
81 PRICE CHANGE	11,198,706	(57,584)	5,325,912	(2,393,263)	(1,809,905)	326,433	(189,732)	98,250

PacifiCorp
Normalized Results of Operations
Tab 4 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		4.8	4.9	4.10	4.11	4.12
		Generation Overhaul Expense	Incremental O&M	Intercompany Administrative Service Agreement (IASA)	Memeberships and Subscriptions	O&M Escalation
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-
6	Total Operating Revenues	-	-	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	(611,082)	1,698,855	-	-	2,814,645
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	1,214,337	-	-	463,272
12	Other Power Supply	(57,474)	(119,220)	-	-	1,168,628
13	Embedded Cost Differential (ECD)	-	-	-	-	-
13	Transmission	-	34,571	-	-	593,697
14	Distribution	-	-	-	-	2,028,638
15	Customer Accounting	-	-	-	-	747,090
16	Customer Service & Info	-	-	-	-	79,585
17	Sales	-	-	-	-	-
18	Administrative & General	-	-	(33,522)	(292,488)	(131,107)
19						
20	Total O&M Expenses	(668,556)	2,828,544	(33,522)	(292,488)	7,764,447
21						
22	Depreciation	-	-	-	-	-
23	Amortization	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	223,441	(945,342)	11,204	97,754	(2,594,995)
26	Income Taxes - State	30,362	(128,456)	1,522	13,283	(352,617)
27	Income Taxes - Def Net	-	-	-	-	-
28	Investment Tax Credit Adj	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	(414,752)	1,754,745	(20,796)	(181,451)	4,816,835
32						
33	Operating Rev For Return:	414,752	(1,754,745)	20,796	181,451	(4,816,835)
34						
35	Rate Base:					
36	Electric Plant In Service	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-
41	Prepayments	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-
44	Working Capital	(8,346)	35,309	(418)	(3,651)	96,923
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	(8,346)	35,309	(418)	(3,651)	96,923
49						
50	Rate Base Deductions:					
51	Accum Prov For Deprec	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-
58						
59	Total Rate Base Deductions	-	-	-	-	-
60						
61	Total Rate Base:	(8,346)	35,309	(418)	(3,651)	96,923
62						
63	Return on Rate Base	0.013%	-0.055%	0.001%	0.006%	-0.150%
64						
65	Return on Equity	0.025%	-0.104%	0.001%	0.011%	-0.285%
66						
67	TAX CALCULATION:					
68	Operating Revenue	668,556	(2,828,544)	33,522	292,488	(7,764,447)
69	Other Deductions					
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	(210)	890	(11)	(92)	2,442
72	Schedule "M" Additions	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	668,766	(2,829,433)	33,533	292,580	(7,766,889)
75						
76	State Income Taxes	30,362	(128,456)	1,522	13,283	(352,617)
77	Taxable Income	638,404	(2,700,977)	32,010	279,297	(7,414,273)
78						
79	Federal Income Taxes + Other	223,441	(945,342)	11,204	97,754	(2,594,995)
80						
81	PRICE CHANGE	(689,463)	2,917,000	(34,570)	(301,635)	8,007,263

PacifiCorp PAGE 4.1
Oregon General Rate Case - December 2013
Miscellaneous General Expense and Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gains on Property Sales	421	1	(226,093)	SG	25.777%	(58,280)	
Gains on Property Sales	421	1	(20,186)	OR	100.000%	(20,186)	
Gains on Property Sales	421	1	(146,248)	UT	0.000%	-	
Gains on Property Sales	421	1	392,528	SO	27.165%	106,630	
			-			28,163	4.1.1
Loss on Property Sales	421	1	10,000	OR	100.000%	10,000	
Loss on Property Sales	421	1	346	UT	0.000%	-	
Loss on Property Sales	421	1	(10,346)	SO	27.165%	(2,810)	
			-			7,190	4.1.1
Adjustment to Expense:							
Office Supplies and Expenses	921	1	(1,645)	SO	27.165%	(447)	
Other Expenses	557	1	(2,954)	SG	25.777%	(761)	
Operation Supervision & Engineering	580	1	(357)	SNPD	26.906%	(96)	
Customer Receipts and Collections	903	1	(11,058)	CN	29.363%	(3,247)	
Informational & Instructional Advertising	909	1	(14,078)	CN	29.363%	(4,134)	
Informational & Instructional Advertising	909	1	(306)	OR	100.000%	(306)	
Administrative & General	920	1	(1,571)	SO	27.165%	(427)	
Office Supplies and Expenses	921	1	(63,787)	SO	27.165%	(17,328)	
Outside Services	923	1	(90,860)	SO	27.165%	(24,682)	
Miscellaneous General Expenses	930	1	(137,387)	UT	0.000%	-	
Miscellaneous General Expenses	930	1	(62,450)	OR	100.000%	(62,450)	
Miscellaneous General Expenses	930	1	(990)	SO	27.165%	(269)	
Informational & Instructional Advertising	909	1	(411)	CN	29.363%	(121)	
Regulatory Commission Expense	928	1	(32,852)	SO	27.165%	(8,924)	
Regulatory Commission Expense	928	1	32,852	OR	100.000%	32,852	
Office Supplies and Expenses	921	1	(2,840)	SO	27.165%	(771)	
Total Miscellaneous General Expense Removal			(390,693)			(91,111)	4.1.1

Description of Adjustment:

This adjustment removes from results of operations certain miscellaneous expenses that should have been charged to non-regulated accounts. It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

PacifiCorp
Oregon General Rate Case - December 2013
Miscellaneous General Expense & Revenue

Description	FERC	Factor	Amt to Exclude
FERC 421 - (Gain)/Loss on Sale of Utility Plant			
Gains on Property Sales	421	SG	226,093
Gains on Property Sales	421	OR	20,186
Gains on Property Sales	421	UT	146,248
Gains on Property Sales	421	SO	(392,528)
Loss on Property Sales	421	OR	(10,000)
Loss on Property Sales	421	UT	(346)
Loss on Property Sales	421	SO	10,346
			-
Non-utility Flights			
Office Supplies and Expenses	921	SO	1,645
Transmission	557	SG	2,954
Distribution	580	SNPD	357
			4,956
FERC 903 - Customer Accounts			
Miscellaneous	903	CN	11,058
			11,058
FERC 909 - Informational & Instructional Advertising			
Festivals	909	OR	251
Informational	909	CN	10,881
Miscellaneous	909	CN	1,891
Blue Sky	909	CN	1,306
Blue Sky	909	OR	55
			14,385
FERC 920 - Administrative & General Salaries			
Klamath Legislative	920	SO	**1,571**
FERC 921 - Office Supplies & Expenses			
Charitable Donations and Sponsorships	921	SO	16,340
Employee Expenses	921	SO	904
Legislative & Lobbyist	921	SO	8,941
SERP Bank Fees	921	SO	35,079
Misc. Expense	921	SO	2,523
			63,787
FERC 923 - Outside Services			
Blue Sky	923	SO	1,360
Parandco	923	SO	89,500
			90,860
FERC 928 - Regulatory Commission Expense			
Legal	928	SO	32,852
Legal	928	OR	(32,852)
			-
FERC 930 - Misc General Expense			
EDCU Rent Contribution	930	UT	73,721
Utah Sports Authority Rent Contribution	930	UT	57,066
EDCU Other Contribution	930	UT	6,600
Sponsorships	930	SO	990
Challenge Grants	930	OR	62,450
			200,827
Centennial Celebration Expenses			
Advertising	909	CN	411
Office Supplies and Expenses	921	SO	2,840
			3,251
Total Misc. General Expense Removed			**390,693**
			Ref 4.1

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefits

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Total O&M Expense Adjustment	500-935	3	18,056,398	Multiple (1)	Multiple (1)	5,164,407	4.2.2

(1) See pages 4.2.9 through 4.2.11

Description of Adjustment:

The Company has several labor groups, each with different effective contract renewal dates. The Company negotiates wage increases with each of these groups throughout the year. This adjustment recognizes increases that have occurred, or are projected to occur during the twelve month period ending December 2013. See page 4.2.1 for more information on how this adjustment was calculated.

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefit Adjustment

The actual (12 months ended June 2011), and pro forma period (12 months ending December 2013) labor expenses are summarized on page 4.2.2. The following is an explanation of the procedures used to develop the pro forma labor expenses.

1. Actual June 2011 total labor related expenses are identified on page 4.2.2, including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.

2. Actual June 2011 expenses for regular time, overtime, and premium pay were escalated prospectively by labor group to December 2013 (see pages 4.2.3 & .4). Union costs were escalated using the contractual and target increases found on page 4.2.5. Non-union costs were escalated using actual and CPI indices.

3. Annual Incentive Plan (AIP) compensation is included using a three year average of the actual payment rate from 2009 through 2011, multiplied by pro forma wages. AIP is the second step of a two-stage compensation philosophy that provides employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan; instead, they receive annual increases to their wages that are reflected in the escalation described above.

4. Pro forma December 2013 pension and employee benefit expenses are based on either 2013 actuarial projections or are calculated by using actual June 2011 data escalated to December 2013. These expenses can be found on page 4.2.7.

5. Payroll tax calculations can be found on page 4.2.8.

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefit Adjustment

Account	Description	Actual 12 Months Ended June 2011	Pro Forma 12 Months Ending December 2013	Adjustment	Ref.
5001XX	Regular Ordinary Time	417,960,505	437,270,415	19,309,910	4.2.3
5002XX	Overtime	58,205,316	60,894,420	2,689,104	4.2.3
5003XX	Premium Pay	7,121,231	7,450,234	329,003	4.2.3
	Subtotal for Escalation	**483,287,052**	**505,615,070**	**22,328,018**	4.2.3 &.4
5005XX	Unused Leave Accrual	2,055,421	2,150,382	94,961	4.2.6
500600	Temporary/Contract Labor	-	-	-	
500700	Severance/Redundancy (1)	212,461	212,461	-	
500850	Other Salary/Labor Costs	5,465,297	5,465,297	-	
50109X	JO Cutbacks	(1,210,862)	(1,266,804)	(55,942)	4.2.6
	Subtotal Bare Labor	**489,809,370**	**512,176,406**	**22,367,037**	
500410	Annual Incentive Plan	29,448,840	29,235,220	(213,620)	4.2.6
	Total Incentive	**29,448,840**	**29,235,220**	**(213,620)**	
500250	Overtime Meals	1,037,830	1,037,830	-	
500400	Bonus and Awards	866,550	866,550	-	
501325	Physical Exam	1,985	1,985	-	
502300	Education Assistance	269,820	269,820	-	
580899	Mining Salary/Benefit Credit	(249,273)	(249,273)	-	
	Total Other Labor	**1,926,911**	**1,926,911**	**-**	
	Subtotal Labor and Incentive	**521,185,120**	**543,338,537**	**22,153,417**	
50110X	Pensions (2)	30,032,084	40,699,088	10,667,004	4.2.7
501115	SERP Plan	3,479,776	-	(3,479,776)	4.2.7
50115X	Post Retirement Benefits - FAS 106 (2)	15,216,196	3,103,164	(12,113,032)	4.2.7
501160	Post Employment Benefits - FAS 112	6,320,724	6,612,744	292,020	4.2.7
	Total Pensions	**55,048,781**	**50,414,996**	**(4,633,785)**	4.2.7
501102	Pension Administration	111,401	111,401	-	4.2.7
50112X	Medical	58,079,222	61,757,716	3,678,495	4.2.7
501175	Dental	1,902,305	2,348,419	446,113	4.2.7
501200	Vision	253,027	258,413	5,385	4.2.7
50122X	Life	948,113	991,916	43,803	4.2.7
501250	401(k)	19,146,764	20,382,692	1,235,928	4.2.7
501251	401(k) Administration	190,122	190,122	-	4.2.7
501252	401(k) Fixed	16,775,895	17,550,947	775,052	4.2.7
501275	Accidental Death & Disability	49,500	51,787	2,287	4.2.7
501300	Long-Term Disability	3,162,992	3,309,123	146,131	4.2.7
5016XX	Worker's Compensation	1,614,303	1,688,885	74,581	4.2.7
502900	Other Salary Overhead	1,997,686	1,997,686	-	4.2.7
	Total Benefits	**104,231,331**	**110,639,106**	**6,407,776**	4.2.7
	Subtotal Pensions and Benefits	**159,280,111**	**161,054,102**	**1,773,991**	4.2.7
580500	Payroll Tax Expense	36,412,834	38,008,231	1,595,397	4.2.8
580700	Payroll Tax Expense-Unemployment	3,900,674	3,900,674	-	
	Total Payroll Taxes	**40,313,508**	**41,908,905**	**1,595,397**	
Total Labor		**720,778,739**	**746,301,544**	**25,522,805**	4.2.11
Non-Utility and Capitalized Labor		210,855,641	218,322,048	7,466,407	4.2.11
Total Utility Labor		**509,923,098**	**527,979,496**	**18,056,398**	4.2.11

Notes:
(1) MEHC Transition severance amortization accrual effects are not included.
(2) Pension Curtailment Gain and Pension, Post Retirement Measurement Date Change (See adj no. 8.10) and the Boilermaker Pension Reserve are not included (See adj no. 4.4).

PacifiCorp
Oregon General Rate Case - December 2013
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2011
Pro Forma: 12 Months Ending December 2013

Labor (12 months ended June 2011)

Acct	Account Desc.	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total	
5001XX	Reg/Ordinary Time	34,897	34,673	35,298	33,213	34,542	36,541	33,572	32,209	37,990	33,917	34,941	36,166	417,961	Ref. 4.2.2
5002XX	Overtime	4,481	4,767	5,266	4,765	4,926	4,801	3,806	4,508	7,066	4,487	4,499	4,834	58,205	Ref. 4.2.2
5003XX	Premium Pay	705	730	590	488	749	644	363	586	586	618	445	618	7,121	Ref. 4.2.2
Grand Total		**40,083**	**40,170**	**41,154**	**38,466**	**40,217**	**41,986**	**37,741**	**37,303**	**45,642**	**39,022**	**39,885**	**41,618**	**483,287**	Ref. 4.2.2

Labor (12 months ended June 2011)

Group Code	Labor Group	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
2	Officer/Exempt	15,538	14,141	15,187	14,278	14,374	16,038	14,194	13,366	17,163	14,836	14,909	15,679	179,702
3	IBEW 125	3,012	3,225	3,305	2,920	3,208	3,382	2,963	3,068	3,511	2,686	2,974	3,017	37,271
4	IBEW 659	3,494	3,599	3,644	3,632	3,665	3,721	3,421	3,490	5,058	2,899	3,450	3,695	43,770
5	UWUA 197	179	161	205	188	197	194	186	156	320	129	170	185	2,270
8	UWUA 127	3,754	3,808	3,954	3,653	3,685	4,064	3,765	3,618	4,175	4,104	4,140	4,259	46,980
9	IBEW 57 WY	58	60	62	57	61	58	58	53	61	57	66	67	718
11	IBEW 57 PD	8,607	9,430	8,697	8,184	9,124	8,733	7,625	8,026	9,034	8,494	8,356	8,896	103,205
12	IBEW 57 PS	3,507	3,827	4,108	3,671	4,080	3,838	3,654	3,729	4,157	3,926	3,904	3,846	46,249
13	PCCC Non-Exempt	674	719	710	646	662	676	666	675	694	648	646	661	8,075
15	IBEW 57 CT	228	235	244	282	212	253	253	219	350	274	250	253	3,054
18	Non-Exempt	1,033	965	1,038	955	950	1,028	954	903	1,118	969	1,019	1,061	11,994
Grand Total		**40,083**	**40,170**	**41,154**	**38,466**	**40,217**	**41,986**	**37,741**	**37,303**	**45,642**	**39,022**	**39,885**	**41,618**	**483,287**

Annualization Increase

Group Code	Labor Group	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
2	Officer/Exempt							1.96%					
3	IBEW 125												
4	IBEW 659												
5	UWUA 197												1.50%
8	UWUA 127				1.50%								
9	IBEW 57 WY	1.50%											
11	IBEW 57 PD								1.75%				
12	IBEW 57 PS								1.75%				
13	PCCC Non-Exempt												
15	IBEW 57 CT												1.75%
18	Non-Exempt							1.96%					

June 2011 Annualized Labor

Group Code	Labor Group	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
2	Officer/Exempt	15,842	14,418	15,485	14,558	14,656	16,352	14,194	13,366	17,163	14,836	14,909	15,679	181,457
3	IBEW 125	3,012	3,225	3,305	2,920	3,208	3,382	2,963	3,068.24	3,511	2,686	2,974	3,017	37,271
4	IBEW 659	3,494	3,599	3,644	3,632	3,665	3,721	3,421	3,490	5,058	2,899	3,450	3,695	43,770
5	UWUA 197	181	164	208	191	200	197	189	158	325	131	172	185	2,302
8	UWUA 127	3,810	3,865	4,014	3,653	3,685	4,064	3,765	3,618	4,175	4,104	4,140	4,259	47,152
9	IBEW 57 WY	58	60	62	57	61	58	58	53	61	57	66	67	718
11	IBEW 57 PD	8,758	9,595	8,850	8,327	9,284	8,885	7,758	8,026	9,034	8,494	8,356	8,896	104,262
12	IBEW 57 PS	3,568	3,894	4,180	3,736	4,151	3,906	3,718	3,729	4,157	3,926	3,904	3,846	46,716
13	PCCC Non-Exempt	674	719	710	646	662	676	666	675	694	648	646	661	8,075
15	IBEW 57 CT	232	239	248	287	216	258	258	223	357	279	254	253	3,103
18	Non-Exempt	1,053	984	1,058	974	969	1,049	954	903	1,118	969	1,019	1,061	12,111
Grand Total		**40,682**	**40,762**	**41,763**	**38,980**	**40,756**	**42,548**	**37,946**	**37,309**	**45,653**	**39,029**	**39,892**	**41,618**	**486,936**

PacifiCorp
Oregon General Rate Case - December 2013
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2011
Pro Forma: 12 Months Ending December 2013

Pro Forma Increases applied to escalate to December 2013

Group Code	Labor Group		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	Officer/Exempt													
		12/26/2011	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%
		12/26/2012	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%
3	IBEW 125													
		8/26/2011	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
		1/26/2012	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
		1/26/2013		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
4	IBEW 659													
		8/26/2011	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
		3/26/2012	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
		3/26/2013				1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
5	UWUA 197													
		5/26/2012	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
		5/26/2013						2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	UWUA 127 Wyoming													
		9/26/2011	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
		9/26/2012	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
		9/26/2013										2.00%	2.00%	2.00%
9	IBEW 415 (Laramie 57)													
		6/26/2011	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
		6/26/2012	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%	1.76%
		6/26/2013							2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
11	IBEW 57 PD													
		1/26/2012	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
		1/26/2013		2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
12	IBEW 57 PS													
		1/26/2012	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
		1/26/2013		2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
15	IBEW 57 CT													
		5/26/2012	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
		5/26/2013						2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%
18	Non-Exempt													
		12/26/2011	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%	1.93%
		12/26/2012	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%

Pro Forma Labor December 2013

Group Code	Labor Group	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	
2	Officer/Exempt	14,709	13,850	17,784	15,374	15,449	16,246	16,416	14,940	16,045	15,085	15,186	16,945	188,030	Ref. 4.2.6
3	IBEW 125	3,038	3,208	3,671	2,808	3,110	3,154	3,150	3,372	3,456	3,053	3,355	3,536	38,912	
4	IBEW 659	3,516	3,587	5,198	3,024	3,599	3,854	3,644	3,755	3,801	3,789	3,823	3,882	45,472	
5	UWUA 197	193	161	332	133	176	193	189	170	216	199	208	205	2,375	
8	UWUA 127	3,898	3,746	4,323	4,249	4,287	4,410	3,944	4,001	4,155	3,857	3,891	4,291	49,053	
9	IBEW 57 WY	60	55	63	59	68	69	61	64	66	60	64	62	749	
11	IBEW 57 PD	7,913	8,371	9,422	8,859	8,715	9,278	9,134	10,007	9,230	8,685	9,683	9,267	108,562	
12	IBEW 57 PS	3,792	3,889	4,336	4,094	4,072	4,011	3,722	4,061	4,360	3,896	4,330	4,073	48,637	
13	PCCC Non-Exempt	666	675	694	648	646	661	674	719	710	646	662	676	8,075	Ref. 4.2.6
15	IBEW 57 CT	263	227	364	285	259	263	241	249	258	299	225	268	3,201	
18	Non-Exempt	989	936	1,159	1,005	1,056	1,100	1,091	1,019	1,097	1,009	1,004	1,087	12,550	Ref. 4.2.6
Grand Total		**39,037**	**38,704**	**47,345**	**40,537**	**41,437**	**43,239**	**42,266**	**42,357**	**43,393**	**40,578**	**42,430**	**44,291**	**505,615**	Ref. 4.2.2

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefit Adjustment

Labor Increases - July 2010 through December 2013

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month. For example, an increase that occurs on December 26, 2010 is shown as effective on January 1, 2011.

12 Months Ended June 2011

Group Code	Labor Group	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	
2	Officer/Exempt							1.96%						(1)
3	IBEW 125													
4	IBEW 659													
5	UWUA 197												1.50%	(2)
8	UWUA 127				1.50%									(2)
9	IBEW 57 WY	1.50%												(2)
11	IBEW 57 PD								1.75%					(2)
12	IBEW 57 PS								1.75%					(2)
13	PCCC Non-Exempt													
15	IBEW 57 CT												1.75%	(2)
18	Non-Exempt							1.96%						(1)

12 Months Ended June 2012

Group Code	Labor Group	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	
2	Officer/Exempt							1.93%						(1)
3	IBEW 125			1.00%					1.50%					(2)
4	IBEW 659			1.25%							1.50%			(2)
5	UWUA 197												2.00%	(2)
8	UWUA 127				1.50%									(2)
9	IBEW 57 WY	1.50%												(2)
11	IBEW 57 PD								2.00%					(2)
12	IBEW 57 PS								2.00%					(2)
13	PCCC Non-Exempt													
15	IBEW 57 CT												2.00%	(2)
18	Non-Exempt							1.93%						(1)

12 Months Ending June 2013

Group Code	Labor Group	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	
2	Officer/Exempt							1.66%						(4)
3	IBEW 125								2.00%					(2)
4	IBEW 659										1.50%			(2)
5	UWUA 197												2.00%	(2)
8	UWUA 127				2.00%									(2)
9	IBEW 57 WY	1.76%												(3)
11	IBEW 57 PD								2.25%					(3)
12	IBEW 57 PS								2.25%					(3)
13	PCCC Non-Exempt													
15	IBEW 57 CT												2.04%	(3)
18	Non-Exempt							1.66%						(4)

6 Months Ending December 2013

Group Code	Labor Group	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	
2	Officer/Exempt							
3	IBEW 125							
4	IBEW 659							
5	UWUA 197							
8	UWUA 127				2.00%			(2)
9	IBEW 57 WY	2.25%						(3)
11	IBEW 57 PD							
12	IBEW 57 PS							
13	PCCC Non-Exempt							
15	IBEW 57 CT							
18	Non-Exempt							

(1) Overall Actual
(2) Labor increases supported by union contracts
(3) Labor increases supported by planning targets. No current contract in place.
(4) Consumer Price Index (CPI)

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefit Adjustment

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay June 2011 - ACTUAL	483,287,052		4.2.2
Regular Time/Overtime/Premium Pay December 2013 - PRO FORMA	505,615,070	CAGR[1]	4.2.2
% Increase	4.62%	1.82%	

Miscellaneous Bare Labor Escalation

Description	Account	June 2011 Actual	Pro Forma Increase	Dec 2013 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,055,421	4.62%	2,150,382	**94,961**	**4.2.2**
Joint Owner Cutbacks	50109X	(1,210,862)	4.62%	(1,266,804)	**(55,942)**	**4.2.2**
		844,560		883,579	39,019	

Annual Incentive Plan Escalation

Description	Account	June 2011 Actual	Dec 2013 Pro Forma	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	500410	29,448,840	29,235,220	**(213,620)**	**4.2.2**

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages	Ref.
Cy 2009	180,514,059	8,125,239	11,472,744	200,112,042	29,876,294	14.93%	
Cy 2010	177,805,237	8,161,210	11,363,613	197,330,060	26,606,117	13.48%	
Cy 2011	181,985,233	8,213,064	12,660,309	202,858,606	27,627,365	13.62%	
3-year Total	540,304,529	24,499,512	35,496,666	600,300,708	84,109,776	14.01%	
Test Year	**188,029,637** **Ref 4.2.4**	**8,075,391** **Ref 4.2.4**	**12,549,948** **Ref 4.2.4**	208,654,976	**29,235,220** **Ref 4.2.2**	14.01%	Above

[1]Compound Annual Growth Rate

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefit Adjustment

Account	Description	A Actual June 2011 Net of Joint Venture	B Actual June 2011 GROSS	C December 2013 Projected GROSS	D December 2013 Projected Net of Joint Venture	D - A Pro Forma Adjustment	Ref
50110X	Pensions - FAS 87	30,032,084	30,770,663	41,700,000	40,699,088	**10,667,004**	**4.2.2**
501115	SERP Plan	3,479,776	3,479,776	-	-	**(3,479,776)**	**4.2.2**
50115X	Post Retirement Benefits - FAS 106	15,216,196	15,691,024	3,200,000	3,103,164	**(12,113,032)**	**4.2.2**
501160	Post Employment Benefits - FAS 112	6,320,724	6,511,478	6,812,310	6,612,744	**292,020**	**4.2.2**
	Subtotal	55,048,781	56,452,941	51,712,310	50,414,996	**(4,633,785)**	**4.2.2**
501102	Pension Administration	111,401	111,411	111,411	111,401	**-**	**4.2.2**
50112X	Medical	58,079,222	59,890,015	63,683,198	61,757,716	**3,678,495**	**4.2.2**
501175	Dental	1,902,305	1,975,563	2,438,856	2,348,419	**446,113**	**4.2.2**
501200	Vision	253,027	263,100	268,700	258,413	**5,385**	**4.2.2**
50122X	Life	948,113	976,890	1,022,022	991,916	**43,803**	**4.2.2**
501250	401(k)	19,146,764	19,748,798	21,023,587	20,382,692	**1,235,928**	**4.2.2**
501251	401(k) Administration	190,122	195,872	195,872	190,122	**-**	**4.2.2**
501252	401(k) Fixed	16,775,895	17,571,755	18,383,576	17,550,947	**775,052**	**4.2.2**
501275	Accidental Death & Disability	49,500	49,884	52,189	51,787	**2,287**	**4.2.2**
501300	Long-Term Disability	3,162,992	3,258,440	3,408,981	3,309,123	**146,131**	**4.2.2**
5016XX	Worker's Compensation	1,614,303	1,660,816	1,737,546	1,688,885	**74,581**	**4.2.2**
502900	Other Salary Overhead	1,997,686	1,999,080	1,999,080	1,997,686	**-**	**4.2.2**
	Subtotal	104,231,331	107,701,623	114,325,017	110,639,106	**6,407,776**	**4.2.2**
	Grand Total	159,280,111	164,154,564	166,037,327	**161,054,102**	**1,773,991**	**4.2.2**
					Ref 4.2.2	Ref 4.2.2	

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Employee Benefit Adjustment
Payroll Tax Adjustment Calculation

FICA Calculated on December 2013 Pro Forma Labor		
Pro Forma Wages Adjustment	22,367,037	4.2.2
Pro Forma Incentive Adjustment	(213,620)	4.2.2
	22,153,417	
Medicare Rate (no cap)	1.45%	
	321,225	
Social Security Rate	6.20%	
	1,373,512	
Percentage of Social Security Eligible Wages	92.77%	
	1,274,172	
Total FICA Tax	**1,595,397**	4.2.2

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Benefit Adjustment
Adjustment by FERC Account and 2010 Protocol Factor

Indicator	Actual 12 Months Ended June 2011	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2013	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2013 Oregon Allocated
500SG	15,136,007	2.10%	535,967	15,671,974	25.777%	138,157	4,039,789
501SE	(12,712)	0.00%	(450)	(13,162)	24.314%	(109)	(3,200)
502SG	16,840,474	2.34%	596,322	17,436,796	25.777%	153,715	4,494,710
503SE	70,523	0.01%	2,497	73,021	24.314%	607	17,754
505SG	1,783,113	0.25%	63,140	1,846,253	25.777%	16,276	475,911
506SG	44,404,780	6.16%	1,572,375	45,977,155	25.777%	405,314	11,851,603
510SG	2,789,979	0.39%	98,793	2,888,772	25.777%	25,466	744,643
511SG	6,582,962	0.91%	233,103	6,816,064	25.777%	60,087	1,756,988
512SG	25,704,218	3.57%	910,187	26,614,406	25.777%	234,620	6,860,437
513SG	10,656,551	1.48%	377,349	11,033,900	25.777%	97,270	2,844,225
514SG	2,564,963	0.36%	90,825	2,655,789	25.777%	23,412	684,587
535SG-P	2,331,651	0.32%	82,564	2,414,215	25.777%	21,283	622,316
535SG-U	1,456,818	0.20%	51,586	1,508,404	25.777%	13,297	388,824
536SG-P	79,258	0.01%	2,807	82,065	25.777%	723	21,154
537SG-P	403,193	0.06%	14,277	417,470	25.777%	3,680	107,612
537SG-U	52,702	0.01%	1,866	54,568	25.777%	481	14,066
539SG-P	6,190,567	0.86%	219,208	6,409,776	25.777%	56,506	1,652,258
539SG-U	4,723,082	0.66%	167,245	4,890,326	25.777%	43,111	1,260,587
540SG-P	(161,318)	-0.02%	(5,712)	(167,030)	25.777%	(1,472)	(43,056)
541SG-P	1,311	0.00%	46	1,358	25.777%	12	350
542SG-P	452,156	0.06%	16,011	468,167	25.777%	4,127	120,680
542SG-U	79,743	0.01%	2,824	82,567	25.777%	728	21,283
543SG-P	367,737	0.05%	13,022	380,758	25.777%	3,357	98,149
543SG-U	467,801	0.06%	16,565	484,366	25.777%	4,270	124,856
544SG-P	812,687	0.11%	28,777	841,464	25.777%	7,418	216,906
544SG-U	269,690	0.04%	9,550	279,239	25.777%	2,462	71,980
545SG-P	786,296	0.11%	27,843	814,139	25.777%	7,177	209,862
545SG-U	266,722	0.04%	9,445	276,167	25.777%	2,435	71,188
546SG	1,248	0.00%	44	1,292	25.777%	11	333
548SG	5,208,059	0.72%	184,418	5,392,476	25.777%	47,538	1,390,027
549SG	2,853,051	0.40%	101,027	2,954,077	25.777%	26,042	761,477
552SG	284,665	0.04%	10,080	294,745	25.777%	2,598	75,977
553SG	2,310,501	0.32%	81,815	2,392,316	25.777%	21,090	616,671
554SG	98,635	0.01%	3,493	102,128	25.777%	900	26,326
556SG	558,053	0.08%	19,761	577,813	25.777%	5,094	148,944
557SG	33,407,093	4.63%	1,182,947	34,590,040	25.777%	304,930	8,916,328
560SG	5,257,516	0.73%	186,169	5,443,684	25.777%	47,989	1,403,227
561SG	9,237,885	1.28%	327,114	9,564,999	25.777%	84,321	2,465,585
562SG	1,261,363	0.18%	44,665	1,306,028	25.777%	11,513	336,657
563SG	87,129	0.01%	3,085	90,214	25.777%	795	23,255
566SG	350,055	0.05%	12,395	362,451	25.777%	3,195	93,430
567SG	178,676	0.02%	6,327	185,003	25.777%	1,631	47,688
568SG	1,924,961	0.27%	68,163	1,993,124	25.777%	17,570	513,771
569SG	2,606,786	0.36%	92,306	2,699,092	25.777%	23,794	695,749
570SG	7,714,682	1.07%	273,177	7,987,859	25.777%	70,417	2,059,043
571SG	(2,097,661)	-0.29%	(74,278)	(2,171,939)	25.777%	(19,147)	(559,864)
572SG	75,552	0.01%	2,675	78,227	25.777%	690	20,165
573SG	3,094	0.00%	110	3,203	25.777%	28	826
580CA	(275)	0.00%	(10)	(285)	0.000%	-	-
580OR	827	0.00%	29	856	100.000%	29	856
580SNPD	13,614,704	1.89%	482,097	14,096,802	26.906%	129,712	3,792,863
580WA	(4,275)	0.00%	(151)	(4,427)	0.000%	-	-
581OR	(2)	0.00%	(0)	(2)	100.000%	(0)	(2)
581SNPD	13,325,694	1.85%	471,863	13,797,557	26.906%	126,959	3,712,349
582CA	74,306	0.01%	2,631	76,938	0.000%	-	-
582IDU	112,541	0.02%	3,985	116,527	0.000%	-	-
582OR	685,629	0.10%	24,278	709,907	100.000%	24,278	709,907
582SNPD	26,885	0.00%	952	27,837	26.906%	256	7,490
582UT	762,440	0.11%	26,998	789,438	0.000%	-	-
582WA	166,504	0.02%	5,896	172,400	0.000%	-	-
582WYP	398,651	0.06%	14,116	412,768	0.000%	-	-
583CA	322,791	0.04%	11,430	334,221	0.000%	-	-
583IDU	179,362	0.02%	6,351	185,713	0.000%	-	-
583OR	2,553,634	0.35%	90,424	2,644,059	100.000%	90,424	2,644,059
583SNPD	23,019	0.00%	815	23,834	26.906%	219	6,413
583UT	1,333,478	0.19%	47,218	1,380,696	0.000%	-	-
583WA	295,370	0.04%	10,459	305,829	0.000%	-	-
583WYP	213,189	0.03%	7,549	220,738	0.000%	-	-
583WYU	151,953	0.02%	5,381	157,334	0.000%	-	-
585SNPD	223,278	0.03%	7,906	231,185	26.906%	2,127	62,202
586CA	187,696	0.03%	6,646	194,342	0.000%	-	-
586IDU	262,871	0.04%	9,308	272,180	0.000%	-	-
586OR	2,380,921	0.33%	84,308	2,465,229	100.000%	84,308	2,465,229
586SNPD	1,081,582	0.15%	38,299	1,119,880	26.906%	10,305	301,313

PacifiCorp
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Adjustment by FERC Account and 2010 Protocol Factor

Indicator	Actual 12 Months Ended June 2011	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2013	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2013 Oregon Allocated
586UT	1,168,281	0.16%	41,369	1,209,650	0.000%	-	-
586WA	355,522	0.05%	12,589	368,111	0.000%	-	-
586WYP	413,488	0.06%	14,642	428,130	0.000%	-	-
586WYU	47,764	0.01%	1,691	49,455	0.000%	-	-
587CA	508,017	0.07%	17,989	526,006	0.000%	-	-
587IDU	319,313	0.04%	11,307	330,620	0.000%	-	-
587OR	3,688,001	0.51%	130,592	3,818,593	100.000%	130,592	3,818,593
587UT	4,497,278	0.62%	159,249	4,656,527	0.000%	-	-
587WA	866,346	0.12%	30,677	897,023	0.000%	-	-
587WYP	744,543	0.10%	26,364	770,908	0.000%	-	-
587WYU	51,644	0.01%	1,829	53,473	0.000%	-	-
588CA	7,766	0.00%	275	8,041	0.000%	-	-
588IDU	8,291	0.00%	294	8,585	0.000%	-	-
588OR	84,795	0.01%	3,003	87,798	100.000%	3,003	87,798
588SNPD	1,594,710	0.22%	56,469	1,651,179	26.906%	15,193	444,264
588UT	518,359	0.07%	18,355	536,714	0.000%	-	-
588WA	6,399	0.00%	227	6,625	0.000%	-	-
588WYP	53,697	0.01%	1,901	55,598	0.000%	-	-
588WYU	(40,933)	-0.01%	(1,449)	(42,383)	0.000%	-	-
589CA	13,148	0.00%	466	13,614	0.000%	-	-
589OR	61,081	0.01%	2,163	63,244	100.000%	2,163	63,244
589UT	32,274	0.00%	1,143	33,417	0.000%	-	-
589WA	10,306	0.00%	365	10,671	0.000%	-	-
589WYP	10,091	0.00%	357	10,448	0.000%	-	-
589WYU	(129)	0.00%	(5)	(134)	0.000%	-	-
590CA	16,793	0.00%	595	17,388	0.000%	-	-
590IDU	36,639	0.01%	1,297	37,936	0.000%	-	-
590OR	250,899	0.03%	8,884	259,784	100.000%	8,884	259,784
590SNPD	3,913,386	0.54%	138,573	4,051,959	26.906%	37,284	1,090,214
590UT	273,292	0.04%	9,677	282,969	0.000%	-	-
590WA	9,200	0.00%	326	9,525	0.000%	-	-
590WYP	81,014	0.01%	2,869	83,882	0.000%	-	-
592CA	325,318	0.05%	11,520	336,838	0.000%	-	-
592IDU	463,443	0.06%	16,411	479,853	0.000%	-	-
592OR	2,868,657	0.40%	101,579	2,970,236	100.000%	101,579	2,970,236
592SNPD	1,425,014	0.20%	50,460	1,475,474	26.906%	13,577	396,989
592UT	3,006,620	0.42%	106,465	3,113,084	0.000%	-	-
592WA	630,170	0.09%	22,314	652,485	0.000%	-	-
592WYP	993,269	0.14%	35,172	1,028,441	0.000%	-	-
592WYU	534	0.00%	19	553	0.000%	-	-
593CA	1,749,598	0.24%	61,953	1,811,551	0.000%	-	-
593IDU	2,103,710	0.29%	74,492	2,178,202	0.000%	-	-
593OR	9,271,889	1.29%	328,318	9,600,207	100.000%	328,318	9,600,207
593SNPD	207,603	0.03%	7,351	214,954	26.906%	1,978	57,835
593UT	9,877,024	1.37%	349,746	10,226,769	0.000%	-	-
593WA	519,793	0.07%	18,406	538,199	0.000%	-	-
593WYP	1,139,640	0.16%	40,355	1,179,995	0.000%	-	-
593WYU	175,380	0.02%	6,210	181,590	0.000%	-	-
594CA	356,476	0.05%	12,623	369,099	0.000%	-	-
594IDU	448,409	0.06%	15,878	464,287	0.000%	-	-
594OR	3,882,046	0.54%	137,463	4,019,509	100.000%	137,463	4,019,509
594UT	7,571,149	1.05%	268,095	7,839,244	0.000%	-	-
594WA	766,794	0.11%	27,152	793,946	0.000%	-	-
594WYP	886,369	0.12%	31,386	917,756	0.000%	-	-
594WYU	117,941	0.02%	4,176	122,117	0.000%	-	-
595SNPD	646,629	0.09%	22,897	669,526	26.906%	6,161	180,142
596CA	108,063	0.01%	3,826	111,889	0.000%	-	-
596IDU	128,472	0.02%	4,549	133,021	0.000%	-	-
596OR	913,818	0.13%	32,358	946,176	100.000%	32,358	946,176
596UT	385,478	0.05%	13,650	399,128	0.000%	-	-
596WA	137,642	0.02%	4,874	142,516	0.000%	-	-
596WYP	262,471	0.04%	9,294	271,765	0.000%	-	-
596WYU	55,881	0.01%	1,979	57,859	0.000%	-	-
597CA	53,526	0.01%	1,895	55,421	0.000%	-	-
597IDU	265,161	0.04%	9,389	274,551	0.000%	-	-
597OR	861,951	0.12%	30,522	892,473	100.000%	30,522	892,473
597SNPD	897,696	0.12%	31,787	929,484	26.906%	8,553	250,085
597UT	1,803,538	0.25%	63,863	1,867,401	0.000%	-	-
597WA	372,838	0.05%	13,202	386,040	0.000%	-	-
597WYP	449,744	0.06%	15,925	465,669	0.000%	-	-
597WYU	82,625	0.01%	2,926	85,551	0.000%	-	-
598CA	20,520	0.00%	727	21,247	0.000%	-	-
598OR	64,888	0.01%	2,298	67,186	100.000%	2,298	67,186
598SNPD	1,111,633	0.15%	39,363	1,150,996	26.906%	10,591	309,685

PacifiCorp
Oregon General Rate Case - December 2013
Wage and Benefit Adjustment
Adjustment by FERC Account and 2010 Protocol Factor

Indicator	Actual 12 Months Ended June 2011	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2013	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2013 Oregon Allocated
598UT	5,670	0.00%	201	5,871	0.000%	-	-
598WA	37,657	0.01%	1,333	38,991	0.000%	-	-
901CN	2,125,035	0.29%	75,248	2,200,283	29.363%	22,095	646,066
901OR	860	0.00%	30	890	100.000%	30	890
902CA	739,938	0.10%	26,201	766,140	0.000%	-	-
902CN	1,738,342	0.24%	61,555	1,799,897	29.363%	18,074	528,501
902IDU	1,326,107	0.18%	46,958	1,373,065	0.000%	-	-
902OR	8,302,723	1.15%	294,000	8,596,723	100.000%	294,000	8,596,723
902UT	3,954,286	0.55%	140,021	4,094,307	0.000%	-	-
902WA	1,324,451	0.18%	46,899	1,371,350	0.000%	-	-
902WYP	1,356,994	0.19%	48,051	1,405,046	0.000%	-	-
902WYU	255,018	0.04%	9,030	264,048	0.000%	-	-
903CA	170,531	0.02%	6,039	176,570	0.000%	-	-
903CN	33,232,814	4.61%	1,176,775	34,409,589	29.363%	345,535	10,103,640
903IDU	290,309	0.04%	10,280	300,588	0.000%	-	-
903OR	1,581,156	0.22%	55,989	1,637,145	100.000%	55,989	1,637,145
903UT	2,612,714	0.36%	92,516	2,705,230	0.000%	-	-
903WA	465,817	0.06%	16,495	482,312	0.000%	-	-
903WYP	347,706	0.05%	12,312	360,018	0.000%	-	-
903WYU	69,702	0.01%	2,468	72,170	0.000%	-	-
905CN	92,765	0.01%	3,285	96,050	29.363%	965	28,203
907CN	259,843	0.04%	9,201	269,044	29.363%	2,702	78,999
908CA	38,985	0.01%	1,380	40,365	0.000%	-	-
908CN	2,378,251	0.33%	84,214	2,462,465	29.363%	24,728	723,050
908IDU	449,739	0.06%	15,925	465,664	0.000%	-	-
908OR	1,509,797	0.21%	53,462	1,563,259	100.000%	53,462	1,563,259
908OTHER	35,792	0.00%	1,267	37,059	0.000%	-	-
908UT	2,292,751	0.32%	81,186	2,373,937	0.000%	-	-
908WA	215,732	0.03%	7,639	223,371	0.000%	-	-
908WYP	933,774	0.13%	33,065	966,839	0.000%	-	-
909CN	495,810	0.07%	17,557	513,367	29.363%	5,155	150,739
910CN	1,622	0.00%	57	1,679	29.363%	17	493
920CA	222,772	0.03%	7,888	230,660	0.000%	-	-
920OR	7	0.00%	0	8	100.000%	0	8
920SO	77,908,635	10.81%	2,758,748	80,667,383	27.165%	749,414	21,913,283
920UT	2	0.00%	0	2	0.000%	-	-
920WA	4	0.00%	0	5	0.000%	-	-
921SO	(266,373)	-0.04%	(9,432)	(275,806)	27.165%	(2,562)	(74,923)
921WA	22	0.00%	1	23	0.000%	-	-
922SO	25,960,275	3.60%	919,254	26,879,529	27.165%	249,715	7,301,820
928CA	64,491	0.01%	2,284	66,774	0.000%	-	-
928IDU	688,197	0.10%	24,369	712,566	0.000%	-	-
928OR	270,923	0.04%	9,593	280,516	100.000%	9,593	280,516
928SO	372,878	0.05%	13,204	386,081	27.165%	3,587	104,879
928UT	1,141,044	0.16%	40,404	1,181,448	0.000%	-	-
928WA	538,652	0.07%	19,074	557,726	0.000%	-	-
928WYP	816,282	0.11%	28,905	845,187	0.000%	-	-
929SO	(1,065,041)	-0.15%	(37,713)	(1,102,754)	27.165%	(10,245)	(299,563)
935CA	(5,063)	0.00%	(179)	(5,242)	0.000%	-	-
935OR	16,109	0.00%	570	16,679	100.000%	570	16,679
935SO	2,811,071	0.39%	99,540	2,910,611	27.165%	27,040	790,667
935UT	(400)	0.00%	(14)	(414)	0.000%	-	-
935WA	158	0.00%	6	163	0.000%	-	-
Utility Labor	**509,923,098**	**70.746%**	**18,056,398**	**527,979,496**		**5,164,407**	151,010,247
			Ref 4.2			**Ref 4.2**	
Capital/Non Utility	210,855,641	29.254%	7,466,407	218,322,048		28.602%	28.602%
Total Labor	**720,778,739**	**100.000%**	**25,522,805**	**746,301,544**			

PacifiCorp PAGE 4.3
Oregon General Rate Case - December 2013
Idaho Irrigation Load Control Program

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Purchased Power	557	1	(9,002,888)	SG	25.777%	(2,320,689)	4.3.1
Customer Assistance	908	1	(26,042)	ID	0.000%	-	4.3.1
Other Purchased Power	557	1	9,028,930	ID	0.000%	-	4.3.1
			9,002,888			-	
Total Adjustment			-			(2,320,689)	

Description of Adjustment:

Payments made to Idaho irrigators as part of the Idaho Irrigation Load Control Program are system allocated in the unadjusted data. This adjustment situs assigns the payments to Idaho. DSM and a portion of program administrative costs are currently situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in allocation factors. Allocation of Class 1 DSM programs continues to be reviewed by the MSP standing committee.

PacifiCorp
Oregon General Rate Case - December 2013
Idaho Irrigation Load Control

	FERC Account	Factor	Amount
Idaho Irrigation Load Control Incentive Payments	557	SG	7,473,753
Irrigation Load Control Program Costs	557	SG	1,529,136
Irrigation Load Control Program Costs	908	ID	26,042
			9,028,930
			Ref. 4.3

PacifiCorp PAGE 4.4
Oregon General Rate Case - December 2013
Remove Non-Recurring Entries

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
1) California Reg Asset Set-Up	920	1	222,772	SO	27.165%	60,516	4.4.1
2) Jim Bridger Turbine Upgrade	557	1	(3,033,000)	SG	25.777%	(781,821)	4.4.1
3) Boilermaker Pension Reserve	557	1	(4,302,803)	SE	24.314%	(1,046,163)	4.4.1
4) Settlement Fees							
	506	1	48,112	SG	25.777%	12,402	4.4.1
	560	1	(600)	SG	25.777%	(155)	4.4.1
	580	1	600	SNPD	26.906%	161	4.4.1
	598	1	144	SNPD	26.906%	39	4.4.1
Total Settlement Fees			48,256			12,447	
Total Non-Recurring Entries			(7,064,775)			(1,755,021)	

Description of Adjustment:

A variety of accounting entries were made to expense accounts during the twelve months ended June 2011 that are non-recurring in nature or relate to a prior period. These transactions are removed from results of operations to normalize the test period results. A description of each item is provided on page 4.4.1.

PacifiCorp
Oregon General Rate Case - December 2013
Remove Non-Recurring Entries

No.	Postg Date	Text	FERC Acct	Amount as Booked	Reference
1	9/28/2010	**California Regulatory Asset Set-Up:** A&G Expense was credited when the California MEHC Transition Plan Regulatory asset was set up in September 2010. This was allocated system-wide using an SO factor and needs to be removed from results in all jurisdictions.	920	(222,772)	Ref 4.4
2	10/26/2010	**Jim Bridger Unit 2, 3 and 4 turbine upgrades:** The contract with the vendor is being renegotiated due to certain portions of the Jim Bridger turbine upgrade projects being delayed, deferred and/or potentially cancelled due to project reconfiguration, scope and timing changes in the projects which result from transmission constraints and other issues. This should not impact results of operations.	557	3,033,000	Ref 4.4
3	6/21/2011	**Boilermaker Pension Reserve:** The Company withdrew from the Boilermaker Pension reserve at Bridger Plant. The entry establishing a contingent liability for indemnification of the union needs to be removed from results as non-recurring. The Company may need to request recovery in the future depending on the outcome.	557	4,302,803	Ref 4.4
4	Various	**Settlement Fees:** A variety of accounting entries were made to expense accounts during the twelve months ended June 2011 for settlement fees involving possible compliance violations. These transactions are removed from results of operations to normalize the test period results.	Various	(48,256)	Ref 4.4
		Total		**7,064,775**	**Ref 4.4**

Settlement Fee Summary by Account/Factor:

Account	Factor	Amount
506	SG	(48,112)
560	SG	600
580	SNPD	(600)
598	SNPD	(144)
		(48,256)

PacifiCorp PAGE 4.5
Oregon General Rate Case - December 2013
Uncollectible Accounts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Uncollectible Accounts - 12 ME December 2013	904	3	316,534	OR	100.000%	316,534	4.5.1

Description of Adjustment:

This adjusts the Company's actual June 2011uncollectible accounts expense to the December 2013 pro forma test period by applying the unadjusted uncollectible rate (unadjusted uncollectible accounts expense/unadjusted general business revenues) to the normalized level of general business revenues.

PacifiCorp
Oregon General Rate Case - December 2013
Uncollectible Accounts

	Amount		Reference
12 ME June 2011 Unadjusted Uncollectible Accounts:			
Oregon Situs Uncollectible Accounts Expense	5,462,397	**A**	Below
Unadjusted Oregon General Business Revenues	**1,057,442,899**	**B**	Pg. 2.2, General Business Revenues
Uncollectible Rate	0.517%	**C**	**=A/B**
12 ME December 2013 Uncollectible Accounts:			
Normalized Oregon General Business Revenues	**1,182,374,668**	**D**	Pg. 3.1.1, Pro Forma Revenues
Uncollectible Rate	0.517%	**C**	Above
12 ME December 2013 Uncollectible Accounts Expense	6,107,753	**E**	**=D*C**
Uncollectible Accounts Expense Included in Filing	5,462,397	**A**	Above
Escalation Percentage	5.87%	**F**	Page 4.12.8
Escalation Applied	328,822	**F**	Pg. 4.12.2, O&M Escalation
Total Expense with Escalation	5,791,219	**G**	**=A+F**
Adjustment to Expense	**316,534**		**=E-G**
	Ref 4.5		

Uncollectible Accounts	5,996,810	Pg 2.12, Oregon Situs from Account 904
Remove Joint Use Bad Debt	142,433	
Remove Grid West Amortization	391,980	
	5,462,397	

PacifiCorp PAGE 4.6
Oregon General Rate Case - December 2013
DSM Revenue & Expense Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue and Expense:							
Remove DSM Revenue	456	1	(1,085,528)	CA	0.000%	-	
	456	1	(6,003,419)	ID	0.000%	-	
	456	1	(21,405,215)	OR	100.000%	(21,405,215)	
	456	1	(53,697,394)	UT	0.000%	-	
	456	1	(8,762,731)	WA	0.000%	-	
	456	1	(3,341,257)	WY	0.000%	-	
			(94,295,544)			(21,405,215)	4.6.1
Adjustment to Expense:							
Remove DSM Amortization Expense	908	1	(1,085,528)	CA	0.000%	-	
	908	1	(6,003,419)	ID	0.000%	-	
	908	1	(21,405,215)	OR	100.000%	(21,405,215)	
	908	1	(53,697,394)	UT	0.000%	-	
	908	1	(8,762,731)	WA	0.000%	-	
	908	1	(3,341,257)	WY	0.000%	-	
			(94,295,544)			(21,405,215)	4.6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	36,000	SO	27.165%	9,779	
Deferred Tax Expense	41110	1	(13,663)	SO	27.165%	(3,712)	
Beg/End Average Accum Def Tax	283	1	(1,210,681)	SO	27.165%	(328,881)	
Beg/End Average Accum Def Tax	190	1	(882,055)	OR	100.000%	(882,055)	

Description of Adjustment:

This adjustment removes revenues and expenses that are related to DSM programs, the costs of which are recovered through a surcharge on customer bills.

PacifiCorp
Oregon General Rate Case - December 2013
DSM Revenue & Expense Removal
SAP Unadjusted July 2010 - June 2011

Remove DSM Revenue:

FERC Account	Description	Allocation	Unadjusted Actuals	
456	DSM Revenue - CA SBC	CA	1,085,528	
	DSM REV - ID SBC	IDU	6,003,419	
	DSM Revenue OR ECC	OR	21,405,215	
	DSM Revenue - Utah SBC Offset	UT	53,697,394	
	DSM Revenue - WA SBC	WA	8,762,731	
	DSM REV - WY SBC	WY	3,341,257	
			94,295,544	**Ref. 4.6**

Remove DSM Amortization Expense:

FERC Account	Description	Allocation	Unadjusted Actuals	
908	CA DSM AMORT-SBC/ECC	CA	1,085,528	
	IDU DSM AMORT-SBC/ECC	IDU	6,003,419	
	OR DSM AMORT-SBC/ECC	OR	21,405,215	
	UT DSM AMORT-SBC/ECC	UT	53,697,394	
	WA DSM AMORT-SBC/ECC	WA	8,762,731	
	WY DSM AMORT-SBC/ECC	WY	3,341,257	
			94,295,544	**Ref. 4.6**

PacifiCorp PAGE 4.7
Oregon General Rate Case - December 2013
Insurance Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Change in Third Party Liability insurance due to the end of captive insurance coverage:							
Remove captive third party liability insurance from results	925	3	(965,209)	SO	27.165%	(262,199)	4.7.1
Remove captive insurance reimbursements	925	3	856,101	SO	27.165%	232,560	4.7.1
Remove accrual for Oregon liability reserve for part of the base period from results	925	3	(62,118)	SO	27.165%	(16,874)	4.7.1
Remove portion of injuries and damages	925	3	(1,130,000)	SO	27.165%	(306,964)	4.7.1
Annual accrual for Oregon liability reserve	925	3	248,469	OR	100.000%	248,469	4.7.1
Change in Property Insurance due to the end of captive insurance coverage:							
Remove captive premium and related accrual from base period	924	3	(14,264,744)	SO	27.165%	(3,875,016)	4.7.2
Remove post-captive accrual for part of the base period from results	924	3	(1,319,337)	OR	100.000%	(1,319,337)	4.7.2
Annual accrual for property damage expense:							
Property Insurance - Transmission	924	3	115,531	OR	100.000%	115,531	4.7.2
Property Insurance - Oregon Distribution	924	3	4,507,220	OR	100.000%	4,507,220	4.7.2
Property Insurance - Non-T&D	924	3	654,585	OR	100.000%	654,585	4.7.2
Remove entries related to the California CEMA regulatory asset	924	1	664,363	SO	27.165%	180,474	4.7.3
Adjustment to Tax:							
Accumulated Deferred Tax - Property Insurance	190	1	(2,075,160)	SO	27.165%	(563,717)	

Description of Adjustment:

This adjustment reflects the end of coverage by the captive insurance company on March 21,2011. The Company has replaced the captive insurance with self-insurance accruals for liability and property insurance per the stipulation approved in UE-217. This adjustment also removes the entries related to the California CEMA regulatory asset.

PacifiCorp
Oregon General Rate Case - December 2013
Insurance Expense
Liability Insurance Expense

Third Party Liability Insurance Expense - Captive portion

A portion of third party liability was covered by captive insurance through March 21, 2011 and replaced by self-insurance thereafter.

The captive third party liability expense in the base period will be replaced by the expected extra self insurance expense.

Remove from Base Period	
Captive insurance premium in base results	**965,209** Ref 4.7
Captive insurance reimbursements in base period	**(856,101)** Ref 4.7
Accrual for increased liability expense due to end of the captive insurance in base results April 2011 - June 2011 (accrued on an SO factor, should have been situs to Oregon)	**62,118** Ref 4.7
Accrual for injuries and damages covered by captive insurance	**1,130,000** Ref 4.7
Add for Test Period	
	Oregon Allocated Portion
Annual Accrual for increased expense due to the end of captive insurance per UE-217 @ $20,706/month	**$248,469** Ref 4.7

PacifiCorp
Oregon General Rate Case - December 2013
Insurance Expense
Property Damage Not Covered by Commercial Insurance

Commercial insurance covers a portion of non-T&D property damage above a deductible. Up through March 21, 2011, captive insurance covered a portion and the rest was self-insured. After March 21, 2011, all property damage not covered by commercial insurance is self-insured.

Actual captive property insurance premium in base period	3,424,231	
Actual property insurance provision under captive in base period	10,840,514	
Total Company	**14,264,744**	Ref 4.7

Following the termination of the captive insurance coverage on March 21, 2011, the insurance accrual will be based on the average of damages agreed to in the UE-217 stipulation.

Actual Accrual March 2011 - June 2011	**1,319,337**	Ref 4.7

	Stipulated Amounts		
	System Transmission Losses - Oregon Portion	Oregon Distribution Losses	System Non-T&D Losses - Oregon Portion
Annual Average per UE-217 stipulation	**$115,531**	**$4,507,220**	**$654,585**
	Ref 4.7	Ref 4.7	Ref 4.7

PacifiCorp
Oregon General Rate Case - December 2013
Insurance Expense
Remove California CEMA from Results

California Emergency Memorandum Account (CEMA)

Year	Period	Document Nc	Account	Description	FERC Acct	Locatn	Allocator	Amount	Pstng Date
2011	010	10154363	549301	CEMA Set-Up	9240000	000103	SO	(1,230,000)	10/31/2010
2012	003	10154539	549301	CEMA Amortization	9240000	000103	SO	55,539	03/31/2011
2012	003	10154539	549301	CEMA Amortization	9240000	000103	SO	101,301	03/31/2011
2012	003	10154539	549301	CEMA Amortization	9240000	000103	SO	4,250	03/31/2011
2012	003	10154539	549301	CEMA Amortization	9240000	000103	SO	108,776	03/31/2011
2012	004	10154575	549301	CEMA Amortization	9240000	000103	SO	94,572	04/30/2011
2012	005	10154615	549301	CEMA Amortization	9240000	000103	SO	95,711	05/31/2011
2012	006	10154656	549301	CEMA Amortization	9240000	000103	SO	105,487	06/30/2011
								(664,363)	

Ref 4.7

PacifiCorp PAGE 4.8
Oregon General Rate Case - December 2013
Generation Overhaul Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Steam	510	1	(4,254,585)	SG	25.777%	(1,096,711)	4.8.1
Generation Overhaul Expense - Steam	510	1	1,883,950	SG	25.777%	485,629	4.8.1
Generation Overhaul Expense - Other	553	1	(222,964)	SG	25.777%	(57,474)	4.8.1
			(2,593,598)			(668,556)	

Description of Adjustment:

This adjustment normalizes generation overhaul expenses in the twelve months ended June 2011 using a four-year average methodology. In this adjustment overhaul expenses from June 2008 - June 2010 are restated to constant dollars to make them comparable prior to averaging. For new generating units, which include Lake Side and Chehalis, the four-year average is comprised of the overhaul expense for the first four full years these plants are operational. The actual overhaul costs for the year ended June 2011 are subtracted from the four-year average which results in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2013
Generation Overhaul Expense

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars	Escalated Expense
Year Ending June 2008	2,511,698	7.27%	2,694,288
Year Ending June 2009	6,887,775	3.87%	7,154,563
Year Ending June 2010	3,582,976	2.49%	3,672,282
Year Ending June 2011	2,392,915		2,392,915
4 Year Average	3,843,841		3,978,512

New Plant Overhaul Expense		
Lake Side Plant - 4 Year Average	1,458,392	
Chehalis Plant - 4 Year Average	761,968	
Total New Plant Overhaul Expense	2,220,359	**Ref 4.8.2**
Total 4 Year Average - Other	6,198,871	
Year Ending June 2011 Overhaul Expense - Other	6,421,835	**Ref 4.8.2**
Total 4 Year Average - Other	6,198,871	
Adjustment	**(222,964)**	**Ref 4.8**

FUNCTION: STEAM

Period	Overhaul Expense	Restate to Constant Dollars	Escalated Expense
Year Ending June 2008	7,372,612	7.64%	7,936,230
Year Ending June 2009	29,068,705	3.96%	30,219,399
Year Ending June 2010	28,397,796	3.05%	29,264,499
Year Ending June 2011	28,146,156		28,146,156
4 Year Average	23,246,317		23,891,571

Total 4 Year Average - Steam	23,891,571	
Year Ending June 2011 Overhaul Expense - Steam	28,146,156	**Ref 4.8.2**
Total 4 Year Average - Steam	23,891,571	
Adjustment	**(4,254,585)**	**Ref 4.8**

Cholla

Period	Overhaul Expense	Restate to Constant Dollars	Escalated Expense
Year Ending June 2008	7,095,000	7.64%	7,637,396
Year Ending June 2009	(635,000)	3.96%	(660,137)
Year Ending June 2010	542,000	3.05%	558,542
Year Ending June 2011	-		-
4 Year Average	1,750,500		1,883,950

Total 4 Year Average - Cholla	1,883,950	
Year Ending June 2011 Overhaul Expense - Cholla	-	**Ref 4.8.2**
Total 4 Year Average - Cholla	1,883,950	
Adjustment	**1,883,950**	**Ref 4.8**

***Restatment Rates: Ref 4.8.3**

PacifiCorp
Oregon General Rate Case - December 2013
Generation Overhaul Expense

Existing Units

	Yr. Ending June 2008	Yr. Ending June 2009	Yr. Ending June 2010	Yr. Ending June 2011	
Steam					
Blundell	61,712	490,791	146,606	72,000	
BlundellIGC	(92,229)	-	-	-	
Carbon	1,766,156	1,692,506	(37,187)	715,000	
DaveJohnston	1,013,548	11,415,596	9,056,000	(588,000)	
Gadsby	-	1,105,000	3,225,000	36,000	
Hunter	(1,535,635)	(25,000)	8,946,180	5,052,010	
Huntington	-	769,000	967,000	6,294,000	
JimBridger	2,679,000	4,969,000	5,056,000	5,050,000	
Naughton	1,616,060	6,860,813	(4,803)	2,108,146	
Wyodak	-	-	-	5,657,000	
Colstrip	650,000	1,156,000	-	851,000	
Craig	784,000	235,000	948,000	2,467,000	
Hayden	430,000	400,000	95,000	432,000	
Total - Steam	7,372,612	29,068,705	28,397,796	**28,146,156**	**Ref 4.8.1**
	-				
Cholla	7,095,000	(635,000)	542,000	-	**Ref 4.8.1**
Other					
Hermiston	1,235,000	2,923,000	638,000	2,067,000	
Camas	-	-	500,000	6,000	
Currant Creek	1,276,698	3,964,775	2,444,976	319,915	
Total - Other	2,511,698	6,887,775	3,582,976	**2,392,915**	**Below**
Grand Total	16,979,310	35,321,480	32,522,771	30,539,071	
	-	-	-	-	

New Generating Units[1]

	Actual				Budget	
	Yr. Ending June 2008	Yr. Ending June 2009	Yr. Ending June 2010	Yr. Ending June 2011	Yr. Ending June 2012	**4 Year Average**
Lake Side		554,080	1,220,644	4,006,957	-	1,445,420
Chehalis	-	1,732,000	148,395	21,964	1,104,000	751,590
	-	2,286,080	1,369,038	4,028,920	1,104,000	2,197,010
Restatement Percentage[2]		103.87%	102.49%	100%	97.35%	
Restatement in 2011 Dollars	Yr. Ending June 2008[2]	Yr. Ending June 2009[2]	Yr. Ending June 2010	Yr. Ending June 2011	Yr. Ending June 2012	**4 Year Average**
Lake Side		575,542	1,251,068	4,006,957	-	1,458,392
Chehalis		1,799,087	152,094	21,964	1,074,727	761,968
	-	2,374,628	1,403,162	**4,028,920**	1,074,727	**2,220,359**
				Below		**Ref 4.8.1**

[1]Lake Side & Chehalis are Function - Other
[2]Both historical and budgeted expense is restated in June 2011 dollars using escalation factors.

12 ME June 2011 Overhaul Expense - Other

June 2011 Existing Plant:	2,392,915	**Above**
June 2011 New Generating Units:	4,028,920	**Above**
	6,421,835	**Ref 4.8.1**

Escalation Rates: OTHER	**June08**	**June09**	**June10**	**June11**	**June11**
Escalation Rate to June 2011	7.27%	3.87%	2.49%		
Deflation rate from Dec 2011 to June 2011					97.35%

Escalation Rates: STEAM	**June08**	**June09**	**June10**	**June11**
Escalation Rate to June 2011	7.64%	3.96%	3.05%	

PacifiCorp PAGE 4.9
Oregon General Rate Case - December 2013
Incremental O&M

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Coal Fired Generation	512	3	(217,124)	SG	25.777%	(55,968)	4.9.1
Geothermal Generation	512	3	(385,806)	SG	25.777%	(99,450)	4.9.1
Gas Generation	549	3	(874,842)	SG	25.777%	(225,509)	4.9.1
Gas Generation - Gadsby	549	3	(1,144,064)	SG	25.777%	(294,907)	4.9.1
Partner Operated Generation - Steam	512	3	3,562,839	SG	25.777%	918,398	4.9.1
Partner Operated Generation - Other	549	3	2,026,318	SG	25.777%	522,327	4.9.1
Partner Operated Generation - Cholla	512	3	3,630,638	SG	25.777%	935,875	4.9.1
Hydro - West	535	3	4,157,647	SG-P	25.777%	1,071,723	4.9.2
Hydro - East	535	3	553,258	SG-U	25.777%	142,614	4.9.2
Wind Generation	549	3	(469,913)	SG-W	25.777%	(121,130)	4.9.2
Populus to Ben Lomond	571	2	134,113	SG	25.777%	34,571	4.9.2
			10,973,064			2,828,544	4.9.2

Description of Adjustment:

This adjustment adds incremental O&M to the twelve months ended June 2011 to bring it to the projected O&M level for the twelve months ending December 2013, after accounting for inflation escalation applied in adjustment 4.12. See also direct testimony of Company witnesses Tallman and Ralston.

PacifiCorp
Oregon General Rate Case - December 2013
Incremental O&M
O&M by Plant (Excluding labor, net power costs, and overhauls)

	12ME Jun 2011 Actuals (A)	12ME Dec13 Forecast (B)	Increase to Test Period (C = B - A)	Inflation* (D)	Adjustment (E = C - D)
Coal Fired Generation					
Carbon	4,070,073	5,076,647	1,006,574	249,143	757,432
Dave Johnston	20,554,122	19,045,643	(1,508,479)	1,258,186	(2,766,665)
Hunter	24,320,896	27,959,756	3,638,859	1,488,763	2,150,097
Huntington	18,789,166	18,588,566	(200,600)	1,150,147	(1,350,747)
Jim Bridger	20,551,704	21,794,272	1,242,568	1,258,038	(15,469)
Naughton	13,155,727	16,033,290	2,877,563	805,306	2,072,258
Wyodak	6,646,680	5,989,518	(657,163)	406,865	(1,064,028)
	108,088,368	114,487,691	6,399,323	6,616,447	(217,124)
Gas & Geothermal Generation					
Blundell	1,454,948	1,158,204	(296,744)	89,062	(385,806)
Chehalis	1,642,437	1,749,807	107,371	127,053	(19,682)
Currant Creek	1,608,427	1,355,794	(252,633)	124,422	(377,054)
Gadsby	4,508,918	3,713,646	(795,272)	348,792	(1,144,064)
Lake Side	2,851,758	2,594,253	(257,505)	220,601	(478,106)
	12,066,488	10,571,705	(1,494,783)	909,930	(2,404,713)
Partner Operated Generation**					
Camas	24,521	91,567	67,046	1,897	65,149
Cholla	26,070,821	31,297,340	5,226,519	1,595,881	3,630,638
Colstrip	7,539,098	8,795,858	1,256,760	461,493	795,267
Craig	10,650,471	14,017,000	3,366,529	651,951	2,714,578
Hayden	5,307,283	5,685,153	377,870	324,876	52,993
Hermiston	4,289,335	6,582,311	2,292,976	331,806	1,961,169
	53,881,528	66,469,228	12,587,699	3,367,905	9,219,795
Subtotal	174,036,384	191,528,624	17,492,240	10,894,281	6,597,958

** Inflation is included in Adjustment 4.12*
The escalation factors used in this adjustment are an average based on operations and maintenance FERC account balances at June 2011.

Steam average:	*6.121%*
Other average:	*7.736%*
Hydro average:	*7.252%*
Transmission average:	*6.137%*

***O&M at partner operated plants include labor and non-labor costs incurred by the plant operator.*

PacifiCorp
Oregon General Rate Case - December 2013
Incremental O&M
Non-Labor O&M

	12ME Jun 2011 Actuals (A)	12ME Dec13 Forecast (B)	Increase to Test Period (C = B - A)	Inflation* (D)	Adjustment (E = C - D)	
Hydro Generation						
FERC Land Use Fee	(247,892)	747,180	995,072	(17,978)	1,013,050	
FERC Admin Fees	2,258,515	2,642,161	383,646	163,791	219,855	
NERC-CIPS Contract Services	129,259	349,638	220,379	9,374	211,005	
LR Recreation Services	321,493	441,710	120,216	23,315	96,901	
Other Regulatory fees	601,978	706,615	104,637	43,656	60,980	
Training	65,876	127,635	61,759	4,777	56,981	
Hydro North/LR Forest Mgmt	308,475	367,589	59,114	22,371	36,743	
Reduction to Grace Flowline Maint.	-	(25,527)	(25,527)	-	(25,527)	
Lewis River Implementation	1,009,847	2,478,518	1,468,671	73,236	1,395,435	
North Umpqua Implementation	751,164	1,607,815	856,650	54,476	802,175	
Hydro Dam Safety	595,915	1,046,397	450,482	43,217	407,265	
Develop Standard Operating Procedures	-	104,150	104,150	-	104,150	
Update Supporting Technical Information Documents	-	104,150	104,150	-	104,150	
Generator Cleaning	27,506	257,242	229,736	1,995	227,741	
	5,822,137	10,955,273	5,133,136	422,231	4,710,905	
Wind Generation						
Materials	1,551,747	6,626,506	5,074,759	120,037	4,954,722	
Third Party Contracts	19,450,288	14,829,331	(4,620,957)	1,504,599	(6,125,555)	
Other	4,148,664	4,000,839	(147,825)	320,925	(468,750)	
Oil Changes	-	1,169,671	1,169,671	-	1,169,671	
	25,150,699	26,626,347	1,475,648	1,945,560	(469,913)	Ref. 4.9.3
Populus to Ben Lomond	99,764	240,000	140,236	6,123	134,113	
Subtotal	31,072,600	37,821,619	6,749,020	2,373,914	4,375,105	
Grand Total	205,108,984	229,350,244	24,241,259	13,268,195	**10,973,064**	**Ref 4.9**

** Inflation is included in Adjustment 4.12*
The escalation factors used in this adjustment are an average based on operations and maintenance FERC account balances at June 2011.

Steam average:	*6.121%*
Other average:	*7.736%*
Hydro average:	*7.252%*
Transmission average:	*6.137%*

PacifiCorp
Oregon General Rate Case - December 2013
Incremental O&M

Wind Generation Increase to Test Period Detail by Plant

	Wind Administration	Dunlap	Seven Mile I & II	High Plains & McFadden Ridge	Foote Creek	Glenrock I & III	Goodnoe Hills	Leaning Juniper	Marengo I & II	Total
Materials	26,250	774,064	680,430	885,668	6,249	926,933	393,177	(111,943)	1,493,930	5,074,759
Third Party Contracts	(54,616)	1,055,015	(379,289)	(35,803)	(254,418)	(380,712)	(537,251)	113,058	(4,146,940)	(4,620,957)
Other	(3,137)	59,463	(60,062)	(99,499)	(53,811)	(21,393)	(124,891)	177,880	(22,376)	(147,825)
Oil Changes	-	613,870	-	-	-	-	-	555,801	-	1,169,671
Total	(31,503)	2,502,412	241,079	750,366	(301,980)	524,829	(268,965)	734,795	(2,675,386)	**1,475,648**

Ref. 4.9.2

PacifiCorp PAGE 4.10
Oregon General Rate Case - December 2013
Intercompany Administrative Service Agreement (IASA) Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove disallowed portion of intercompany administrative service agreement	930	1	(123,402)	SO	27.165%	(33,522)	

Detail of Adjustment:

Remove SERP	(123,197)
Remove Legislative	(204)
	(123,402)

Description of Adjustment:

The portion of the intercompany administrative service agreement related to the Supplemental Executive Retirement Plan (SERP) and legislative activity are removed by this adjustment.

PacifiCorp
Oregon General Rate Case - December 2013
Memberships and Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Total Memberships and Subscriptions in Account 930.2							
	930	1	(6,121,779)	SO	27.165%	(1,662,980)	
	930	1	(38)	UT	0.000%	-	
	930	1	(63,186)	OR	100.000%	(63,186)	
	930	1	(100)	WYP	0.000%	-	
Total			(6,185,103)			(1,726,167)	4.11.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,799,835	SO	27.165%	488,925	4.11.1
OR Situs Memberships	930	1	552	OR	100.000%	552	4.11.1
Total			1,800,387			489,477	
Add Back 100% of Mandated Memberships							
WECC	930	1	3,475,804	SO	27.165%	944,202	4.11.1

Description of Adjustment:

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order UE-94. National and regional trade organizations are recognized at 75%. Western Electricity Coordinating Council dues are included at 100% since it is a mandated membership.

Account	Factor	Description	Amount	
Remove Total Memberships and Subscriptions in Account 930.2				
930.2	SO	Included in Unadjusted Resutls	(6,121,779)	
930.2	UT	Included in Unadjusted Resutls	(38)	
930.2	OR	Included in Unadjusted Resutls	(63,186)	
930.2	WYP	Included in Unadjusted Resutls	(100)	
			(6,185,103)	Ref 4.11
Allowed National and Regional Trade Memberships at 75%				
930.2	SO	AFCOM	510	
930.2	SO	Americas' SAP User Group	5,000	
930.2	SO	Associated Oregon Industries	28,000	
930.2	SO	Associated Taxpayers of Idaho Inc	850	
930.2	SO	Association of Idaho Cities	300	
930.2	SO	Association of Washington Business	4,000	
930.2	SO	Association of Washington Cities	1,000	
930.2	SO	Columbia Corridor Assn	3,000	
930.2	SO	Consortium for Energy Efficiency	16,950	
930.2	SO	E Source Companies LLC	3,256	
930.2	SO	Edison Electric Institute	734,271	
930.2	SO	Electric Power Research Institute	503,309	
930.2	SO	EUCG Inc	3,000	
930.2	SO	Idaho Association of Counties	450	
930.2	SO	IESNA	500	
930.2	SO	Intermountain Electrical Assoc	9,490	
930.2	SO	Institute of Supply Management	411	
930.2	SO	Lane Utilities Coordinating Council	100	
930.2	SO	Metropolitan Utility Coordinating	125	
930.2	SO	Montana Tax Foundation Inc	1,050	
930.2	SO	National Automated Clearing House	4,500	
930.2	SO	National Electric Energy Testing Research and Application Center	23,750	
930.2	SO	National Joint Utilities	9,000	
930.2	SO	North American Electric Reliability Council	297,139	
930.2	SO	North American Transmission Forum	32,991	
930.2	SO	Northern Tier Transmission Group	418,088	
930.2	SO	Northwest Energy Efficiency Council	2,000	
930.2	SO	Northwest Public Power Association	620	
930.2	SO	Oregon Business Association	12,250	
930.2	SO	Oregon Business Council	33,595	
930.2	SO	Oregon Rural Electric Cooperative	750	
930.2	SO	Pacific NW Utilities Conference	69,069	
930.2	SO	Portland Business Alliance	39,400	
930.2	SO	Project Management Institute	561	
930.2	SO	Rocky Mountain Electrical League	18,000	
930.2	SO	Society for Human Resource Management	160	
930.2	SO	Society for Information Management	900	
930.2	SO	Solar Electric Power Association	7,000	
930.2	SO	Southern Oregon Timber Industries	260	
930.2	SO	The Eastern Idaho Water Rights Coalition Inc	250	
930.2	SO	The Information Systems Audit and Control Association	195	
930.2	SO	UT Water Users Association	500	
930.2	SO	Utah Community Forest Council	500	
930.2	SO	Utah Foundation	20,000	
930.2	SO	Utah Information Technologies	5,500	
930.2	SO	Utah Manufacturers Association	6,000	
930.2	SO	Utah Taxpayers Association	20,000	
930.2	SO	Walla Walla Area Utilities Coord	100	
930.2	SO	Washington Research Council	2,000	
930.2	SO	Washington Pulp & Paper Foundation	1,800	
930.2	SO	Western Energy Institute	42,004	
930.2	SO	Western Lampac	2,000	
930.2	SO	Wyoming Assoc of Municipalities	325	
930.2	SO	Wyoming Business Alliance	5,000	
930.2	SO	Wyoming Taxpayers Association	8,000	
		Total of Memberships Above	2,399,779	
		75% of Memberships Above	1,799,835	Ref 4.11
930.2	OR	East Linn Utilities Coordinating	125	
930.2	OR	Hood River Underground	35	
930.2	OR	Linn-Benton Utilities	175	
930.2	OR	Other	401	
			736	
		75% of OR Situs Memberships	552	Ref 4.11
Mandated Membership Fees at 100%				
930.2	SO	Western Electricity Coordinating Council	3,475,804	Ref 4.11
		Total Memberships and Subscriptions Allowed	**5,276,191**	

PacifiCorp
Oregon General Rate Case - December 2013
O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
O&M Expense Escalation (Non-NPC, Non-Labor)	500-935	3	28,529,998	Multiple	Multiple	7,764,447	4.12.3

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2011 to December 2013 for accounts 500 to 935, excluding NPC and property and liability insurance, using specific escalation indices. Before escalation indices were applied, June 2011 actual data was separated into labor and non-labor components, and costs that should not be included in June 2011 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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Oregon General Rate Case - December 2013
O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	378,410	SG	25.777%	97,543	
Steam Operations	501	3	1,781,823	SE	24.314%	433,224	
Steam Operations	502	3	1,880,339	SG	25.777%	484,698	
Steam Operations	503	3	(5,909)	SE	24.314%	(1,437)	
Steam Operations	505	3	206,334	SG	25.777%	53,187	
Steam Operations	506	3	532,093	SG	25.777%	137,158	
Steam Operations	507	3	24,057	SG	25.777%	6,201	
Steam Maintenance	510	3	64,495	SG	25.777%	16,625	
Steam Maintenance	511	3	790,782	SG	25.777%	203,841	
Steam Maintenance	512	3	3,638,533	SG	25.777%	937,910	
Steam Maintenance	513	3	1,299,557	SG	25.777%	334,989	
Steam Maintenance	514	3	429,467	SG	25.777%	110,704	
Hydro Operations	535	3	242,619	SG-P	25.777%	62,540	
Hydro Operations	535	3	(186,027)	SG-U	25.777%	(47,952)	
Hydro Operations	536	3	9,428	SG-P	25.777%	2,430	
Hydro Operations	537	3	232,312	SG-P	25.777%	59,884	
Hydro Operations	537	3	16,189	SG-U	25.777%	4,173	
Hydro Operations	539	3	1,062,288	SG-P	25.777%	273,828	
Hydro Operations	539	3	208,267	SG-U	25.777%	53,685	
Hydro Operations	540	3	25,023	SG-P	25.777%	6,450	
Hydro Operations	540	3	77	SG-U	25.777%	20	
Hydro Maintenance	541	3	18	SG-P	25.777%	5	
Hydro Maintenance	542	3	26,569	SG-P	25.777%	6,849	
Hydro Maintenance	542	3	(2,642)	SG-U	25.777%	(681)	
Hydro Maintenance	543	3	47,139	SG-P	25.777%	12,151	
Hydro Maintenance	543	3	7,796	SG-U	25.777%	2,010	
Hydro Maintenance	544	3	21,534	SG-P	25.777%	5,551	
Hydro Maintenance	544	3	4,230	SG-U	25.777%	1,090	
Hydro Maintenance	545	3	54,911	SG-P	25.777%	14,154	
Hydro Maintenance	545	3	27,489	SG-U	25.777%	7,086	
Other Operations	546	3	32,205	SG	25.777%	8,301	
Other Operations	548	3	704,973	SG	25.777%	181,722	
Other Operations	549	3	16,781	SG	25.777%	4,326	
Other Operations	549	3	1,420,456	SG-W	25.777%	366,153	
Other Operations	550	3	4,957	SG	25.777%	1,278	
Other Operations	550	3	306,957	SG-W	25.777%	79,125	
Other Maintenance	552	3	122,766	SG	25.777%	31,646	
Other Maintenance	553	3	249,594	SG	25.777%	64,338	
Other Maintenance	553	3	134,128	SG-W	25.777%	34,574	
Other Maintenance	554	3	15,567	SG	25.777%	4,013	
Other Maintenance	554	3	118,571	SG-W	25.777%	30,564	
Other Operations	556	3	52,085	SG	25.777%	13,426	
Other Operations	557	3	717,173	OR	Situs	(4,363)	
Other Operations	557	3	1,280,162	SG	25.777%	329,989	
Other Operations	557	3	91,007	SGCT	25.862%	23,536	
Transmission Operations	560	3	49,068	SG	25.777%	12,648	
Transmission Operations	561	3	100,412	SG	25.777%	25,883	
Transmission Operations	562	3	99,652	SG	25.777%	25,687	
Transmission Operations	563	3	1,924	SG	25.777%	496	
Transmission Operations	566	3	193,426	SG	25.777%	49,860	
Transmission Operations	567	3	105,979	SG	25.777%	27,318	
Transmission Maintenance	568	3	21,613	SG	25.777%	5,571	
Transmission Maintenance	569	3	131,402	SG	25.777%	33,872	
Transmission Maintenance	570	3	207,428	SG	25.777%	53,469	
Transmission Maintenance	571	3	1,372,510	SG	25.777%	353,794	
Transmission Maintenance	572	3	3,890	SG	25.777%	1,003	
Transmission Maintenance	573	3	15,885	SG	25.777%	4,095	
			20,387,772			5,040,242	4.12.3

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Oregon General Rate Case - December 2013
O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Operations	580	3	2,827	OR	Situs	(51)	
Distribution Operations	580	3	16,228	SNPD	26.906%	4,366	
Distribution Operations	581	3	28,982	SNPD	26.906%	7,798	
Distribution Operations	582	3	113,748	OR	Situs	25,739	
Distribution Operations	582	3	415	SNPD	26.906%	112	
Distribution Operations	583	3	57,649	OR	Situs	25,685	
Distribution Operations	583	3	441	SNPD	26.906%	119	
Distribution Operations	584	3	17	OR	Situs	-	
Distribution Operations	585	3	(114)	SNPD	26.906%	(31)	
Distribution Operations	586	3	57,550	OR	Situs	28,477	
Distribution Operations	586	3	15,878	SNPD	26.906%	4,272	
Distribution Operations	587	3	125,632	OR	Situs	40,091	
Distribution Operations	588	3	32,462	OR	Situs	11,537	
Distribution Operations	588	3	150,893	SNPD	26.906%	40,599	
Distribution Operations	589	3	184,204	OR	Situs	102,936	
Distribution Operations	589	3	3,978	SNPD	26.906%	1,070	
Distribution Maintenance	590	3	10,855	OR	Situs	4,763	
Distribution Maintenance	590	3	3,513	SNPD	26.906%	945	
Distribution Maintenance	591	3	118,894	OR	Situs	33,896	
Distribution Maintenance	591	3	5,727	SNPD	26.906%	1,541	
Distribution Maintenance	592	3	353,346	OR	Situs	135,186	
Distribution Maintenance	592	3	2,032	SNPD	26.906%	547	
Distribution Maintenance	593	3	4,403,965	OR	Situs	1,372,522	
Distribution Maintenance	593	3	51,084	SNPD	26.906%	13,745	
Distribution Maintenance	594	3	655,571	OR	Situs	136,646	
Distribution Maintenance	594	3	14	SNPD	26.906%	4	
Distribution Maintenance	595	3	-	OR	Situs	-	
Distribution Maintenance	595	3	15,259	SNPD	26.906%	4,106	
Distribution Maintenance	596	3	146,887	OR	Situs	18,181	
Distribution Maintenance	597	3	60,904	OR	Situs	11,130	
Distribution Maintenance	597	3	8,146	SNPD	26.906%	2,192	
Distribution Maintenance	598	3	137,387	OR	Situs	27,037	
Distribution Maintenance	598	3	(98,565)	SNPD	26.906%	(26,520)	
Customer Accounts Operations	901	3	99	OR	Situs	9	
Customer Accounts Operations	901	3	29,320	CN	29.363%	8,609	
Customer Accounts Operations	902	3	200,488	OR	Situs	89,067	
Customer Accounts Operations	902	3	27,445	CN	29.363%	8,059	
Customer Accounts Operations	903	3	134,923	OR	Situs	37,742	
Customer Accounts Operations	903	3	905,306	CN	29.363%	265,824	
Customer Accounts Operations	904	3	716,136	OR	Situs	328,822	
Customer Accounts Operations	904	3	22,929	CN	29.363%	6,733	
Customer Accounts Operations	905	3	614	OR	Situs	614	
Customer Accounts Operations	905	3	5,489	CN	29.363%	1,612	
Customer Service Operations	907	3	1,069	CN	29.363%	314	
Customer Service Operations	908	3	81,488	OR	Situs	3,798	
Customer Service Operations	908	3	6,637	CN	29.363%	1,949	
Customer Service Operations	908	3	268,899	OTHER	0.000%	-	
Customer Service Operations	909	3	29,655	OR	Situs	11,676	
Customer Service Operations	909	3	198,082	CN	29.363%	58,163	
Customer Service Operations	910	3	12,554	CN	29.363%	3,686	
A&G Operations	920	3	(577,886)	OR	Situs	(57,755)	
A&G Operations	920	3	(113,681)	SO	27.165%	(30,881)	
A&G Operations	921	3	45,276	OR	Situs	16,704	
A&G Operations	921	3	498,861	SO	27.165%	135,516	
A&G Operations	922	3	(4,055,177)	SO	27.165%	(1,101,588)	
A&G Operations	923	3	1,184	OR	Situs	763	
A&G Operations	923	3	826,542	SO	27.165%	224,530	
			5,932,063			2,042,601	4.12.3

PacifiCorp
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	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
A&G Operations	928	3	678,961	OR	Situs	166,204	
A&G Operations	928	3	98,068	SG	25.777%	25,279	
A&G Operations	928	3	82,502	SO	27.165%	22,412	
A&G Operations	929	3	(435,707)	SO	27.165%	(118,360)	
A&G Operations	930	3	66,487	OR	Situs	58,024	
A&G Operations	930	3	-	CN	29.363%	-	
A&G Operations	930	3	730,365	SO	27.165%	198,404	
A&G Operations	931	3	86,375	OR	Situs	84,018	
A&G Operations	931	3	423,377	SO	27.165%	115,010	
A&G Operations	935	3	5,139	OR	Situs	1,690	
A&G Operations	935	3	474,597	SO	27.165%	128,924	
			2,210,164			681,605	Below
			20,387,772			5,040,242	4.12.1
			5,932,063			2,042,601	4.12.2
			2,210,164			681,605	Above
			28,529,998			7,764,447	Ref 4.12

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O&M Expense Escalation
12 months ending December 2013

Function	Allocation Code	Jun 2011 Unadjusted O&M	3.2 Wheeling Revenue	4.1 Miscellaneous General Expense	4.2 Remove Unadjusted Labor	4.3 Idaho Irrigation Load Control Program	4.4 Remove Non-Recurring Entries	4.6 DSM Revenue and Expense Removal	4.7 Insurance Expense	4.8 Generation Overhaul Expense	4.10 Intercompany Administrative Serv. Agreement	4.11 Memberships and Subscriptions	5.1 Net Power Cost Study	5.5 BPA Residential Exchange	8.10 Regulatory Asset Amortization	8.12 Misc Asset Sales and Removals	8.13 Remove Rolling Hills
Steam Operation																	
	NPCSE	617,817,176	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSSECH	49,297,564	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCID	(103,365)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCWYP	(305,917)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SE	18,028,755	-	-	(57,812)	-	-	-	-	-	-	-	-	-	-	-	-
	SG	101,269,707	-	-	(78,166,531)	-	48,112	-	-	-	-	-	-	-	-	-	-
	SSECH	3,225,441	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SSGCH	12,906,431	-	-	2,156	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Operation Total	802,135,801	-	-	(78,222,186)	-	48,112	-	-	-	-	-	-	-	-	-	-
Steam Maintenance																	
	SG	178,928,431	-	-	(48,448,087)	-	-	-	-	(4,254,585)	-	-	-	-	-	-	-
	SSGCH	9,937,915	-	-	149,414	-	-	-	-	1,883,950	-	-	-	-	-	-	-
	Steam Maintenance Total	188,866,346	-	-	(48,298,673)	-	-	-	-	(2,370,634)	-	-	-	-	-	-	-
Hydro Operations																	
	SG-P	28,959,606	-	-	(8,843,352)	-	-	-	-	-	-	-	-	-	-	-	-
	SG-U	6,725,448	-	-	(6,232,602)	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro Operations Total	35,685,054	-	-	(15,075,953)	-	-	-	-	-	-	-	-	-	-	-	-
Hydro Maintenance																	
	SG-P	5,680,021	-	-	(2,420,187)	-	-	-	-	-	-	-	-	-	-	-	-
	SG-U	1,884,380	-	-	(1,083,956)	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro Maintenance Total	7,564,400	-	-	(3,504,143)	-	-	-	-	-	-	-	-	-	-	-	-
Purchased Power																	
	ID	83,840	-	-	-	-	-	-	-	-	-	-	-	(83,840)	-	-	-
	NPCSE	23,644,780	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSG	402,775,436	-	-	-	-	-	-	-	-	-	-	27,567,522	-	-	-	-
	OR	(22,356,044)	-	-	-	-	-	-	-	-	-	-	-	22,356,044	-	-	-
	SG	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WA	(8,714,605)	-	-	-	-	-	-	-	-	-	-	-	8,714,605	-	-	-
	Purchase Power Total	395,433,407	-	-	-	-	-	-	-	-	-	-	27,567,522	30,986,809	-	-	-
Other Operations																	
	ID	(32,973)	-	-	-	9,028,930	-	-	-	-	-	-	-	-	-	-	-
	NPCSE	365,731,151	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSSECT	16,065,664	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OR	(53,813)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SG	80,410,213	-	(2,954)	(41,481,305)	(9,002,868)	(3,033,000)	-	-	-	-	-	-	-	(844,678)	-	(903,082)
	SG-W	21,304,758	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SGCT	1,122,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SSGCT	1,195,095	-	-	(546,196)	-	-	-	-	-	-	-	-	-	-	-	-
	WA	(97,006)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other Operations Total	485,645,514	-	(2,954)	(42,027,503)	26,042	(3,033,000)	-	-	-	-	-	-	-	(844,678)	-	(903,082)
Other Maintenance																	
	SG	9,696,398	-	-	(2,420,146)	-	-	-	-	(222,964)	-	-	-	-	-	-	-
	SG-W	4,932,422	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SSGCT	792,299	-	-	(273,655)	-	-	-	-	-	-	-	-	-	-	-	-
	Other Maintenance Total	15,421,118	-	-	(2,693,801)	-	-	-	-	(222,964)	-	-	-	-	-	-	-
Transmission Operations																	
	NPCSE	6,292,490	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSG	131,608,086	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SG	25,922,230	(879,133)	-	(16,372,623)	-	(600)	-	-	-	-	-	-	-	-	(53,959)	-
	Transmission Operations Total	163,822,806	(879,133)	-	(16,372,623)	-	(600)	-	-	-	-	-	-	-	-	(53,959)	-
Transmission Maintenance																	
	SG	39,572,591	-	-	(10,227,413)	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission Maintenance Total	39,572,591	-	-	(10,227,413)	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Operations																	
	CA	1,451,133	-	-	(1,113,449)	-	-	-	-	-	-	-	-	-	-	-	-
	ID	1,131,688	-	-	(882,379)	-	-	-	-	-	-	-	-	-	-	-	-
	OR	13,246,007	-	-	(9,454,887)	-	-	-	-	-	-	-	-	-	-	-	-
	SNPD	33,394,285	-	(357)	(29,889,873)	-	600	-	-	-	-	-	-	-	-	-	-
	UT	11,543,456	-	-	(8,312,110)	-	-	-	-	-	-	-	-	-	-	-	-
	WA	2,281,761	-	-	(1,696,171)	-	-	-	-	-	-	-	-	-	-	-	-
	WYP	2,833,140	-	-	(1,833,658)	-	-	-	-	-	-	-	-	-	-	-	-
	WYU	300,403	-	-	(210,299)	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution Operations Total	66,181,872	-	(357)	(53,392,824)	-	600	-	-	-	-	-	-	-	-	-	-

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12 months ending December 2013

Function	Allocation Code	Jun 2011 Unadjusted O&M	3.2 Wheeling Revenue	4.1 Miscellaneous General Expense	4.2 Remove Unadjusted Labor	4.3 Idaho Irrigation Load Control Program	4.4 Remove Non-Recurring Entries	4.6 - DSM Revenue and Expense Removal	4.7 - Insurance Expense	4.8 Generation Overhaul Expense	4.10 Intercompany Administrative Serv. Agreement	4.11 - Memberships and Subscriptions	5.1 Net Power Cost Study	5.5 - BPA Residential Exchange	8.10 Regulatory Asset Amortization	8.12 Misc Asset Sales and Removals	8.13 - Remove Rolling Hills
Distribution Maintenance																	
	CA	7,372,701	-	-	(2,630,294)	-	-	-	-	-	-	-	-	-	-	-	-
	ID	7,407,060	-	-	(3,445,834)	-	-	-	-	-	-	-	-	-	-	-	-
	OR	42,889,767	-	-	(18,114,148)	-	-	-	-	-	-	-	-	-	-	-	-
	SNPD	8,019,637	-	-	(8,201,961)	-	144	-	-	-	-	-	-	-	-	-	-
	UT	60,174,197	-	-	(22,922,770)	-	-	-	-	-	-	-	-	-	-	-	-
	WA	7,099,800	-	-	(2,474,095)	-	-	-	-	-	-	-	-	-	-	-	-
	WYP	10,900,635	-	-	(3,812,506)	-	-	-	-	-	-	-	-	-	-	-	-
	WYU	1,854,360	-	-	(432,360)	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Maintenance Total		145,718,158	-	-	(62,033,968)	-	144	-	-	-	-	-	-	-	-	-	-
Customer Accounts Operations																	
	CA	1,597,043	-	-	(910,470)	-	-	-	-	-	-	-	-	-	-	-	-
	CN	54,083,088	-	(11,058)	(37,188,956)	-	-	-	-	-	-	-	-	-	-	-	-
	ID	2,477,028	-	-	(1,616,416)	-	-	-	-	-	-	-	-	-	-	-	-
	OR	18,053,658	-	-	(9,884,739)	-	-	-	-	-	-	-	-	-	(391,980)	-	-
	UT	11,788,893	-	-	(6,567,000)	-	-	-	-	-	-	-	-	-	-	-	-
	WA	3,902,736	-	-	(1,790,268)	-	-	-	-	-	-	-	-	-	-	-	-
	WYP	2,898,315	-	-	(1,704,701)	-	-	-	-	-	-	-	-	-	-	-	-
	WYU	408,601	-	-	(324,720)	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts Operations Total		95,209,362	-	(11,058)	(59,987,268)	-	-	-	-	-	-	-	-	-	(391,980)	-	-
Customer Service Operations																	
	CA	1,377,188	-	-	(38,985)	-	-	(1,085,528)	-	-	-	-	-	-	-	-	-
	CN	7,171,566	-	(14,489)	(3,135,527)	-	-	-	-	-	-	-	-	-	-	-	-
	ID	6,926,879	-	-	(449,739)	(26,042)	-	(6,003,419)	-	-	-	-	-	-	-	-	-
	OR	23,200,319	-	(306)	(1,509,797)	-	-	(21,405,215)	-	-	-	-	-	-	-	-	-
	OTHER	4,988,538	-	-	(35,792)	-	-	-	-	-	-	-	-	-	-	-	-
	UT	56,671,513	-	-	(2,292,751)	-	-	(53,697,394)	-	-	-	-	-	-	-	-	-
	WA	9,063,084	-	-	(215,732)	-	-	(8,762,731)	-	-	-	-	-	-	-	-	-
	WYP	4,570,790	-	-	(933,774)	-	-	(3,341,257)	-	-	-	-	-	-	-	-	-
	WYU	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service Operations Total		113,969,877	-	(14,795)	(8,612,096)	(26,042)	-	(94,295,544)	-	-	-	-	-	-	-	-	-
A&G Operations & Maintenance																	
	920	70,168,202	-	(1,571)	(78,131,421)	-	222,772	-	-	-	-	-	-	-	(2,095,915)	-	-
	921	9,641,195	-	(68,272)	266,351	-	-	-	-	-	-	-	-	-	-	-	-
	922	(31,726,905)	-	-	(25,960,275)	-	-	-	-	-	-	-	-	-	-	-	-
	923	14,146,288	-	(90,860)	-	-	-	-	-	-	-	-	-	-	-	-	-
	924	25,385,458	-	-	-	-	-	-	664,363	-	-	-	-	-	-	-	-
	925	8,314,977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	928	18,415,884	-	-	(3,892,466)	-	-	-	-	-	-	-	-	-	-	-	-
	929	(6,811,639)	-	-	1,065,041	-	-	-	-	-	-	-	-	-	-	-	(451,580)
	930	16,206,212	-	(200,827)	-	-	-	-	-	-	(123,402)	(908,912)	-	-	(155,424)	-	-
	931	6,408,304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	935	23,814,472	-	-	(2,821,875)	-	-	-	-	-	-	-	-	-	-	-	-
A&G Operations & Maintenance Total		153,962,449	-	(361,529)	(109,474,645)	-	222,772	-	664,363	-	(123,402)	(908,912)	-	-	(2,251,339)	-	(451,580)
Grand Total		2,709,188,753	(879,133)	(390,693)	(509,923,098)	0	(2,761,972)	(94,295,544)	664,363	(2,593,598)	(123,402)	(908,912)	27,567,522	30,986,809	(3,488,197)	(53,959)	(1,354,661)

PacifiCorp
Oregon General Rate Case - December 2013
O&M Expense Escalation
12 months ending December 2013

4.12

Function	Allocation Code	O&M Before Escalation	Escalation Percentages	O&M Escalation	O&M After Escalation
Steam Operation					
	NPCSE	617,817,176	0.00%	-	617,817,176
	NPCSSECH	49,297,564	0.00%	-	49,297,564
	NPCID	(103,365)	0.00%	-	(103,365)
	NPCWYP	(305,917)	0.00%	-	(305,917)
	SE	17,970,953	8.38%	1,505,674	19,476,627
	SG	23,151,288	8.38%	1,939,703	25,090,991
	SSECH	3,225,441	8.38%	270,240	3,495,680
	SSGCH	12,908,587	8.38%	1,081,530	13,990,117
	Steam Operation Total	723,961,726		4,797,147	728,758,873
Steam Maintenance					
	SG	126,225,758	4.50%	5,683,783	131,909,542
	SSGCH	11,971,280	4.50%	539,051	12,510,331
	Steam Maintenance Total	138,197,039		6,222,834	144,419,873
Hydro Operations					
	SG-P	20,116,255	7.81%	1,571,670	21,687,925
	SG-U	492,846	7.81%	38,506	531,352
	Hydro Operations Total	20,609,101		1,610,176	22,219,277
Hydro Maintenance					
	SG-P	3,259,834	4.61%	150,171	3,410,005
	SG-U	800,423	4.61%	36,873	837,297
	Hydro Maintenance Total	4,060,257		187,044	4,247,301
Purchased Power					
	ID	0	0.00%	-	0
	NPCSE	23,644,780	0.00%	-	23,644,780
	NPCSG	430,342,958	0.00%	-	430,342,958
	OR	-	0.00%	-	0
	SG	-	0.00%	-	0
	WA	(0)	0.00%	-	(0)
	Purchase Power Total	453,987,738		-	453,987,738
Other Operations					
	ID	8,995,957	8.11%	729,402	9,725,359
	NPCSE	365,731,151	0.00%	-	365,731,151
	NPCSSECT	16,065,664	0.00%	-	16,065,664
	OR	(53,813)	8.11%	(4,363)	(58,176)
	SG	25,142,106	8.11%	2,038,549	27,180,655
	SG-W	21,304,758	8.11%	1,727,413	23,032,171
	SGCT	1,122,425	8.11%	91,007	1,213,432
	SSGCT	648,897	8.11%	52,613	701,510
	WA	(97,006)	8.11%	(7,865)	(104,872)
	Other Operations Total	438,860,139		4,626,756	443,486,895
Other Maintenance					
	SG	7,053,287	5.12%	361,355	7,414,643
	SG-W	4,932,422	5.12%	252,699	5,185,120
	SSGCT	518,644	5.12%	26,571	545,215
	Other Maintenance Total	12,504,353		640,625	13,144,978
Transmission Operations					
	NPCSE	6,292,490	0.00%	-	6,292,490
	NPCSG	131,608,086	0.00%	-	131,608,086
	SG	8,615,915	6.39%	550,461	9,166,377
	Transmission Operations Total	146,516,491		550,461	147,066,952
Transmission Maintenance					
	SG	29,345,178	5.97%	1,752,728	31,097,905
	Transmission Maintenance Total	29,345,178		1,752,728	31,097,905
Distribution Operations					
	CA	337,684	6.18%	20,880	358,564
	ID	249,308	6.18%	15,415	264,724
	OR	3,791,120	6.18%	234,414	4,025,534
	SNPD	3,504,655	6.18%	216,701	3,721,356
	UT	3,231,347	6.18%	199,802	3,431,148
	WA	585,590	6.18%	36,208	621,798
	WYP	999,482	6.18%	61,800	1,061,282
	WYU	90,104	6.18%	5,571	95,675
	Distribution Operations Total	12,789,290		790,791	13,580,082

PacifiCorp
Oregon General Rate Case - December 2013
O&M Expense Escalation
12 months ending December 2013

Function	Allocation Code	O&M Before Escalation	Escalation Percentages	4.12 O&M Escalation	O&M After Escalation
Distribution Maintenance					
	CA	4,742,408	7.02%	332,939	5,075,346
	ID	3,961,227	7.02%	278,096	4,239,323
	OR	24,775,619	7.02%	1,739,361	26,514,980
	SNPD	(182,180)	7.02%	(12,790)	(194,970)
	UT	37,251,427	7.02%	2,615,219	39,866,646
	WA	4,625,704	7.02%	324,745	4,950,450
	WYP	7,088,128	7.02%	497,619	7,585,747
	WYU	1,422,000	7.02%	99,831	1,521,831
Distribution Maintenance Total		83,684,333		5,875,020	89,559,353
Customer Accounts Operations					
	CA	686,574	5.87%	40,280	726,854
	CN	16,883,074	5.87%	990,489	17,873,562
	ID	860,612	5.87%	50,490	911,102
	OR	7,776,938	5.87%	456,254	8,233,192
	UT	5,221,893	5.87%	306,356	5,528,249
	WA	2,112,468	5.87%	123,933	2,236,401
	WYP	1,193,614	5.87%	70,026	1,263,641
	WYU	83,882	5.87%	4,921	88,803
Customer Accounts Operations Total		34,819,056		2,042,749	36,861,804
Customer Service Operations					
	CA	252,675	5.43%	13,718	266,393
	CN	4,021,550	5.43%	218,342	4,239,892
	ID	447,679	5.43%	24,306	471,985
	OR	285,001	5.43%	15,474	300,475
	OTHER	4,952,746	5.43%	268,899	5,221,645
	UT	681,369	5.43%	36,993	718,362
	WA	84,621	5.43%	4,594	89,216
	WYP	295,758	5.43%	16,058	311,816
	WYU	-	5.43%	-	0
Customer Service Operations Total		11,021,400		598,384	11,619,784
A&G Operations & Maintenance					
	920	(9,837,933)	7.03%	(691,567)	(10,529,500)
	921	9,839,275	5.53%	544,137	10,383,412
	922	(57,687,180)	7.03%	(4,055,177)	(61,742,357)
	923	14,055,428	5.89%	827,726	14,883,154
	924	26,049,821	0.00%	-	26,049,821
	925	8,314,977	0.00%	-	8,314,977
	926	-	-7.93%	-	0
	928	14,523,419	5.92%	859,531	15,382,950
	929	(6,198,178)	7.03%	(435,707)	(6,633,885)
	930	14,817,647	5.38%	796,852	15,614,499
	931	6,408,304	7.95%	509,751	6,918,055
	935	20,992,597	2.29%	479,736	21,472,333
A&G Operations & Maintenance Total		41,276,177		(1,164,717)	40,113,460
	Grand Total	2,151,634,278		28,529,998	2,180,164,276
				Ref 4.12.3	

	Escalation Factors June 2011 to December 2013	FERC Accounts
STEAM PRODUCTION PLANT		
Operation:	8.38%	500 - 507
Maintenance:	4.50%	510 - 514
HYDRO PRODUCTION PLANT		
Operation:	7.81%	535 - 540
Maintenance:	4.61%	541 - 545
OTHER PRODUCTION PLANT		
Operation:	8.11%	546 - 550; 556 - 557
Maintenance:	5.12%	551 - 554
TRANSMISSION PLANT		
Operation:	6.39%	560 - 567
Maintenance:	5.97%	568 - 573
DISTRIBUTION PLANT		
Operation:	6.18%	580 - 589
Maintenance:	7.02%	590 - 598
CUSTOMER ACCOUNTS		
Operation:	5.87%	901 - 905
CUSTOMER SERVICE and INFORMATION		
Operation:	5.43%	907 - 910
SALES		
Operation:	6.20%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	7.03%	920, 922, 929
Operation:	5.53%	921
Operation:	5.89%	923
Operation:	8.59%	926
Operation:	9.53%	927
Operation:	5.92%	928
Operation:	5.38%	930
Operation:	7.95%	931
Maintenance:	2.29%	935

Note: Please see Confidential Exhibit PAC/1107 for details of escalation factors.

The following adjustments were used to develop pro forma net power costs for the test period. The Company's booked power costs for the twelve months ended June 2011 provide the starting point for establishing the adjustment amounts for the December 2013 test period.

PacifiCorp
Normalized Results of Operations
Tab 5 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Total Adjustments	5.1 Net Power Cost	5.2 James River Royalty Offset	5.3 Little Mountain	5.4 Electric Lake Settlement	5.5 BPA Residential Exchange	5.6 Black Cap Solar LLC Project
1	Operating Revenues:							
2	General Business Revenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	23,550,079	23,550,079	-	-	-	-	-
5	Other Operating Revenues	220,109	-	1,206,267	(986,158)	-	-	-
6	Total Operating Revenues	23,770,188	23,550,079	1,206,267	(986,158)	-	-	-
7								
8	Operating Expenses:							
9	Steam Production	28,633,999	28,633,999	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-
12	Other Power Supply	84,763,922	61,978,118	-	(298,251)	225,427	22,356,044	502,584
13	Embedded Cost Differential (ECD)	-	-	-	-	-	-	-
13	Transmission	(1,591,989)	(1,591,989)	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	-	-	-	-	-	-	-
19								
20	Total O&M Expenses	111,805,932	89,020,128	-	(298,251)	225,427	22,356,044	502,584
21								
22	Depreciation	-	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	(29,427,530)	(21,885,066)	402,948	(229,742)	(75,341)	(7,471,727)	(168,602)
26	Income Taxes - State	(3,998,713)	(2,973,817)	54,754	(31,218)	(10,238)	(1,015,284)	(22,910)
27	Income Taxes - Def Net	-	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	78,379,690	64,161,245	457,702	(559,211)	139,849	13,869,034	311,071
32								
33	Operating Rev For Return:	(54,609,502)	(40,611,166)	748,565	(426,947)	(139,849)	(13,869,034)	(311,071)
34								
35	Rate Base:							
36	Electric Plant In Service	75,000	-	-	-	-	-	75,000
37	Plant Held for Future Use	-	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	1,577,139	1,291,039	9,210	(11,252)	2,814	279,070	6,259
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	1,652,139	1,291,039	9,210	(11,252)	2,814	279,070	81,259
49								
50	Rate Base Deductions:							
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	-	-	-	-	-	-	-
60								
61	Total Rate Base:	1,652,139	1,291,039	9,210	(11,252)	2,814	279,070	81,259
62								
63	Return on Rate Base	-1.704%	-1.268%	0.023%	-0.013%	-0.004%	-0.432%	-0.010%
64								
65	Return on Equity	-3.227%	-2.401%	0.044%	-0.025%	-0.008%	-0.819%	-0.019%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(88,035,744)	(65,470,049)	1,206,267	(687,907)	(225,427)	(22,356,044)	(502,584)
69	Other Deductions							
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	41,625	32,527	232	(283)	71	7,031	2,047
72	Schedule "M" Additions	-	-	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-	-
74	Income Before Tax	(88,077,369)	(65,502,576)	1,206,035	(687,623)	(225,498)	(22,363,075)	(504,631)
75								
76	State Income Taxes	(3,998,713)	(2,973,817)	54,754	(31,218)	(10,238)	(1,015,284)	(22,910)
77	Taxable Income	(84,078,657)	(62,528,759)	1,151,281	(656,405)	(215,261)	(21,347,792)	(481,721)
78								
79	Federal Income Taxes + Other	(29,427,530)	(21,885,066)	402,948	(229,742)	(75,341)	(7,471,727)	(168,602)
80								
81	PRICE CHANGE	90,852,814	67,572,247	(1,241,185)	707,126	232,477	23,055,179	526,970

PacifiCorp PAGE 5.1
Oregon General Rate Case - December 2013
Net Power Cost Study

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	25,837,906	SG	25.777%	6,660,277	5.1.1
Existing Firm UPL	447NPC	3	30,104,809	SG	25.777%	7,760,163	5.1.1
Post-Merger Firm	447NPC	3	36,337,294	SG	25.777%	9,366,721	5.1.1
Non-Firm	447NPC	3	(975,104)	SE	24.314%	(237,082)	5.1.1
Total Sales for Resale			91,304,905			23,550,079	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	5,432,688	SG	25.777%	1,400,392	5.1.1
Existing Firm Demand UPL	555NPC	3	51,932,017	SG	25.777%	13,386,597	5.1.1
Existing Firm Energy	555NPC	3	37,962,219	SE	24.314%	9,229,951	5.1.1
Post-merger Firm	555NPC	3	151,738,982	SG	25.777%	39,113,993	5.1.1
Secondary Purchases	555NPC	3	(23,644,780)	SE	24.314%	(5,748,878)	5.1.1
Seasonal Contracts	555NPC	3	-	SG	25.777%	-	5.1.1
Other Generation	555NPC	3	5,498,155	SG	25.777%	1,417,268	5.1.1
Total Purchased Power Adjustments:			228,919,281			58,799,323	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	24,712,270	SG	25.777%	6,370,120	5.1.1
Existing Firm UPL	565NPC	3	-	SG	25.777%	-	5.1.1
Post-merger Firm	565NPC	3	(27,687,811)	SG	25.777%	(7,137,130)	5.1.1
Non-Firm	565NPC	3	(3,393,089)	SE	24.314%	(824,979)	5.1.1
Total Wheeling Expense Adjustments:			(6,368,631)			(1,591,989)	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	103,365	ID	0.000%	-	5.1.1
Fuel - Overburden Amortization - Wyoming	501NPC	3	305,917	WYP	0.000%	-	5.1.1
Fuel Consumed - Coal	501NPC	3	117,083,997	SE	24.314%	28,467,240	5.1.1
Fuel Consumed - Gas	501NPC	3	(7,336,292)	SE	24.314%	(1,783,711)	5.1.1
Steam from Other Sources	503NPC	3	861,913	SE	24.314%	209,561	5.1.1
Natural Gas Consumed	547NPC	3	(16,684,928)	SE	24.314%	(4,056,693)	5.1.1
Simple Cycle Combustion Turbines	547NPC	3	1,132,236	SE	24.314%	275,287	5.1.1
Cholla / APS Exchange	501NPC	3	7,160,252	SE	24.314%	1,740,909	5.1.1
Total Fuel Expense Adjustments:			102,626,460			24,852,593	
Total Power Cost Adjustment			233,872,205			58,509,847	
Oregon Solar Project	555NPC	3	(145,921)	OR	100.000%	(145,921)	5.1.1
Remove Power Cost Deferrals	555NPC	1	27,567,522	SG	25.777%	7,106,123	5.1.1

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 temperature conditions for the twelve-month period ending December 2013. The GRID study for this adjustment is based on forecasted loads for the period.

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 NPC as part of the general rate case.

PacifiCorp
Oregon General Rate Case - December 2013
Net Power Cost Adjustment

Description	Account	(1) Total Account (B Tabs)	(2) Remove Non- NPC	(3) Unadjusted NPC (1) + (2)	(4) Type 1 Adjustments	(5) Type 1 Normalized NPC (3) + (4)	(6) Type 3 Pro Forma NPC	(7) Type 3 Adjustment (6) - (5)	2010 Protocol Factor
Sales for Resale (Account 447)									
Existing Firm Sales PPL	447.12			-		-	25,837,906	25,837,906	SG
Existing Firm Sales UPL	447.122			-		-	30,104,809	30,104,809	SG
Post-merger Firm Sales	447.13, 447.14, 447.2, 447.61, 447.62	369,045,839		369,045,839		369,045,839	405,383,133	36,337,294	SG
Non-firm Sales	447.5	975,104		975,104		975,104	-	(975,104)	SE
Transmission Services	447.9	1,429,558	(1,429,558)	-		-		-	S
On-system Wholesale Sales	447.1	7,728,994	(7,728,994)	-		-		-	S
Total Revenue Adjustments		379,179,495	(9,158,552)	370,020,943	-	370,020,943	461,325,848	91,304,905	
Purchased Power (Account 555)									
Existing Firm Demand PPL	555.66			-		-	5,432,688	5,432,688	SG
Existing Firm Demand UPL	555.68			-		-	51,932,017	51,932,017	SG
Existing Firm Energy	555.65, 555.69			-		-	37,962,219	37,962,219	SE
Post-merger Firm	555, 555.55,555.61,555.62, 555.63, 555.64, 555.67, 555.8	402,775,436		402,775,436	27,567,522	430,342,958	582,081,940	151,738,982	SG
Secondary Purchases	555.7, 555.25	23,644,780		23,644,780		23,644,780	-	(23,644,780)	SE
Seasonal Contracts				-		-	-	-	
Wind Integration Charge						-	5,498,155	5,498,155	SG
BPA Regional Adjustments	555.11, 555.12, 555.133	(30,986,809)	30,986,809	-		-	-	-	S
Total Purchased Power Adjustment		395,433,407	30,986,809	426,420,216	27,567,522	453,987,738	682,907,019	228,919,281	
Wheeling (Account 565)									
Existing Firm PPL	565.26			-		-	24,712,270	24,712,270	SG
Existing Firm UPL	565.27	0		-		-	-	-	SG
Post-merger Firm	565.0, 565.46, 565.1	131,608,086		131,608,086		131,608,086	103,920,275	(27,687,811)	SG
Non-firm	565.25	6,292,490		6,292,490		6,292,490	2,899,400	(3,393,089)	SE
Total Wheeling Expense Adjustment		137,900,576	-	137,900,576	-	137,900,576	131,531,945	(6,368,631)	
Fuel Expense (Accounts 501, 503 and 547)									
Fuel - Overburden Amortization - Idaho	501.12	(103,365)		(103,365)		(103,365)	-	103,365	ID
Fuel - Overburden Amortization - Wyoming	501.12	(305,917)		(305,917)		(305,917)	-	305,917	WYP
Fuel Consumed - Coal	501.1	600,800,161		600,800,161		600,800,161	717,884,157	117,083,997	SE
Fuel Consumed - Gas	501.35	13,695,407		13,695,407		13,695,407	6,359,116	(7,336,292)	SE
Steam From Other Sources	503	3,321,608		3,321,608		3,321,608	4,183,520	861,913	SE
Natural Gas Consumed	547	365,731,151		365,731,151		365,731,151	349,046,222	(16,684,928)	SE
Simple Cycle Combustion Turbines	547	16,065,664		16,065,664		16,065,664	17,197,901	1,132,236	SE
Cholla/APS Exchange	501.1,501.2,501.45	49,297,564		49,297,564		49,297,564	56,457,816	7,160,252	SE
Miscellaneous Fuel Costs	501,501.2,501.3, 501.4, 501.45, 501.5,501.51	21,254,205	(21,254,205)	-		-		-	SE
Total Fuel Expense		1,069,756,478	(21,254,205)	1,048,502,273	-	1,048,502,273	1,151,128,733	102,626,460	
Net Power Cost		**1,223,910,966**	**18,891,156**	**1,242,802,122**	**27,567,522**	**1,270,369,644**	**1,504,241,849**	**233,872,205**	
			Ref 5.1.4	**Ref. 2.2 line 66**	**Ref 5.1**		**Ref 5.1.3**	**Ref 5.1**	
					Oregon Solar Project	**Ref 5.1.5**	**(145,921)**	**(145,921)**	OR
							Ref. 5.1	**Ref. 5.1**	
						Total NPC	**1,504,095,928**	**233,726,284**	
							Ref. 2.2 line 66		

PacifiCorp
Oregon General Rate Case - December 2013
Net Power Cost Adjustment

Study Results
MERGED PEAK/ENERGY SPLIT
Period Ending **($)**
Dec-13

	Merged 01/13-12/13	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	25,837,906	25,837,906			
Post Merger	405,383,133				405,383,133
Utah Pre Merger	30,104,809	30,104,809			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	461,325,848	55,942,715	-	-	405,383,133
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	1,013,318	303,995	709,323		
Misc/Pacific	345,000	71,540	273,460		
Q.F. Contracts/PPL	56,924,311	5,057,153	24,639,185		27,227,974
Small Purchases west	15,932		15,932		
Pacific Sub Total	58,298,561	5,432,688	25,637,899	-	27,227,974
Gemstate	2,867,100		2,867,100		
GSLM	-		-		
QF Contracts/UPL	120,922,590	21,827,208	9,354,518		89,740,864
IPP Layoff	30,104,809	30,104,809	-		
Small Purchases east	102,703		102,703		
UP&L to PP&L	-	-	-		
Utah Sub Total	153,997,202	51,932,017	12,324,320	-	89,740,864
APS Supplemental p27875	2,645,331				2,645,331
Avoided Cost Resource	-				-
Blanding Purchase p379174	-				-
BPA Reserve Purchase	296,483				296,483
Chehalis Station Service	-				-
Combine Hills Wind p160595	4,297,314				4,297,314
Deseret Purchase p194277	34,105,073				34,105,073
Georgia-Pacific Camas	8,442,461				8,442,461
Hermiston Purchase p99563	104,983,159				104,983,159
Hurricane Purchase p393045	-				-
Idaho Power p278538	-				-
Kennecott Generation Incentive	1,823,579				1,823,579
LADWP p491303-4	-				-
MagCorp p229846	-				-
MagCorp Reserves p510378	4,787,940				4,787,940
Nucor p346856	5,457,000				5,457,000
P4 Production p137215/p145258	19,999,999				19,999,999
Rock River Wind p100371	4,940,852				4,940,852
Roseburg Forest Products p312292	-				-
Three Buttes Wind p460457	20,598,497				20,598,497
Top of the World Wind p522807	40,244,928				40,244,928
Tri-State Purchase p27057	9,969,503				9,969,503
West Valley Toll	16,811,701				16,811,701
Wolverine Creek Wind p244520	10,044,128				10,044,128
BPA So. Idaho p64885/p83975/p64705	(1,184)				(1,184)
Cargill p483225/s6 p485390/s89	1,416,800				1,416,800
PSCo Exchange p340325	5,400,000				5,400,000
Shell p489963/s489962	369,600				369,600

PacifiCorp
Oregon General Rate Case - December 2013
Net Power Cost Adjustment

Study Results
MERGED PEAK/ENERGY SPLIT
Period Ending **($)**
Dec-13

	Merged 01/13-12/13	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
Seasonal Purchased Power Placeholder					
Short Term Firm Purchases	168,479,938				168,479,938
New Firm Sub Total	465,113,102	0	0	0	465,113,102
Wind Integration Charge	5,498,155				5,498,155
Non Firm Sub Total	-			0	
TOTAL PURCHASED PW & NET INT.	682,907,019	57,364,705	37,962,219	0	587,580,095
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilitie	24,712,270	24,712,270			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	103,920,275				103,920,275
Nonfirm Wheeling	2,899,400			2,899,400	
TOTAL WHEELING & U. OF F. EXPENSE	131,531,945	24,712,270	0	2,899,400	103,920,275
THERMAL FUEL BURN EXPENSE					
Carbon	22,219,031			22,219,031	
Cholla	56,457,816			56,457,816	
Colstrip	15,633,420			15,633,420	
Craig	22,895,032			22,895,032	
Chehalis	80,743,531			80,743,531	
Currant Creek	101,069,994			101,069,994	
Dave Johnston	61,861,196			61,861,196	
Gadsby	6,359,116			6,359,116	
Gadsby CT	17,197,901			17,197,901	
Hayden	13,865,406			13,865,406	
Hermiston	67,133,696			67,133,696	
Hunter	157,876,777			157,876,777	
Huntington	102,371,596			102,371,596	
Jim Bridger	192,415,279			192,415,279	
Lake Side	100,099,001			100,099,001	
Little Mountain	-			-	
Naughton	108,227,274			108,227,274	
Wyodak	20,519,147			20,519,147	
TOTAL FUEL BURN EXPENSE	1,146,945,212	-	-	1,146,945,212	0
OTHER GENERATION EXPENSE					
Blundell	4,183,520			4,183,520	
TOTAL OTHER GEN. EXPENSE	4,183,520	-	-	4,183,520	0
NET POWER COST	**1,504,241,849**	26,134,259	37,962,219	1,154,028,133	286,117,237

Ref 5.1

PacifiCorp
Oregon General Rate Case - December 2013
Net Power Cost Adjustment
Amounts removed from accounts for consistency with GRID

Non-Net Power Costs		
Sales for Resale (Account 447)		
Transmission Services - revenues received not included in GRID	1,429,558	
On System Wholesale sales - these are not included in GRID	7,728,994	
	9,158,552	**Ref 5.1.1**
Purchased Power (Account 555)		
BPA regional adjustments - these are credits that are passed to customers in the northwest and are not included in GRID	(30,986,809)	**Ref 5.1.1**
Fuel Expense (Accounts 501, 503 and 547)		
Cholla fuel handling	2,961,032	
Cholla start-up diesel	264,409	
Fuel handling	6,553,599	
Start up gas	388,183	
Diesel	10,392,852	
Residual disposal	556,930	
Other non GRID	137,200	
	21,254,205	**Ref 5.1.1**
Total non-NPC costs to remove for consistency with GRID	**(18,891,156)**	**Ref 5.1.1**
Other adjustment for consistency with GRID		
Net Power Cost Deferral	(27,567,522)	**Ref 5.1.1**

PacifiCorp
Oregon General Rate Case - December 2013
Net Power Cost Adjustment
Oregon Solar Project

	Total	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Total Energy impact	**(145,921)**	(4,909)	(8,491)	(8,459)	(12,831)	(12,537)	(13,067)	(20,491)	(21,393)	(18,040)	(11,944)	(7,477)	(6,281)
	Ref. 5.1												

Reconciliation of Net Power Cost Adjustment to TAM filing

The net power cost adjustment adjusts the base period to the normalized net power cost forecast for calendar year 2013. The TAM adjustment adjusts the net power costs from the CY 2012 to the normalized net power cost forecast for CY 2013.

Net Power Cost Adjustment	Total Company	Oregon Portion
Normalized net power costs for CY 2013	1,504,095,928	370,158,430
Base period net power costs - 12 months ended June 2011	1,270,369,644	304,688,381
Net power cost adjustment in filing	233,726,284	65,470,049
TAM filing		
Normalized net power costs for CY 2013	1,504,095,928	370,158,430
UE - 227 Final net power costs for CY 2012	1,463,120,302	366,682,292
	40,975,626	3,476,138
Load change		6,426,615
Increase Including Load Change	40,975,626	9,902,753

PacifiCorp
PacifiCorp
Net Power Cost Adjustment
CY 2013 TAM

		Total Company					Oregon Allocated	
	ACCT.	UE-227 Final TAM CY 2012	TAM CY 2013	Factor	Factors CY 2012	Factors CY 2013	Final TAM CY 2012	TAM CY 2013
Sales for Resale								
Existing Firm PPL	447	25,687,328	25,837,906	SG	26.314%	25.777%	6,759,357	6,660,277
Existing Firm UPL	447	25,490,583	30,104,809	SG	26.314%	25.777%	6,707,586	7,760,163
Post-Merger Firm	447	463,122,887	405,383,133	SG	26.314%	25.777%	121,866,048	104,496,238
Non-Firm	447	-		SE	24.796%	24.314%	-	-
Total Sales for Resale		514,300,798	461,325,848				135,332,992	118,916,679
Purchased Power								
Existing Firm Demand PPL	555	3,986,517	5,432,688	SG	26.314%	25.777%	1,049,011	1,400,392
Existing Firm Demand UPL	555	46,848,001	51,932,017	SG	26.314%	25.777%	12,327,572	13,386,597
Existing Firm Energy	555	26,937,826	37,962,219	SE	24.796%	24.314%	6,679,426	9,229,951
Post-merger Firm	555	570,696,383	582,081,940	SG	26.314%	25.777%	150,172,913	150,044,164
Secondary Purchases	555	-		SE	24.796%	24.314%	-	-
Other Generation Expense	555	3,633,079	5,498,155	SG	26.314%	25.777%	956,008	1,417,268
Total Purchased Power		652,101,807	682,907,019				171,184,929	175,478,372
Wheeling Expense								
Existing Firm PPL	565	27,123,063	24,712,270	SG	26.314%	25.777%	7,137,156	6,370,120
Existing Firm UPL	565	-	-	SG	26.314%	25.777%	-	-
Post-merger Firm	565	102,633,849	103,920,275	SG	26.314%	25.777%	27,007,047	26,787,690
Non-Firm	565	2,855,823	2,899,400	SE	24.796%	24.314%	708,122	704,946
Total Wheeling Expense		132,612,736	131,531,945				34,852,325	33,862,757
Fuel Expense								
Fuel Consumed - Coal	501	700,992,991	717,884,157	SE	24.796%	24.314%	173,816,205	174,542,900
Fuel Consumed - Coal (Cholla)	501	57,666,585	56,457,816	SSECH/SE	25.371%	24.314%	14,630,638	13,726,882
Fuel Consumed - Gas	501	6,860,109	6,359,116	SE	24.796%	24.314%	1,701,013	1,546,125
Natural Gas Consumed	547	420,276,987	349,046,222	SE	24.796%	24.314%	104,210,672	84,865,419
Simple Cycle Comb. Turbines	547	35,476,150	17,197,901	SSECT/SE	24.788%	24.314%	8,793,761	4,181,415
Steam from Other Sources	503	3,760,489	4,183,520	SE	24.796%	24.314%	932,440	1,017,161
Total Fuel Expense		1,225,033,311	1,151,128,733				304,084,729	279,879,902
Net Power Cost		1,495,447,056	1,504,241,849				374,788,992	370,304,351
Liquidated Damages Adjustment		(405,489)		SG	26.314%	25.655%	(106,700)	
UE-227 Settlement Adjustment		(31,921,264)					(8,000,000)	
Oregon Situs Solar Project Benefit			(145,921)	OR	100.000%	100.000%		(145,921)
Total Net of Adjustments		1,463,120,302	1,504,095,928				366,682,292	370,158,430
			40,975,626				Increase Absent Load Change	3,476,138
							Oregon-allocated NPC Baseline in Rates from UE-227	366,682,292
							$ Change due to load variance from UE-227 forecast	(6,426,615)
							2013 Recovery of NPC in Rates	360,255,677
							Increase Including Load Change	**9,902,753**

PacifiCorp PAGE 5.2
Oregon General Rate Case - December 2013
James River Royalty Offset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenue	456	3	4,679,599	SG	25.777%	1,206,267	Below

Adjustment Detail:

	12 Months Ended December 2013	
James River Offset		
Capital Recovery	4,095,230	
Major Maintenance Allowance	584,369	
Total Offset	4,679,599	Above

Description of Adjustment:

On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's net power costs as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This pro forma adjustment adds the royalty offset to FERC account 456, other electric revenue, for the twelve-month period ending December 2013, the same period used in determining pro forma net power costs in this filing.

PacifiCorp PAGE 5.3
Oregon General Rate Case - December 2013
Little Mountain

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment To Revenue:							
Other Electric Revenue	456	3	(3,825,706)	SG	25.777%	(986,158)	5.3.1
Adjustment to Expense:							
Generation Expense	548	3	(1,157,038)	SG	25.777%	(298,251)	5.3.1

Description of Adjustment:

The Company has provided both electricity and steam from the Little Mountain plant to the Great Salt Lake Minerals Company since 1968. The current contract associated with this arrangement expires on February 28, 2012. However, on August 1, 2011 the electrical generator at the Little Mountain Plant experienced a significant electrical fault. In August 2011, the Company installed a mobile packaged boiler in order to provide enough steam for Great Salt Lake Minerals to maintain its operations. Since the plant no longer produces power due to the generator failure on August 1, this adjustment removes the steam revenue and related O&M expense to align with the net power costs. The plant balance is removed in the Retirements Adjustment No. 8.6 and depreciation expense and reserve balances are removed in the Depreciation Expense No. 6.1 and Depreciation Reserve No. 6.2 adjustments.

PacifiCorp
Oregon General Rate Case - December 2013
Little Mountain

Remove Little Mountain Revenue

Description	FERC Acct	Factor	12 ME June 2011	12 ME Dec 2013	Adjustment	Ref.
Steam Revenue	456	SG	3,825,706	-	**(3,825,706)**	**Ref 5.3**

Remove Little Mountain O&M Expense

Labor Expense

Description	FERC Acct	Factor	Labor Expense	Labor Escalation*	Escalated Labor O&M June 2011	Total Labor 12 ME Dec 2013	Adjustment
Generation Expense	548	SG	825,775	3.54%	855,016	-	(855,016)
				Below			

Non-Labor Expense

Description	FERC Acct	Factor	Non-Labor Expense	Non-Labor Escalation	Escalated Non-Labor O&M June 2011	Total Non-Labor 12 ME Dec 2013	Adjustment
Generation Expense	548	SG	279,370	8.11%	302,022	-	(302,022)
				Ref 4.12.8			

Total O&M Adjustment **(1,157,038)**
Ref 5.3

*These costs are escalated in the Wage and Employee Benefit adjustment, so the amount of this adjustment is increased based on the overall escalation to completely remove these expenses including escalation from results of operations.

June 2011 Total Utility Labor =	509,923,098	Page 4.2.2
December 2013 Escalated Utility Labor =	527,979,497	Page 4.2.2
Escalation Factor	3.54%	Above

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Settlement of Costs:							
Amortization O&M Portion	557	3	874,524	SG	25.777%	225,427	5.4.1

Adjustment Detail:

Amortization O&M Portion	808,935
Escalation Rate	8.11%
Escalation Amount	65,589
Amortization O&M Portion with Escalation	874,524

Description of Adjustment:

Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake, Utah. Electric Lake is owned by the Company and provides water for the Huntington power plant. The two companies disputed the claim made by the Company that CFC's mining operations punctured the lake and caused water to flow into the Skyline mine. The two companies negotiated a settlement and release agreement for the claims made by the Company. The amortization for this settlement ended January 2011. This adjustment removes the amortization of savings from actual results.

PacifiCorp
Oregon General Rate Case - December 2013
Electric Lake Settlement

Settlement of Costs

Value of Settlement	10,087,658			
Offset O&M	71%			
Reduction of O&M	7,162,237			
Amortization Account 25399 over 3 years	-			
Amortization Account 254	-			
Reduction to Account 557	-			
Account 557 Reduction in actual results	(808,935)			
Adjustment needed to reflect reduction amount	**808,935**	**Ref 5.4**		
Reduction to Account 557	-			
Regulatory Liability Account 25399	Jun-10	Jun-11	Dec-12	Dec-13
Offset O&M Account 557	1,073,760	357,920	-	-
Amortization of Offset	(715,840)	(357,920)	-	-
Remaining Liability Balance	357,920	-	-	-
December 2012 / December 2013 Average	-			
Regulatory Asset 186.5	Jun-10	Jun-11	Dec-12	Dec-13
Set-Up Deferred Asset	3,107,258	1,139,031	-	-
Amortization	(1,968,228)	(1,139,031)	-	-
Ending Balance	1,139,031	-	-	-
December 2012 / December 2013 Average	-			
Account 186.5 balance in actual results	-			
Adjustment needed to reflect account balance	-			
December 2012 / December 2013 Average	-			
Regulatory Liability Account 254	Jun-10	Jun-11	Dec-12	Dec-13
Set-Up Deferred Asset	(2,206,878)	(808,935)	-	-
Amortization	1,397,943	808,935	-	-
Ending Balance	(808,935)	-	-	-
December 2012 / December 2013 Average	-			
Account 254 balance in actual results	-			
Adjustment needed to reflect account balance	-			
December 2012 / December 2013 Average	-			

PacifiCorp PAGE 5.5
Oregon General Rate Case - December 2013
BPA Residential Exchange

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Purchased Power Expense	555	1	22,356,044	OR	100.000%	22,356,044	
Purchased Power Expense	555	1	8,714,605	WA	0.000%	-	
Purchased Power Expense	555	1	(83,840)	ID	0.000%	-	
			30,986,809			22,356,044	

Description of Adjustment:

The Company receives a monthly purchase power credit from Bonneville Power Administration (BPA). This credit is treated as a 100% pass-through to eligible customers. Both a revenue credit and a purchase power expense credit is posted to unadjusted results which need to be removed for normalized results. This adjustment reverses the BPA purchase power expense credit recorded. The Revenue Normalizing adjustment No. 3.1 removes the revenue credit passed onto customers.

PacifiCorp PAGE 5.6
Oregon General Rate Case - December 2013
Black Cap Solar LLC Proejct

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Lease and O&M Expense	550	3	502,584	OR	100.000%	502,584	Conf. Ex. PAC/1103
Adjustment to Rate Base:							
Land	340	3	75,000	OR	100.000%	75,000	Conf. Ex. PAC/1103

Description of Adjustment:

This adjustment accounts for the test period costs related to the Black Cap Solar LLC project, which is projected to become operational in October 2012. This adjustment adds the O&M expense, the lease payment expense, and the land balance associated with the project to the test period. The net power cost benefit associated with this project is included in the NPC Adjustment (page 5.1) and the TAM.

Because this project is being procured to satisfy the Company's obligation under Oregon Statute ORS 757.370, it's classified as a state specific initiative under of the 2010 Protocol allocation methodology. As such, the costs and benefits associated with this project are situs assigned to Oregon customers.

6. DEPRECIATION &
AMORTIZATION ADJ.

The following adjustments were used to arrive at the normalized levels of depreciation and amortization expense along with the associated reserve balances reflected in the test period.

PacifiCorp
Normalized Results of Operations
Tab 6 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Total Adjustments	6.1 Depreciation / Amortization Expense	6.2 Depreciation / Amortization Reserve
1	Operating Revenues:			
2	General Business Revenues	-	-	-
3	Interdepartmental	-	-	-
4	Special Sales	-	-	-
5	Other Operating Revenues	-	-	-
6	Total Operating Revenues	-	-	-
7				
8	Operating Expenses:			
9	Steam Production	-	-	-
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	-
12	Other Power Supply	-	-	-
13	Embedded Cost Differential (ECD)	-	-	-
13	Transmission	-	-	-
14	Distribution	-	-	-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-	-	-
17	Sales	-	-	-
18	Administrative & General	-	-	-
19				
20	Total O&M Expenses	-	-	-
21				
22	Depreciation	21,767,438	21,767,438	-
23	Amortization	189,821	189,821	-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(5,813,854)	(7,334,729)	1,520,875
26	Income Taxes - State	(790,006)	(996,668)	206,662
27	Income Taxes - Def Net	-	-	-
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	-
30				
31	Total Operating Expenses:	15,353,399	13,625,863	1,727,537
32				
33	Operating Rev For Return:	(15,353,399)	(13,625,863)	(1,727,537)
34				
35	Rate Base:			
36	Electric Plant In Service	-	-	-
37	Plant Held for Future Use	-	-	-
38	Misc Deferred Debits	-	-	-
39	Elec Plant Acq Adj	-	-	-
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	-
42	Fuel Stock	-	-	-
43	Material & Supplies	-	-	-
44	Working Capital	(132,881)	(167,643)	34,761
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(132,881)	(167,643)	34,761
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(174,810,209)	-	(174,810,209)
52	Accum Prov For Amort	(5,898,357)	-	(5,898,357)
53	Accum Def Income Tax	-	-	-
54	Unamortized ITC	-	-	-
55	Customer Adv For Const	-	-	-
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	-	-
58				
59	Total Rate Base Deductions	(180,708,566)	-	(180,708,566)
60				
61	Total Rate Base:	(180,841,448)	(167,643)	(180,673,805)
62				
63	Return on Rate Base	-0.053%	-0.424%	0.371%
64				
65	Return on Equity	-0.100%	-0.802%	0.703%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(21,957,259)	(21,957,259)	-
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	(4,556,242)	(4,224)	(4,552,019)
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(17,401,017)	(21,953,036)	4,552,019
75				
76	State Income Taxes	(790,006)	(996,668)	206,662
77	Taxable Income	(16,611,011)	(20,956,368)	4,345,357
78				
79	Federal Income Taxes + Other	(5,813,854)	(7,334,729)	1,520,875
80				
81	PRICE CHANGE	1,706,702	22,592,858	(20,886,156)

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	8,387,598	SG	25.777%	2,162,084	
Steam Depreciation Expense	403SP	3	5,243,328	SG	25.777%	1,351,581	
Steam Depreciation Expense	403SP	3	48,344,957	SG	25.777%	12,461,955	
Steam Depreciation Expense	403SP	3	3,728,456	SG	25.777%	961,090	
Hydro Depreciation Expense	403HP	3	(36,256)	SG	25.777%	(9,346)	
Hydro Depreciation Expense	403HP	3	(72,802)	SG	25.777%	(18,766)	
Hydro Depreciation Expense	403HP	3	4,401,632	SG-P	25.777%	1,134,615	
Hydro Depreciation Expense	403HP	3	920,694	SG-U	25.777%	237,329	
Other Depreciation Expense	403OP	3	(126,905)	SG	25.777%	(32,713)	
Other Depreciation Expense	403OP	3	(296,048)	SG	25.777%	(76,313)	
Other Depreciation Expense	403OP	3	(4,975,015)	SG-W	25.777%	(1,282,417)	
Other Depreciation Expense	403OP	3	67,523	SG	25.777%	17,406	
Transmission Depreciation Expense	403TP	3	(385,456)	SG	25.777%	(99,360)	
Transmission Depreciation Expense	403TP	3	(22,677)	SG	25.777%	(5,846)	
Transmission Depreciation Expense	403TP	3	10,268,256	SG	25.777%	2,646,864	
Distribution Depreciation Expense	403360	3	128,420	Situs	100.000%	21,825	
Distribution Depreciation Expense	403361	3	190,978	Situs	100.000%	32,457	
Distribution Depreciation Expense	403362	3	1,981,766	Situs	100.000%	336,808	
Distribution Depreciation Expense	403364	3	2,297,435	Situs	100.000%	390,457	
Distribution Depreciation Expense	403365	3	1,573,939	Situs	100.000%	267,496	
Distribution Depreciation Expense	403366	3	733,392	Situs	100.000%	124,642	
Distribution Depreciation Expense	403367	3	1,742,580	Situs	100.000%	296,157	
Distribution Depreciation Expense	403368	3	2,668,054	Situs	100.000%	453,445	
Distribution Depreciation Expense	403369	3	1,426,621	Situs	100.000%	242,459	
Distribution Depreciation Expense	403370	3	431,057	Situs	100.000%	73,260	
Distribution Depreciation Expense	403371	3	21,195	Situs	100.000%	3,602	
Distribution Depreciation Expense	403373	3	146,360	Situs	100.000%	24,874	
General Depreciation Expense	403GP	3	105,370	CA	0.000%	-	
General Depreciation Expense	403GP	3	279,708	OR	100.000%	279,708	
General Depreciation Expense	403GP	3	174,606	WA	0.000%	-	
General Depreciation Expense	403GP	3	371,993	WYP	0.000%	-	
General Depreciation Expense	403GP	3	383,899	UT	0.000%	-	
General Depreciation Expense	403GP	3	83,430	ID	0.000%	-	
General Depreciation Expense	403GP	3	(60,924)	WYU	0.000%	-	
General Depreciation Expense	403GP	3	(138,789)	SG	25.777%	(35,776)	
General Depreciation Expense	403GP	3	(237,760)	SG	25.777%	(61,288)	
General Depreciation Expense	403GP	3	487,057	SG	25.777%	125,549	
General Depreciation Expense	403GP	3	(699,062)	SO	27.165%	(189,900)	
General Depreciation Expense	403GP	3	(38,150)	SG	25.777%	(9,834)	
General Depreciation Expense	403GP	3	318	SG	25.777%	82	
General Depreciation Expense	403GP	3	(189,655)	CN	29.363%	(55,688)	
General Depreciation Expense	403GP	3	(4,367)	SE	24.314%	(1,062)	
Total Depreciation Expense			89,306,754			21,767,438	6.1.2

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.6. The annualized 2012 depreciation and amortization expense for the test period is calculated by applying composite depreciation and amortization rates to the December 2012 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2013
Amortization Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	-	CA	0.000%	-	
Intangible Amortization	404IP	3	105,176	CN	29.363%	30,883	
Intangible Amortization	404IP	3	(607)	SG	25.777%	(156)	
Intangible Amortization	404IP	3	-	SG	25.777%	-	
Intangible Amortization	404IP	3	(17)	ID	0.000%	-	
Intangible Amortization	404IP	3	(5,570)	OR	100.000%	(5,570)	
Intangible Amortization	404IP	3	322,794	SE	24.314%	78,483	
Intangible Amortization	404IP	3	(3,707,586)	SG	25.777%	(955,710)	
Intangible Amortization	404IP	3	(108,164)	SG-P	25.777%	(27,882)	
Intangible Amortization	404IP	3	(5,628)	SG-U	25.777%	(1,451)	
Intangible Amortization	404IP	3	(77,056)	SG	25.777%	(19,863)	
Intangible Amortization	404IP	3	5,894,850	SO	27.165%	1,601,335	
Intangible Amortization	404IP	3	(366)	UT	0.000%	-	
Intangible Amortization	404IP	3	(445)	WA	0.000%	-	
Intangible Amortization	404IP	3	(3,883)	WYP	0.000%	-	
Intangible Amortization	404IP	3	-	WYU	0.000%	-	
Hydro Amortization	404HP	3	-	SG	25.777%	-	
Hydro Amortization	404HP	3	80,700	SG-P	25.777%	20,802	
Hydro Amortization	404HP	3	(1,885)	SG-U	25.777%	(486)	
Other Amortization	404OP	3	-	SG	25.777%	-	
General Amortization	404GP	3	(160,577)	CA	0.000%	-	
General Amortization	404GP	3	3,285	CN	29.363%	965	
General Amortization	404GP	3	(529,812)	OR	100.000%	(529,812)	
General Amortization	404GP	3	(6,319)	SO	27.165%	(1,717)	
General Amortization	404GP	3	(72)	UT	0.000%	-	
General Amortization	404GP	3	10,202	WA	0.000%	-	
General Amortization	404GP	3	116,386	WYP	0.000%	-	
General Amortization	404GP	3	42	WYU	0.000%	-	
			1,925,451			189,821	6.1.3

Description of Adjustment:

This adjustment reflects the incremental amortization expense that is calculated on the plant additions included in this filing in adjustment 8.6. The annualized 2012 depreciation and amortization expense for the test period is calculated by applying composite depreciation and amortization rates to the December 2012 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2011 Expense	Annualized 12 ME Dec 2012 Expense	Adjustment to Test Period
DEPRECIATION EXPENSE					
Steam Production Plant:					
Pre-merger Pacific	403SP	SG	21,699,385	30,086,982	8,387,598
Pre-merger Utah	403SP	SG	24,153,559	29,396,887	5,243,328
Post-merger	403SP	SG	69,042,358	117,387,315	48,344,957
Post-merger	403SP	SG	7,849,360	11,577,816	3,728,456
Total Steam Plant			122,744,661	188,449,000	65,704,339
Hydro Production Plant:					
Pre-merger Pacific	403HP	SG	2,929,785	2,893,529	(36,256)
Pre-merger Utah	403HP	SG	1,004,089	931,287	(72,802)
Post-merger	403HP	SG-P	4,814,922	9,216,554	4,401,632
Post-merger	403HP	SG-U	2,344,785	3,265,479	920,694
Total Hydro Plant			11,093,582	16,306,849	5,213,267
Other Production Plant:					
Pre-merger Utah	403OP	SG	123,593	(3,312)	(126,905)
Post-merger	403OP	SG	31,909,006	31,612,958	(296,048)
Post-merger Wind	403OP	SG-W	78,016,380	73,041,365	(4,975,015)
Post-merger	403OP	SG	2,625,250	2,692,774	67,523
Total Other Production Plant			112,674,229	107,343,785	(5,330,444)
Transmission Plant:					
Pre-merger Pacific	403TP	SG	11,173,740	10,788,283	(385,456)
Pre-merger Utah	403TP	SG	12,421,176	12,398,498	(22,677)
Post-merger	403TP	SG	55,933,484	66,201,741	10,268,256
Total Transmission Plant			79,528,400	89,388,522	9,860,122
Distribution Plant:					
California	403360-73	CA	1,145,120	6,721,753	5,576,633
Oregon	403360-73	OR	48,580,477	50,847,961	2,267,483
Washington	403360-73	WA	12,492,977	12,825,736	332,759
Eastern Wyoming	403360-73	WYP	13,381,273	14,516,251	1,134,978
Utah	403360-73	UT	58,007,630	61,305,861	3,298,231
Idaho	403360-73	ID	7,044,028	7,584,857	540,829
Western Wyoming	403360-73	WYU	2,657,099	2,847,983	190,884
Total Distribution Plant			143,308,604	156,650,401	13,341,797
General Plant:					
California	403GP	CA	237,720	343,090	105,370
Oregon	403GP	OR	3,740,188	4,019,896	279,708
Washington	403GP	WA	1,318,138	1,492,744	174,606
Eastern Wyoming	403GP	WYP	1,898,403	2,270,396	371,993
Utah	403GP	UT	3,820,546	4,204,445	383,899
Idaho	403GP	ID	760,905	844,335	83,430
Western Wyoming	403GP	WYU	362,585	301,661	(60,924)
Pre-merger Pacific	403GP	SG	229,826	91,037	(138,789)
Pre-merger Utah	403GP	SG	376,406	138,646	(237,760)
Post-merger	403GP	SG	6,076,018	6,563,075	487,057
General Office	403GP	SO	14,631,939	13,932,877	(699,062)
General Office	403GP	SG	139,134	100,984	(38,150)
General Office	403GP	SG	6,010	6,328	318
Customer Service	403GP	CN	1,706,446	1,516,791	(189,655)
Fuel Related	403GP	SE	21,246	16,878	(4,367)
Total General Plant			35,325,510	35,843,183	517,673
Total Depreciation Expense			504,674,985	593,981,739	**89,306,754**
					Ref 6.1

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2011 Expense	Annualized 12 ME Dec 2012 Expense	Adjustment to Test Period
AMORTIZATION EXPENSE					
Intangible Plant:					
California	404IP	CA	-	-	-
Customer Service	404IP	CN	5,695,883	5,801,059	105,176
Pre-merger Utah	404IP	SG	16,758	16,151	(607)
Pre-merger Pacific	404IP	SG	-	-	-
Idaho	404IP	ID	20,532	20,515	(17)
Oregon	404IP	OR	14,532	8,962	(5,570)
Fuel Related	404IP	SE	13,653	336,447	322,794
Post-merger	404IP	SG	9,020,716	5,313,130	(3,707,586)
Hydro Relicensing	404IP	SG-P	2,615,539	2,507,375	(108,164)
Hydro Relicensing	404IP	SG-U	307,800	302,172	(5,628)
Post-merger	404IP	SG	77,056	-	(77,056)
General Office	404IP	SO	15,076,510	20,971,360	5,894,850
Utah	404IP	UT	13,251	12,885	(366)
Washington	404IP	WA	445	-	(445)
Eastern Wyoming	404IP	WYP	147,182	143,299	(3,883)
Western Wyoming	404IP	WYU	-	-	-
Total Intangible Plant			33,019,857	35,433,357	2,413,500
Hydro Production Plant:					
Pre-merger Pacific	404HP	SG	-	-	-
Post-merger	404HP	SG-P	168,315	249,015	80,700
Post-merger	404HP	SG-U	46,417	44,532	(1,885)
Total Hydro Plant			214,732	293,548	78,815
Other Production Plant:					
Post-merger	404OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	404GP	CA	236,225	75,648	(160,577)
General Office	404GP	CN	270,082	273,367	3,285
Oregon	404GP	OR	777,880	248,068	(529,812)
General Office	404GP	SO	1,265,577	1,259,258	(6,319)
Utah	404GP	UT	799	728	(72)
Washington	404GP	WA	111,163	121,365	10,202
Eastern Wyoming	404GP	WYP	541,786	658,172	116,386
Western Wyoming	404GP	WYU	4,742	4,784	42
Total General Plant			3,208,254	2,641,390	(566,864)
Total Amortization			36,442,844	38,368,295	**1,925,451**
					Ref 6.1.1
Total Depreciation and Amortization			541,117,829	632,350,034	91,232,205
				Ref. 6.1.13	

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Jun 2011	Depreciation Expense Jun 2011	Adjustments	Adjusted EPIS Balance Jul 2011	Depreciation Expense Jul 2011	Adjustments	Adjusted EPIS Balance Aug 2011	Depreciation Expense Aug 2011	Adjustments	Adjusted EPIS Balance Sep 2011	Depreciation Expense Sep 2011	Adjustments
DEPRECIATION EXPENSE														
Steam Production Plant:														
Pre-merger Pacific	SG	2.839%	1,090,045,310	2,578,667	(1,687,650)	1,088,357,661	2,576,670	(1,687,650)	1,086,670,011	2,572,678	(1,687,650)	1,084,982,362	2,568,686	(1,687,650)
Pre-merger Utah	SG	2.506%	1,194,738,007	2,494,547	(1,197,003)	1,193,541,004	2,493,298	(1,197,003)	1,192,344,001	2,490,798	(1,197,003)	1,191,146,998	2,488,299	(1,197,003)
Post-merger	SG	3.027%	3,125,357,446	7,882,552	9,693,666	3,135,051,112	7,894,776	1,161,498	3,136,212,609	7,908,465	312,795	3,136,525,404	7,910,324	11,674,247
Geothermal - Blundell	SG	3.027%	26,273,155	66,264	(17,367)	26,255,788	66,242	(17,367)	26,238,421	66,199	(17,367)	26,221,054	66,155	(17,367)
Pollution Control Equipment	SG	3.027%	-	-	1,947,489	1,947,489	2,456	13,526,940	15,474,429	21,970	1,307,520	16,781,949	40,677	388,419
Pollution Control Equipment	SG	2.312%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	520,843,160	1,003,310	(1,807,429)	519,035,731	1,001,569	(1,807,429)	517,228,302	998,087	(1,807,429)	515,420,872	994,606	(1,687,371)
Total Steam Plant			5,957,257,079	14,025,340	6,931,706	5,964,188,785	14,035,011	9,978,988	5,974,167,773	14,058,197	(3,089,134)	5,971,078,639	14,068,747	7,473,275
Hydro Production Plant:														
Pre-merger Pacific	SG	1.546%	193,652,145	249,506	(163,300)	193,488,846	249,400	(163,300)	193,325,546	249,190	(163,300)	193,162,246	248,980	(163,300)
Pre-merger Utah	SG	2.230%	43,721,885	81,245	(72,500)	43,649,384	81,178	(72,500)	43,576,884	81,043	(72,500)	43,504,384	80,909	(747,433)
Post-merger	SG-P	1.964%	244,748,314	400,609	151,652	244,899,967	400,733	15,950	244,915,917	400,870	(35,100)	244,880,817	400,855	1,698,789
Post-merger	SG-U	2.749%	96,382,433	220,830	951,646	97,334,078	221,920	229,901	97,563,979	223,274	47,183	97,611,162	223,591	(300,744)
Total Hydro Plant			578,504,777	952,190	867,498	579,372,275	953,232	10,051	579,382,326	954,377	(223,717)	579,158,609	954,334	487,313
Other Production Plant:														
Pre-merger Utah	SG	10.234%	1,207,690	10,299	(1,809)	1,205,881	10,292	(1,809)	1,204,072	10,276	(1,809)	1,202,263	10,261	(1,809)
Post-merger	SG	2.602%	1,230,406,793	2,667,682	754,423	1,231,161,216	2,668,500	(2,278,397)	1,228,882,819	2,666,848	(2,166,554)	1,226,716,265	2,662,029	(2,166,554)
Post-merger Wind	SG-W	4.042%	1,798,555,325	6,057,661	(52,068)	1,798,503,257	6,057,573	(525,420)	1,797,977,838	6,056,601	1,018,509	1,798,996,346	6,057,431	574,940
Post-merger	SG	3.321%	78,966,675	218,514	(68,760)	78,897,914	218,419	(68,760)	78,829,154	218,229	(68,760)	78,760,393	218,038	(68,760)
Total Other Plant			3,109,136,483	8,954,157	631,786	3,109,768,269	8,954,784	(2,874,386)	3,106,893,883	8,951,954	(1,218,615)	3,105,675,267	8,947,760	(1,662,184)
Transmission Plant:														
Pre-merger Pacific	SG	1.944%	562,508,283	911,057	(402,614)	562,105,669	910,731	(402,614)	561,703,055	910,079	(402,614)	561,300,441	909,427	(402,614)
Pre-merger Utah	SG	1.897%	659,011,430	1,041,671	(297,993)	658,713,437	1,041,436	(297,993)	658,415,443	1,040,965	(297,993)	658,117,450	1,040,494	(297,993)
Post-merger	SG	1.890%	3,233,142,263	5,092,630	7,766,727	3,240,908,990	5,098,747	12,599,277	3,253,508,267	5,114,787	6,413,636	3,259,921,903	5,129,761	4,997,992
Total Transmission Plant			4,454,661,976	7,045,359	7,066,120	4,461,728,096	7,050,914	11,898,669	4,473,626,765	7,065,830	5,713,029	4,479,339,794	7,079,681	4,297,384
Distribution Plant:														
California	CA	2.881%	219,979,421	528,088	389,697	220,369,118	528,555	636,262	221,005,379	529,787	1,771,151	222,776,531	532,677	882,422
Oregon	OR	2.847%	1,723,708,872	4,089,795	4,918,885	1,728,627,757	4,095,630	7,279,641	1,735,907,398	4,110,102	3,085,956	1,738,993,355	4,122,399	3,518,542
Washington	WA	3.121%	401,662,069	1,044,579	793,992	402,456,061	1,045,612	311,917	402,767,978	1,047,050	714,232	403,482,210	1,048,384	(348,327)
Eastern Wyoming	WYP	2.827%	477,607,666	1,125,272	3,977,329	481,584,995	1,129,957	3,733,300	485,318,295	1,139,041	2,915,407	488,233,702	1,146,873	5,610,241
Utah	UT	2.482%	2,363,965,358	4,890,422	5,153,790	2,369,119,149	4,895,753	5,971,289	2,375,090,438	4,907,260	6,705,122	2,381,795,560	4,920,372	7,646,887
Idaho	ID	2.570%	279,009,730	597,648	422,990	279,432,720	598,101	608,521	280,041,241	599,206	752,262	280,793,503	600,663	982,290
Western Wyoming	WYU	2.990%	96,464,758	240,393	(68,439)	96,396,319	240,308	(68,439)	96,327,881	240,137	(68,439)	96,259,442	239,967	(68,439)
Total Distribution Plant			5,562,397,875	12,516,196	15,588,245	5,577,986,119	12,533,916	18,472,491	5,596,458,611	12,572,582	15,875,691	5,612,334,302	12,611,334	18,223,617
General Plant:														
California	CA	2.192%	11,931,434	21,799	(39,229)	11,892,205	21,763	(21,104)	11,871,101	21,708	192,007	12,063,108	21,864	174,082
Oregon	OR	2.472%	142,070,133	292,657	(268,806)	141,801,327	292,380	(376,629)	141,424,698	291,716	3,052,946	144,477,644	294,472	2,293,893
Washington	WA	3.436%	39,405,786	112,840	485,576	39,891,362	113,535	317,319	40,208,682	114,685	1,227,701	41,436,382	116,897	971,799
Eastern Wyoming	WYP	3.832%	49,730,091	158,798	1,339,006	51,069,098	160,936	35,681	51,104,778	163,131	1,808,438	52,913,216	166,075	841,029
Utah	UT	2.218%	167,649,575	309,942	5,667,117	173,316,692	315,180	(34,960)	173,281,732	320,387	710,849	173,992,580	321,011	1,513,390
Idaho	ID	2.283%	33,117,528	63,014	1,399,960	34,517,488	64,346	(71,891)	34,445,597	65,610	38,315	34,483,912	65,578	235,324
Western Wyoming	WYU	2.730%	11,902,959	27,080	(48,190)	11,854,769	27,025	(48,190)	11,806,579	26,916	(48,190)	11,758,388	26,806	(48,190)
Pre-merger Pacific	SG	3.128%	3,823,163	9,966	(53,738)	3,769,426	9,896	(53,738)	3,715,688	9,756	(53,738)	3,661,950	9,616	(53,738)
Pre-merger Utah	SG	2.484%	7,619,888	15,772	(119,261)	7,500,627	15,649	(119,261)	7,381,365	15,402	(119,261)	7,262,104	15,155	(119,261)
Post-merger	SG	3.322%	186,178,898	515,416	(644,983)	185,533,915	514,523	1,214,804	186,748,719	515,312	1,010,026	187,758,745	518,391	(14,345)
General Office	SO	6.440%	228,293,763	1,225,105	(836,510)	227,457,253	1,222,861	(1,384,578)	226,072,675	1,216,901	(204,331)	225,868,344	1,212,638	(681,101)
General Office	SG	2.915%	4,002,876	9,723	(30,869)	3,972,007	9,686	(30,869)	3,941,138	9,611	(30,869)	3,910,269	9,536	(30,869)
General Office	SG	3.287%	204,151	559	(656)	203,495	558	(656)	202,839	557	(656)	202,184	555	(656)
Customer Service	CN	8.065%	21,425,448	143,990	(148,992)	21,276,456	143,489	(148,992)	21,127,464	142,488	(148,992)	20,978,472	141,487	(148,992)
Fuel Related	SE	2.989%	660,194	1,645	(5,492)	654,702	1,638	(5,492)	649,209	1,624	(5,492)	643,717	1,610	(5,492)
Total General Plant			908,015,890	2,908,307	6,694,932	914,710,822	2,913,466	(728,558)	913,982,264	2,915,801	7,428,752	921,411,016	2,921,691	4,926,872
Mining Plant:														
Coal Mine	SE	3.555%	286,661,904	849,254	199,256	286,861,160	849,549	1,053,087	287,914,247	851,404	(740,975)	287,173,272	851,866	1,435,121
Total Mining Plant			286,661,904	849,254	199,256	286,861,160	849,549	1,053,087	287,914,247	851,404	(740,975)	287,173,272	851,866	1,435,121
Subtotal			20,856,635,983	47,250,802	37,979,544	20,894,615,526	47,290,872	37,810,342	20,932,425,869	47,370,146	23,745,031	20,956,170,900	47,435,413	35,181,398

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Jun 2011	Depreciation Expense Jun 2011	Adjustments	Adjusted EPIS Balance Jul 2011	Depreciation Expense Jul 2011	Adjustments	Adjusted EPIS Balance Aug 2011	Depreciation Expense Aug 2011	Adjustments	Adjusted EPIS Balance Sep 2011	Depreciation Expense Sep 2011	Adjustments
AMORTIZATION EXPENSE														
Intangible Plant:														
California	CA	0.000%	216,407	-	-	216,407	-	-	216,407	-	-	216,407	-	-
Customer Service	CN	4.806%	121,077,156	484,944	(21,129)	121,056,027	484,901	(21,129)	121,034,899	484,817	(21,129)	121,013,770	484,732	(21,129)
Pre-merger Utah	SG	2.788%	600,993	1,397	(1,219)	599,774	1,395	(1,219)	598,554	1,392	(1,219)	597,335	1,389	(1,219)
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	1.437%	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-
Oregon	OR	0.679%	1,853,709	1,048	(31,797)	1,821,912	1,039	(31,797)	1,790,115	1,021	(31,797)	1,758,317	1,003	(31,797)
Fuel Related	SE	9.509%	3,654,416	28,958	(6,503)	3,647,913	28,932	(6,503)	3,641,409	28,881	(6,503)	3,634,906	28,829	(6,503)
Post-merger	SG	3.923%	141,397,273	462,248	(936,843)	140,460,431	460,717	(826,997)	139,633,434	457,834	(874,684)	138,758,750	455,052	(819,786)
Hydro Relicensing	SG-P	2.628%	99,510,474	217,912	(229,530)	99,280,945	217,660	(229,530)	99,051,415	217,158	(229,530)	98,821,886	216,655	(229,530)
Hydro Relicensing	SG-U	3.338%	9,189,363	25,564	(7,683)	9,181,680	25,554	(7,683)	9,173,997	25,532	(7,683)	9,166,315	25,511	(7,683)
General Office	SO	5.497%	375,888,954	1,722,013	96,500	375,985,454	1,722,234	(371,199)	375,614,255	1,721,605	642,294	376,256,550	1,722,226	344,828
Utah	UT	0.429%	3,003,131	1,074	(52)	3,003,079	1,074	(52)	3,003,027	1,074	(52)	3,002,975	1,074	(52)
Washington	WA	0.000%	627,214	-	(10,434)	616,779	-	(10,434)	606,345	-	(10,434)	595,911	-	(10,434)
Eastern Wyoming	WYP	10.387%	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			759,826,327	2,958,809	(1,148,690)	758,677,637	2,957,158	(1,506,542)	757,171,094	2,952,965	(540,737)	756,630,357	2,950,123	(783,305)
Hydro Production Plant:														
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-
Post-merger	SG-U	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant			10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-
Other Production Plant:														
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-
General Plant:														
California	CA	5.332%	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-
General Office	CN	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	3.118%	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-
General Office	SO	7.580%	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-
Utah	UT	3.892%	18,702	61	-	18,702	61	-	18,702	61	-	18,702	61	-
Washington	WA	4.304%	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-
Eastern Wyoming	WYP	7.941%	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-
Western Wyoming	WYU	8.595%	55,654	399	-	55,654	399	-	55,654	399	-	55,654	399	-
Total General Plant			40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-
Subtotal			811,245,768	3,203,387	(1,148,690)	810,097,078	3,201,737	(1,506,542)	808,590,535	3,197,543	(540,737)	808,049,798	3,194,702	(783,305)
Total			21,667,881,750	50,454,189	36,830,854	21,704,712,604	50,492,609	36,303,800	21,741,016,404	50,567,689	23,204,294	21,764,220,698	50,630,115	34,398,093

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Oct 2011	Depreciation Expense Oct 2011	Adjustments	Adjusted EPIS Balance Nov 2011	Depreciation Expense Nov 2011	Adjustments	Adjusted EPIS Balance Dec 2011	Depreciation Expense Dec 2011	Adjustments	Adjusted EPIS Balance Jan 2012	Depreciation Expense Jan 2012	Adjustments
DEPRECIATION EXPENSE														
Steam Production Plant:														
Pre-merger Pacific	SG	2.839%	1,083,294,712	2,564,693	(1,687,650)	1,081,607,062	2,560,701	(1,687,650)	1,079,919,413	2,556,708	(1,671,972)	1,078,247,440	2,552,735	(1,671,972)
Pre-merger Utah	SG	2.506%	1,189,949,995	2,485,800	(1,197,003)	1,188,752,991	2,483,301	(1,197,003)	1,187,555,988	2,480,801	(1,189,808)	1,186,366,180	2,478,310	(1,189,808)
Post-merger	SG	3.027%	3,148,199,651	7,925,441	50,061,670	3,198,261,321	8,003,294	17,802,304	3,216,063,624	8,088,874	(1,090,100)	3,214,973,524	8,109,950	(96,199)
Geothermal - Blundell	SG	3.027%	26,203,687	66,111	(17,367)	26,186,320	66,067	175,590	26,361,910	66,267	(17,426)	26,344,484	66,466	(17,426)
Pollution Control Equipment	SG	3.027%	17,170,368	42,816	149,412,712	166,583,080	231,725	8,173,906	174,756,986	430,452	1,567,014	176,324,000	442,736	2,948,913
Pollution Control Equipment	SG	2.312%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	513,733,502	991,240	5,029,472	518,762,974	994,459	(760,327)	518,002,647	998,570	(1,797,572)	516,205,074	996,107	(1,797,572)
Total Steam Plant			5,978,551,913	14,076,100	201,601,834	6,180,153,747	14,339,545	22,506,821	6,202,660,568	14,621,673	(4,199,865)	6,198,460,703	14,646,302	(1,824,064)
Hydro Production Plant:														
Pre-merger Pacific	SG	1.546%	192,998,946	248,769	(3,772,979)	189,225,967	246,233	(163,300)	189,062,668	243,698	(159,430)	188,903,238	243,490	(159,430)
Pre-merger Utah	SG	2.230%	42,756,951	80,147	(72,500)	42,684,451	79,385	(72,500)	42,611,951	79,250	(70,660)	42,541,291	79,117	(70,660)
Post-merger	SG-P	1.964%	246,579,606	402,216	7,599,724	254,179,329	409,826	26,151,193	280,330,523	437,448	234,863	280,565,385	459,043	2,695,842
Post-merger	SG-U	2.749%	97,310,419	223,301	13,478	97,323,897	222,972	2,717,361	100,041,258	226,100	(117,769)	99,923,489	229,078	(117,769)
Total Hydro Plant			579,645,922	954,433	3,767,722	583,413,644	958,416	28,632,755	612,046,399	986,496	(112,996)	611,933,403	1,010,728	2,347,984
Other Production Plant:														
Pre-merger Utah	SG	10.234%	1,200,454	10,245	(1,809)	1,198,645	10,230	(1,809)	1,196,836	10,214	(1,793)	1,195,043	10,199	(1,793)
Post-merger	SG	2.602%	1,224,549,710	2,657,332	(1,365,584)	1,223,184,126	2,653,503	(1,201,585)	1,221,982,541	2,650,720	(5,858,000)	1,216,124,541	2,643,067	(2,151,721)
Post-merger Wind	SG-W	4.042%	1,799,571,286	6,060,115	2,316,591	1,801,887,877	6,064,984	2,050,535	1,803,938,412	6,072,338	(57,048)	1,803,881,364	6,075,695	806,294
Post-merger	SG	3.321%	78,691,633	217,848	176,155	78,867,788	217,997	1,682,869	80,550,657	220,569	(70,140)	80,480,517	222,800	982,488
Total Other Plant			3,104,013,083	8,945,540	1,125,353	3,105,138,436	8,946,714	2,530,009	3,107,668,445	8,953,842	(5,986,980)	3,101,681,465	8,951,762	(364,731)
Transmission Plant:														
Pre-merger Pacific	SG	1.944%	560,897,827	908,775	(607,831)	560,289,996	907,956	(402,614)	559,887,382	907,138	(400,738)	559,486,644	906,488	(400,738)
Pre-merger Utah	SG	1.897%	657,819,456	1,040,023	(297,993)	657,521,463	1,039,552	(297,993)	657,223,469	1,039,081	(297,185)	656,926,284	1,038,610	(297,185)
Post-merger	SG	1.890%	3,264,919,895	5,138,748	3,997,685	3,268,917,580	5,145,833	15,929,856	3,284,847,436	5,161,527	14,440,631	3,299,288,067	5,185,446	2,149,700
Total Transmission Plant			4,483,637,179	7,087,546	3,091,861	4,486,729,039	7,093,341	15,229,248	4,501,958,287	7,107,746	13,742,708	4,515,700,995	7,130,544	1,451,777
Distribution Plant:														
California	CA	2.881%	223,658,953	535,862	1,134,768	224,793,721	538,283	2,664,793	227,458,514	542,844	448,938	227,907,453	546,581	477,844
Oregon	OR	2.847%	1,742,511,897	4,130,234	6,199,203	1,748,711,100	4,141,762	10,726,133	1,759,437,233	4,161,842	1,890,994	1,761,328,227	4,176,810	1,942,070
Washington	WA	3.121%	403,133,883	1,048,860	1,321,670	404,455,552	1,050,125	1,507,000	405,962,552	1,053,803	358,726	406,321,278	1,056,230	400,714
Eastern Wyoming	WYP	2.827%	493,843,943	1,156,916	3,572,171	497,416,115	1,167,734	2,237,434	499,653,549	1,174,578	934,998	500,588,547	1,178,315	898,281
Utah	UT	2.482%	2,389,442,447	4,935,217	5,374,312	2,394,816,759	4,948,686	15,985,909	2,410,802,667	4,970,780	931,746	2,411,734,413	4,988,280	740,117
Idaho	ID	2.570%	281,775,793	602,521	770,098	282,545,891	604,398	650,151	283,196,042	605,919	891,639	284,087,681	607,570	868,324
Western Wyoming	WYU	2.990%	96,191,003	239,796	(68,439)	96,122,565	239,626	(68,439)	96,054,126	239,455	(68,147)	95,985,979	239,285	(68,147)
Total Distribution Plant			5,630,557,919	12,649,406	18,303,784	5,648,861,703	12,690,614	33,702,981	5,682,564,684	12,749,220	5,388,894	5,687,953,578	12,793,069	5,259,202
General Plant:														
California	CA	2.192%	12,237,190	22,199	53,211	12,290,402	22,406	2,178,129	14,468,531	24,445	8,474	14,477,005	26,442	46,825
Oregon	OR	2.472%	146,771,537	299,979	1,493,875	148,265,412	303,881	6,082,537	154,347,950	311,684	713,937	155,061,886	318,684	2,599,989
Washington	WA	3.436%	42,408,182	120,046	143,332	42,551,514	121,643	524,996	43,076,510	122,599	(74,950)	43,001,560	123,244	446,537
Eastern Wyoming	WYP	3.832%	53,754,245	170,305	829,150	54,583,395	172,972	876,265	55,459,660	175,694	824,545	56,284,205	178,410	447,437
Utah	UT	2.218%	175,505,970	323,067	1,846,094	177,352,065	326,173	4,406,831	181,758,896	331,953	78,900	181,837,796	336,099	1,531,602
Idaho	ID	2.283%	34,719,236	65,838	75,680	34,794,916	66,134	246,402	35,041,317	66,441	(8,006)	35,033,312	66,667	404,770
Western Wyoming	WYU	2.730%	11,710,198	26,696	(48,190)	11,662,007	26,587	(48,190)	11,613,817	26,477	(47,025)	11,566,792	26,369	(47,025)
Pre-merger Pacific	SG	3.128%	3,608,212	9,476	(53,738)	3,554,475	9,336	(53,738)	3,500,737	9,196	(49,206)	3,451,531	9,062	(49,206)
Pre-merger Utah	SG	2.484%	7,142,842	14,908	(119,261)	7,023,581	14,661	(119,261)	6,904,320	14,414	(108,062)	6,796,258	14,179	(108,062)
Post-merger	SG	3.322%	187,744,400	519,770	(46,780)	187,697,620	519,685	5,672,689	193,370,309	527,472	(663,764)	192,706,545	534,406	194,340
General Office	SO	6.440%	225,187,243	1,210,262	(953,731)	224,233,512	1,205,876	3,293,445	227,526,957	1,212,153	(478,891)	227,048,066	1,219,705	(1,533,723)
General Office	SG	2.915%	3,879,400	9,461	(30,869)	3,848,531	9,386	(30,869)	3,817,663	9,311	(29,441)	3,788,222	9,238	(29,441)
General Office	SG	3.287%	201,528	553	(656)	200,872	551	(656)	200,216	549	(643)	199,573	548	(643)
Customer Service	CN	8.065%	20,829,480	140,486	(148,992)	20,680,488	139,484	(148,992)	20,531,496	138,483	(143,627)	20,387,870	137,500	(143,627)
Fuel Related	SE	2.989%	638,225	1,597	(5,492)	632,732	1,583	(5,492)	627,240	1,569	(5,218)	622,021	1,556	(5,218)
Total General Plant			926,337,888	2,934,643	3,033,634	929,371,522	2,940,357	22,874,096	952,245,618	2,972,442	17,024	952,262,642	3,002,108	3,754,557
Mining Plant:														
Coal Mine	SE	3.555%	288,608,393	852,895	(646,265)	287,962,128	854,063	3,027,498	290,989,625	857,590	1,874,215	292,863,841	864,851	(23,791)
Total Mining Plant			288,608,393	852,895	(646,265)	287,962,128	854,063	3,027,498	290,989,625	857,590	1,874,215	292,863,841	864,851	(23,791)
Subtotal			20,991,352,298	47,500,562	230,277,922	21,221,630,220	47,823,050	128,503,407	21,350,133,627	48,249,009	10,723,000	21,360,856,627	48,399,365	10,600,933

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Oct 2011	Depreciation Expense Oct 2011	Adjustments	Adjusted EPIS Balance Nov 2011	Depreciation Expense Nov 2011	Adjustments	Adjusted EPIS Balance Dec 2011	Depreciation Expense Dec 2011	Adjustments	Adjusted EPIS Balance Jan 2012	Depreciation Expense Jan 2012	Adjustments
AMORTIZATION EXPENSE														
Intangible Plant:														
California	CA	0.000%	216,407	-	-	216,407	-	-	216,407	-	-	216,407	-	-
Customer Service	CN	4.806%	120,992,641	484,648	(21,129)	120,971,513	484,563	(21,129)	120,950,384	484,478	(21,106)	120,929,278	484,394	(21,106)
Pre-merger Utah	SG	2.788%	596,116	1,387	(1,219)	594,896	1,384	(1,219)	593,677	1,381	(1,205)	592,472	1,378	(1,205)
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	1.437%	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-
Oregon	OR	0.679%	1,726,520	985	(31,797)	1,694,723	967	(31,797)	1,662,925	949	(28,525)	1,634,401	932	(28,525)
Fuel Related	SE	9.509%	3,628,403	28,778	(6,503)	3,621,900	28,726	(6,503)	3,615,397	28,675	(6,434)	3,608,963	28,624	(6,434)
Post-merger	SG	3.923%	137,938,964	452,282	(878,475)	137,060,489	449,506	351,579	137,412,067	448,645	(855,498)	136,556,569	447,821	(855,498)
Hydro Relicensing	SG-P	2.628%	98,592,356	216,153	(229,530)	98,362,827	215,650	(229,530)	98,133,297	215,147	(226,353)	97,906,944	214,648	(226,353)
Hydro Relicensing	SG-U	3.338%	9,158,632	25,490	(7,683)	9,150,949	25,468	(7,683)	9,143,267	25,447	(7,644)	9,135,622	25,426	(7,644)
General Office	SO	5.497%	376,601,378	1,724,487	(117,638)	376,483,740	1,725,007	2,308,157	378,791,897	1,730,025	390,697	379,182,594	1,736,207	(509,454)
Utah	UT	0.429%	3,002,923	1,074	(52)	3,002,871	1,074	(52)	3,002,819	1,074	(52)	3,002,767	1,074	(52)
Washington	WA	0.000%	585,476	-	(10,434)	575,042	-	(10,434)	564,608	-	(9,393)	555,215	-	(9,393)
Eastern Wyoming	WYP	10.387%	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			755,847,052	2,948,934	(1,304,460)	754,542,592	2,945,997	2,351,389	756,893,981	2,949,473	(765,513)	756,128,468	2,954,155	(1,665,663)
Hydro Production Plant:														
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-
Post-merger	SG-U	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant			10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-
Other Production Plant:														
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-
General Plant:														
California	CA	5.332%	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-
General Office	CN	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	3.118%	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-
General Office	SO	7.580%	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-
Utah	UT	3.892%	18,702	61	-	18,702	61	-	18,702	61	-	18,702	61	-
Washington	WA	4.304%	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-
Eastern Wyoming	WYP	7.941%	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-
Western Wyoming	WYU	8.595%	55,654	399	-	55,654	399	-	55,654	399	-	55,654	399	-
Total General Plant			40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-
Subtotal			807,266,493	3,193,512	(1,304,460)	805,962,034	3,190,575	2,351,389	808,313,423	3,194,051	(765,513)	807,547,910	3,198,733	(1,665,663)
Total			21,798,618,791	50,694,074	228,973,462	22,027,592,254	51,013,625	130,854,796	22,158,447,050	51,443,060	9,957,487	22,168,404,537	51,598,097	8,935,270

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Feb 2012	Depreciation Expense Feb 2012	Adjustments	Adjusted EPIS Balance Mar 2012	Depreciation Expense Mar 2012	Adjustments	Adjusted EPIS Balance Apr 2012	Depreciation Expense Apr 2012	Adjustments	Adjusted EPIS Balance May 2012	Depreciation Expense May 2012	Adjustments
DEPRECIATION EXPENSE														
Steam Production Plant:														
Pre-merger Pacific	SG	2.839%	1,076,575,468	2,548,779	(1,671,972)	1,074,903,496	2,544,824	(1,671,972)	1,073,231,524	2,540,869	(1,671,972)	1,071,559,551	2,536,913	(1,671,972)
Pre-merger Utah	SG	2.506%	1,185,176,373	2,475,825	(1,189,808)	1,183,986,565	2,473,341	(1,189,808)	1,182,796,758	2,470,857	(1,189,808)	1,181,606,950	2,468,372	(1,189,808)
Post-merger	SG	3.027%	3,214,877,325	8,108,454	(1,285,732)	3,213,591,593	8,106,711	48,374,879	3,261,966,472	8,166,093	18,274,958	3,280,241,430	8,250,143	18,607,829
Geothermal - Blundell	SG	3.027%	26,327,059	66,422	(17,426)	26,309,633	66,378	(17,426)	26,292,207	66,334	(17,426)	26,274,781	66,290	(17,426)
Pollution Control Equipment	SG	3.027%	179,272,912	448,430	12,425,078	191,697,990	467,818	100,179,753	291,877,743	609,820	126,871,285	418,749,028	896,146	48,719,053
Pollution Control Equipment	SG	2.312%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	514,407,502	992,644	(1,520,794)	512,886,708	989,448	(1,797,572)	511,089,136	986,252	(1,797,572)	509,291,564	982,789	(1,480,510)
Total Steam Plant			6,196,636,639	14,640,555	6,739,346	6,203,375,985	14,648,520	143,877,854	6,347,253,839	14,840,225	140,469,465	6,487,723,304	15,200,654	62,967,167
Hydro Production Plant:														
Pre-merger Pacific	SG	1.546%	188,743,809	243,284	(159,430)	188,584,379	243,079	(159,430)	188,424,949	242,873	(159,430)	188,265,520	242,668	(159,430)
Pre-merger Utah	SG	2.230%	42,470,631	78,986	(70,660)	42,399,971	78,855	(70,660)	42,329,312	78,723	(70,660)	42,258,652	78,592	(70,660)
Post-merger	SG-P	1.964%	283,261,227	461,441	10,702,030	293,963,257	472,406	236,217	294,199,475	481,358	626,640	294,826,115	482,065	337,991
Post-merger	SG-U	2.749%	99,805,719	228,808	(117,769)	99,687,950	228,539	49,967	99,737,917	228,461	(117,769)	99,620,148	228,383	(117,769)
Total Hydro Plant			614,281,387	1,012,520	10,354,171	624,635,558	1,022,878	56,095	624,691,653	1,031,416	278,781	624,970,434	1,031,708	(9,867)
Other Production Plant:														
Pre-merger Utah	SG	10.234%	1,193,250	10,184	(1,793)	1,191,458	10,169	(1,793)	1,189,665	10,153	(1,793)	1,187,872	10,138	(1,793)
Post-merger	SG	2.602%	1,213,972,821	2,634,384	(2,151,721)	1,211,821,100	2,629,719	(2,151,721)	1,209,669,379	2,625,053	(1,895,975)	1,207,773,404	2,620,665	(1,479,439)
Post-merger Wind	SG-W	4.042%	1,804,687,658	6,076,957	(57,048)	1,804,630,609	6,078,219	(57,048)	1,804,573,561	6,078,027	(57,048)	1,804,516,513	6,077,835	457,671
Post-merger	SG	3.321%	81,463,005	224,063	154,915	81,617,921	225,636	(70,140)	81,547,781	225,754	(70,140)	81,477,641	225,559	(70,140)
Total Other Plant			3,101,316,734	8,945,587	(2,055,646)	3,099,261,088	8,943,742	(2,280,701)	3,096,980,386	8,938,987	(2,024,956)	3,094,955,430	8,934,198	(1,093,700)
Transmission Plant:														
Pre-merger Pacific	SG	1.944%	559,085,906	905,839	(400,738)	558,685,168	905,190	(400,738)	558,284,430	904,541	(400,738)	557,883,692	903,891	(400,738)
Pre-merger Utah	SG	1.897%	656,629,099	1,038,141	(297,185)	656,331,914	1,037,671	(297,185)	656,034,729	1,037,201	(297,185)	655,737,544	1,036,731	(297,185)
Post-merger	SG	1.890%	3,301,437,767	5,198,512	27,772,437	3,329,210,203	5,222,077	14,649,421	3,343,859,624	5,255,488	10,415,250	3,354,274,874	5,275,228	27,312,271
Total Transmission Plant			4,517,152,772	7,142,491	27,074,514	4,544,227,286	7,164,938	13,951,498	4,558,178,784	7,197,229	9,717,327	4,567,896,110	7,215,850	26,614,348
Distribution Plant:														
California	CA	2.881%	228,385,297	547,693	569,288	228,954,585	548,950	479,222	229,433,807	550,209	478,599	229,912,406	551,359	499,451
Oregon	OR	2.847%	1,763,270,297	4,181,357	2,335,943	1,765,606,240	4,186,432	4,642,016	1,770,248,257	4,194,710	2,042,123	1,772,290,380	4,202,640	2,113,498
Washington	WA	3.121%	406,721,992	1,057,217	528,531	407,250,523	1,058,425	452,473	407,702,996	1,059,701	449,494	408,152,490	1,060,874	481,890
Eastern Wyoming	WYP	2.827%	501,486,827	1,180,474	949,378	502,436,206	1,182,651	1,020,948	503,457,154	1,184,972	1,017,402	504,474,556	1,187,373	1,071,411
Utah	UT	2.482%	2,412,474,530	4,990,009	2,967,072	2,415,441,602	4,993,843	1,195,924	2,416,637,526	4,998,149	29,940,084	2,446,577,610	5,030,356	11,722,167
Idaho	ID	2.570%	284,956,005	609,455	936,815	285,892,821	611,388	1,024,520	286,917,340	613,489	1,003,343	287,920,683	615,661	1,053,819
Western Wyoming	WYU	2.990%	95,917,831	239,115	(68,147)	95,849,684	238,945	(68,147)	95,781,537	238,775	(68,147)	95,713,389	238,606	(68,147)
Total Distribution Plant			5,693,212,780	12,805,321	8,218,880	5,701,431,661	12,820,636	8,746,956	5,710,178,616	12,840,006	34,862,898	5,745,041,514	12,886,868	16,874,089
General Plant:														
California	CA	2.192%	14,523,830	26,493	(9,135)	14,514,695	26,527	224,622	14,739,317	26,724	(9,767)	14,729,550	26,920	546,286
Oregon	OR	2.472%	157,661,876	322,097	(90,424)	157,571,452	324,682	219,553	157,791,005	324,815	1,350,085	159,141,090	326,432	2,472,412
Washington	WA	3.436%	43,448,097	123,776	71,730	43,519,827	124,518	(71,646)	43,448,181	124,518	(71,476)	43,376,705	124,313	265,554
Eastern Wyoming	WYP	3.832%	56,731,642	180,441	624,425	57,356,067	182,152	(9,978)	57,346,089	183,133	(6,216)	57,339,873	183,107	222,386
Utah	UT	2.218%	183,369,398	337,588	865,130	184,234,528	339,803	701,038	184,935,566	341,251	120,006	185,055,572	342,010	2,208,519
Idaho	ID	2.283%	35,438,082	67,045	(3,333)	35,434,749	67,427	945,749	36,380,499	68,323	(889)	36,379,610	69,222	535
Western Wyoming	WYU	2.730%	11,519,766	26,262	(47,025)	11,472,741	26,155	(47,025)	11,425,716	26,048	(47,025)	11,378,691	25,941	(47,025)
Pre-merger Pacific	SG	3.128%	3,402,325	8,933	(49,206)	3,353,120	8,805	(49,206)	3,303,914	8,677	(49,206)	3,254,708	8,548	(49,206)
Pre-merger Utah	SG	2.484%	6,688,196	13,955	(108,062)	6,580,134	13,732	(108,062)	6,472,073	13,508	(108,062)	6,364,011	13,284	(108,062)
Post-merger	SG	3.322%	192,900,886	533,756	966,538	193,867,423	535,363	(328,196)	193,539,227	536,246	(344,687)	193,194,540	535,315	(40,849)
General Office	SO	6.440%	225,514,343	1,214,305	(1,538,100)	223,976,243	1,206,063	(1,459,449)	222,516,794	1,198,020	(1,516,968)	220,999,826	1,190,034	(1,211,182)
General Office	SG	2.915%	3,758,781	9,166	(29,441)	3,729,341	9,095	(29,441)	3,699,900	9,023	(29,441)	3,670,459	8,952	(29,441)
General Office	SG	3.287%	198,930	546	(643)	198,287	544	(643)	197,644	542	(643)	197,001	541	(643)
Customer Service	CN	8.065%	20,244,243	136,534	(143,627)	20,100,616	135,569	(143,627)	19,956,989	134,604	(143,627)	19,813,362	133,639	(143,627)
Fuel Related	SE	2.989%	616,803	1,543	(5,218)	611,585	1,530	(5,218)	606,367	1,517	(5,218)	601,148	1,504	(5,218)
Total General Plant			956,017,199	3,002,441	503,610	956,520,808	3,001,965	(161,528)	956,359,280	2,996,950	(863,134)	955,496,146	2,989,762	4,080,439
Mining Plant:														
Coal Mine	SE	3.555%	292,840,050	867,592	(348,951)	292,491,099	867,040	(647,791)	291,843,308	865,564	160,209	292,003,517	864,841	366,209
Total Mining Plant			292,840,050	867,592	(348,951)	292,491,099	867,040	(647,791)	291,843,308	865,564	160,209	292,003,517	864,841	366,209
Subtotal			21,371,457,560	48,416,507	50,485,923	21,421,943,484	48,469,719	163,542,382	21,585,485,866	48,710,377	182,600,590	21,768,086,456	49,123,881	109,798,684

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Feb 2012	Depreciation Expense Feb 2012	Adjustments	Adjusted EPIS Balance Mar 2012	Depreciation Expense Mar 2012	Adjustments	Adjusted EPIS Balance Apr 2012	Depreciation Expense Apr 2012	Adjustments	Adjusted EPIS Balance May 2012	Depreciation Expense May 2012	Adjustments
AMORTIZATION EXPENSE														
Intangible Plant:														
California	CA	0.000%	216,407	-	-	216,407	-	-	216,407	-	-	216,407	-	-
Customer Service	CN	4.806%	120,908,171	484,309	(21,106)	120,887,065	484,225	(21,106)	120,865,958	484,140	(21,106)	120,844,852	484,056	(21,106)
Pre-merger Utah	SG	2.788%	591,268	1,375	(1,205)	590,063	1,373	(1,205)	588,859	1,370	(1,205)	587,654	1,367	(1,205)
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	1.437%	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-
Oregon	OR	0.679%	1,605,876	916	(28,525)	1,577,351	900	(28,525)	1,548,826	884	(28,525)	1,520,302	868	(28,525)
Fuel Related	SE	9.509%	3,602,529	28,573	(6,434)	3,596,095	28,522	(6,434)	3,589,662	28,471	(6,434)	3,583,228	28,420	(6,434)
Post-merger	SG	3.923%	135,701,071	445,025	(855,498)	134,845,573	442,228	(855,498)	133,990,075	439,431	(855,498)	133,134,577	436,634	(855,498)
Hydro Relicensing	SG-P	2.628%	97,680,591	214,153	(226,353)	97,454,238	213,657	(226,353)	97,227,885	213,161	(226,353)	97,001,532	212,665	(226,353)
Hydro Relicensing	SG-U	3.338%	9,127,978	25,404	(7,644)	9,120,334	25,383	(7,644)	9,112,690	25,362	(7,644)	9,105,045	25,341	(7,644)
General Office	SO	5.497%	378,673,140	1,735,935	(513,188)	378,159,952	1,733,592	(446,071)	377,713,881	1,731,395	(495,155)	377,218,726	1,729,239	1,636,730
Utah	UT	0.429%	3,002,715	1,074	(52)	3,002,663	1,074	(52)	3,002,611	1,074	(52)	3,002,559	1,074	(52)
Washington	WA	0.000%	545,822	-	(9,393)	536,429	-	(9,393)	527,037	-	(9,393)	517,644	-	(9,393)
Eastern Wyoming	WYP	10.387%	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			754,462,805	2,950,415	(1,669,398)	752,793,407	2,944,604	(1,602,281)	751,191,126	2,938,938	(1,651,365)	749,539,761	2,933,314	480,520
Hydro Production Plant:														
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-
Post-merger	SG-U	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant			10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-
Other Production Plant:														
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-
General Plant:														
California	CA	5.332%	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-
General Office	CN	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	3.118%	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-
General Office	SO	7.580%	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-
Utah	UT	3.892%	18,702	61	-	18,702	61	-	18,702	61	-	18,702	61	-
Washington	WA	4.304%	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-
Eastern Wyoming	WYP	7.941%	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-
Western Wyoming	WYU	8.595%	55,654	399	-	55,654	399	-	55,654	399	-	55,654	399	-
Total General Plant			40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-
Subtotal			805,882,246	3,194,993	(1,669,398)	804,212,848	3,189,182	(1,602,281)	802,610,568	3,183,517	(1,651,365)	800,959,203	3,177,893	480,520
Total			22,177,339,807	51,611,500	48,816,525	22,226,156,332	51,658,902	161,940,102	22,388,096,434	51,893,894	180,949,225	22,569,045,659	52,301,774	110,279,204

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Jun 2012	Depreciation Expense Jun 2012	Adjustments	Adjusted EPIS Balance Jul 2012	Depreciation Expense Jul 2012	Adjustments	Adjusted EPIS Balance Aug 2012	Depreciation Expense Aug 2012	Adjustments	Adjusted EPIS Balance Sep 2012	Depreciation Expense Sep 2012	Adjustments
DEPRECIATION EXPENSE														
Steam Production Plant:														
Pre-merger Pacific	SG	2.839%	1,069,887,579	2,532,958	(1,671,972)	1,068,215,607	2,529,003	(1,671,972)	1,066,543,634	2,525,047	(1,671,972)	1,064,871,662	2,521,092	(1,671,972)
Pre-merger Utah	SG	2.506%	1,180,417,143	2,465,888	(1,189,808)	1,179,227,335	2,463,404	(1,189,808)	1,178,037,527	2,460,920	(1,189,808)	1,176,847,720	2,458,435	(1,189,808)
Post-merger	SG	3.027%	3,298,849,258	8,296,655	15,955,580	3,314,804,839	8,340,241	5,040,885	3,319,845,723	8,366,719	1,407,172	3,321,252,895	8,374,850	3,604,967
Geothermal - Blundell	SG	3.027%	26,257,356	66,246	(17,426)	26,239,930	66,202	(17,426)	26,222,504	66,158	(17,426)	26,205,079	66,115	192,646
Pollution Control Equipment	SG	3.027%	467,468,081	1,117,577	1,845,738	469,313,818	1,181,342	3,892,638	473,206,456	1,188,578	2,162,139	475,368,595	1,196,214	2,202,246
Pollution Control Equipment	SG	2.312%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	507,811,054	979,632	(1,745,085)	506,065,969	976,525	(1,738,917)	504,327,051	973,169	(1,737,889)	502,589,162	969,821	(1,736,861)
Total Steam Plant			6,550,690,471	15,458,955	13,177,027	6,563,867,498	15,556,717	4,315,400	6,568,182,897	15,580,593	(1,047,785)	6,567,135,113	15,586,527	1,401,218
Hydro Production Plant:														
Pre-merger Pacific	SG	1.546%	188,106,090	242,463	(159,430)	187,946,661	242,257	(159,430)	187,787,231	242,052	(159,430)	187,627,802	241,846	(159,430)
Pre-merger Utah	SG	2.230%	42,187,992	78,461	(70,660)	42,117,333	78,329	(70,660)	42,046,673	78,198	(70,660)	41,976,013	78,067	(70,660)
Post-merger	SG-P	1.964%	295,164,106	482,854	608,982	295,773,088	483,629	117,870	295,890,957	484,224	74,357,491	370,248,448	545,175	4,120,120
Post-merger	SG-U	2.749%	99,502,378	228,113	(117,769)	99,384,609	227,844	(117,769)	99,266,840	227,574	(117,769)	99,149,071	227,304	(117,769)
Total Hydro Plant			624,960,567	1,031,891	261,124	625,221,690	1,032,059	(229,989)	624,991,701	1,032,047	74,009,633	699,001,334	1,092,392	3,772,261
Other Production Plant:														
Pre-merger Utah	SG	10.234%	1,186,080	10,123	(1,793)	1,184,287	10,107	(1,793)	1,182,494	10,092	(1,209,482)	(26,988)	4,927	(1,793)
Post-merger	SG	2.602%	1,206,293,966	2,617,006	(1,580,008)	1,204,713,958	2,613,690	(2,151,721)	1,202,562,237	2,609,644	(2,676,328)	1,199,885,909	2,604,410	15,489,351
Post-merger Wind	SG-W	4.042%	1,804,974,184	6,078,509	(54,137)	1,804,920,046	6,079,189	(54,137)	1,804,865,909	6,079,007	(54,137)	1,804,811,771	6,078,824	(54,137)
Post-merger	SG	3.321%	81,407,502	225,365	(70,140)	81,337,362	225,171	(70,140)	81,267,222	224,977	(70,140)	81,197,082	224,783	(70,140)
Total Other Plant			3,093,861,730	8,931,004	(1,706,078)	3,092,155,653	8,928,157	(2,277,791)	3,089,877,862	8,923,720	(4,010,088)	3,085,867,775	8,912,945	15,363,281
Transmission Plant:														
Pre-merger Pacific	SG	1.944%	557,482,954	903,242	(400,738)	557,082,215	902,593	(400,738)	556,681,477	901,944	(400,738)	556,280,739	901,295	(400,738)
Pre-merger Utah	SG	1.897%	655,440,359	1,036,262	(297,185)	655,143,175	1,035,792	(297,185)	654,845,990	1,035,322	(297,185)	654,548,805	1,034,852	(297,185)
Post-merger	SG	1.890%	3,381,587,145	5,304,941	3,887,630	3,385,474,776	5,329,513	25,434,252	3,410,909,028	5,352,605	3,962,763	3,414,871,791	5,375,758	8,170,328
Total Transmission Plant			4,594,510,459	7,244,445	3,189,707	4,597,700,166	7,267,898	24,736,329	4,622,436,495	7,289,872	3,264,840	4,625,701,335	7,311,905	7,472,405
Distribution Plant:														
California	CA	2.881%	230,411,857	552,533	474,585	230,886,442	553,702	579,643	231,466,084	554,967	491,711	231,957,795	556,253	442,079
Oregon	OR	2.847%	1,774,403,878	4,207,570	1,940,745	1,776,344,623	4,212,380	2,269,817	1,778,614,440	4,217,375	1,802,989	1,780,417,429	4,222,206	1,733,576
Washington	WA	3.121%	408,634,380	1,062,085	428,270	409,062,650	1,063,268	525,294	409,587,944	1,064,508	399,404	409,987,348	1,065,711	354,139
Eastern Wyoming	WYP	2.827%	505,545,967	1,189,834	1,183,910	506,729,877	1,192,491	1,292,913	508,022,790	1,195,409	1,133,066	509,155,856	1,198,266	1,077,911
Utah	UT	2.482%	2,458,299,776	5,073,450	2,066,701	2,460,366,477	5,087,712	2,479,288	2,462,845,765	5,092,415	1,695,371	2,464,541,136	5,096,733	1,714,757
Idaho	ID	2.570%	288,974,502	617,864	1,053,775	290,028,277	620,121	1,125,075	291,153,352	622,455	1,036,045	292,189,397	624,770	967,205
Western Wyoming	WYU	2.990%	95,645,242	238,436	(68,147)	95,577,095	238,266	(68,147)	95,508,947	238,096	(68,147)	95,440,800	237,926	(68,147)
Total Distribution Plant			5,761,915,603	12,941,771	7,079,839	5,768,995,442	12,967,940	8,203,882	5,777,199,324	12,985,225	6,490,438	5,783,689,762	13,001,865	6,221,519
General Plant:														
California	CA	2.192%	15,275,836	27,411	(10,083)	15,265,753	27,900	(9,476)	15,256,277	27,882	394,471	15,650,747	28,234	19,052
Oregon	OR	2.472%	161,613,502	330,369	(379,545)	161,233,957	332,525	357,116	161,591,074	332,502	1,532,252	163,123,326	334,448	(399,656)
Washington	WA	3.436%	43,642,258	124,591	(71,126)	43,571,132	124,869	(70,922)	43,500,210	124,666	(73,383)	43,426,827	124,459	(73,659)
Eastern Wyoming	WYP	3.832%	57,562,259	183,452	270,307	57,832,566	184,239	51,692	57,884,258	184,753	380,786	58,265,044	185,444	173,162
Utah	UT	2.218%	187,264,091	344,163	350,255	187,614,346	346,528	3,475	187,617,821	346,855	(15,100)	187,602,721	346,844	573,257
Idaho	ID	2.283%	36,380,145	69,222	90,988	36,471,132	69,309	223,952	36,695,084	69,609	80,841	36,775,926	69,899	5,739
Western Wyoming	WYU	2.730%	11,331,666	25,834	(47,025)	11,284,640	25,727	(47,025)	11,237,615	25,620	(47,025)	11,190,590	25,513	(47,025)
Pre-merger Pacific	SG	3.128%	3,205,502	8,420	(49,206)	3,156,297	8,292	(49,206)	3,107,091	8,164	(49,206)	3,057,885	8,035	(49,206)
Pre-merger Utah	SG	2.484%	6,255,949	13,061	(108,062)	6,147,887	12,837	(108,062)	6,039,825	12,613	(133,689)	5,906,137	12,363	(108,062)
Post-merger	SG	3.322%	193,153,691	534,781	(446,204)	192,707,487	534,107	286,786	192,994,274	533,886	83,398	193,077,671	534,399	950,240
General Office	SO	6.440%	219,788,644	1,182,714	(927,592)	218,861,052	1,176,975	(1,244,723)	217,616,330	1,171,146	(1,049,795)	216,566,535	1,164,990	(367,217)
General Office	SG	2.915%	3,641,019	8,880	(29,441)	3,611,578	8,809	(29,441)	3,582,137	8,737	(29,441)	3,552,697	8,666	(29,441)
General Office	SG	3.287%	196,358	539	(643)	195,715	537	(643)	195,072	535	(643)	194,428	533	(643)
Customer Service	CN	8.065%	19,669,735	132,673	(143,627)	19,526,108	131,708	(143,627)	19,382,481	130,743	(143,627)	19,238,854	129,778	(143,627)
Fuel Related	SE	2.989%	595,930	1,491	(5,218)	590,712	1,478	(5,218)	585,493	1,465	(5,218)	580,275	1,452	(5,218)
Total General Plant			959,576,585	2,987,600	(1,506,222)	958,070,362	2,985,840	(785,321)	957,285,042	2,979,176	924,620	958,209,662	2,975,056	497,698
Mining Plant:														
Coal Mine	SE	3.555%	292,369,726	865,621	580,209	292,949,935	867,023	(349,791)	292,600,144	867,364	(554,791)	292,045,353	866,024	(469,791)
Total Mining Plant			292,369,726	865,621	580,209	292,949,935	867,023	(349,791)	292,600,144	867,364	(554,791)	292,045,353	866,024	(469,791)
Subtotal			21,877,885,140	49,461,287	21,075,605	21,898,960,745	49,605,635	33,612,719	21,932,573,465	49,657,997	79,076,868	22,011,650,333	49,746,715	34,258,591

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Jun 2012	Depreciation Expense Jun 2012	Adjustments	Adjusted EPIS Balance Jul 2012	Depreciation Expense Jul 2012	Adjustments	Adjusted EPIS Balance Aug 2012	Depreciation Expense Aug 2012	Adjustments	Adjusted EPIS Balance Sep 2012	Depreciation Expense Sep 2012	Adjustments
AMORTIZATION EXPENSE														
Intangible Plant:														
California	CA	0.000%	216,407	-	-	216,407	-	-	216,407	-	-	216,407	-	-
Customer Service	CN	4.806%	120,823,746	483,971	(21,106)	120,802,639	483,887	(21,106)	120,781,533	483,802	(21,106)	120,760,426	483,717	(21,106)
Pre-merger Utah	SG	2.788%	586,450	1,364	(1,205)	585,245	1,361	(1,205)	584,041	1,359	(1,205)	582,836	1,356	(1,205)
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	1.437%	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	-
Oregon	OR	0.679%	1,491,777	852	(28,525)	1,463,252	836	(28,525)	1,434,728	819	(28,525)	1,406,203	803	(28,525)
Fuel Related	SE	9.509%	3,576,794	28,369	(6,434)	3,570,360	28,318	(6,434)	3,563,927	28,267	(6,434)	3,557,493	28,216	(6,434)
Post-merger	SG	3.923%	132,279,079	433,838	(855,498)	131,423,580	431,041	(855,498)	130,568,082	428,244	(855,498)	129,712,584	425,447	(104,337)
Hydro Relicensing	SG-P	2.628%	96,775,179	212,170	(226,353)	96,548,827	211,674	(226,353)	96,322,474	211,178	(226,353)	96,096,121	210,683	(226,353)
Hydro Relicensing	SG-U	3.338%	9,097,401	25,319	(7,644)	9,089,757	25,298	(7,644)	9,082,113	25,277	(7,644)	9,074,469	25,255	(7,644)
General Office	SO	5.497%	378,855,455	1,731,854	7,793	378,863,249	1,735,621	(262,832)	378,600,416	1,735,036	(96,489)	378,503,927	1,734,213	485,994
Utah	UT	0.429%	3,002,507	1,074	(52)	3,002,455	1,074	(52)	3,002,402	1,074	(52)	3,002,350	1,074	(52)
Washington	WA	0.000%	508,251	-	(9,393)	498,858	-	(9,393)	489,465	-	(9,393)	480,072	-	(9,393)
Eastern Wyoming	WYP	10.387%	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	-
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			750,020,281	2,932,461	(1,148,416)	748,871,865	2,932,760	(1,419,042)	747,452,823	2,928,708	(1,252,699)	746,200,124	2,924,416	80,946
Hydro Production Plant:														
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	-
Post-merger	SG-U	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant			10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	-
Other Production Plant:														
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-
General Plant:														
California	CA	5.332%	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	-
General Office	CN	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	3.118%	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	-
General Office	SO	7.580%	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	-
Utah	UT	3.892%	18,702	61	-	18,702	61	-	18,702	61	-	18,702	61	-
Washington	WA	4.304%	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	-
Eastern Wyoming	WYP	7.941%	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	-
Western Wyoming	WYU	8.595%	55,654	399	-	55,654	399	-	55,654	399	-	55,654	399	-
Total General Plant			40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	-
Subtotal			801,439,723	3,177,039	(1,148,416)	800,291,306	3,177,338	(1,419,042)	798,872,264	3,173,286	(1,252,699)	797,619,565	3,168,994	80,946
Total			22,679,324,863	52,638,326	19,927,189	22,699,252,052	52,782,973	32,193,677	22,731,445,729	52,831,283	77,824,169	22,809,269,898	52,915,710	34,339,538

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Oct 2012	Depreciation Expense Oct 2012	Adjustments	Adjusted EPIS Balance Nov 2012	Depreciation Expense Nov 2012	Adjustments	Adjusted EPIS Balance Dec 2012	Depreciation Expense Dec 2012	Test Period Depreciation Expense
DEPRECIATION EXPENSE											
Steam Production Plant:											
Pre-merger Pacific	SG	2.839%	1,063,199,690	2,517,137	(1,671,972)	1,061,527,717	2,513,181	(1,671,972)	1,059,855,745	2,509,226	30,086,982
Pre-merger Utah	SG	2.506%	1,175,657,912	2,455,951	(1,189,808)	1,174,468,105	2,453,467	(1,189,808)	1,173,278,297	2,450,983	29,396,887
Post-merger	SG	3.027%	3,324,857,863	8,381,171	5,787,050	3,330,644,913	8,393,015	34,139,209	3,364,784,121	8,443,365	101,836,996
Geothermal - Blundell	SG	3.027%	26,397,725	66,336	(17,426)	26,380,299	66,556	94,602	26,474,902	66,654	801,277
Pollution Control Equipment	SG	3.027%	477,570,841	1,201,718	737,251	478,308,093	1,205,425	9,013,238	487,321,331	1,217,721	14,749,041
Pollution Control Equipment	SG	2.312%	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	500,852,300	966,474	(1,743,029)	499,109,271	963,122	1,751,805	500,861,076	963,131	11,577,816
Total Steam Plant			6,568,536,331	15,588,786	1,902,067	6,570,438,398	15,594,767	42,137,075	6,612,575,472	15,651,079	188,449,000
Hydro Production Plant:											
Pre-merger Pacific	SG	1.546%	187,468,372	241,641	(159,430)	187,308,942	241,436	(159,430)	187,149,513	241,230	2,893,529
Pre-merger Utah	SG	2.230%	41,905,353	77,935	(70,660)	41,834,694	77,804	(70,660)	41,764,034	77,673	931,287
Post-merger	SG-P	1.964%	374,368,568	609,402	22,507,758	396,876,327	631,195	72,354,269	469,230,596	708,831	9,216,554
Post-merger	SG-U	2.749%	99,031,301	227,034	18,703,723	117,735,025	248,326	1,034,565	118,769,589	270,938	3,265,479
Total Hydro Plant			702,773,595	1,156,013	40,981,392	743,754,987	1,198,760	73,158,745	816,913,732	1,298,672	16,306,849
Other Production Plant:											
Pre-merger Utah	SG	10.234%	(28,781)	(238)	(1,793)	(30,574)	(253)	(1,793)	(32,366)	(268)	(3,312)
Post-merger	SG	2.602%	1,215,375,260	2,618,300	(2,151,721)	1,213,223,540	2,632,759	1,838,690	1,215,062,230	2,632,420	31,612,958
Post-merger Wind	SG-W	4.042%	1,804,757,634	6,078,642	(54,137)	1,804,703,496	6,078,460	2,497,577	1,807,201,074	6,082,574	73,041,365
Post-merger	SG	3.321%	81,126,943	224,589	(70,140)	81,056,803	224,395	36,107	81,092,910	224,348	2,692,774
Total Other Plant			3,101,231,056	8,921,294	(2,277,791)	3,098,953,266	8,935,361	4,370,582	3,103,323,847	8,939,074	107,343,785
Transmission Plant:											
Pre-merger Pacific	SG	1.944%	555,880,001	900,646	(400,738)	555,479,263	899,997	(400,738)	555,078,525	899,348	10,788,283
Pre-merger Utah	SG	1.897%	654,251,620	1,034,383	(297,185)	653,954,435	1,033,913	(297,185)	653,657,250	1,033,443	12,398,498
Post-merger	SG	1.890%	3,423,042,119	5,385,313	5,961,597	3,429,003,716	5,396,443	73,437,282	3,502,440,998	5,458,975	66,201,741
Total Transmission Plant			4,633,173,739	7,320,342	5,263,674	4,638,437,413	7,330,353	72,739,359	4,711,176,773	7,391,766	89,388,522
Distribution Plant:											
California	CA	2.881%	232,399,874	557,374	406,297	232,806,171	558,392	527,423	233,333,594	559,513	6,721,753
Oregon	OR	2.847%	1,782,151,005	4,226,402	1,610,672	1,783,761,677	4,230,369	2,128,327	1,785,890,003	4,234,805	50,847,961
Washington	WA	3.121%	410,341,487	1,066,691	222,335	410,563,822	1,067,440	416,053	410,979,876	1,068,270	12,825,736
Eastern Wyoming	WYP	2.827%	510,233,767	1,200,871	990,210	511,223,977	1,203,307	2,212,880	513,436,857	1,207,081	14,516,251
Utah	UT	2.482%	2,466,255,893	5,100,260	1,326,772	2,467,582,664	5,103,406	1,954,416	2,469,537,080	5,106,800	61,305,861
Idaho	ID	2.570%	293,156,602	626,915	929,807	294,086,409	628,947	993,837	295,080,246	631,007	7,584,857
Western Wyoming	WYU	2.990%	95,372,653	237,756	(68,147)	95,304,505	237,587	(68,147)	95,236,358	237,417	2,847,983
Total Distribution Plant			5,789,911,281	13,016,269	5,417,945	5,795,329,227	13,029,449	8,164,788	5,803,494,015	13,044,893	156,650,401
General Plant:											
California	CA	2.192%	15,669,799	28,612	(10,252)	15,659,547	28,620	(10,819)	15,648,728	28,601	343,090
Oregon	OR	2.472%	162,723,670	335,614	(199,255)	162,524,415	334,997	96,770	162,621,185	334,892	4,019,896
Washington	WA	3.436%	43,353,168	124,249	163,324	43,516,491	124,377	(75,326)	43,441,165	124,503	1,492,744
Eastern Wyoming	WYP	3.832%	58,438,206	186,328	388,041	58,826,248	187,224	424,646	59,250,894	188,522	2,270,396
Utah	UT	2.218%	188,175,978	347,360	26,542	188,202,520	347,914	1,315,145	189,517,665	349,155	4,204,445
Idaho	ID	2.283%	36,781,665	69,981	179,630	36,961,295	70,157	17,350	36,978,645	70,345	844,335
Western Wyoming	WYU	2.730%	11,143,565	25,406	(47,025)	11,096,539	25,299	(47,025)	11,049,514	25,192	301,661
Pre-merger Pacific	SG	3.128%	3,008,679	7,907	(49,206)	2,959,474	7,779	(49,206)	2,910,268	7,651	91,037
Pre-merger Utah	SG	2.484%	5,798,075	12,113	(108,062)	5,690,013	11,889	(108,062)	5,581,952	11,666	138,646
Post-merger	SG	3.322%	194,027,911	535,830	(660,764)	193,367,148	536,230	4,192,795	197,559,943	541,119	6,563,075
General Office	SO	6.440%	216,199,318	1,161,188	(101,628)	216,097,690	1,159,930	263,909	216,361,599	1,160,365	13,932,877
General Office	SG	2.915%	3,523,256	8,594	(29,441)	3,493,815	8,523	(29,441)	3,464,375	8,451	100,984
General Office	SG	3.287%	193,785	532	(643)	193,142	530	(643)	192,499	528	6,328
Customer Service	CN	8.065%	19,095,227	128,812	(143,627)	18,951,600	127,847	(143,627)	18,807,973	126,882	1,516,791
Fuel Related	SE	2.989%	575,057	1,439	(5,218)	569,839	1,426	(5,218)	564,620	1,413	16,878
Total General Plant			958,707,360	2,973,964	(597,584)	958,109,776	2,972,743	5,841,250	963,951,026	2,979,283	35,843,183
Mining Plant:											
Coal Mine	SE	3.555%	291,575,562	864,507	(435,791)	291,139,771	863,165	3,429,844	294,569,615	867,600	10,472,171
Total Mining Plant			291,575,562	864,507	(435,791)	291,139,771	863,165	3,429,844	294,569,615	867,600	10,472,171
Subtotal			22,045,908,924	49,841,175	50,253,913	22,096,162,837	49,924,598	209,841,643	22,306,004,480	50,172,367	604,453,911

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Expense

Description	Factor	DEPE Rate	Adjusted EPIS Balance Oct 2012	Depreciation Expense Oct 2012	Adjustments	Adjusted EPIS Balance Nov 2012	Depreciation Expense Nov 2012	Adjustments	Adjusted EPIS Balance Dec 2012	Depreciation Expense Dec 2012	Test Period Depreciation Expense
AMORTIZATION EXPENSE											
Intangible Plant:											
California	CA	0.000%	216,407	-	-	216,407	-	-	216,407	-	-
Customer Service	CN	4.806%	120,739,320	483,633	(21,106)	120,718,213	483,548	(21,106)	120,697,107	483,464	5,801,059
Pre-merger Utah	SG	2.788%	581,632	1,353	(1,205)	580,427	1,350	(1,205)	579,223	1,347	16,151
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	ID	1.437%	1,427,593	1,710	-	1,427,593	1,710	-	1,427,593	1,710	20,515
Oregon	OR	0.679%	1,377,678	787	(28,525)	1,349,153	771	(28,525)	1,320,629	755	8,962
Fuel Related	SE	9.509%	3,551,059	28,165	(6,434)	3,544,625	28,114	(6,434)	3,538,192	28,063	336,447
Post-merger	SG	3.923%	129,608,247	423,879	980,578	130,588,825	425,311	4,847,523	135,436,348	434,837	5,313,130
Hydro Relicensing	SG-P	2.628%	95,869,768	210,187	(226,353)	95,643,415	209,691	(226,353)	95,417,062	209,196	2,507,375
Hydro Relicensing	SG-U	3.338%	9,066,824	25,234	(7,644)	9,059,180	25,213	(7,644)	9,051,536	25,192	302,172
General Office	SO	5.497%	378,989,921	1,735,106	712,637	379,702,559	1,737,851	1,774,612	381,477,170	1,743,548	20,971,360
Utah	UT	0.429%	3,002,298	1,074	(52)	3,002,246	1,074	(52)	3,002,194	1,074	12,885
Washington	WA	0.000%	470,680	-	(9,393)	461,287	-	(9,393)	451,894	-	-
Eastern Wyoming	WYP	10.387%	1,379,644	11,942	-	1,379,644	11,942	-	1,379,644	11,942	143,299
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant			746,281,070	2,923,068	1,392,504	747,673,574	2,926,575	6,321,423	753,994,997	2,941,127	35,433,357
Hydro Production Plant:											
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	10,133,687	20,751	-	10,133,687	20,751	-	10,133,687	20,751	249,015
Post-merger	SG-U	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	44,532
Total Hydro Plant			10,847,712	24,462	-	10,847,712	24,462	-	10,847,712	24,462	293,548
Other Production Plant:											
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-
General Plant:											
California	CA	5.332%	1,418,687	6,304	-	1,418,687	6,304	-	1,418,687	6,304	75,648
General Office	CN	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	273,367
Oregon	OR	3.118%	7,957,177	20,672	-	7,957,177	20,672	-	7,957,177	20,672	248,068
General Office	SO	7.580%	16,612,597	104,938	-	16,612,597	104,938	-	16,612,597	104,938	1,259,258
Utah	UT	3.892%	18,702	61	-	18,702	61	-	18,702	61	728
Washington	WA	4.304%	2,820,084	10,114	-	2,820,084	10,114	-	2,820,084	10,114	121,365
Eastern Wyoming	WYP	7.941%	8,287,954	54,848	-	8,287,954	54,848	-	8,287,954	54,848	658,172
Western Wyoming	WYU	8.595%	55,654	399	-	55,654	399	-	55,654	399	4,784
Total General Plant			40,571,729	220,116	-	40,571,729	220,116	-	40,571,729	220,116	2,641,390
Subtotal			797,700,512	3,167,646	1,392,504	799,093,015	3,171,153	6,321,423	805,414,439	3,185,705	38,368,295
Total			22,843,609,436	53,008,821	51,646,417	22,895,255,852	53,095,751	216,163,066	23,111,418,918	53,358,072	642,822,206
											Ref. 6.1.3
										Total Not Including Mining	**632,350,034**

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Reserve	108SP	3	(15,297,553)	SG	25.777%	(3,943,274)	
Steam Depreciation Reserve	108SP	3	(22,859,473)	SG	25.777%	(5,892,522)	
Steam Depreciation Reserve	108SP	3	(242,154,530)	SG	25.777%	(62,420,549)	
Steam Depreciation Reserve	108SP	3	468,441	SG	25.777%	120,751	
Hydro Depreciation Reserve	108HP	3	2,122,833	SG	25.777%	547,206	
Hydro Depreciation Reserve	108HP	3	544,652	SG	25.777%	140,396	
Hydro Depreciation Reserve	108HP	3	12,853,341	SG-P	25.777%	3,313,226	
Hydro Depreciation Reserve	108HP	3	(4,220,585)	SG-U	25.777%	(1,087,947)	
Other Depreciation Reserve	108OP	3	1,181,850	SG	25.777%	304,647	
Other Depreciation Reserve	108OP	3	(3,332,359)	SG	25.777%	(858,987)	
Other Depreciation Reserve	108OP	3	(107,921,830)	SG-W	25.777%	(27,819,177)	
Other Depreciation Reserve	108OP	3	(2,749,635)	SG	25.777%	(708,778)	
Transmission Depreciation Reserve	108TP	3	(8,812,631)	SG	25.777%	(2,271,646)	
Transmission Depreciation Reserve	108TP	3	(13,285,867)	SG	25.777%	(3,424,719)	
Transmission Depreciation Reserve	108TP	3	(61,886,687)	SG	25.777%	(15,952,627)	
Distribution Depreciation Reserve	108360	3	(1,428,181)	Situs	100.000%	(576,589)	
Distribution Depreciation Reserve	108361	3	(2,123,898)	Situs	100.000%	(857,466)	
Distribution Depreciation Reserve	108362	3	(22,039,581)	Situs	100.000%	(8,897,878)	
Distribution Depreciation Reserve	108364	3	(25,550,191)	Situs	100.000%	(10,315,191)	
Distribution Depreciation Reserve	108365	3	(17,504,062)	Situs	100.000%	(7,066,786)	
Distribution Depreciation Reserve	108366	3	(8,156,186)	Situs	100.000%	(3,292,837)	
Distribution Depreciation Reserve	108367	3	(19,379,546)	Situs	100.000%	(7,823,961)	
Distribution Depreciation Reserve	108368	3	(29,671,914)	Situs	100.000%	(11,979,224)	
Distribution Depreciation Reserve	108369	3	(15,865,708)	Situs	100.000%	(6,405,346)	
Distribution Depreciation Reserve	108370	3	(4,793,868)	Situs	100.000%	(1,935,393)	
Distribution Depreciation Reserve	108371	3	(235,715)	Situs	100.000%	(95,164)	
Distribution Depreciation Reserve	108373	3	(1,627,691)	Situs	100.000%	(657,136)	
General Depreciation Reserve	108GP	3	97,408	CA	0.000%	-	
General Depreciation Reserve	108GP	3	1,845,992	OR	100.000%	1,845,992	
General Depreciation Reserve	108GP	3	(807,555)	WA	0.000%	-	
General Depreciation Reserve	108GP	3	(602,498)	WYP	0.000%	-	
General Depreciation Reserve	108GP	3	(419,900)	UT	0.000%	-	
General Depreciation Reserve	108GP	3	347,988	ID	0.000%	-	
General Depreciation Reserve	108GP	3	(2,698)	WYU	0.000%	-	
General Depreciation Reserve	108GP	3	676,519	SG	25.777%	174,387	
General Depreciation Reserve	108GP	3	1,588,955	SG	25.777%	409,587	
General Depreciation Reserve	108GP	3	(1,919,020)	SG	25.777%	(494,669)	
General Depreciation Reserve	108GP	3	11,449,400	SO	27.165%	3,110,228	
General Depreciation Reserve	108GP	3	257,944	SG	25.777%	66,490	
General Depreciation Reserve	108GP	3	(2,073)	SG	25.777%	(534)	
General Depreciation Reserve	108GP	3	254,766	CN	29.363%	74,807	
General Depreciation Reserve	108GP	3	28,100	SE	24.314%	6,832	
Mining Depreciation Reserve	108MP	3	(601,972)	SE	24.314%	(146,361)	
Total Depreciation Reserve			(601,535,218)			(174,810,209)	6.2.2

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2012 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2011 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2011 to December 31, 2012. An incremental amount has been added to the December 31, 2012 balance to reflect the annualized 2012 depreciation & amortization expense being added in through adjustment 6.1.

PacifiCorp
Oregon General Rate Case - December 2013
Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	-	CA	0.000%	-	
Intangible Amortization Reserve	111IP	3	(8,329,149)	CN	29.363%	(2,445,677)	
Intangible Amortization Reserve	111IP	3	(30,773)	ID	0.000%	-	
Intangible Amortization Reserve	111IP	3	(2,709)	SG	25.777%	(698)	
Intangible Amortization Reserve	111IP	3	518,152	OR	100.000%	518,152	
Intangible Amortization Reserve	111IP	3	(393,045)	SE	24.314%	(95,563)	
Intangible Amortization Reserve	111IP	3	7,510,666	SG	25.777%	1,936,036	
Intangible Amortization Reserve	111IP	3	287,614	SG-P	25.777%	74,139	
Intangible Amortization Reserve	111IP	3	(317,348)	SG-U	25.777%	(81,803)	
Intangible Amortization Reserve	111IP	3	(17,242,123)	SO	27.165%	(4,683,820)	
Intangible Amortization Reserve	111IP	3	-	SG	25.777%	-	
Intangible Amortization Reserve	111IP	3	(18,392)	UT	0.000%	-	
Intangible Amortization Reserve	111IP	3	175,320	WA	0.000%	-	
Intangible Amortization Reserve	111IP	3	(214,949)	WYP	0.000%	-	
Intangible Amortization Reserve	111IP	3	-	WYU	0.000%	-	
Intangible Amortization Reserve	111IP	3	-	SG	25.777%	-	
Hydro Amortization Reserve	111HP	3	-	SG	25.777%	-	
Hydro Amortization Reserve	111HP	3	(373,523)	SG-P	25.777%	(96,284)	
Hydro Amortization Reserve	111HP	3	(66,799)	SG-U	25.777%	(17,219)	
Other Amortizaton Reserve	111OP	3	-	SG	25.777%	-	
General Amortization Reserve	111GP	3	(113,472)	CA	0.000%	-	
General Amortization Reserve	111GP	3	(410,051)	CN	29.363%	(120,403)	
General Amortization Reserve	111GP	3	-	SG	25.777%	-	
General Amortization Reserve	111GP	3	(372,102)	OR	100.000%	(372,102)	
General Amortization Reserve	111GP	3	(1,888,888)	SO	27.165%	(513,116)	
General Amortization Reserve	111GP	3	(1,092)	UT	0.000%	-	
General Amortization Reserve	111GP	3	(182,048)	WA	0.000%	-	
General Amortization Reserve	111GP	3	(987,258)	WYP	0.000%	-	
General Amortization Reserve	111GP	3	(7,176)	WYU	0.000%	-	
			(22,459,142)			(5,898,357)	6.2.3

Description of Adjustment:

This adjustment steps forward the amortization reserve to a December 2012 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2011 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2011 to December 31, 2012. An incremental amount has been added to the December 31, 2012 balance to reflect the annualized 2012 depreciation & amortization expense being added in through adjustment 6.1.

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2011 Reserve	CY 2012 Adjusted Reserve Year End Balance	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(764,758,175)	(780,055,729)	(15,297,553)
Pre-merger Utah	108SP	SG	(814,824,873)	(837,684,347)	(22,859,473)
Post-merger	108SP	SG	(611,942,587)	(854,097,116)	(242,154,530)
Post-merger	108SP	SG	(168,303,056)	(167,834,615)	468,441
Total Steam Plant			(2,359,828,691)	(2,639,671,807)	(279,843,116)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG	(132,598,114)	(130,475,281)	2,122,833
Pre-merger Utah	108HP	SG	(29,241,674)	(28,697,021)	544,652
Post-merger	108HP	SG-P	(59,256,678)	(46,403,338)	12,853,341
Post-merger	108HP	SG-U	(17,589,885)	(21,810,471)	(4,220,585)
Total Hydro Plant			(238,686,352)	(227,386,111)	11,300,240
Other Production Plant:					
Pre-merger Utah	108OP	SG	(1,548,574)	(366,724)	1,181,850
Post-merger	108OP	SG	(187,032,713)	(190,365,072)	(3,332,359)
Post-merger - Wind	108OP	SG-W	(208,280,655)	(316,202,485)	(107,921,830)
Post-merger	108OP	SG	(21,791,105)	(24,540,740)	(2,749,635)
Total Other Plant			(418,653,047)	(531,475,021)	(112,821,974)
Transmission Plant:					
Pre-merger Pacific	108TP	SG	(369,436,693)	(378,249,324)	(8,812,631)
Pre-merger Utah	108TP	SG	(398,038,617)	(411,324,484)	(13,285,867)
Post-merger	108TP	SG	(428,515,792)	(490,402,478)	(61,886,687)
Total Transmission Plant			(1,195,991,101)	(1,279,976,286)	(83,985,185)
Distribution Plant:					
California	108360-73	CA	(99,270,654)	(107,534,773)	(8,264,119)
Oregon	108360-73	OR	(775,616,895)	(835,519,865)	(59,902,970)
Washington	108360-73	WA	(175,598,438)	(187,589,890)	(11,991,452)
Eastern Wyoming	108360-73	WYP	(190,036,208)	(204,164,039)	(14,127,832)
Utah	108360-73	UT	(727,039,669)	(770,481,140)	(43,441,471)
Idaho	108360-73	ID	(118,550,028)	(126,139,855)	(7,589,827)
Western Wyoming	108360-73	WYU	(36,797,860)	(39,856,731)	(3,058,871)
Total Distribution Plant			(2,122,909,752)	(2,271,286,293)	(148,376,541)
General Plant:					
California	108GP	CA	(4,392,558)	(4,295,150)	97,408
Oregon	108GP	OR	(45,213,577)	(43,367,585)	1,845,992
Washington	108GP	WA	(17,168,715)	(17,976,270)	(807,555)
Eastern Wyoming	108GP	WYP	(17,702,986)	(18,305,484)	(602,498)
Utah	108GP	UT	(54,986,003)	(55,405,903)	(419,900)
Idaho	108GP	ID	(10,741,877)	(10,393,889)	347,988
Western Wyoming	108GP	WYU	(4,199,639)	(4,202,337)	(2,698)
Pre-merger Pacific	108GP	SG	(2,646,509)	(1,969,989)	676,519
Pre-merger Utah	108GP	SG	(4,558,040)	(2,969,084)	1,588,955
Post-merger	108GP	SG	(52,502,669)	(54,421,689)	(1,919,020)
General Office	108GP	SO	(74,737,799)	(63,288,399)	11,449,400
General Office	108GP	SG	(1,930,396)	(1,672,452)	257,944
General Office	108GP	SG	(44,066)	(46,139)	(2,073)
Customer Service	108GP	CN	(7,761,004)	(7,506,237)	254,766
Fuel Related	108GP	SE	(309,947)	(281,847)	28,100
Total General Plant			(298,895,785)	(286,102,456)	12,793,330
Mining Plant:					
Coal Mine	108MP	SE	(156,346,430)	(156,948,403)	(601,972)
Total Mining Plant			(156,346,430)	(156,948,403)	(601,972)
Total Depreciation Reserve			(6,791,311,158)	(7,392,846,377)	**(601,535,218)**
					Ref 6.2

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2011 Reserve	CY 2012 Adjusted Reserve Year End Balance	Adjustment to Test Period
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	-	-	-
Customer Service	111IP	CN	(97,854,280)	(106,183,429)	(8,329,149)
Idaho	111IP	ID	(766,964)	(797,736)	(30,773)
Pre-merger Utah	111IP	SG	(357,775)	(360,485)	(2,709)
Oregon	111IP	OR	(51,762)	466,390	518,152
Fuel Related	111IP	SE	(1,452,677)	(1,845,722)	(393,045)
Post-merger	111IP	SG	(49,291,670)	(41,781,003)	7,510,666
Hydro Relicensing	111IP	SG-P	(15,377,660)	(15,090,046)	287,614
Hydro Relicensing	111IP	SG-U	(3,523,610)	(3,840,958)	(317,348)
General Office	111IP	SO	(266,767,979)	(284,010,102)	(17,242,123)
Pre-merger Pacific	111IP	SG	-	-	-
Utah	111IP	UT	(34,134)	(52,526)	(18,392)
Washington	111IP	WA	(1,822)	173,498	175,320
Eastern Wyoming	111IP	WYP	(272,874)	(487,822)	(214,949)
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	(171,088)	(171,088)	-
Total Intangible Plant			(435,924,293)	(453,981,028)	(18,056,735)
Hydro Production Plant:					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(240,880)	(614,404)	(373,523)
Post-merger	111HP	SG-U	(460,259)	(527,058)	(66,799)
Total Hydro Plant			(701,139)	(1,141,461)	(440,322)
Other Production Plant:					
Post-merger	111OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	111GP	CA	(1,199,435)	(1,312,907)	(113,472)
General Office	111GP	CN	(2,861,226)	(3,271,277)	(410,051)
General Office	111GP	SG	-	-	-
Oregon	111GP	OR	(6,518,199)	(6,890,301)	(372,102)
General Office	111GP	SO	(11,320,920)	(13,209,808)	(1,888,888)
Utah	111GP	UT	(12,120)	(13,212)	(1,092)
Washington	111GP	WA	(1,515,595)	(1,697,643)	(182,048)
Eastern Wyoming	111GP	WYP	(7,088,170)	(8,075,428)	(987,258)
Western Wyoming	111GP	WYU	(36,320)	(43,495)	(7,176)
Total General Plant			(30,551,986)	(34,514,072)	(3,962,085)
Total Amortization Reserve			(467,177,419)	(489,636,561)	**(22,459,142)**
					Ref 6.2.1
Total Depreciation & Amortization Reserve			(7,258,488,577)	(7,882,482,937)	(623,994,360)
				Ref. 6.2.11	

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2011	Adjustments	Adjusted Reserve Balance Jul 2011	Adjustments	Adjusted Reserve Balance Aug 2011	Adjustments	Adjusted Reserve Balance Sep 2011	Adjustments	Adjusted Reserve Balance Oct 2011	Adjustments	Adjusted Reserve Balance Nov 2011
DEPRECIATION RESERVE												
Steam Production Plant:												
Pre-merger Pacific	SG	(764,758,175)	(889,021)	(765,647,196)	(885,028)	(766,532,224)	(881,036)	(767,413,260)	(877,044)	(768,290,304)	(873,051)	(769,163,355)
Pre-merger Utah	SG	(814,824,873)	(1,296,294)	(816,121,168)	(1,293,795)	(817,414,963)	(1,291,296)	(818,706,259)	(1,288,797)	(819,995,056)	(1,286,297)	(821,281,353)
Post-merger	SG	(724,982,448)	(5,934,891)	(730,917,340)	(5,948,580)	(736,865,920)	(5,950,440)	(742,816,360)	(5,965,556)	(748,781,916)	(6,043,409)	(754,825,325)
Geothermal - Blundell	SG	(2,864,947)	(48,875)	(2,913,823)	(48,832)	(2,962,654)	(48,788)	(3,011,442)	(48,744)	(3,060,186)	(48,700)	(3,108,886)
Pollution Control Equipment	SG	-	(2,456)	(2,456)	(21,970)	(24,426)	(40,677)	(65,103)	(42,816)	(107,919)	(231,725)	(339,644)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(182,693,711)	805,860	(181,887,851)	809,342	(181,078,509)	812,824	(180,265,685)	816,190	(179,449,495)	812,971	(178,636,525)
Total Steam Plant		(2,490,124,156)	(7,365,677)	(2,497,489,833)	(7,388,864)	(2,504,878,697)	(7,399,413)	(2,512,278,110)	(7,406,766)	(2,519,684,876)	(7,670,212)	(2,527,355,088)
Hydro Production Plant:												
Pre-merger Pacific	SG	(132,598,114)	(86,101)	(132,684,215)	(85,890)	(132,770,105)	(85,680)	(132,855,785)	(85,469)	(132,941,255)	3,526,746	(129,414,509)
Pre-merger Utah	SG	(29,241,674)	(8,678)	(29,250,352)	(8,543)	(29,258,895)	(8,408)	(29,267,303)	667,286	(28,600,017)	(6,885)	(28,606,901)
Post-merger	SG-P	(59,256,678)	137,626	(59,119,053)	924,655	(58,194,398)	3,890,163	(54,304,235)	1,859,020	(52,445,215)	3,324,150	(49,121,064)
Post-merger	SG-U	(17,589,885)	(220,974)	(17,810,859)	(222,327)	(18,033,186)	(222,645)	(18,255,830)	95,336	(18,160,494)	(222,025)	(18,382,519)
Total Hydro Plant		(238,686,352)	(178,126)	(238,864,478)	607,894	(238,256,584)	3,573,430	(234,683,154)	2,536,173	(232,146,980)	6,621,986	(225,524,994)
Other Production Plant:												
Pre-merger Utah	SG	(1,548,574)	(8,483)	(1,557,057)	(8,467)	(1,565,524)	(8,452)	(1,573,976)	(8,436)	(1,582,412)	(8,421)	(1,590,833)
Post-merger	SG	(187,032,713)	(501,946)	(187,534,658)	(500,293)	(188,034,952)	(495,475)	(188,530,427)	(490,778)	(189,021,204)	(486,948)	(189,508,153)
Post-merger Wind	SG-W	(208,280,655)	(6,000,763)	(214,281,418)	(5,536,655)	(219,818,073)	(6,000,621)	(225,818,694)	(6,003,304)	(231,821,998)	(6,008,174)	(237,830,172)
Post-merger	SG	(21,791,105)	(149,659)	(21,940,764)	(149,468)	(22,090,232)	(149,278)	(22,239,510)	(149,088)	(22,388,598)	(149,236)	(22,537,834)
Total Other Plant		(418,653,047)	(6,660,850)	(425,313,897)	(6,194,884)	(431,508,782)	(6,653,825)	(438,162,607)	(6,651,606)	(444,814,213)	(6,652,779)	(451,466,992)
Transmission Plant:												
Pre-merger Pacific	SG	(369,436,693)	(508,117)	(369,944,810)	(507,465)	(370,452,275)	(506,813)	(370,959,088)	(506,161)	(371,465,248)	(300,126)	(371,765,374)
Pre-merger Utah	SG	(398,038,617)	(743,442)	(398,782,059)	(742,971)	(399,525,030)	(742,500)	(400,267,530)	(742,029)	(401,009,560)	(741,558)	(401,751,118)
Post-merger	SG	(428,515,792)	(3,171,943)	(431,687,734)	(3,187,982)	(434,875,716)	(3,202,956)	(438,078,672)	(3,211,943)	(441,290,616)	(3,166,821)	(444,457,437)
Total Transmission Plant		(1,195,991,101)	(4,423,502)	(1,200,414,603)	(4,438,418)	(1,204,853,021)	(4,452,269)	(1,209,305,290)	(4,460,133)	(1,213,765,424)	(4,208,505)	(1,217,973,929)
Distribution Plant:												
California	CA	(99,270,654)	(438,071)	(99,708,724)	(439,302)	(100,148,027)	(442,192)	(100,590,219)	(445,377)	(101,035,596)	(447,798)	(101,483,394)
Oregon	OR	(775,616,895)	(3,234,915)	(778,851,810)	(3,249,387)	(782,101,197)	(3,261,684)	(785,362,881)	(3,269,519)	(788,632,399)	(3,281,047)	(791,913,447)
Washington	WA	(175,598,438)	(652,412)	(176,250,849)	(653,850)	(176,904,699)	(655,184)	(177,559,883)	(655,660)	(178,215,543)	(656,925)	(178,872,468)
Eastern Wyoming	WYP	(190,036,208)	(736,320)	(190,772,527)	(745,403)	(191,517,930)	(753,235)	(192,271,165)	(763,279)	(193,034,444)	(774,096)	(193,808,540)
Utah	UT	(727,039,669)	(2,310,981)	(729,350,650)	(2,322,488)	(731,673,138)	(2,335,600)	(734,008,739)	(2,315,398)	(736,324,137)	(2,363,914)	(738,688,052)
Idaho	ID	(118,550,028)	(399,761)	(118,949,789)	(400,865)	(119,350,654)	(402,323)	(119,752,977)	(404,180)	(120,157,157)	(406,057)	(120,563,215)
Western Wyoming	WYU	(36,797,860)	(171,869)	(36,969,729)	(171,699)	(37,141,428)	(171,528)	(37,312,956)	(171,358)	(37,484,313)	(171,187)	(37,655,500)
Total Distribution Plant		(2,122,909,752)	(7,944,328)	(2,130,854,079)	(7,982,994)	(2,138,837,073)	(8,021,746)	(2,146,858,819)	(8,024,771)	(2,154,883,590)	(8,101,026)	(2,162,984,615)
General Plant:												
California	CA	(4,392,558)	3,427	(4,389,131)	3,482	(4,385,649)	3,326	(4,382,323)	2,992	(4,379,331)	2,784	(4,376,547)
Oregon	OR	(45,213,577)	97,921	(45,115,656)	98,585	(45,017,071)	95,829	(44,921,242)	90,322	(44,830,920)	86,420	(44,744,500)
Washington	WA	(17,168,715)	(43,448)	(17,212,163)	(44,597)	(17,256,761)	(46,810)	(17,303,570)	(49,959)	(17,353,529)	(51,555)	(17,405,084)
Eastern Wyoming	WYP	(17,702,986)	(27,001)	(17,729,987)	(29,196)	(17,759,183)	(32,140)	(17,791,323)	(36,370)	(17,827,693)	(39,037)	(17,866,730)
Utah	UT	(54,986,003)	(31,905)	(55,017,908)	(37,111)	(55,055,019)	(37,736)	(55,092,755)	(39,792)	(55,132,547)	(42,897)	(55,175,444)
Idaho	ID	(10,741,877)	18,221	(10,723,656)	16,958	(10,706,698)	16,990	(10,689,709)	16,729	(10,672,980)	16,433	(10,656,546)
Western Wyoming	WYU	(4,199,639)	(722)	(4,200,361)	(613)	(4,200,974)	(503)	(4,201,477)	(393)	(4,201,871)	(284)	(4,202,154)
Pre-merger Pacific	SG	(2,646,509)	38,949	(2,607,560)	39,089	(2,568,470)	39,229	(2,529,241)	39,369	(2,489,872)	39,510	(2,450,362)
Pre-merger Utah	SG	(4,558,040)	91,382	(4,466,657)	91,629	(4,375,028)	91,876	(4,283,152)	92,123	(4,191,029)	92,370	(4,098,659)
Post-merger	SG	(52,502,669)	(113,452)	(52,616,121)	(114,241)	(52,730,362)	(117,320)	(52,847,682)	(118,698)	(52,966,380)	(118,614)	(53,084,994)
General Office	SO	(74,737,799)	595,634	(74,142,166)	601,593	(73,540,572)	605,856	(72,934,716)	608,232	(72,326,484)	612,619	(71,713,865)
General Office	SG	(1,930,396)	14,373	(1,916,023)	14,448	(1,901,575)	14,523	(1,887,052)	14,598	(1,872,454)	14,673	(1,857,782)
General Office	SG	(44,066)	(129)	(44,195)	(127)	(44,322)	(125)	(44,448)	(124)	(44,571)	(122)	(44,693)
Customer Service	CN	(7,761,004)	5,502	(7,755,501)	6,504	(7,748,997)	7,505	(7,741,492)	8,506	(7,732,986)	9,508	(7,723,478)
Fuel Related	SE	(309,947)	1,578	(308,369)	1,592	(306,777)	1,606	(305,171)	1,619	(303,552)	1,633	(301,919)
Total General Plant		(298,895,785)	650,331	(298,245,454)	647,996	(297,597,459)	642,106	(296,955,353)	629,155	(296,326,198)	623,441	(295,702,758)
Mining Plant:												
Coal Mine	SE	(156,346,430)	(25,203)	(156,371,633)	(27,058)	(156,398,692)	(27,521)	(156,426,212)	(28,549)	(156,454,761)	(29,717)	(156,484,478)
Total Mining Plant		(156,346,430)	(25,203)	(156,371,633)	(27,058)	(156,398,692)	(27,521)	(156,426,212)	(28,549)	(156,454,761)	(29,717)	(156,484,478)
Subtotal		(6,921,606,623)	(25,947,355)	(6,947,553,978)	(24,776,328)	(6,972,330,306)	(22,339,238)	(6,994,669,544)	(23,406,497)	(7,018,076,042)	(19,416,812)	(7,037,492,854)

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2011	Adjustments	Adjusted Reserve Balance Jul 2011	Adjustments	Adjusted Reserve Balance Aug 2011	Adjustments	Adjusted Reserve Balance Sep 2011	Adjustments	Adjusted Reserve Balance Oct 2011	Adjustments	Adjusted Reserve Balance Nov 2011
AMORTIZATION RESERVE												
Intangible Plant:												
California	CA	-	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(97,854,280)	(463,773)	(98,318,052)	(463,688)	(98,781,741)	(463,604)	(99,245,344)	(463,519)	(99,708,863)	(463,434)	(100,172,298)
Idaho	ID	(766,964)	(1,710)	(768,673)	(1,710)	(770,383)	(1,710)	(772,092)	(1,710)	(773,802)	(1,710)	(775,512)
Pre-merger Utah	SG	(357,775)	(176)	(357,951)	(173)	(358,124)	(170)	(358,294)	(167)	(358,461)	(164)	(358,626)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(51,762)	30,758	(21,004)	30,776	9,772	30,794	40,566	30,812	71,378	30,830	102,207
Fuel Related	SE	(1,452,677)	(22,429)	(1,475,106)	(22,378)	(1,497,484)	(22,326)	(1,519,810)	(22,275)	(1,542,085)	(22,223)	(1,564,308)
Post-merger	SG	(49,291,670)	419,593	(48,872,077)	422,476	(48,449,601)	425,257	(48,024,344)	428,027	(47,596,317)	430,803	(47,165,515)
Hydro Relicensing	SG-P	(15,377,660)	11,869	(15,365,791)	12,372	(15,353,419)	12,874	(15,340,545)	13,377	(15,327,168)	13,880	(15,313,288)
Hydro Relicensing	SG-U	(3,523,610)	(17,871)	(3,541,481)	(17,850)	(3,559,331)	(17,828)	(3,577,159)	(17,807)	(3,594,966)	(17,786)	(3,612,752)
General Office	SO	(266,767,979)	(944,305)	(267,712,283)	(943,675)	(268,655,959)	(944,296)	(269,600,255)	(946,557)	(270,546,812)	(947,078)	(271,493,890)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	(34,134)	(1,022)	(35,156)	(1,022)	(36,178)	(1,022)	(37,200)	(1,022)	(38,222)	(1,022)	(39,244)
Washington	WA	(1,822)	10,434	8,613	10,434	19,047	10,434	29,481	10,434	39,916	10,434	50,350
Eastern Wyoming	WYP	(272,874)	(11,942)	(284,815)	(11,942)	(296,757)	(11,942)	(308,698)	(11,942)	(320,640)	(11,942)	(332,582)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)
Total Intangible Plant		(435,924,293)	(990,573)	(436,914,866)	(986,380)	(437,901,246)	(983,538)	(438,884,784)	(982,348)	(439,867,132)	(979,412)	(440,846,544)
Hydro Production Plant:												
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(240,880)	(20,751)	(261,632)	(20,751)	(282,383)	(20,751)	(303,134)	(20,751)	(323,886)	(20,751)	(344,637)
Post-merger	SG-U	(460,259)	(3,711)	(463,970)	(3,711)	(467,681)	(3,711)	(471,392)	(3,711)	(475,103)	(3,711)	(478,814)
Total Hydro Plant		(701,139)	(24,462)	(725,602)	(24,462)	(750,064)	(24,462)	(774,526)	(24,462)	(798,989)	(24,462)	(823,451)
Other Production Plant:												
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-
General Plant:												
California	CA	(1,199,435)	(6,304)	(1,205,739)	(6,304)	(1,212,043)	(6,304)	(1,218,347)	(6,304)	(1,224,651)	(6,304)	(1,230,955)
General Office	CN	(2,861,226)	(22,781)	(2,884,007)	(22,781)	(2,906,787)	(22,781)	(2,929,568)	(22,781)	(2,952,349)	(22,781)	(2,975,129)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(6,518,199)	(20,672)	(6,538,871)	(20,672)	(6,559,544)	(20,672)	(6,580,216)	(20,672)	(6,600,888)	(20,672)	(6,621,561)
General Office	SO	(11,320,920)	(104,938)	(11,425,859)	(104,938)	(11,530,797)	(104,938)	(11,635,735)	(104,938)	(11,740,673)	(104,938)	(11,845,612)
Utah	UT	(12,120)	(61)	(12,181)	(61)	(12,242)	(61)	(12,302)	(61)	(12,363)	(61)	(12,424)
Washington	WA	(1,515,595)	(10,114)	(1,525,709)	(10,114)	(1,535,823)	(10,114)	(1,545,937)	(10,114)	(1,556,050)	(10,114)	(1,566,164)
Eastern Wyoming	WYP	(7,088,170)	(54,848)	(7,143,018)	(54,848)	(7,197,865)	(54,848)	(7,252,713)	(54,848)	(7,307,561)	(54,848)	(7,362,408)
Western Wyoming	WYU	(36,320)	(399)	(36,719)	(399)	(37,117)	(399)	(37,516)	(399)	(37,914)	(399)	(38,313)
Total General Plant		(30,551,986)	(220,116)	(30,772,102)	(220,116)	(30,992,218)	(220,116)	(31,212,334)	(220,116)	(31,432,450)	(220,116)	(31,652,565)
Subtotal		(467,177,419)	(1,235,151)	(468,412,570)	(1,230,958)	(469,643,528)	(1,228,116)	(470,871,644)	(1,226,927)	(472,098,570)	(1,223,990)	(473,322,560)
Total		(7,388,784,042)	(27,182,506)	(7,415,966,548)	(26,007,286)	(7,441,973,834)	(23,567,354)	(7,465,541,188)	(24,633,424)	(7,490,174,612)	(20,640,802)	(7,510,815,414)

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Reserve

Description	Factor	Adjustments	Adjusted Reserve Balance Dec 2011	Adjustments	Adjusted Reserve Balance Jan 2012	Adjustments	Adjusted Reserve Balance Feb 2012	Adjustments	Adjusted Reserve Balance Mar 2012	Adjustments	Adjusted Reserve Balance Apr 2012	Adjustments
DEPRECIATION RESERVE												
Steam Production Plant:												
Pre-merger Pacific	SG	(869,059)	(770,032,414)	(880,762)	(770,913,176)	(876,807)	(771,789,983)	(872,852)	(772,662,835)	(868,896)	(773,531,731)	(864,941)
Pre-merger Utah	SG	(1,283,798)	(822,565,151)	(1,288,502)	(823,853,653)	(1,286,018)	(825,139,670)	(1,283,533)	(826,423,204)	(1,281,049)	(827,704,253)	(1,278,565)
Post-merger	SG	(5,602,225)	(760,427,550)	(6,090,107)	(766,517,656)	(6,088,611)	(772,606,267)	(5,317,670)	(777,923,937)	(6,146,250)	(784,070,188)	(6,230,300)
Geothermal - Blundell	SG	(48,900)	(3,157,786)	(49,040)	(3,206,826)	(48,997)	(3,255,823)	(48,953)	(3,304,775)	(48,909)	(3,353,684)	(48,865)
Pollution Control Equipment	SG	(430,452)	(770,096)	(327,218)	(1,097,314)	(332,913)	(1,430,227)	(352,301)	(1,782,528)	(494,303)	(2,276,830)	(780,628)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	808,859	(177,827,666)	801,465	(177,026,200)	804,928	(176,221,272)	808,124	(175,413,148)	811,320	(174,601,827)	814,783
Total Steam Plant		(7,425,574)	(2,534,780,662)	(7,834,164)	(2,542,614,826)	(7,828,417)	(2,550,443,242)	(7,067,184)	(2,557,510,427)	(8,028,087)	(2,565,538,513)	(8,388,516)
Hydro Production Plant:												
Pre-merger Pacific	SG	(80,398)	(129,494,907)	(84,060)	(129,578,967)	(83,855)	(129,662,822)	(83,649)	(129,746,471)	(83,444)	(129,829,915)	(83,238)
Pre-merger Utah	SG	(6,750)	(28,613,651)	(8,457)	(28,622,109)	(8,326)	(28,630,435)	(8,195)	(28,638,630)	(8,064)	(28,646,694)	(7,932)
Post-merger	SG-P	600,778	(48,520,287)	168,999	(48,351,288)	213,600	(48,137,687)	445,636	(47,692,052)	776,684	(46,915,368)	755,977
Post-merger	SG-U	(225,153)	(18,607,673)	(223,855)	(18,831,527)	(223,585)	(19,055,112)	(223,315)	(19,278,428)	(223,237)	(19,501,665)	(223,160)
Total Hydro Plant		288,476	(225,236,518)	(147,373)	(225,383,891)	(102,165)	(225,486,057)	130,476	(225,355,580)	461,939	(224,893,642)	441,647
Other Production Plant:												
Pre-merger Utah	SG	(8,406)	(1,599,238)	(8,406)	(1,607,645)	(8,391)	(1,616,036)	(8,376)	(1,624,412)	(8,361)	(1,632,772)	(8,345)
Post-merger	SG	(484,165)	(189,992,318)	3,334,007	(186,658,311)	(482,663)	(187,140,974)	(477,998)	(187,618,972)	(473,333)	(188,092,305)	(468,945)
Post-merger Wind	SG-W	(6,015,528)	(243,845,700)	(6,018,647)	(249,864,347)	(6,019,909)	(255,884,256)	(6,021,171)	(261,905,427)	(6,020,979)	(267,926,405)	(6,020,786)
Post-merger	SG	(151,808)	(22,689,643)	(152,661)	(22,842,303)	(153,923)	(22,996,226)	(155,497)	(23,151,723)	(155,614)	(23,307,337)	(155,420)
Total Other Plant		(6,659,907)	(458,126,899)	(2,845,707)	(460,972,606)	(6,664,886)	(467,637,493)	(6,663,041)	(474,300,534)	(6,658,286)	(480,958,819)	(6,653,496)
Transmission Plant:												
Pre-merger Pacific	SG	(504,524)	(372,269,898)	(505,750)	(372,775,648)	(505,100)	(373,280,748)	(504,451)	(373,785,200)	(503,802)	(374,289,002)	(503,153)
Pre-merger Utah	SG	(741,087)	(402,492,205)	(741,425)	(403,233,631)	(740,956)	(403,974,586)	(740,486)	(404,715,072)	(740,016)	(405,455,088)	(739,546)
Post-merger	SG	(3,234,722)	(447,692,159)	(3,227,827)	(450,919,987)	(3,240,893)	(454,160,880)	(3,264,459)	(457,425,339)	(3,297,869)	(460,723,208)	(3,317,609)
Total Transmission Plant		(4,480,334)	(1,222,454,263)	(4,475,002)	(1,226,929,265)	(4,486,949)	(1,231,416,215)	(4,509,396)	(1,235,925,611)	(4,541,687)	(1,240,467,298)	(4,560,309)
Distribution Plant:												
California	CA	(452,359)	(101,935,753)	(453,020)	(102,388,773)	(454,132)	(102,842,905)	(455,389)	(103,298,295)	(456,648)	(103,754,943)	(457,798)
Oregon	OR	(3,301,126)	(795,214,573)	(3,298,254)	(798,512,827)	(3,302,801)	(801,815,628)	(3,307,876)	(805,123,505)	(3,316,155)	(808,439,659)	(3,324,084)
Washington	WA	(660,604)	(179,533,072)	(658,820)	(180,191,891)	(659,807)	(180,851,699)	(661,016)	(181,512,714)	(662,291)	(182,175,005)	(663,464)
Eastern Wyoming	WYP	(780,940)	(194,589,480)	(766,507)	(195,355,987)	(768,667)	(196,124,654)	(770,843)	(196,895,497)	(773,164)	(197,668,662)	(775,566)
Utah	UT	(2,386,009)	(741,074,061)	(2,352,296)	(743,426,356)	(2,354,025)	(745,780,381)	(2,357,860)	(748,138,241)	(2,362,166)	(750,500,407)	(2,394,372)
Idaho	ID	(407,578)	(120,970,793)	(406,254)	(121,377,047)	(408,139)	(121,785,185)	(410,072)	(122,195,258)	(412,173)	(122,607,430)	(414,345)
Western Wyoming	WYU	(171,016)	(37,826,516)	(171,138)	(37,997,654)	(170,968)	(38,168,622)	(170,798)	(38,339,420)	(170,628)	(38,510,048)	(170,458)
Total Distribution Plant		(8,159,632)	(2,171,144,247)	(8,106,288)	(2,179,250,535)	(8,118,539)	(2,187,369,075)	(8,133,854)	(2,195,502,929)	(8,153,225)	(2,203,656,153)	(8,200,086)
General Plant:												
California	CA	746	(4,375,801)	8,869	(4,366,932)	8,819	(4,358,113)	8,785	(4,349,328)	8,588	(4,340,741)	8,391
Oregon	OR	78,617	(44,665,883)	124,499	(44,541,384)	121,085	(44,420,299)	118,501	(44,301,798)	118,368	(44,183,431)	116,751
Washington	WA	(52,512)	(17,457,596)	(42,071)	(17,499,668)	(42,603)	(17,542,271)	(43,345)	(17,585,616)	(43,345)	(17,628,962)	(43,141)
Eastern Wyoming	WYP	(41,760)	(17,908,489)	(22,293)	(17,930,783)	(24,324)	(17,955,107)	(26,035)	(17,981,142)	(27,016)	(18,008,158)	(26,991)
Utah	UT	(48,677)	(55,224,122)	(877)	(55,224,999)	(2,366)	(55,227,365)	(4,582)	(55,231,947)	(6,029)	(55,237,976)	(6,788)
Idaho	ID	16,127	(10,640,419)	24,238	(10,616,181)	23,861	(10,592,321)	23,479	(10,568,842)	22,582	(10,546,260)	21,683
Western Wyoming	WYU	(174)	(4,202,329)	(1,231)	(4,203,560)	(1,124)	(4,204,684)	(1,017)	(4,205,701)	(910)	(4,206,611)	(803)
Pre-merger Pacific	SG	39,650	(2,410,712)	35,252	(2,375,461)	35,380	(2,340,080)	35,508	(2,304,572)	35,637	(2,268,935)	35,765
Pre-merger Utah	SG	92,617	(4,006,042)	81,652	(3,924,390)	81,876	(3,842,514)	82,100	(3,760,414)	82,323	(3,678,091)	82,547
Post-merger	SG	(126,401)	(53,211,395)	(108,314)	(53,319,710)	(107,665)	(53,427,374)	(109,272)	(53,536,646)	(110,155)	(53,646,801)	(109,224)
General Office	SO	606,341	(71,107,524)	592,961	(70,514,563)	598,362	(69,916,201)	606,604	(69,309,597)	614,647	(68,694,950)	622,633
General Office	SG	14,748	(1,843,034)	13,393	(1,829,641)	13,464	(1,816,177)	13,536	(1,802,641)	13,607	(1,789,034)	13,679
General Office	SG	(120)	(44,813)	(131)	(44,944)	(129)	(45,073)	(127)	(45,200)	(126)	(45,326)	(124)
Customer Service	CN	10,509	(7,712,969)	6,127	(7,706,842)	7,093	(7,699,749)	8,058	(7,691,692)	9,023	(7,682,669)	9,988
Fuel Related	SE	1,647	(300,272)	1,386	(298,886)	1,399	(297,487)	1,412	(296,075)	1,425	(294,650)	1,438
Total General Plant		591,356	(295,111,402)	713,460	(294,397,942)	713,127	(293,684,815)	713,603	(292,971,212)	718,617	(292,252,595)	725,806
Mining Plant:												
Coal Mine	SE	(33,245)	(156,517,723)	(28,060)	(156,545,783)	(30,801)	(156,576,584)	(30,249)	(156,606,834)	(28,773)	(156,635,606)	(28,050)
Total Mining Plant		(33,245)	(156,517,723)	(28,060)	(156,545,783)	(30,801)	(156,576,584)	(30,249)	(156,606,834)	(28,773)	(156,635,606)	(28,050)
Subtotal		(25,878,860)	(7,063,371,714)	(22,723,135)	(7,086,094,849)	(26,518,631)	(7,112,613,480)	(25,559,646)	(7,138,173,126)	(26,229,501)	(7,164,402,627)	(26,663,005)

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Reserve

Description	Factor	Adjustments	Adjusted Reserve Balance Dec 2011	Adjustments	Adjusted Reserve Balance Jan 2012	Adjustments	Adjusted Reserve Balance Feb 2012	Adjustments	Adjusted Reserve Balance Mar 2012	Adjustments	Adjusted Reserve Balance Apr 2012	Adjustments
AMORTIZATION RESERVE												
Intangible Plant:												
California	CA	-	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(463,350)	(100,635,647)	(463,287)	(101,098,935)	(463,203)	(101,562,137)	(463,118)	(102,025,256)	(463,034)	(102,488,289)	(462,949)
Idaho	ID	(1,710)	(777,221)	(1,710)	(778,931)	(1,710)	(780,640)	(1,710)	(782,350)	(1,710)	(784,060)	(1,710)
Pre-merger Utah	SG	(162)	(358,787)	(174)	(358,961)	(171)	(359,132)	(168)	(359,300)	(165)	(359,465)	(162)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	30,848	133,055	27,592	160,648	27,608	188,256	27,625	215,881	27,641	243,522	27,657
Fuel Related	SE	(22,172)	(1,586,480)	(22,190)	(1,608,670)	(22,139)	(1,630,808)	(22,088)	(1,652,896)	(22,037)	(1,674,933)	(21,986)
Post-merger	SG	431,664	(46,733,850)	407,677	(46,326,174)	410,473	(45,915,700)	413,270	(45,502,430)	416,067	(45,086,363)	418,864
Hydro Relicensing	SG-P	14,382	(15,298,906)	11,705	(15,287,201)	12,200	(15,275,001)	12,696	(15,262,305)	13,192	(15,249,113)	13,687
Hydro Relicensing	SG-U	(17,764)	(3,630,516)	(17,781)	(3,648,297)	(17,760)	(3,666,057)	(17,739)	(3,683,796)	(17,718)	(3,701,514)	(17,696)
General Office	SO	(952,095)	(272,445,986)	(952,270)	(273,398,255)	(951,998)	(274,350,253)	(949,655)	(275,299,908)	(947,458)	(276,247,366)	(945,302)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	(1,022)	(40,266)	(1,022)	(41,288)	(1,022)	(42,310)	(1,022)	(43,331)	(1,022)	(44,353)	(1,022)
Washington	WA	10,434	60,784	9,393	70,177	9,393	79,570	9,393	88,963	9,393	98,356	9,393
Eastern Wyoming	WYP	(11,942)	(344,523)	(11,942)	(356,465)	(11,942)	(368,406)	(11,942)	(380,348)	(11,942)	(392,290)	(11,942)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)	-
Total Intangible Plant		(982,887)	(441,829,431)	(1,014,008)	(442,843,439)	(1,010,268)	(443,853,707)	(1,004,457)	(444,858,164)	(998,792)	(445,856,956)	(993,168)
Hydro Production Plant:												
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(20,751)	(365,388)	(20,751)	(386,139)	(20,751)	(406,891)	(20,751)	(427,642)	(20,751)	(448,393)	(20,751)
Post-merger	SG-U	(3,711)	(482,525)	(3,711)	(486,236)	(3,711)	(489,947)	(3,711)	(493,658)	(3,711)	(497,369)	(3,711)
Total Hydro Plant		(24,462)	(847,913)	(24,462)	(872,376)	(24,462)	(896,838)	(24,462)	(921,300)	(24,462)	(945,763)	(24,462)
Other Production Plant:												
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-
General Plant:												
California	CA	(6,304)	(1,237,259)	(6,304)	(1,243,563)	(6,304)	(1,249,867)	(6,304)	(1,256,171)	(6,304)	(1,262,475)	(6,304)
General Office	CN	(22,781)	(2,997,910)	(22,781)	(3,020,690)	(22,781)	(3,043,471)	(22,781)	(3,066,251)	(22,781)	(3,089,032)	(22,781)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(20,672)	(6,642,233)	(20,672)	(6,662,905)	(20,672)	(6,683,577)	(20,672)	(6,704,250)	(20,672)	(6,724,922)	(20,672)
General Office	SO	(104,938)	(11,950,550)	(104,938)	(12,055,488)	(104,938)	(12,160,426)	(104,938)	(12,265,364)	(104,938)	(12,370,303)	(104,938)
Utah	UT	(61)	(12,484)	(61)	(12,545)	(61)	(12,606)	(61)	(12,666)	(61)	(12,727)	(61)
Washington	WA	(10,114)	(1,576,278)	(10,114)	(1,586,392)	(10,114)	(1,596,506)	(10,114)	(1,606,619)	(10,114)	(1,616,733)	(10,114)
Eastern Wyoming	WYP	(54,848)	(7,417,256)	(54,848)	(7,472,104)	(54,848)	(7,526,951)	(54,848)	(7,581,799)	(54,848)	(7,636,647)	(54,848)
Western Wyoming	WYU	(399)	(38,712)	(399)	(39,110)	(399)	(39,509)	(399)	(39,908)	(399)	(40,306)	(399)
Total General Plant		(220,116)	(31,872,681)	(220,116)	(32,092,797)	(220,116)	(32,312,913)	(220,116)	(32,533,029)	(220,116)	(32,753,145)	(220,116)
Subtotal		(1,227,465)	(474,550,026)	(1,258,586)	(475,808,612)	(1,254,846)	(477,063,458)	(1,249,035)	(478,312,493)	(1,243,370)	(479,555,863)	(1,237,746)
Total		(27,106,326)	(7,537,921,740)	(23,981,721)	(7,561,903,461)	(27,773,477)	(7,589,676,938)	(26,808,681)	(7,616,485,619)	(27,472,871)	(7,643,958,490)	(27,900,751)

PacifiCorp
Oregon General Rate Case - December 2013
Jun 2011 - Dec 2012 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance May 2012	Adjustments	Adjusted Reserve Balance Jun 2012	Adjustments	Adjusted Reserve Balance Jul 2012	Adjustments	Adjusted Reserve Balance Aug 2012	Adjustments	Adjusted Reserve Balance Sep 2012	Adjustments	Adjusted Reserve Balance Oct 2012
DEPRECIATION RESERVE												
Steam Production Plant:												
Pre-merger Pacific	SG	(774,396,672)	(860,986)	(775,257,658)	(857,030)	(776,114,688)	(853,075)	(776,967,763)	(849,120)	(777,816,883)	(845,164)	(778,662,047)
Pre-merger Utah	SG	(828,982,818)	(1,276,081)	(830,258,899)	(1,273,596)	(831,532,495)	(1,271,112)	(832,803,607)	(1,268,628)	(834,072,235)	(1,266,144)	(835,338,379)
Post-merger	SG	(790,300,488)	(6,276,812)	(796,577,299)	(6,320,398)	(802,897,698)	(6,346,876)	(809,244,574)	(6,355,008)	(815,599,581)	(6,361,328)	(821,960,910)
Geothermal - Blundell	SG	(3,402,548)	(48,821)	(3,451,369)	(48,777)	(3,500,146)	(48,733)	(3,548,879)	(48,689)	(3,597,568)	(48,910)	(3,646,477)
Pollution Control Equipment	SG	(3,057,459)	(1,002,059)	(4,059,518)	(1,065,825)	(5,125,342)	(1,073,061)	(6,198,403)	(1,080,696)	(7,279,100)	(1,086,200)	(8,365,300)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(173,787,044)	817,940	(172,969,104)	821,047	(172,148,057)	824,403	(171,323,654)	827,752	(170,495,903)	831,098	(169,664,804)
Total Steam Plant		(2,573,927,029)	(8,646,817)	(2,582,573,847)	(8,744,579)	(2,591,318,426)	(8,768,454)	(2,600,086,880)	(8,774,389)	(2,608,861,269)	(8,776,648)	(2,617,637,917)
Hydro Production Plant:												
Pre-merger Pacific	SG	(129,913,153)	(83,033)	(129,996,186)	(82,828)	(130,079,014)	(82,622)	(130,161,636)	(82,417)	(130,244,053)	(82,211)	(130,326,264)
Pre-merger Utah	SG	(28,654,626)	(7,801)	(28,662,427)	(7,670)	(28,670,096)	(7,538)	(28,677,635)	(7,407)	(28,685,042)	(7,276)	(28,692,318)
Post-merger	SG-P	(46,159,391)	875,188	(45,284,203)	974,413	(44,309,790)	698,818	(43,610,972)	887,867	(42,723,105)	(51,360)	(42,774,466)
Post-merger	SG-U	(19,724,825)	(222,890)	(19,947,715)	(222,620)	(20,170,335)	(222,350)	(20,392,685)	(222,080)	(20,614,766)	(221,811)	(20,836,576)
Total Hydro Plant		(224,451,995)	561,464	(223,890,531)	661,295	(223,229,235)	386,307	(222,842,928)	575,962	(222,266,966)	(362,658)	(222,629,624)
Other Production Plant:												
Pre-merger Utah	SG	(1,641,118)	(8,330)	(1,649,448)	(8,315)	(1,657,762)	(8,299)	(1,666,062)	1,204,555	(461,506)	2,031	(459,476)
Post-merger	SG	(188,561,250)	(465,286)	(189,026,535)	(461,969)	(189,488,504)	(457,924)	(189,946,428)	71,918	(189,874,510)	(466,580)	(190,341,089)
Post-merger Wind	SG-W	(273,947,192)	(6,021,461)	(279,968,653)	(6,022,141)	(285,990,793)	(6,021,958)	(292,012,752)	(6,021,776)	(298,034,528)	(6,021,594)	(304,056,121)
Post-merger	SG	(23,462,757)	(155,226)	(23,617,982)	(155,032)	(23,773,014)	(154,837)	(23,927,851)	(154,643)	(24,082,495)	(154,449)	(24,236,944)
Total Other Plant		(487,612,315)	(6,650,302)	(494,262,618)	(6,647,456)	(500,910,073)	(6,643,019)	(507,553,092)	(4,899,946)	(512,453,038)	(6,640,592)	(519,093,631)
Transmission Plant:												
Pre-merger Pacific	SG	(374,792,156)	(502,504)	(375,294,660)	(501,855)	(375,796,515)	(501,206)	(376,297,721)	(500,557)	(376,798,278)	(499,908)	(377,298,186)
Pre-merger Utah	SG	(406,194,634)	(739,077)	(406,933,711)	(738,607)	(407,672,318)	(738,137)	(408,410,455)	(737,667)	(409,148,122)	(737,198)	(409,885,320)
Post-merger	SG	(464,040,817)	(3,347,322)	(467,388,139)	(3,371,894)	(470,760,033)	(3,394,987)	(474,155,020)	(3,418,139)	(477,573,159)	(3,427,695)	(481,000,854)
Total Transmission Plant		(1,245,027,607)	(4,588,903)	(1,249,616,510)	(4,612,356)	(1,254,228,866)	(4,634,330)	(1,258,863,196)	(4,656,364)	(1,263,519,560)	(4,664,800)	(1,268,184,360)
Distribution Plant:												
California	CA	(104,212,740)	(458,972)	(104,671,712)	(460,141)	(105,131,852)	(461,406)	(105,593,258)	(462,692)	(106,055,950)	(463,813)	(106,519,763)
Oregon	OR	(811,763,744)	(3,329,014)	(815,092,758)	(3,333,824)	(818,426,582)	(3,338,819)	(821,765,401)	(3,343,651)	(825,109,052)	(3,347,846)	(828,456,898)
Washington	WA	(182,838,469)	(664,675)	(183,503,144)	(665,859)	(184,169,003)	(667,099)	(184,836,102)	(668,301)	(185,504,403)	(669,281)	(186,173,683)
Eastern Wyoming	WYP	(198,444,227)	(778,026)	(199,222,254)	(780,683)	(200,002,937)	(783,601)	(200,786,538)	(786,459)	(201,572,997)	(789,063)	(202,362,060)
Utah	UT	(752,894,779)	(2,437,466)	(755,332,244)	(2,451,729)	(757,783,973)	(2,456,431)	(760,240,404)	(2,193,773)	(762,434,177)	(2,464,276)	(764,898,453)
Idaho	ID	(123,021,775)	(416,548)	(123,438,323)	(418,805)	(123,857,128)	(421,139)	(124,278,266)	(423,453)	(124,701,719)	(425,599)	(125,127,318)
Western Wyoming	WYU	(38,680,506)	(170,288)	(38,850,794)	(170,119)	(39,020,913)	(169,949)	(39,190,862)	(169,779)	(39,360,641)	(169,609)	(39,530,250)
Total Distribution Plant		(2,211,856,240)	(8,254,989)	(2,220,111,229)	(8,281,159)	(2,228,392,388)	(8,298,443)	(2,236,690,831)	(8,048,107)	(2,244,738,938)	(8,329,488)	(2,253,068,426)
General Plant:												
California	CA	(4,332,349)	7,901	(4,324,448)	7,411	(4,317,036)	7,429	(4,309,607)	7,078	(4,302,529)	6,700	(4,295,830)
Oregon	OR	(44,066,680)	112,814	(43,953,866)	110,658	(43,843,208)	110,681	(43,732,527)	108,735	(43,623,791)	107,569	(43,516,223)
Washington	WA	(17,672,102)	(43,418)	(17,715,521)	(43,697)	(17,759,218)	(43,493)	(17,802,711)	(43,287)	(17,845,998)	(43,076)	(17,889,074)
Eastern Wyoming	WYP	(18,035,149)	(27,336)	(18,062,485)	(28,122)	(18,090,607)	(28,636)	(18,119,243)	(29,327)	(18,148,570)	(30,211)	(18,178,782)
Utah	UT	(55,244,764)	(8,941)	(55,253,705)	(11,306)	(55,265,011)	(11,633)	(55,276,644)	(11,622)	(55,288,266)	(12,138)	(55,300,404)
Idaho	ID	(10,524,577)	21,683	(10,502,893)	21,596	(10,481,297)	21,297	(10,460,000)	21,007	(10,438,993)	20,924	(10,418,069)
Western Wyoming	WYU	(4,207,414)	(696)	(4,208,110)	(589)	(4,208,699)	(482)	(4,209,181)	(375)	(4,209,556)	(268)	(4,209,825)
Pre-merger Pacific	SG	(2,233,171)	35,893	(2,197,277)	36,021	(2,161,256)	36,150	(2,125,106)	36,278	(2,088,828)	36,406	(2,052,422)
Pre-merger Utah	SG	(3,595,544)	82,771	(3,512,773)	82,994	(3,429,779)	83,218	(3,346,561)	109,095	(3,237,466)	83,718	(3,153,747)
Post-merger	SG	(53,756,025)	(108,690)	(53,864,715)	(108,016)	(53,972,731)	(107,795)	(54,080,526)	131,380	(53,949,146)	(109,738)	(54,058,885)
General Office	SO	(68,072,317)	629,953	(67,442,364)	635,692	(66,806,672)	641,521	(66,165,152)	647,677	(65,517,474)	651,479	(64,865,995)
General Office	SG	(1,775,355)	13,750	(1,761,605)	13,822	(1,747,783)	13,893	(1,733,890)	13,965	(1,719,925)	14,036	(1,705,888)
General Office	SG	(45,449)	(122)	(45,571)	(120)	(45,692)	(118)	(45,810)	(117)	(45,927)	(115)	(46,042)
Customer Service	CN	(7,672,680)	10,954	(7,661,727)	11,919	(7,649,808)	12,884	(7,636,924)	13,849	(7,623,075)	14,815	(7,608,260)
Fuel Related	SE	(293,213)	1,451	(291,762)	1,464	(290,298)	1,477	(288,821)	1,490	(287,331)	1,503	(285,828)
Total General Plant		(291,526,789)	727,967	(290,798,822)	729,728	(290,069,094)	736,391	(289,332,702)	1,005,826	(288,326,876)	741,604	(287,585,272)
Mining Plant:												
Coal Mine	SE	(156,663,657)	(28,830)	(156,692,487)	(30,232)	(156,722,719)	(30,573)	(156,753,292)	(29,233)	(156,782,526)	(27,716)	(156,810,242)
Total Mining Plant		(156,663,657)	(28,830)	(156,692,487)	(30,232)	(156,722,719)	(30,573)	(156,753,292)	(29,233)	(156,782,526)	(27,716)	(156,810,242)
Subtotal		(7,191,065,632)	(26,880,411)	(7,217,946,043)	(26,924,759)	(7,244,870,801)	(27,252,121)	(7,272,122,922)	(24,826,251)	(7,296,949,173)	(28,060,299)	(7,325,009,472)

PacifiCorp
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Description	Factor	Adjusted Reserve Balance May 2012	Adjustments	Adjusted Reserve Balance Jun 2012	Adjustments	Adjusted Reserve Balance Jul 2012	Adjustments	Adjusted Reserve Balance Aug 2012	Adjustments	Adjusted Reserve Balance Sep 2012	Adjustments	Adjusted Reserve Balance Oct 2012
AMORTIZATION RESERVE												
Intangible Plant:												
California	CA	-	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(102,951,239)	(462,865)	(103,414,103)	(462,780)	(103,876,883)	(462,696)	(104,339,579)	(462,611)	(104,802,190)	(462,526)	(105,264,716)
Idaho	ID	(785,769)	(1,710)	(787,479)	(1,710)	(789,188)	(1,710)	(790,898)	(1,710)	(792,607)	(1,710)	(794,317)
Pre-merger Utah	SG	(359,627)	(160)	(359,787)	(157)	(359,944)	(154)	(360,098)	(151)	(360,249)	(148)	(360,398)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	271,178	27,673	298,851	27,689	326,541	27,705	354,246	27,721	381,967	27,738	409,705
Fuel Related	SE	(1,696,919)	(21,935)	(1,718,854)	(21,884)	(1,740,738)	(21,833)	(1,762,571)	(21,782)	(1,784,353)	(21,731)	(1,806,084)
Post-merger	SG	(44,667,499)	421,660	(44,245,839)	424,457	(43,821,382)	427,254	(43,394,128)	430,051	(42,964,077)	431,620	(42,532,457)
Hydro Relicensing	SG-P	(15,235,426)	14,183	(15,221,242)	14,679	(15,206,564)	15,174	(15,191,389)	15,670	(15,175,719)	16,166	(15,159,553)
Hydro Relicensing	SG-U	(3,719,210)	(17,675)	(3,736,885)	(17,654)	(3,754,539)	(17,633)	(3,772,171)	(17,611)	(3,789,783)	(17,590)	(3,807,373)
General Office	SO	(277,192,668)	(947,917)	(278,140,584)	(951,684)	(279,092,268)	(951,099)	(280,043,367)	(950,276)	(280,993,644)	(951,169)	(281,944,812)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	(45,375)	(1,022)	(46,397)	(1,022)	(47,419)	(1,022)	(48,440)	(1,022)	(49,462)	(1,022)	(50,484)
Washington	WA	107,748	9,393	117,141	9,393	126,534	9,393	135,927	9,393	145,320	9,393	154,712
Eastern Wyoming	WYP	(404,231)	(11,942)	(416,173)	(11,942)	(428,114)	(11,942)	(440,056)	(11,942)	(451,998)	(11,942)	(463,939)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)	-	(171,088)
Total Intangible Plant		(446,850,124)	(992,314)	(447,842,438)	(992,613)	(448,835,052)	(988,561)	(449,823,612)	(984,270)	(450,807,882)	(982,922)	(451,790,804)
Hydro Production Plant:												
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(469,145)	(20,751)	(489,896)	(20,751)	(510,647)	(20,751)	(531,398)	(20,751)	(552,150)	(20,751)	(572,901)
Post-merger	SG-U	(501,080)	(3,711)	(504,791)	(3,711)	(508,502)	(3,711)	(512,213)	(3,711)	(515,924)	(3,711)	(519,636)
Total Hydro Plant		(970,225)	(24,462)	(994,687)	(24,462)	(1,019,150)	(24,462)	(1,043,612)	(24,462)	(1,068,074)	(24,462)	(1,092,536)
Other Production Plant:												
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-
General Plant:												
California	CA	(1,268,779)	(6,304)	(1,275,083)	(6,304)	(1,281,387)	(6,304)	(1,287,691)	(6,304)	(1,293,995)	(6,304)	(1,300,299)
General Office	CN	(3,111,813)	(22,781)	(3,134,593)	(22,781)	(3,157,374)	(22,781)	(3,180,154)	(22,781)	(3,202,935)	(22,781)	(3,225,716)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(6,745,594)	(20,672)	(6,766,267)	(20,672)	(6,786,939)	(20,672)	(6,807,611)	(20,672)	(6,828,284)	(20,672)	(6,848,956)
General Office	SO	(12,475,241)	(104,938)	(12,580,179)	(104,938)	(12,685,117)	(104,938)	(12,790,055)	(104,938)	(12,894,994)	(104,938)	(12,999,932)
Utah	UT	(12,788)	(61)	(12,848)	(61)	(12,909)	(61)	(12,970)	(61)	(13,030)	(61)	(13,091)
Washington	WA	(1,626,847)	(10,114)	(1,636,961)	(10,114)	(1,647,074)	(10,114)	(1,657,188)	(10,114)	(1,667,302)	(10,114)	(1,677,416)
Eastern Wyoming	WYP	(7,691,494)	(54,848)	(7,746,342)	(54,848)	(7,801,190)	(54,848)	(7,856,037)	(54,848)	(7,910,885)	(54,848)	(7,965,733)
Western Wyoming	WYU	(40,705)	(399)	(41,104)	(399)	(41,502)	(399)	(41,901)	(399)	(42,300)	(399)	(42,698)
Total General Plant		(32,973,261)	(220,116)	(33,193,376)	(220,116)	(33,413,492)	(220,116)	(33,633,608)	(220,116)	(33,853,724)	(220,116)	(34,073,840)
Subtotal		(480,793,609)	(1,236,893)	(482,030,502)	(1,237,191)	(483,267,693)	(1,233,139)	(484,500,832)	(1,228,848)	(485,729,680)	(1,227,500)	(486,957,180)
Total		(7,671,859,241)	(28,117,303)	(7,699,976,544)	(28,161,950)	(7,728,138,494)	(28,485,260)	(7,756,623,755)	(26,055,099)	(7,782,678,854)	(29,287,798)	(7,811,966,652)

PacifiCorp
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Jun 2011 - Dec 2012 Depreciation & Amortization Reserve

Description	Factor	Adjustments	Adjusted Reserve Balance Nov 2012	Adjustments	Adjusted Reserve Balance Dec 2012	CY 2012 Year End Balance	Incremental Reserve For Annualized Depreciation	CY 2012 Adjusted Reserve Year End Balance
DEPRECIATION RESERVE								
Steam Production Plant:								
Pre-merger Pacific	SG	(841,209)	(779,503,257)	(837,254)	(780,340,510)	(780,340,510)	284,782	(780,055,729)
Pre-merger Utah	SG	(1,263,659)	(836,602,038)	(1,261,175)	(837,863,213)	(837,863,213)	178,866	(837,684,347)
Post-merger	SG	(6,373,172)	(828,334,082)	(5,380,522)	(833,714,604)	(833,714,604)	(2,499,630)	(836,214,234)
Geothermal - Blundell	SG	(49,131)	(3,695,608)	(49,228)	(3,744,836)	(3,744,836)	(5,118)	(3,749,955)
Pollution Control Equipment	SG	(1,089,907)	(9,455,207)	(1,102,203)	(10,557,410)	(10,557,410)	(3,575,518)	(14,132,928)
Pollution Control Equipment	SG	-	-	-	-	-	-	-
Post-merger	SG	834,450	(168,830,354)	834,441	(167,995,913)	(167,995,913)	161,298	(167,834,615)
Total Steam Plant		(8,782,629)	(2,626,420,546)	(7,795,940)	(2,634,216,486)	(2,634,216,486)	(5,455,321)	(2,639,671,807)
Hydro Production Plant:								
Pre-merger Pacific	SG	(82,006)	(130,408,270)	(81,801)	(130,490,071)	(130,490,071)	14,790	(130,475,281)
Pre-merger Utah	SG	(7,144)	(28,699,462)	(7,013)	(28,706,475)	(28,706,475)	9,454	(28,697,021)
Post-merger	SG-P	(368,153)	(43,142,618)	(345,789)	(43,488,407)	(43,488,407)	(2,914,931)	(46,403,338)
Post-merger	SG-U	(243,103)	(21,079,679)	(265,715)	(21,345,394)	(21,345,394)	(465,077)	(21,810,471)
Total Hydro Plant		(700,406)	(223,330,030)	(700,317)	(224,030,347)	(224,030,347)	(3,355,764)	(227,386,111)
Other Production Plant:								
Pre-merger Utah	SG	2,046	(457,430)	2,061	(455,369)	(455,369)	88,645	(366,724)
Post-merger	SG	(481,039)	(190,822,128)	588,897	(190,233,231)	(190,233,231)	(131,840)	(190,365,072)
Post-merger Wind	SG-W	(6,021,411)	(310,077,532)	(6,025,526)	(316,103,058)	(316,103,058)	(99,427)	(316,202,485)
Post-merger	SG	(154,255)	(24,391,199)	(154,208)	(24,545,407)	(24,545,407)	4,667	(24,540,740)
Total Other Plant		(6,654,659)	(525,748,290)	(5,588,776)	(531,337,066)	(531,337,066)	(137,955)	(531,475,021)
Transmission Plant:								
Pre-merger Pacific	SG	(499,259)	(377,797,446)	(498,610)	(378,296,055)	(378,296,055)	46,732	(378,249,324)
Pre-merger Utah	SG	(736,728)	(410,622,048)	(736,258)	(411,358,306)	(411,358,306)	33,822	(411,324,484)
Post-merger	SG	(3,438,825)	(484,439,679)	(3,501,356)	(487,941,035)	(487,941,035)	(2,461,443)	(490,402,478)
Total Transmission Plant		(4,674,811)	(1,272,859,172)	(4,736,225)	(1,277,595,396)	(1,277,595,396)	(2,380,890)	(1,279,976,286)
Distribution Plant:								
California	CA	(464,831)	(106,984,594)	(465,952)	(107,450,546)	(107,450,546)	(84,227)	(107,534,773)
Oregon	OR	(3,351,814)	(831,808,712)	(3,356,249)	(835,164,961)	(835,164,961)	(354,904)	(835,519,865)
Washington	WA	(670,030)	(186,843,714)	(670,861)	(187,514,574)	(187,514,574)	(75,316)	(187,589,890)
Eastern Wyoming	WYP	(791,500)	(203,153,560)	(795,273)	(203,948,833)	(203,948,833)	(215,206)	(204,164,039)
Utah	UT	(2,467,422)	(767,365,875)	(2,470,816)	(769,836,692)	(769,836,692)	(644,448)	(770,481,140)
Idaho	ID	(427,630)	(125,554,949)	(429,691)	(125,984,639)	(125,984,639)	(155,215)	(126,139,855)
Western Wyoming	WYU	(169,439)	(39,699,689)	(169,269)	(39,868,958)	(39,868,958)	12,227	(39,856,731)
Total Distribution Plant		(8,342,667)	(2,261,411,093)	(8,358,112)	(2,269,769,205)	(2,269,769,205)	(1,517,088)	(2,271,286,293)
General Plant:								
California	CA	6,692	(4,289,138)	6,711	(4,282,427)	(4,282,427)	(12,723)	(4,295,150)
Oregon	OR	108,186	(43,408,037)	108,291	(43,299,746)	(43,299,746)	(67,839)	(43,367,585)
Washington	WA	(43,205)	(17,932,279)	(43,331)	(17,975,609)	(17,975,609)	(661)	(17,976,270)
Eastern Wyoming	WYP	(31,107)	(18,209,889)	(32,405)	(18,242,294)	(18,242,294)	(63,190)	(18,305,484)
Utah	UT	(12,693)	(55,313,096)	(13,933)	(55,327,029)	(55,327,029)	(78,874)	(55,405,903)
Idaho	ID	20,748	(10,397,321)	20,561	(10,376,760)	(10,376,760)	(17,129)	(10,393,889)
Western Wyoming	WYU	(161)	(4,209,986)	(54)	(4,210,040)	(4,210,040)	7,703	(4,202,337)
Pre-merger Pacific	SG	36,535	(2,015,888)	36,663	(1,979,225)	(1,979,225)	9,235	(1,969,989)
Pre-merger Utah	SG	83,942	(3,069,805)	84,166	(2,985,640)	(2,985,640)	16,555	(2,969,084)
Post-merger	SG	(110,139)	(54,169,024)	(115,028)	(54,284,052)	(54,284,052)	(137,637)	(54,421,689)
General Office	SO	652,737	(64,213,258)	652,302	(63,560,956)	(63,560,956)	272,557	(63,288,399)
General Office	SG	14,108	(1,691,781)	14,179	(1,677,601)	(1,677,601)	5,149	(1,672,452)
General Office	SG	(113)	(46,155)	(111)	(46,266)	(46,266)	127	(46,139)
Customer Service	CN	15,780	(7,592,480)	16,745	(7,575,735)	(7,575,735)	69,498	(7,506,237)
Fuel Related	SE	1,516	(284,312)	1,529	(282,783)	(282,783)	936	(281,847)
Total General Plant		742,825	(286,842,447)	736,285	(286,106,163)	(286,106,163)	3,707	(286,102,456)
Mining Plant:								
Coal Mine	SE	(26,374)	(156,836,616)	(30,809)	(156,867,425)	(156,867,425)	(80,977)	(156,948,403)
Total Mining Plant		(26,374)	(156,836,616)	(30,809)	(156,867,425)	(156,867,425)	(80,977)	(156,948,403)
Subtotal		(28,438,722)	(7,353,448,194)	(26,473,895)	(7,379,922,089)	(7,379,922,089)	(12,924,288)	(7,392,846,377)

PacifiCorp
Oregon General Rate Case - December 2013
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Description	Factor	Adjustments	Adjusted Reserve Balance Nov 2012	Adjustments	Adjusted Reserve Balance Dec 2012	CY 2012 Year End Balance	Incremental Reserve For Annualized Depreciation	CY 2012 Adjusted Reserve Year End Balance
AMORTIZATION RESERVE								
Intangible Plant:								
California	CA	-	-	-	-	-	-	-
Customer Service	CN	(462,442)	(105,727,158)	(462,357)	(106,189,516)	(106,189,516)	6,087	(106,183,429)
Idaho	ID	(1,710)	(796,027)	(1,710)	(797,736)	(797,736)	-	(797,736)
Pre-merger Utah	SG	(146)	(360,543)	(143)	(360,686)	(360,686)	202	(360,485)
Montana	MT	-	-	-	-	-	-	-
Oregon	OR	27,754	437,459	27,770	465,228	465,228	1,161	466,390
Fuel Related	SE	(21,680)	(1,827,764)	(21,629)	(1,849,393)	(1,849,393)	3,671	(1,845,722)
Post-merger	SG	430,187	(42,102,270)	420,661	(41,681,609)	(41,681,609)	(99,394)	(41,781,003)
Hydro Relicensing	SG-P	16,662	(15,142,892)	17,157	(15,125,734)	(15,125,734)	35,689	(15,090,046)
Hydro Relicensing	SG-U	(17,569)	(3,824,941)	(17,547)	(3,842,489)	(3,842,489)	1,531	(3,840,958)
General Office	SO	(953,914)	(282,898,727)	(959,611)	(283,858,338)	(283,858,338)	(151,764)	(284,010,102)
Pre-merger Pacific	SG	-	-	-	-	-	-	-
Utah	UT	(1,022)	(51,506)	(1,022)	(52,527)	(52,527)	1	(52,526)
Washington	WA	9,393	164,105	9,393	173,498	173,498	-	173,498
Eastern Wyoming	WYP	(11,942)	(475,881)	(11,942)	(487,822)	(487,822)	-	(487,822)
Western Wyoming	WYU	-	-	-	-	-	-	-
General Office	SG	-	(171,088)	-	(171,088)	(171,088)	-	(171,088)
Total Intangible Plant		(986,428)	(452,777,232)	(1,000,980)	(453,778,212)	(453,778,212)	(202,816)	(453,981,028)
Hydro Production Plant:								
Pre-merger Pacific	SG	-	-	-	-	-	-	-
Post-merger	SG-P	(20,751)	(593,652)	(20,751)	(614,404)	(614,404)	-	(614,404)
Post-merger	SG-U	(3,711)	(523,347)	(3,711)	(527,058)	(527,058)	-	(527,058)
Total Hydro Plant		(24,462)	(1,116,999)	(24,462)	(1,141,461)	(1,141,461)	-	(1,141,461)
Other Production Plant:								
Post-merger	SG	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-
General Plant:								
California	CA	(6,304)	(1,306,603)	(6,304)	(1,312,907)	(1,312,907)	-	(1,312,907)
General Office	CN	(22,781)	(3,248,496)	(22,781)	(3,271,277)	(3,271,277)	-	(3,271,277)
General Office	SG	-	-	-	-	-	-	-
Oregon	OR	(20,672)	(6,869,628)	(20,672)	(6,890,301)	(6,890,301)	-	(6,890,301)
General Office	SO	(104,938)	(13,104,870)	(104,938)	(13,209,808)	(13,209,808)	-	(13,209,808)
Utah	UT	(61)	(13,152)	(61)	(13,212)	(13,212)	-	(13,212)
Washington	WA	(10,114)	(1,687,529)	(10,114)	(1,697,643)	(1,697,643)	-	(1,697,643)
Eastern Wyoming	WYP	(54,848)	(8,020,580)	(54,848)	(8,075,428)	(8,075,428)	-	(8,075,428)
Western Wyoming	WYU	(399)	(43,097)	(399)	(43,495)	(43,495)	-	(43,495)
Total General Plant		(220,116)	(34,293,956)	(220,116)	(34,514,072)	(34,514,072)	-	(34,514,072)
Subtotal		(1,231,006)	(488,188,186)	(1,245,558)	(489,433,744)	(489,433,744)	(202,816)	(489,636,561)
Total		(29,669,728)	(7,841,636,380)	(27,719,453)	(7,869,355,833)	(7,869,355,833)	(13,127,104)	(7,882,482,937)

Ref. 6.2.3

PacifiCorp
Oregon General Rate Case - December 2013
Hydro Decommissioning
Spending, Accruals, and Balances - East Side, West Side, and Total Resources

West Side	Spend	Accruals	Balance
July-10	48,640	(185,352)	(16,982,743)
August-10	59,434	(185,352)	(17,108,662)
September-10	63,474	(284,687)	(17,329,876)
October-10	114,294	(180,352)	(17,395,934)
November-10	75,279	(185,352)	(17,506,008)
December-10	398,765	(185,352)	(17,292,595)
January-11	314,550	(185,352)	(17,163,397)
February-11	524,213	(185,352)	(16,824,537)
March-11	257,382	(185,352)	(16,752,507)
April-11	194,589	(185,352)	(16,743,270)
May-11	227,209	(185,352)	(16,701,414)
June-11	766,645	(185,352)	(16,120,121)

East Side	Spend	Accruals	Balance
July-10	-	(112,546)	2,314,621
August-10	-	(112,546)	2,202,075
September-10	-	(112,546)	2,089,529
October-10	-	(112,546)	1,976,984
November-10	-	(112,546)	1,864,438
December-10	-	(112,546)	1,751,892
January-11	-	(112,546)	1,639,346
February-11	-	(112,546)	1,526,800
March-11	-	(112,546)	1,414,254
April-11	-	(112,546)	1,301,709
May-11	-	(112,546)	1,189,163
June-11	-	(112,546)	1,076,617

Total Resources	Spend	Accruals	Balance
July-10	48,640	(297,898)	(14,668,122)
August-10	59,434	(297,898)	(14,906,587)
September-10	63,474	(397,233)	(15,240,346)
October-10	114,294	(292,898)	(15,418,951)
November-10	75,279	(297,898)	(15,641,570)
December-10	398,765	(297,898)	(15,540,703)
January-11	314,550	(297,898)	(15,524,051)
February-11	524,213	(297,898)	(15,297,737)
March-11	257,382	(297,898)	(15,338,252)
April-11	194,589	(297,898)	(15,441,561)
May-11	227,209	(297,898)	(15,512,251)
June-11	766,645	(297,898)	(15,043,504)

West Side	Spend	Accruals	Balance
July-11	510,133	(185,352)	(15,795,341)
August-11	1,297,299	(185,352)	(14,683,394)
September-11	4,262,792	(185,352)	(10,605,954)
October-11	2,233,011	(185,352)	(8,558,296)
November-11	380,161	(185,352)	(8,363,488)
December-11	1,010,000	(185,352)	(7,538,840)
January-12	570,000	(185,352)	(7,154,192)
February-12	617,000	(185,352)	(6,722,545)
March-12	860,000	(185,352)	(6,047,897)
April-12	1,200,000	(185,352)	(5,033,250)
May-12	1,180,000	(185,352)	(4,038,602)
June-12	1,300,000	(185,352)	(2,923,954)
July-12	1,400,000	(185,352)	(1,709,307)
August-12	1,125,000	(185,352)	(769,659)
September-12	1,375,000	(185,352)	419,988
October-12	500,000	(185,352)	734,636
November-12	205,000	(185,352)	754,284
December-12	305,000	(185,352)	873,931

East Side	Spend	Accruals	Balance
July-11	-	(112,546)	964,071
August-11	-	(112,546)	851,525
September-11	-	(112,546)	738,979
October-11	-	(112,546)	626,434
November-11	-	(112,546)	513,888
December-11	-	(112,546)	401,342
January-12	-	(112,546)	288,796
February-12	-	(112,546)	176,250
March-12	-	(112,546)	63,704
April-12	-	(112,546)	(48,841)
May-12	-	(112,546)	(161,387)
June-12	-	(112,546)	(273,933)
July-12	-	(112,546)	(386,479)
August-12	-	(112,546)	(499,025)
September-12	-	(112,546)	(611,571)
October-12	-	(112,546)	(724,116)
November-12	-	(112,546)	(836,662)
December-12	-	(112,546)	(949,208)

Total Resources	Spend	Accruals	Balance
July-11	510,133	(297,898)	(14,831,269)
August-11	1,297,299	(297,898)	(13,831,869)
September-11	4,262,792	(297,898)	(9,866,975)
October-11	2,233,011	(297,898)	(7,931,862)
November-11	380,161	(297,898)	(7,849,600)
December-11	1,010,000	(297,898)	(7,137,498)
January-12	570,000	(297,898)	(6,865,396)
February-12	617,000	(297,898)	(6,546,295)
March-12	860,000	(297,898)	(5,984,193)
April-12	1,200,000	(297,898)	(5,082,091)
May-12	1,180,000	(297,898)	(4,199,989)
June-12	1,300,000	(297,898)	(3,197,888)
July-12	1,400,000	(297,898)	(2,095,786)
August-12	1,125,000	(297,898)	(1,268,684)
September-12	1,375,000	(297,898)	(191,582)
October-12	500,000	(297,898)	10,520
November-12	205,000	(297,898)	(82,379)
December-12	305,000	(297,898)	(75,277)

PacifiCorp
Oregon General Rate Case - December 2013
Oregon Coal-fired Steam Plant Depreciation

Depreciation Reserve Adjustment

Adjustment to June 2011 Reserve:	**Total Company**	**Factor**	**Factor %**	**Oregon Allocated**
Steam Plant Accumulated Depreciation*	(115,904,809)	SG	25.777%	(29,876,962)
Steam Plant Accumulated Depreciation*	(14,390,655)	SG	25.777%	(3,709,502)
	(130,295,464)			(33,586,464)

*This represents 3 and 1/2 years (January 2008 - June 2011) of the increase at the current approved rate

Depreciation Reserve Adjustment By Plant

Plant	**Factor**	**Adjustment to Reserve**
CHOLLA	SG	(14,390,655)
NAUGHTON	SG	(491,037)
HUNTINGTON	SG	(11,956,488)
HUNTER	SG	(29,974,755)
CRAIG	SG	(4,972,998)
HAYDEN	SG	(2,326,315)
COLSTRIP	SG	(5,357,947)
DAVE JOHNSTON	SG	(11,566,277)
JIM BRIDGER	SG	(37,083,691)
WYODAK	SG	(12,175,300)
		(130,295,464)

This is the increase in the depreciation reserve June 2011 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2011 to reflect the different depreciation rates Oregon is using for the coal-fired generating plants. This was approved in the Depreciation Study, in Docket UM-1329 in Order 08-427, with rates effective January 1, 2008.

PacifiCorp
Oregon General Rate Case - December 2013
Depreciation Reserve

Removal Projects Included in the Filing

Steam Projects:	Factor	In-Service	Amount (July11-Dec12)
Wyodak U1 - Precipitator Demolition	SG	Mar-12	769,198
DJ U3-4 Engr Analysis and Demo Obsolete Equ	SG	Dec-11	526,765
DJ U3 - Precipitator Demolition	SG	Dec-12	1,043,000

Other Projects:	Factor	In-Service	Amount (July11-Dec12)
Little Mountain De-comissioning	SG	Dec-12	1,069,596

7. TAX ADJUSTMENTS

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's June 2011 accrued tax data provided the basis for known and measurable adjustments to the December 2013 test period.

The tax impacts of the following adjustments are included within the adjustment itself:

- SO2 Emission Allowances, page 3.3
- DSM Expense and Revenue, page 4.6
- Insurance Expense, Page 4.7
- Powerdale Hydro Removal, page 8.9
- Regulatory Asset Amortization, page 8.10
- Carbon Plant Closure, page 8.15

The tax impacts of the following adjustments are included within adjustments 7.6 through 7.8:

- Little Mountain, page 5.3
- Pro Forma Plant Additions 8.6
- Pro Forma Plant Retirements 8.7
- Klamath Hydroelectric Settlement Agreement, page 8.11
- Misc. Asset Sales and Removals, page 8.12

PacifiCorp
Normalized Results of Operations
Tab 7 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Total Adjustments	7.2 Property Tax Expense	7.3 Renewable Energy Tax Credit	7.4 AFUDC Equity	7.5 Medicare Tax Deferral	7.6 Pro Forma Schedule Ms	7.7 Pro Forma Deferred Income Tax Expense
1	Operating Revenues:							
2	General Business Revenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-	-	-
6	Total Operating Revenues	-	-	-	-	-	-	-
7								
8	Operating Expenses:							
9	Steam Production	-	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-
12	Other Power Supply	-	-	-	-	-	-	-
13	Embedded Cost Differential (ECD)	-	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	894,329	-	-	-	894,329	-	-
19								
20	Total O&M Expenses	894,329	-	-	-	894,329	-	-
21								
22	Depreciation	-	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-	-
24	Taxes Other Than Income	8,218,308	4,325,021	-	-	-	-	-
25	Income Taxes - Federal	129,687,041	(1,445,487)	(1,158,441)	(509,421)	(298,898)	133,229,602	-
26	Income Taxes - State	17,745,972	(196,418)	(26,750)	(69,222)	(40,615)	18,096,684	-
27	Income Taxes - Def Net	(150,916,795)	-	-	-	-	-	(150,916,795)
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	5,628,855	2,683,116	(1,185,190)	(578,643)	554,815	151,326,285	(150,916,795)
32								
33	Operating Rev For Return:	(5,628,855)	(2,683,116)	1,185,190	578,643	(554,815)	(151,326,285)	150,916,795
34								
35	Rate Base:							
36	Electric Plant In Service	-	-	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	3,149,978	53,989	(23,848)	(11,643)	11,164	3,044,955	-
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	3,149,978	53,989	(23,848)	(11,643)	11,164	3,044,955	-
49								
50	Rate Base Deductions:							
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	(139,344,711)	-	-	-	-	-	-
54	Unamortized ITC	1,968,723	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	(137,375,989)	-	-	-	-	-	-
60								
61	Total Rate Base:	(134,226,011)	53,989	(23,848)	(11,643)	11,164	3,044,955	-
62								
63	Return on Rate Base	0.156%	-0.089%	0.039%	0.019%	-0.018%	-4.992%	4.971%
64								
65	Return on Equity	0.295%	-0.168%	0.074%	0.036%	-0.035%	-9.454%	9.414%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(9,112,637)	(4,325,021)	-	-	(894,329)	-	-
69	Other Deductions							
70	Interest (AFUDC)	1,525,003	-	-	1,525,003	-	-	-
71	Interest	(3,381,781)	1,360	(601)	(293)	281	76,717	-
72	Schedule "M" Additions	(8,055,058)	-	-	-	-	(8,055,058)	-
73	Schedule "M" Deductions	(406,781,149)	-	-	-	-	(406,737,139)	-
74	Income Before Tax	391,470,233	(4,326,381)	601	(1,524,710)	(894,610)	398,605,365	-
75								
76	State Income Taxes	17,745,972	(196,418)	(26,750)	(69,222)	(40,615)	18,096,684	-
77	Taxable Income	373,724,261	(4,129,964)	27,351	(1,455,488)	(853,995)	380,508,682	-
78								
79	Federal Income Taxes + Other	129,687,041	(1,445,487)	(1,158,441)	(509,421)	(298,898)	133,229,602	-
80								
81	PRICE CHANGE	(8,304,587)	4,460,276	(1,970,201)	(961,906)	922,297	251,557,157	(250,477,200)

PacifiCorp
Normalized Results of Operations
Tab 7 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		7.8	7.9	7.10	7.11
		Pro Forma ADIT Balances	Wyoming Wind Generation Tax	ADIT Corrections	Franchise Tax
1	Operating Revenues:				
2	General Business Revenues	-	-	-	-
3	Interdepartmental	-	-	-	-
4	Special Sales	-	-	-	-
5	Other Operating Revenues	-	-	-	-
6	Total Operating Revenues	-	-	-	-
7					
8	Operating Expenses:				
9	Steam Production	-	-	-	-
10	Nuclear Production	-	-	-	-
11	Hydro Production	-	-	-	-
12	Other Power Supply	-	-	-	-
13	Embedded Cost Differential (ECD)	-	-	-	-
13	Transmission	-	-	-	-
14	Distribution	-	-	-	-
15	Customer Accounting	-	-	-	-
16	Customer Service & Info	-	-	-	-
17	Sales	-	-	-	-
18	Administrative & General	-	-	-	-
19					
20	Total O&M Expenses	-	-	-	-
21					
22	Depreciation	-	-	-	-
23	Amortization	-	-	-	-
24	Taxes Other Than Income	-	381,430	-	3,511,857
25	Income Taxes - Federal	1,169,143	(127,480)	1,739	(1,173,715)
26	Income Taxes - State	158,867	(17,322)	236	(159,488)
27	Income Taxes - Def Net	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-
30					
31	Total Operating Expenses:	1,328,010	236,628	1,975	2,178,653
32					
33	Operating Rev For Return:	(1,328,010)	(236,628)	(1,975)	(2,178,653)
34					
35	Rate Base:				
36	Electric Plant In Service	-	-	-	-
37	Plant Held for Future Use	-	-	-	-
38	Misc Deferred Debits	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-
40	Nuclear Fuel	-	-	-	-
41	Prepayments	-	-	-	-
42	Fuel Stock	-	-	-	-
43	Material & Supplies	-	-	-	-
44	Working Capital	26,722	4,761	40	43,838
45	Weatherization Loans	-	-	-	-
46	Misc Rate Base	-	-	-	-
47					
48	Total Electric Plant:	26,722	4,761	40	43,838
49					
50	Rate Base Deductions:				
51	Accum Prov For Deprec	-	-	-	-
52	Accum Prov For Amort	-	-	-	-
53	Accum Def Income Tax	(140,884,915)	-	1,540,204	-
54	Unamortized ITC	1,968,723	-	-	-
55	Customer Adv For Const	-	-	-	-
56	Customer Service Deposits	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-
58					
59	Total Rate Base Deductions	(138,916,193)	-	1,540,204	-
60					
61	Total Rate Base:	(138,889,471)	4,761	1,540,244	43,838
62					
63	Return on Rate Base	0.313%	-0.008%	-0.004%	-0.075%
64					
65	Return on Equity	0.593%	-0.015%	-0.008%	-0.143%
66					
67	TAX CALCULATION:				
68	Operating Revenue	-	(381,430)	-	(3,511,857)
69	Other Deductions				
70	Interest (AFUDC)	-	-	-	-
71	Interest	(3,499,276)	120	38,806	1,104
72	Schedule "M" Additions	-	-	-	-
73	Schedule "M" Deductions	-	-	(44,010)	-
74	Income Before Tax	3,499,276	(381,550)	5,204	(3,512,961)
75					
76	State Income Taxes	158,867	(17,322)	236	(159,488)
77	Taxable Income	3,340,409	(364,228)	4,968	(3,353,473)
78					
79	Federal Income Taxes + Other	1,169,143	(127,480)	1,739	(1,173,715)
80					
81	PRICE CHANGE	(16,055,826)	393,359	205,775	3,621,682

PacifiCorp PAGE 7.1
Oregon General Rate Case - December 2013
Interest True-Up

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	427	3	1,017,621	OR	100.000%	1,017,621	Below

	Total Company		
Interest June 2011	312,146,753	80,964,831	2.18
Interest Dec 2013	317,137,259	81,982,452	Below
Adjustment:	4,990,506	1,017,621	

Rate Base	12,592,848,464	3,253,958,859	2.2
Other & Non-Utility	(5,379,228)		
Adjusted Rate Base	12,587,469,236	3,253,958,859	2.2
Weighted Cost of Debt	2.519%	2.519%	2.1
	317,137,259	81,982,452	2.18

Description of Adjustment:

This adjustment synchronizes interest expense with the jurisdictional allocated rate base. This is calculated by multiplying net rate base by the Company's weighted cost of debt. A separate column is not shown for adjustment 7.1 on page 7.0.2 as the interest true-up component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

PacifiCorp
Oregon General Rate Case - December 2013
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	15,921,444	GPS	27.165%	4,325,021	7.2.1

Description of Adjustment:

This adjustment normalizes the difference between actual accrued property tax expense and forecasted property tax expense resulting from estimated capital additions. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1104.

PacifiCorp
Oregon General Rate Case - December 2013
Estimated Property Tax Expense for December 2013
Property Tax Adjustment Summary

FERC Account	G/L Account	Co. Code	Factor	Total	Ref
408.15	579000	1000		108,846,556	
Total Accrued Property Tax - 12 Months End. June 2011				108,846,556	
Forecasted Property Tax Exp. for the Twelve Months Ending Dec 2013				**124,768,000**	See Conf. Ex. PAC/1104
Less Accrued Property Tax - 12 Months Ended June 30, 2011				(108,846,556)	
Incremental Adjustment to Property Taxes				**15,921,444**	7.2

PacifiCorp PAGE 7.3
Oregon General Rate Case - December 2013
Renewable Energy Tax Credit

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
FED Renewable Energy Tax Credit	40910	3	(62,989,912)	SG	25.777%	(16,237,007)	
OR BETC Credit	40911	3	(392,418)	SG	25.777%	(101,154)	
Total			(63,382,330)			(16,338,161)	7.3.1
Remove from Base Period:							
FED Renewable Energy Tax Credit	40910	1	58,458,716	SG	25.777%	15,068,994	
UT Renewable Energy Tax Credit	40911	1	288,539	SG	25.777%	74,377	

Description of Adjustment:

The Company is entitled to recognize federal and state income tax credits as a result of placing renewable generating plants in service. The federal tax credit is based on the kilowatt hours ("kWh") generated by the plants, and the credit can be taken for the first ten years of generation from qualifying property. This adjustment reflects this credit based on the qualifying production as modeled in GRID for the test period NPC study.

The Utah State production tax credit expired in December 2011 and is not reflected in the test period in this proceeding. The Oregon Business Energy Tax Credit ("BETC") is based on investment in qualifying plant, and the credit is utilized over a three- to five-year period on qualifying property.

PacifiCorp
Oregon General Rate Case - December 2013
Renewable Energy Tax Credit Calculation

Expire 12/1/2011

Description	FED Amount	UT
Hydro		
JC Boyle	8,956,425	
Factor (inflated tax per unit)	0.011	
	98,521	
	Ref 7.3	
Wind/Geothermal		
Total KWh Production	2,858,699,593	-
Factor (inflated tax per unit)	0.022	0.0035
	62,891,391	-
	Ref 7.3	**Ref 7.3**

OR BETC

BETC	OR Leaning Juniper	Pcorp Lighting	2006 Transit Passes	2007 Transit Passes	2008 Transit Passes	2009 Transit Passes	2010 Transit Passes	2010 LCT Lighting	2011 Lemolo Hydro	12 Month Ending 12/31/2013 Amortization
Investment	10,000,000	24,366	266,368	275,107	338,071	349,969	367,356	39,048	3,546,000	
35% Credit	3,500,000	8,528	93,229	96,287	118,325	122,489	128,575	13,667	1,773,000	
Amortization										
12/31/2006	1,000,000	2,437	26,637							
12/31/2007	1,000,000	2,437	26,637	27,511						
6/30/2008	250,000	609	6,659	13,755						
12/31/2008	250,000	609	6,659	13,755	33,807					
6/30/2009	250,000	609	6,659	6,878	16,904					
12/31/2009	250,000	609	6,659	6,878	16,903	34,997				
6/30/2010	250,000	609	6,659	6,878	8,452	17,498	18,368			
12/31/2010	250,000	609	6,660	6,878	8,452	17,498	18,368	3,905		
6/30/2011				6,877	8,452	8,749	18,368	1,953	177,300	
12/31/2011	0	0	0	6,877	8,452	8,749	18,368	1,953	177,300	
3/31/2012					4,226	4,374	4,592	488	88,650	
12/31/2012					12,677	13,123	13,776	1,465	265,950	
3/31/2013						4,374	4,592	488	88,650	**392,418**
12/31/2013						13,124	13,776	1,464	265,950	**Ref #7.3**
12/31/2014							18,368	1,952	354,600	
12/31/2015									354,600	
12/31/2016										
Total Utilized	3,500,000	8,528	93,229	96,287	118,325	122,486	128,576	13,667	1,773,000	

*Transit passes generated in Aug of each year.

PacifiCorp
Oregon General Rate Case - December 2013
AFUDC - Equity

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AFUDC - Equity	419	3	5,821,454	SNP	26.196%	1,525,003	7.4.1

Description of Adjustment:

This adjustment reflects the appropriate level of AFUDC – Equity into regulated results to align the tax Schedule M with regulatory income. Per the Commission Order No. 10-022, AFUDC-Equity in this case is included using flow-through tax treatment.

PacifiCorp
Oregon General Rate Case - December 2013
AFUDC Equity for 12 Months Ended December 2012

Period	Description	Source	Equity
Jun-11 12 months	FERC Account 419	Per SAP A/C 382XXX	(59,310,128)
Dec-12 12 months	AFUDC-Equity SCHMDT	Per PowerTax	(53,488,674)
	Total		(53,488,674)
Adjustment to Account 419		**Ref 7.4**	**5,821,454**

PacifiCorp
Oregon General Rate Case - December 2013
Medicare Deferred Accounting

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Medicare Deferral Amortization	930	3	894,329	OR	100.000%	894,329	7.5.1

Description of Adjustment:

As established in Oregon Docket No. UM-1479 and UE-217 this adjustment recognizes the amortization of the Medicare deferral regulatory asset for the twelve-months ending December 2013. This adjustment also normalizes the base period deferred income tax expense for a recent change in tax law. With the change in law, some of the costs related to other post retirement benefits will become non-deductible for income tax purposes.

PacifiCorp
Oregon General Rate Case - December 2013
Medicare Deferred Accounting

Description		Oregon
Net Tax Benefits of Non-Deductible Post-Retirement Benefits	A	9,665,845
Gross-Up Factor for Income Taxes = (1/(1-.37951))	B	1.6116
Total Company Regulatory Asset for Non-Deducible Post-Retirement Benefits	C	**15,577,761**
Revised Protocol Allocation Factor: SO	D	28.7053%
Jurisdictionally Allocated Regulatory Asset for Non-Deductible Post-Retirment Benefits	E	**4,471,643**

Net Income Impact = **A * D**	2,774,610

Period	Oregon	
Three Months Ended December 31, 2010	0	
Calendar Year Ended December 31, 2011	0	
Calendar Year Ended December 31, 2012	0	
Calendar Year Ended December 31, 2013	**894,329**	**Ref. 7.5**
Calendar Year Ended December 31, 2014	894,328	
Calendar Year Ended December 31, 2015	894,328	
Calendar Year Ended December 31, 2016	894,328	
Calendar Year Ended December 31, 2017	894,328	
Total Amortization: Regulatory Assets	**4,471,641**	

Period	Oregon
Three Months Ended December 31, 2010	0
Calendar Year Ended December 31, 2011	0
Calendar Year Ended December 31, 2012	0
Calendar Year Ended December 31, 2013	554,922
Calendar Year Ended December 31, 2014	554,922
Calendar Year Ended December 31, 2015	554,922
Calendar Year Ended December 31, 2016	554,922
Calendar Year Ended December 31, 2017	554,922
Net Income Impact: Regulatory Assets	**2,774,610**

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Schedule Ms

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	(28,808)	OTHER	0.000%	-	
	SCHMAP	3	295,028	SCHMDEXP	27.513%	81,172	
	SCHMAP	3	(114,031)	SE	24.314%	(27,725)	
	SCHMAP	3	(16,708,952)	SO	27.165%	(4,538,984)	
	SCHMDP	3	(109,247)	SCHMDEXP	27.513%	(30,058)	
	SCHMDP	3	84,737	SE	24.314%	20,603	
	SCHMDP	3	19,564	SNP	26.196%	5,125	
	SCHMDP	3	(24,911,550)	SO	27.165%	(6,767,219)	
Schedule M Adjustment Temporary	SCHMAT	3	(1,314,913)	BADDEBT	46.668%	(613,648)	
	SCHMAT	3	(1,142,586)	CA	0.000%	-	
	SCHMAT	3	22,937,526	CIAC	26.906%	6,171,534	
	SCHMAT	3	(654,936)	IDU	0.000%	-	
	SCHMAT	3	(11,727,014)	OR	100.000%	(11,727,014)	
	SCHMAT	3	(30,712,272)	OTHER	0.000%	-	
	SCHMAT	3	77,987,464	SCHMDEXP	27.513%	21,456,975	
	SCHMAT	3	(32,761,900)	SE	24.314%	(7,965,571)	
	SCHMAT	3	(16,882,886)	SG	25.777%	(4,351,928)	
	SCHMAT	3	-	SGCT	25.862%	-	
	SCHMAT	3	22,149,047	SNP	26.196%	5,802,222	
	SCHMAT	3	(9,587,358)	SNPD	26.906%	(2,579,559)	
	SCHMAT	3	(34,151,588)	SO	27.165%	(9,277,274)	
	SCHMAT	3	(1,901,813)	TROJD	25.516%	(485,258)	
	SCHMAT	3	(1,015,471)	UT	0.000%	-	
	SCHMAT	3	(2,359,364)	WA	0.000%	-	
	SCHMAT	3	(1,443,115)	WYP	0.000%	-	
	SCHMDT	3	(4,778,066)	CA	0.000%	-	
	SCHMDT	3	(48,156)	CN	29.363%	(14,140)	
	SCHMDT	3	(12,790,665)	GPS	27.165%	(3,474,553)	
	SCHMDT	3	(375,013)	IDU	0.000%	-	
	SCHMDT	3	(841,442)	OR	100.000%	(841,442)	
	SCHMDT	3	(112,089,807)	OTHER	0.000%	-	
	SCHMDT	3	(46,649,871)	SE	24.314%	(11,342,225)	
	SCHMDT	3	57,788,543	SG	25.777%	14,896,242	
	SCHMDT	3	(3,357,598)	SNP	26.196%	(879,565)	
	SCHMDT	3	(23,385,443)	SO	27.165%	(6,352,652)	
	SCHMDT	3	(1,498,945,873)	TAXDEPR	26.149%	(391,957,256)	
	SCHMDT	3	(210,493)	UT	0.000%	-	
	SCHMDT	3	(1,135,100)	WA	0.000%	-	
	SCHMDT	3	(2,170,515)	WYP	0.000%	-	
Current Tax Credits	40910	3	104,409	SE	24.314%	25,386	
	40910	3	71,195	SG	25.777%	18,352	
	40910	3	28,808	SO	27.165%	7,826	

Description of Adjustment:

This adjustment normalizes the Schedule M to an estimated pro forma level of expense for the December 2013 test period. The significant change in tax depreciation is primarily driven by the reduced bonus depreciation available in the test period as compared to the base period. Additional line item detail is included in the tax model which is provided with the Company's electronic work papers.

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Deferred Income Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Deferred Tax Expense Debit	41010	3	(1,813,323)	CA	0.000%	-	
	41010	3	(18,276)	CN	29.363%	(5,366)	
	41010	3	(4,854,185)	GPS	27.165%	(1,318,627)	
	41010	3	(142,321)	IDU	0.000%	-	
	41010	3	(319,336)	OR	100.000%	(319,336)	
	41010	3	(42,539,201)	OTHER	0.000%	-	
	41010	3	(17,704,093)	SE	24.314%	(4,304,488)	
	41010	3	21,931,330	SG	25.777%	5,653,273	
	41010	3	(1,274,242)	SNP	26.196%	(333,804)	
	41010	3	(7,846,449)	SO	27.165%	(2,131,487)	
	41010	3	(568,864,948)	TAXDEPR	26.149%	(148,751,698)	
	41010	3	(79,884)	UT	0.000%	-	
	41010	3	(430,782)	WA	0.000%	-	
	41010	3	(823,732)	WYP	0.000%	-	
Deferred Tax Expense Credit	41110	3	499,023	BADDEBT	46.668%	232,886	
	41110	3	757,259	CA	0.000%	-	
	41110	3	(8,705,020)	CIAC	26.906%	(2,342,159)	
	41110	3	42,157	FERC	0.000%	-	
	41110	3	680,305	IDU	0.000%	-	
	41110	3	3,233,795	OR	100.000%	3,233,795	
	41110	3	11,651,949	OTHER	0.000%	-	
	41110	3	(29,597,022)	SCHMDEXP	27.513%	(8,143,137)	
	41110	3	12,433,468	SE	24.314%	3,023,014	
	41110	3	8,179,309	SG	25.777%	2,108,393	
	41110	3	-	SGCT	25.862%	-	
	41110	3	(8,405,785)	SNP	26.196%	(2,202,001)	
	41110	3	3,638,499	SNPD	26.906%	978,969	
	41110	3	12,960,871	SO	27.165%	3,520,819	
	41110	3	721,757	TROJD	25.516%	184,160	
	41110	3	1,780,988	UT	0.000%	-	
	41110	3	(2,209,546)	WA	0.000%	-	
	41110	3	(63,495)	WYP	0.000%	-	
	41110	3	195,832	WYU	0.000%	-	

Description of Adjustment:

This adjustment normalizes the deferred tax expense to an estimated pro forma level of expense for the December 2013 test period. Additional line item detail is included in the tax model which is provided with the Company's electronic work papers.

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma ADIT Balance

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 190	190	3	1,670,977	BADDEBT	46.668%	779,817	
	190	3	(1,425)	CA	0.000%	-	
	190	3	(18,276)	CN	29.363%	(5,366)	
	190	3	33,477	IDU	0.000%	-	
	190	3	2,113,554	OR	100.000%	2,113,554	
	190	3	8,087,675	OTHER	0.000%	-	
	190	3	1,184,634	SE	24.314%	288,026	
	190	3	(37,138,444)	SG	25.777%	(9,573,234)	
	190	3	(986,927)	SNPD	26.906%	(265,541)	
	190	3	6,236,543	SO	27.165%	1,694,156	
	190	3	5,053	TROJD	25.516%	1,289	
	190	3	(49,347)	UT	0.000%	-	
	190	3	4,032,908	WA	0.000%	-	
	190	3	103,136	WYP	0.000%	-	
ADIT Balance 281	281	3	121,387,549	SG	25.777%	31,290,257	
ADIT Balance 282 - YE	282	3	(81,940,882)	CA	0.000%	-	
	282	3	3,031,107,797	DITBAL	27.473%	832,740,315	
	282	3	(10,378,287)	FERC	0.000%	-	
	282	3	(206,913,205)	IDU	0.000%	-	
	282	3	(1,000,030,071)	OR	100.000%	(1,000,030,071)	
	282	3	(45,881,193)	OTHER	0.000%	-	
	282	3	408,127	SE	24.314%	99,230	
	282	3	1,072,100	SG	25.777%	276,357	
	282	3	(2,967,622)	SO	27.165%	(806,154)	
	282	3	(1,581,460,212)	UT	0.000%	-	
	282	3	(233,867,586)	WA	0.000%	-	
	282	3	(422,079,992)	WYP	0.000%	-	
	282	3	(90,755,573)	WYU	0.000%	-	
ADIT Balance 283	283	3	315,496	CA	0.000%	-	
	283	3	1,739,032	GPS	27.165%	472,404	
	283	3	532,974	IDU	0.000%	-	
	283	3	116,933	OR	100.000%	116,933	
	283	3	(19,279,016)	OTHER	0.000%	-	
	283	3	(3,918,725)	SE	24.314%	(952,780)	
	283	3	(2,079,657)	SG	25.777%	(536,076)	
	283	3	1,064,930	SGCT	25.862%	275,410	
	283	3	671,673	SNP	26.196%	175,953	
	283	3	3,536,193	SO	27.165%	960,606	
	283	3	(2,246,379)	UT	0.000%	-	
	283	3	3,437,186	WA	0.000%	-	
	283	3	(922,768)	WYP	0.000%	-	
ADIT Balance 255	255	3	872,621	ITC84	70.976%	619,351	
	255	3	1,357,455	ITC85	67.690%	918,861	
	255	3	493,248	ITC86	64.608%	318,678	
	255	3	59,256	ITC88	61.200%	36,265	
	255	3	117,816	ITC89	56.356%	66,396	
	255	3	57,552	ITC90	15.936%	9,171	

Description of Adjustment:

This adjustment normalizes the accumulated deferred income tax balances to an estimated pro forma level of rate base balance for the December 2013 test period. Additional line item detail is included in the tax model which is provided with the Company's electronic work papers.

PacifiCorp
Oregon General Rate Case - December 2013
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	1,479,722	SG	25.777%	381,430	7.9.1

Description of Adjustment:

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

PacifiCorp
Oregon General Rate Case - December 2013
Wyoming Wind Generation Tax

Wind Plant	Annual NPC MWH Production	Tax Begins	Test Period $1/MWH Tax
Total WY Wind MWH	1,725,585		**1,479,722**
			Ref. 7.9

PacifiCorp
Oregon General Rate Case - December 2013
ADIT Corrections Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Rogue River Settlement Agreement	190	3	(24,774)	SG	25.777%	(6,386)	
Rogue River Settlement Agreement	190	3	24,774	OTHER	0.000%	-	
Lewis River Settlement Agreement	190	3	(243,859)	SG	25.777%	(62,860)	
Lewis River Settlement Agreement	190	3	243,859	OTHER	0.000%	-	
Oregon BETC Credit Carryover	190	3	(5,176,101)	NUTIL	0.000%	-	
Oregon BETC Credit Carryover	190	3	5,176,101	SG	25.777%	1,334,252	
			-			1,265,006	7.10.1
Environmental Clean-up Accrual	283	3	8,392,717	SG	25.777%	2,163,404	
Environmental Clean-up Accrual	283	3	(8,392,717)	SO	27.165%	(2,279,880)	
Trapper Mining Stock Basis	283	3	1,610,936	SE	24.314%	391,675	
Trapper Mining Stock Basis	283	3	(1,610,936)	OTHER	0.000%	-	
			-			275,199	7.10.1
PMI Dividend Received Deduction	SCHMDP	3	(181,010)	SE	24.314%	(44,010)	
PMI Dividend Received Deduction	SCHMDP	3	181,010	NUTIL	0.000%	-	
			-			(44,010)	7.10.1

Description of Adjustment:

This adjustment corrects allocation factors used to allocate accumulated deferred income tax balances and a schedule M.

Thirteen-Month Average Balance at June 2011			Booked Allocation Factor	Corrected Allocation Factor	Amount	
19010000	287289	Rogue River Settlement Agreement	SG	OTHER	24,774	**Ref. 7.10**

This accumulated deferred income tax asset is associated with the Rogue River Settlement Agreement, which is not included in the results of operations. Accordingly, this accumulated deferred income tax asset is being reclassified as OTHER.

19010000	287290	Lewis River Settlement Agreement	SG	OTHER	243,859	**Ref. 7.10**

This accumulated deferred income tax asset is associated with the Lewis River Settlement Agreement, which is not included in the results of operations. Accordingly, this accumulated deferred income tax asset is being reclassified as OTHER.

19010000	287491	Oregon BETC Credit Carryforward	NUTIL	SG	5,176,101	**Ref. 7.10**

This accumulated deferred income tax asset is associated with the carryforward of Oregon Business Energy Tax Credits, which are credited against Oregon state taxable income when the credits are utilized. Until the credits can be utilized the Company carries the benefits on the balance sheet and allocated as SG.

28310000	287634	Environmental Clean-up Accrual	SG	SO	(8,392,717)	**Ref. 7.10**

This accumulated deferred income tax liability is associated with the Company's responsibility for clean-up of environmental hazardous materials. The proper classification of these accounts is SO.

28310000	287770	Trapper Mining Stock Basis	SE	OTHER	(1,610,936)	**Ref. 7.10**

This accumulated deferred income tax liability is associated with the basis in the stock of trapper mining company. The proper classification of this accounts is OTHER.

4099200	920.106	PMI Dividend Received Deduction	SE	NUTIL	(181,010)	**Ref. 7.10**

This permanent schedule m item is associated with the Bridger Reclamation Trust which is not included in the Results of Operations. The proper classification of this account is NUTIL.

PacifiCorp
Oregon General Rate Case - December 2013
Franchise and Resource Supplier Taxes

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Taxes	408	3	3,511,857	OR	100.000%	3,511,857	7.11.1

Description of Adjustment:

This adjustment normalizes the base period Oregon Franchise Tax and the Oregon Energy Resource Supplier Assessment to the December 2013 test period level based on pro forma revenues in adjustment 3.1.

PacifiCorp
Oregon General Rate Case - December 2013
Franchise & Resource Supplier Taxes

Franchise Tax		
Pro Forma Oregon General Business Revenues	1,182,374,668	Ref. 3.1.1
Franchise Tax Rate	2.30%	Ref. 1.5
Pro Forma Franchise Taxes	27,194,617	
Actual Franchise Taxes	23,898,371	Ref. B-5
Franchise Tax Adjustment	**3,296,247**	
Resource Supplier Tax		
Pro Forma Oregon General Business Revenues	1,182,374,668	Ref. 3.1.1
Resource Supplier Tax Rate	0.08%	
	945,900	
Actual Resource Supplier Tax	730,290	Ref. B-5
Resource Supplier Tax Adjustment	**215,610**	
Total Adjustment (Account 408 Situs Oregon)	**3,511,857**	

8. RATE BASE ADJUSTMENTS

Rate Base Adjustment Index

The Company used year-end rate base as of June 2011 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using December 2012 ending balances. Other rate base components are reflected using December 2012/December 2013 beginning/ending average balances. The following rate base adjustments are included.

PacifiCorp
Normalized Results of Operations
Tab 8 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		Total Adjustments	8.2 Trapper Mine Rate Base	8.3 Bridger Mine Rate Base	8.4 Environmental Settlement (PERCO)	8.5 Customer Advances for Construction	8.6 Pro Forma Major Plant Additions	8.7 Pro Forma Major Plant Retirements	8.8 Miscellaneous Rate Base	8.9 Powerdale Hydro Removal
1	Operating Revenues:									
2	General Business Revenues	15,824,000	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-	-	-	-	-
6	Total Operating Revenues	15,824,000	-	-	-	-	-	-	-	-
7										
8	Operating Expenses:									
9	Steam Production	-	-	-	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-	-
11	Hydro Production	(4,231)	-	-	-	-	-	-	-	(9,793)
12	Other Power Supply	3,963,923	-	-	-	-	-	-	-	-
13	Embedded Cost Differential (ECD)	-	-	-	-	-	-	-	-	-
13	Transmission	(13,909)	-	-	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-	-	-
15	Customer Accounting	(391,980)	-	-	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-	-	-
18	Administrative & General	(2,316,256)	-	-	-	-	-	-	-	-
19										
20	Total O&M Expenses	1,237,548	-	-	-	-	-	-	-	(9,793)
21										
22	Depreciation	11,278,223	-	-	-	-	-	-	-	-
23	Amortization	380,938	-	-	-	-	-	-	-	(342,146)
24	Taxes Other Than Income	-	-	-	-	-	-	-	-	-
25	Income Taxes - Federal	2,789,584	(18,580)	(377,045)	-	998	(4,141,811)	978,452	(8,628)	118,061
26	Income Taxes - State	379,058	(2,525)	(51,234)	-	136	(562,803)	132,955	(1,172)	16,043
27	Income Taxes - Def Net	(5,445,771)	-	-	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-	-	-
30										
31	Total Operating Expenses:	10,619,580	(21,104)	(428,279)	-	1,133	(4,704,614)	1,111,408	(9,800)	(217,835)
32										
33	Operating Rev For Return:	5,204,420	21,104	428,279	-	(1,133)	4,704,614	(1,111,408)	9,800	217,835
34										
35	Rate Base:									
36	Electric Plant In Service	369,448,328	2,303,588	44,800,059	-	-	492,125,060	(116,258,540)	-	-
37	Plant Held for Future Use	(13,629,778)	-	-	-	-	-	-	-	-
38	Misc Deferred Debits	2,569,659	-	-	-	-	-	-	3,308,063	(265,470)
39	Elec Plant Acq Adj	(2,805,193)	-	-	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-	-	-
42	Fuel Stock	(2,282,922)	-	-	-	-	-	-	(2,282,922)	-
43	Material & Supplies	-	-	-	-	-	-	-	-	-
44	Working Capital	(7,298)	(96,383)	(8,618)	-	23	(94,665)	22,364	(197)	2,501
45	Weatherization Loans	-	-	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-	-	-
47										
48	Total Electric Plant:	353,292,796	2,207,206	44,791,441	-	23	492,030,395	(116,236,177)	1,024,943	(262,969)
49										
50	Rate Base Deductions:									
51	Accum Prov For Deprec	(11,258,073)	-	-	-	-	-	-	-	-
52	Accum Prov For Amort	(3,198,774)	-	-	-	-	-	-	-	-
53	Accum Def Income Tax	16,494,984	-	-	-	-	-	-	-	206,557
54	Unamortized ITC	-	-	-	-	-	-	-	-	-
55	Customer Adv For Const	(118,548)	-	-	-	(118,548)	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-	-	-	-
58										
59	Total Rate Base Deductions	1,919,589	-	-	-	(118,548)	-	-	-	206,557
60										
61	Total Rate Base:	355,212,385	2,207,206	44,791,441	-	(118,525)	492,030,395	(116,236,177)	1,024,943	(56,412)
62										
63	Return on Rate Base	-0.682%	-0.005%	-0.103%	0.000%	0.000%	-0.951%	0.199%	-0.002%	0.007%
64										
65	Return on Equity	-1.291%	-0.010%	-0.194%	0.000%	0.001%	-1.802%	0.377%	-0.003%	0.013%
66										
67	TAX CALCULATION:									
68	Operating Revenue	2,927,291	-	-	-	-	-	-	-	351,939
69	Other Deductions									
70	Interest (AFUDC)	-	-	-	-	-	-	-	-	-
71	Interest	8,949,462	55,610	1,128,506	-	(2,986)	12,396,548	(2,928,533)	25,823	(1,421)
72	Schedule "M" Additions	8,793,552	-	-	-	-	-	-	-	-
73	Schedule "M" Deductions	(5,577,917)	-	-	-	-	-	-	-	-
74	Income Before Tax	8,349,298	(55,610)	(1,128,506)	-	2,986	(12,396,548)	2,928,533	(25,823)	353,360
75										
76	State Income Taxes	379,058	(2,525)	(51,234)	-	136	(562,803)	132,955	(1,172)	16,043
77	Taxable Income	7,970,240	(53,085)	(1,077,272)	-	2,851	(11,833,745)	2,795,578	(24,651)	337,318
78										
79	Federal Income Taxes + Other	2,789,584	(18,580)	(377,045)	-	998	(4,141,811)	978,452	(8,628)	118,061
80										
81	PRICE CHANGE	38,062,310	255,156	5,177,956	-	(13,702)	56,879,433	(13,437,072)	118,485	(368,959)

PacifiCorp
Normalized Results of Operations
Tab 8 Adjustment Summary
Twelve Months Ending Dec 31, 2013

		8.10	8.11	8.12	8.13	8.14	8.15
		Regulatory Asset Amortization	Klamath Hydroelectric Agreement Settlement	Misc. Asset Sales and Removals	Remove Rolling Hills	FERC 105 (PHFU) Adjustment	Carbon Plant Closure
1	Operating Revenues:						
2	General Business Revenues	-	15,824,000	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-	-
6	Total Operating Revenues	-	15,824,000	-	-	-	-
7							
8	Operating Expenses:						
9	Steam Production	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	-	136,757	(131,195)	-	-	-
12	Other Power Supply	(236,958)	4,433,671	-	(232,789)	-	-
13	Embedded Cost Differential (ECD)	-	-	-	-	-	-
13	Transmission	-	-	(13,909)	-	-	-
14	Distribution	-	-	-	-	-	-
15	Customer Accounting	(391,980)	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	(2,193,584)	-	-	(122,672)	-	-
19							
20	Total O&M Expenses	(2,822,522)	4,570,428	(145,104)	(355,460)	-	-
21							
22	Depreciation	-	672,070	-	-	-	10,606,153
23	Amortization	(343,089)	1,066,173	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-
25	Income Taxes - Federal	1,104,108	3,220,427	71,399	1,652,699	114,711	74,793
26	Income Taxes - State	150,030	437,603	9,702	224,574	15,587	10,163
27	Income Taxes - Def Net	-	-	-	(1,420,630)	-	(4,025,141)
28	Investment Tax Credit Adj.	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-
30							
31	Total Operating Expenses:	(1,911,474)	9,966,700	(64,003)	101,183	130,298	6,665,968
32							
33	Operating Rev For Return:	1,911,474	5,857,300	64,003	(101,183)	(130,298)	(6,665,968)
34							
35	Rate Base:						
36	Electric Plant In Service	-	554,287	(2,790,752)	(51,673,560)	-	388,186
37	Plant Held for Future Use	-	-	-	-	(13,629,778)	-
38	Misc Deferred Debits	(472,933)	-	-	-	-	-
39	Elec Plant Acq Adj	(2,805,193)	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-
44	Working Capital	(31,559)	165,571	(1,288)	30,622	2,622	1,709
45	Weatherization Loans	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	(3,309,685)	719,858	(2,792,040)	(51,642,938)	(13,627,156)	389,895
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	-	(2,422,630)	69,395	4,395,259	-	(13,300,096)
52	Accum Prov For Amort	-	(3,198,774)	-	-	-	-
53	Accum Def Income Tax	(2,207,820)	-	-	14,471,106	-	4,025,141
54	Unamortized ITC	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-
58							
59	Total Rate Base Deductions	(2,207,820)	(5,621,405)	69,395	18,866,365	-	(9,274,955)
60							
61	Total Rate Base:	(5,517,505)	(4,901,546)	(2,722,645)	(32,776,573)	(13,627,156)	(8,885,060)
62							
63	Return on Rate Base	0.069%	0.187%	0.008%	0.068%	0.026%	-0.185%
64							
65	Return on Equity	0.131%	0.354%	0.015%	0.129%	0.049%	-0.351%
66							
67	TAX CALCULATION:						
68	Operating Revenue	3,165,612	9,515,329	145,104	355,460	-	(10,606,153)
69	Other Deductions						
70	Interest (AFUDC)	-	-	-	-	-	-
71	Interest	(139,012)	(123,493)	(68,596)	(825,795)	(343,332)	(223,856)
72	Schedule "M" Additions	-	-	-	(1,812,601)	-	10,606,153
73	Schedule "M" Deductions	-	-	-	(5,577,917)	-	-
74	Income Before Tax	3,304,623	9,638,822	213,700	4,946,572	343,332	223,856
75							
76	State Income Taxes	150,030	437,603	9,702	224,574	15,587	10,163
77	Taxable Income	3,154,593	9,201,220	203,998	4,721,997	327,745	213,693
78							
79	Federal Income Taxes + Other	1,104,108	3,220,427	71,399	1,652,699	114,711	74,793
80							
81	PRICE CHANGE	(3,897,872)	(10,365,795)	(464,174)	(4,141,233)	(1,575,319)	9,895,405

PacifiCorp PAGE 8.1
Oregon General Rate Case - December 2013
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	CWC	3	5,175,968	OR	100.000%	5,175,968	Below
Cash Working Capital June 2011			33,991,603			12,241,198	2.33
Cash Working Capital December 2013			48,296,213			17,417,166	8.1.1
Adjustment:			14,304,610			5,175,968	

Description of Adjustment:

This adjustment is necessary to compute the cash working capital for the normalized results of operations in this filing. Cash working capital is calculated by taking total operation and maintenance expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Net lag days for Oregon are calculated using the Company's 2010 lead lag study. A copy of the Company's 2010 lead/lag study is included in tab 11 of this exhibit. A separate column is not shown for adjustment 8.1 on page 8.0.2 as the cash working capital component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

PacifiCorp
Oregon General Rate Case - December 2013
Twelve Months Ending December 31, 2013

Lead/Lag Study as of 12/10	TOTAL	CA	OR	WA	WY	UT	ID	FERC
Revenue Lag Days	40.11	42.07	42.41	41.27	37.90	41.07	39.58	35.62
Expense Lag Days	34.90	37.40	35.07	35.20	34.97	35.46	34.86	35.10
Net Lag Days	5.21	4.67	7.34	6.07	2.93	5.60	4.72	0.53
O&M Expense	3,046,115,449	60,530,060	802,865,577	223,901,652	459,772,182	1,302,167,718	187,670,623	9,207,639
Embedded Cost Differential	0	0	0	0	0	0	0	0
Taxes Other than Income	167,755,580	4,280,650	65,230,076	10,597,017	21,000,104	58,768,533	7,554,336	324,864
Federal Income Tax	(84,084,977)	1,662,494	(4,057,709)	(8,693,894)	(16,684,369)	(46,509,457)	(8,229,793)	(1,572,249)
State Income Tax	(3,275,376)	363,068	1,549,528	(540,956)	(1,012,392)	(2,787,336)	(660,328)	(186,958)
Total	3,126,510,677	66,836,271	865,587,472	225,263,819	463,075,525	1,311,639,457	186,334,837	7,773,296
Divided by Days in Year		365	365	365	365	365	365	365
Avg. Daily Cost of Service	8,565,783	183,113	2,371,473	617,161	1,268,700	3,593,533	510,506	21,297
Net Lag Days		4.67	7.34	6.07	2.93	5.60	4.72	0.53
Cash Working Capital	48,296,213	855,841	17,417,166	3,746,168	3,718,629	20,138,060	2,409,078	11,271
	Ref. 2.33		Ref. 8.1					

PacifiCorp PAGE 8.2
Oregon General Rate Case - December 2013
Trapper Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	11,574,634	SE	24.314%	2,814,201	Below
Other Tangible Property	399	3	(2,100,118)	SE	24.314%	(510,613)	Below
			9,474,516			2,303,588	Below
Final Reclamation Liability	2533	3	(394,669)	SE	24.314%	(95,958)	Below

Adjustment Detail

June 2011 Year-End Balance	11,574,634	8.2.1
Dec 2012 Year-End Balance	9,474,516	8.2.1
Adj to Dec 2012 Year-End Balance	(2,100,118)	Above
Final Reclamation Liability:		
June 2011 12 Mo. Avg	(4,746,498)	8.2.2
Dec 2012 12 Mo Avg	(5,141,168)	8.2.2
Adj to Dec 12 Mo Avg	(394,669)	Above

Description of Adjustment:

The Company owns a 21.40% interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base. This adjustment reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks forward the Reclamation Liability to December 2012. The adjustment was stipulated to and approved in Oregon UE 111, and has been included in all filings since.

PacifiCorp
Oregon General Rate Case - December 2013
Trapper Mine Rate Base

DESCRIPTION	Actual Jun-11	Pro Forma Jan-12	Pro Forma Feb-12	Pro Forma Mar-12	Pro Forma Apr-12	Pro Forma May-12	Pro Forma Jun-12	Pro Forma Jul-12	Pro Forma Aug-12	Pro Forma Sep-12	Pro Forma Oct-12	Pro Forma Nov-12	Pro Forma Dec-12
Property, Plant, and Equipment													
Lands and Leases	11,156,033	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186
Development Costs	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815
Equipment and Facilities	115,764,582	117,821,577	118,759,765	118,890,239	118,959,890	120,079,237	120,279,798	120,540,779	121,441,205	122,064,706	122,084,006	122,103,307	122,122,608
Total Property, Plant, and Equipment	**129,755,430**	**131,896,578**	**132,834,766**	**132,965,240**	**133,034,891**	**134,154,238**	**134,354,799**	**134,615,780**	**135,516,206**	**136,139,707**	**136,159,007**	**136,178,308**	**136,197,609**
Accumulated Depreciation	(87,867,390)	(95,192,990)	(95,809,521)	(96,426,052)	(97,042,582)	(97,659,113)	(98,275,644)	(98,892,174)	(99,508,705)	(100,125,236)	(100,741,766)	(101,358,297)	(101,974,828)
Total Property, Plant, and Equipment	**41,888,040**	**36,703,588**	**37,025,245**	**36,539,188**	**35,992,308**	**36,495,125**	**36,079,155**	**35,723,606**	**36,007,501**	**36,014,471**	**35,417,241**	**34,820,011**	**34,222,781**
Other :													
Inventories	5,857,184	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387	6,429,387
Prepaid Expenses	273,671	355,000	325,000	295,000	265,000	235,000	205,000	175,000	145,000	115,000	454,000	424,000	394,000
Restricted Funds: Self-bonding for Black Lung	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Deferred GE Royalty Amount	5,568,182	3,977,273	3,863,636	3,750,000	3,636,364	3,522,727	3,409,091	3,295,455	3,181,818	3,068,182	2,954,545	2,840,909	2,727,273
Total Other	**12,199,037**	**11,261,660**	**11,118,024**	**10,974,387**	**10,830,751**	**10,687,115**	**10,543,478**	**10,399,842**	**10,256,205**	**10,112,569**	**10,337,933**	**10,194,296**	**10,050,660**
Total Rate Base	**54,087,077**	**47,965,248**	**48,143,269**	**47,513,575**	**46,823,059**	**47,182,240**	**46,622,634**	**46,123,447**	**46,263,706**	**46,127,040**	**45,755,174**	**45,014,308**	**44,273,441**
PacifiCorp Share	**11,574,634**	**10,264,563**	**10,302,660**	**10,167,905**	**10,020,135**	**10,096,999**	**9,977,244**	**9,870,418**	**9,900,433**	**9,871,187**	**9,791,607**	**9,633,062**	**9,474,516**
	Ref 8.2												

December 2012 Year-End Balance	**9,474,516**	**Ref 8.2**

PacifiCorp
Oregon General Rate Case - December 2013
Trapper Mine
Final Reclamation Liability

Description:	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
Final Reclamation Liability	(4,625,186)	(4,651,923)	(4,666,001)	(4,684,992)	(4,714,853)	(4,736,622)	(4,753,904)	(4,778,349)	(4,804,306)	(4,829,052)	(4,844,979)	(4,867,816)
	Jan-12	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
Final Reclamation Liability	(5,025,792)	(5,045,713)	(5,067,669)	(5,087,593)	(5,109,548)	(5,130,489)	(5,151,398)	(5,174,378)	(5,193,424)	(5,216,404)	(5,236,279)	(5,255,325)

12 Month Average :

July 2010 - June 2011	(4,746,498)	
January 2012 - December 2012	(5,141,168)	
Adjustment to Rate Base	**(394,669)**	**Ref 8.2**

PacifiCorp PAGE 8.3
Oregon General Rate Case - December 2013
Bridger Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	174,436,231	SE	24.314%	42,411,586	Below
Other Tangible Property	399	3	9,823,642	SE	24.314%	2,388,473	Below
			184,259,873			44,800,059	

Adjustment Detail

June 2011 Year-End Balance	174,436,231	8.3.1
Dec 2012 Year-End Balance	184,259,873	8.3.1
Adjustment to Dec 2012 Year-End Balance	9,823,642	Above

Description of Adjustment:

PacifiCorp owns a two-thirds interest in the Bridger Coal Company (BCC), which supplies coal to the Jim Bridger generating plant. The Company's investment in BCC is recorded on the books of Pacific Minerals, INC (PMI), a wholly-owned subsidiary. Because of this ownership arrangement, the coal mine investment is not included in Account 101 -Electric Plant in Service. The normalized costs for BCC provide no return on investment. The return on investment for BCC is removed in the fuels credit which the Company has included as an offset to fuel prices leaving no return in results. This adjustment is necessary to properly reflect the BCC plant investment in the 12-month period. The Bridger Mine adjustment was stipulated to and approved in Oregon UE 111, and has been included in all filings since.

PacifiCorp
Oregon General Rate Case - December 2013
Bridger Mine Rate Base
(000's)

Bridger Total	Actual	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
Description	**Jun-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
1 Structure, Equipment, Mine Dev.	429,424	454,778	455,305	457,346	459,308	449,506	453,530	454,753	457,038	459,646	462,226	467,768	474,367
2 Materials & Supplies	15,042	15,101	15,101	15,101	15,101	15,163	15,163	15,163	15,163	15,163	15,163	15,163	15,163
4 Pit Inventory	24,182	21,954	17,083	20,447	25,114	36,454	37,562	36,356	36,308	37,377	30,107	29,815	31,387
5 Deferred Long Wall Costs	2,650	2,221	3,518	2,711	1,940	2,727	2,002	1,427	650	-	2,169	2,484	2,011
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(209,644)	(225,661)	(228,063)	(230,830)	(233,584)	(227,770)	(230,493)	(233,132)	(235,919)	(238,651)	(240,989)	(243,749)	(246,538)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	261,654	268,393	262,944	264,775	267,878	276,080	277,765	274,567	273,240	273,535	268,676	271,481	276,390
PacifiCorp Share (66.67%)	**174,436**	178,928	175,296	176,517	178,586	184,054	185,176	183,045	182,160	182,357	179,117	180,987	184,260

Ref 8.3

December 2012 Year-End Balance	**184,260**	**Ref 8.3**

PacifiCorp PAGE 8.4
Oregon General Rate Case - December 2013
Environmental Settlement (PERCO)

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Unspent Environmental Proceeds - June 2011	25399	1	(2,825,696)	SO	27.165%	(767,600)	8.4.2
Adj to Dec-13 B/E Avg Unspent Proceeds	25399	3	2,825,696	SO	27.165%	767,600	
Unspent Environmental Proceeds - Beg/End Avg. Dec 2013			-			-	8.4.2

Description of Adjustment:

The Company received an insurance settlement of $38 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company ("PERCO"). Any unspent cash proceeds from the insurance settlement are reflected as a reduction to rate base. The Company expects these cash proceeds to be exhausted prior to December 31, 2012. As such, no reduction to rate base is reflected in the test period.

PacifiCorp
Oregon General Rate Case - December 2013
PacifiCorp Environmental Remediation Co.
Spending by Environmental Project

Site	WBS	Cash Received 1996 & after	Remaining Cash at Jun 30, 2011	ProForma Spending Jul-Dec 11	ProForma Spending Jan-Dec12	Remaining Cash at Dec 31, 2012	ProForma Spending Jan-Dec13	Remaining Cash at Dec 31, 2013
American Barrel	PERC/1997/E/001			124,056	52,371		50,652	
Astoria / Unocal	PERC/1997/E/002			(28,606)	28,304		912,485	
Eugene - PacifiCorp	PERC/1997/E/003			314,180	35,380		-	
Everett - PacifiCorp	PERC/1997/E/004			(18)	377,936		6,926	
Jordan / Barber Tar	PERC/1997/E/005			-	-		-	
Ogden	PERC/1997/E/006			38,068	589,662		22,812	
Tacoma A Street	PERC/1997/E/007			(3,145)	184,367		-	
Tacoma River Street	PERC/1997/E/008			-	-		-	
Bridger GW Sampling	PERC/1997/E/009			-	-		-	
Bridger Landfill Repermitting	PERC/1997/E/010			-	-		-	
Bridger Oil Spill	PERC/1997/E/011			-	-		-	
Carbon Fuel Oil	PERC/1997/E/012			-	-		-	
Carbon Landfill Permit	PERC/1997/E/013			-	-		-	
Carbon Emerg. Gen. Remediation	PERC/1997/E/014			-	-		-	
Centralia Heavy Equipment Shop	PERC/1997/E/013			-	-		-	
Dave Johnston GW Sampling	PERC/1997/E/016			-	-		-	
Dave Johnston Landfill Repermit	PERC/1997/E/017			-	-		-	
Dave Johnston Diesel Release	PERC/1997/E/018			-	-		-	
Dave Johnston Landfill Closure	PERC/1997/E/019			-	-		-	
Dave Johnston Landfill Reclamation	PERC/1997/E/020			-	-		-	
Farm GW Monitoring - Hunter	PERC/1997/E/021			-	-		-	
Farm GW Monitoring - Huntington	PERC/1997/E/022			-	-		-	
Hunter Fuel Oil	PERC/1997/E/023			560	-		-	
Hunter Injection Wells	PERC/1997/E/024			-	-		-	
Hunter Landfill Permit	PERC/1997/E/025			-	-		-	
Huntington Injection Wells	PERC/1997/E/026			-	-		-	
Huntington Landfill Closure	PERC/1997/E/027			72,405	33,021		31,937	
Huntington Landfill Permit	PERC/1997/E/028			-	-		-	
Huntington Lead Paint Removal	PERC/1997/E/029			-	-		-	
Huntington Wellhead Protection	PERC/1997/E/030			-	-		-	
Buried Pitch	PERC/1997/E/031			-	-		-	
Tank Farm	PERC/1997/E/032			-	-		-	
Naughton FGD Pond Closure	PERC/1997/E/033			11,068	37,738		36,499	
Naughton GW Monitoring	PERC/1997/E/034			-	-		-	
Naughton Landfill Repermit	PERC/1997/E/035			-	-		-	
Naughton Landfill Closure	PERC/1997/E/036			-	-		-	
Wyodak Pond Study	PERC/1997/E/037			-	-		-	
Wyodak Fuel Oil	PERC/1997/E/038			34,567	32,078		31,024	
Bank Stabilization & Restoration	PERC/1997/E/039			-	-		-	
Restore River Embankments	PERC/1997/E/040			-	-		-	
Cutler	PERC/1997/E/041			-	-		-	
Bank Stabilization & Restoration	PERC/1997/E/042			-	-		-	
Merwin Hatchery Fix Erosion Problems	PERC/1997/E/044			-	-		-	
Speelyai Hatchery Stabilize River Bank	PERC/1997/E/045			-	-		-	
No. Umpqua Erosion Repairs	PERC/1997/E/046			-	-		-	
Klamath River Domestic Water Studies	PERC/1997/E/048			-	-		-	
Big Fork Flowline Repairs	PERC/1997/E/050			224,826	-		-	
No. Umq Remove Contaminated Soils	PERC/1997/E/052			-	-		-	
Rogue River Domestic Water Studies	PERC/1997/E/053			-	-		-	
UST Removal	PERC/1997/E/054			-	-		-	
Lead Paint Removal	PERC/1997/E/055			-	-		-	
Annex I	PERC/1997/E/056			(12)	-		-	
Cedar Diesel	PERC/1997/E/057			-	-		-	
Holiday Gun Club	PERC/1997/E/058			-	-		-	
Jordan Substation	PERC/1997/E/059			11,992	14,152		13,687	
Montague Ranch	PERC/1997/E/060			99,804	28,304		27,375	
Ross Island Tower Clean-up	PERC/1997/E/061			-	-		-	
Spill Prevention, Containment and Countermeasu	PERC/1997/E/062			-	-		-	
Ashton Substation	PERC/1997/E/070			-	-		-	
Rock Springs Plant Substation	PERC/1997/E/071			-	-		-	
Sinclair Substation	PERC/1997/E/072			-	-		-	
Parco Substation	PERC/1997/E/073			-	-		-	
Garland Substation	PERC/1997/E/074			-	-		-	
Dexter Substation	PERC/1997/E/075			-	-		-	
WyoMont Substation	PERC/1997/E/076			-	-		-	
Salt Lake Automotive Shop	PERC/1997/E/077			-	-		-	
Vernal Diesel	PERC/1997/E/078			-	-		-	
Salt Lake Terminal Oil Spill	PERC/1997/E/079			-	-		-	
Bridger Coal Fuel Oil Spill	PERC/1997/E/080			30,791	84,911		82,124	
Bors Property	PERC/1997/E/081			-	-		-	
Coal Creek	PERC/1997/E/082			-	-		-	
Ekotek / PetroChem	PERC/1997/E/083			-	-		-	

PacifiCorp
Oregon General Rate Case - December 2013
PacifiCorp Environmental Remediation Co.
Spending by Environmental Project

Site	WBS	Cash Received 1996 & after	Remaining Cash at Jun 30, 2011	ProForma Spending Jul-Dec 11	ProForma Spending Jan-Dec12	Remaining Cash at Dec 31, 2012	ProForma Spending Jan-Dec13	Remaining Cash at Dec 31, 2013
Environmental Pacific	PERC/1997/E/084			-	-		-	
Mountaineer Refinery	PERC/1997/E/085			-	-		-	
Northwest Triangle Property	PERC/1997/E/086			-	-		-	
Pinedale	PERC/1997/E/087			-	-		-	
PCB, Inc.	PERC/1997/E/088			-	-		-	
Portable Equipment GW	PERC/1997/E/089			-	-		-	
Idaho Falls Pole Yard	PERC/1997/E/090			-	-		-	
Idaho Falls Pole Yard	PERC/1997/E/091			215,288	75,477		72,999	
Astoria Steam Plant	PERC/1997/E/092			-	-		-	
Bear River Erosion Control	PERC/1997/E/093			-	-		-	
Beaver Bay Drainfield Cleanup	PERC/1998/E/094			-	-		-	
Bridger Boron Contaminated Soil Rem	PERC/1998/E/095			-	-		-	
Bridger Coal Warehouse Spill	PERC/1998/E/097			-	-		-	
Bridger Oil Spill (New Releases)	PERC/1998/E/098			99,113	59,752		57,790	
Cedar Steam Plant	PERC/1998/E/099			341,181	-		-	
Centralia Mine Pond Reclamation	PERC/1998/E/100			-	-		-	
Cougar Shore Line Repair	PERC/1998/E/101			-	-		-	
Mining Central Warehouse Cleanup	PERC/1998/E/102			-	-		-	
Deer Creek Terrace Stabilization	PERC/1998/E/103			-	-		-	
Domestic Water System Testing and Review	PERC/1998/E/104			-	-		-	
Hale Plant Cleanup	PERC/1998/E/105			-	-		-	
Huntington Ash Storm Runoff Pond	PERC/1998/E/106			-	-		-	
Huntington Lead Paint Removal	PERC/1998/E/107			-	-		-	
Lead Paint Removal (1998 Funds)	PERC/1998/E/108			-	-		-	
Lewis / Swift Reservoir Cleanup	PERC/1998/E/109			-	-		-	
Lifton Pumping Station Cleanup	PERC/1998/E/110			-	-		-	
Merwin Oil House Removal	PERC/1998/E/111			-	-		-	
Naughton South Ash Pond Reclam	PERC/1998/E/112			-	-		-	
Ogden Pole Treating Remediation	PERC/1998/E113			-	-		-	
Speelyai Well	PERC/1998/E/114			-	-		-	
Big Fork PCB Soil Cleanup	PERC/2003/E/123			-	-		-	
Pwr Delivery UST Compliance Audit	PERC/2003/E/124			-	-		-	
Bridger FGD Pond 1 Closure	PERC/2007/E/126			669,620	88,056		91,248	
Huntington Plant Fuel and Lube Oil Tank Farm	PERC/2007/E/127			-	-		-	
Olympia, WA	PERC/2007/E/128			(112)	106,718		-	
Powerdale Cleanup	PERC/2008/E/129			57,351	-		-	
Lincoln Steam Plant	PERC/2008/E/130			-	-		-	
Portland Harbor Source Control	PERC/2008/E/131			344,375	299,723		215,844	
Grace Hydro Plant	PERC/2009/E/132			-	-		-	
Huntington Unit #2 Precipitator PCB Remediatior	PERC/2010/E/134			45	-		-	
Dave Johnston Oil Spill	PERC/2010/E/135			71,378	406,931		30,513	
SPCC Oil/Water Separator Project	406860			-	-		-	
Astoria Young's Bay	401980			-	-		-	
Silver Bell / Telluride (hits cost center)	401981			-	-		-	
Attorney contingency fee received				-	-		-	
REGULATED TOTAL		38,624,130	**2,825,696**	2,728,774	2,534,881	-	1,683,915	-
			Page 8.4			**Page 8.4**		**Page 8.4**

Beg/End Avg. 12/31/2013 -

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PacifiCorp PAGE 8.5
Oregon General Rate Case - December 2013
Customer Advances for Construction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Customer Advances	252	1	(71,888)	CA	0.000%	-	
Customer Advances	252	1	184,977	ID	0.000%	-	
Customer Advances	252	1	(351,511)	OR	100.000%	(351,511)	
Customer Advances	252	1	(83,786)	UT	0.000%	-	
Customer Advances	252	1	(303,781)	WA	0.000%	-	
Customer Advances	252	1	(688,728)	WYP	0.000%	-	
Customer Advances	252	1	410,960	WYU	0.000%	-	
Customer Advances	252	1	903,757	SG	25.777%	232,963	
			0			(118,548)	8.5.1

Description of Adjustment:

Customer advances for construction are booked into FERC Account 252. When they are booked, the entries do not reflect the proper allocation. This adjustment corrects the allocation .

June 2011 YEAR / END BASIS:

Account	Booked Allocation	Correct Allocation	Adjustment	Ref.
252CA	-	(71,888)	(71,888)	
252IDU	(592,038)	(407,061)	184,977	
252OR	(7,096,641)	(7,448,152)	(351,511)	
252UT	(2,766,287)	(2,850,072)	(83,786)	
252WA	(4,381)	(308,162)	(303,781)	
252WYP	(788,552)	(1,477,281)	(688,728)	
252WYU	(410,960)	-	410,960	
252NUTIL	53,953	53,953	0	
252SG	(16,205,061)	(15,301,304)	903,757	
Total	**(27,809,967)**	**(27,809,967)**	**0**	**Page 8.5**

PacifiCorp PAGE 8.6
Oregon General Rate Case - December 2013
Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant Additions	312	3	766,555,263	SG	25.777%	197,596,138	
Steam Plant Additions	312	3	12,433,358	SG	25.777%	3,204,966	
			778,988,621			200,801,104	
Hydro Plant Additions	332	3	232,010,072	SG-P	25.777%	59,805,596	
Hydro Plant Additions	332	3	24,799,034	SG-U	25.777%	6,392,485	
			256,809,105			66,198,081	
Other Plant Additions	343	3	27,825,372	SG	25.777%	7,172,589	
Other Plant Additions	343	3	3,380,474	SG	25.777%	871,390	
Other Plant Additions	343	3	10,134,326	SG	25.777%	2,612,341	
			41,340,172			10,656,320	
Transmission Plant Additions	355	3	304,403,191	SG	25.777%	78,466,482	
			304,403,191			78,466,482	
Distribution Plant Additions	360	3	3,129,955	OR	Situs	749,703	
Distribution Plant Additions	361	3	4,654,664	OR	Situs	1,114,909	
Distribution Plant Additions	362	3	48,301,209	OR	Situs	11,569,355	
Distribution Plant Additions	364	3	55,994,944	OR	Situs	13,412,198	
Distribution Plant Additions	365	3	38,361,318	OR	Situs	9,188,501	
Distribution Plant Additions	366	3	17,874,826	OR	Situs	4,281,471	
Distribution Plant Additions	367	3	42,471,565	OR	Situs	10,173,008	
Distribution Plant Additions	368	3	65,027,976	OR	Situs	15,575,836	
Distribution Plant Additions	369	3	34,770,755	OR	Situs	8,328,471	
Distribution Plant Additions	370	3	10,506,081	OR	Situs	2,516,471	
Distribution Plant Additions	371	3	516,585	OR	Situs	123,735	
Distribution Plant Additions	373	3	3,567,194	OR	Situs	854,433	
			325,177,071			77,888,090	
General Plant Additions	397	3	4,797,399	CA	0.000%	-	
General Plant Additions	397	3	-	CN	29.363%	-	
General Plant Additions	397	3	-	SE	24.314%	-	
General Plant Additions	397	3	6,544,813	ID	0.000%	-	
General Plant Additions	397	3	32,816,950	OR	100.000%	32,816,950	
General Plant Additions	397	3	23,580,360	SG	25.777%	6,078,346	
General Plant Additions	397	3	21,499,530	SO	27.165%	5,840,344	
General Plant Additions	397	3	-	SG	25.777%	-	
General Plant Additions	397	3	33,602,990	UT	0.000%	-	
General Plant Additions	397	3	6,463,732	WA	0.000%	-	
General Plant Additions	397	3	13,830,065	WYP	0.000%	-	
			143,135,840			44,735,641	
Intangible Plant Additions	303	3	-	CN	29.363%	-	
Intangible Plant Additions	302	3	9,586,908	SG	25.777%	2,471,232	
Intangible Plant Additions	303	3	19,663,036	SO	27.165%	5,341,461	
			29,249,944			7,812,693	
Mining Plant Additions	399	3	22,895,278	SE	24.314%	5,566,648	
Total Plant Additions			**1,901,999,224**			**492,125,060**	8.6.4

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2012. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over $5 million (total company basis) are described on pages 8.6.15 through 8.6.20.
The related tax impact is included in adjustments 7.6, 7.7 and 7.8.

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment

Function	Factor	Jul-11 Plant Adds	Jul-11 Cumulative Adds	Aug-11 Plant Adds	Aug-11 Cumulative Adds	Sep-11 Plant Adds	Sep-11 Cumulative Adds	Oct-11 Plant Adds	Oct-11 Cumulative Adds	Nov-11 Plant Adds	Nov-11 Cumulative Adds
Steam Production											
	SG	13,707,071	13,707,071	16,754,354	30,461,425	3,686,231	34,147,656	14,128,582	48,276,237	201,540,298	249,816,535
	SG - Cholla	-	-	-	-	-	-	120,058	120,058	6,836,901	6,956,960
Total		13,707,071	13,707,071	16,754,354	30,461,425	3,686,231	34,147,656	14,248,640	48,396,296	208,377,199	256,773,495
Hydro Production											
	SG-U	1,065,138	1,065,138	343,394	1,408,532	160,676	1,569,208	130,439	1,699,647	126,970	1,826,617
	SG-P	365,231	365,231	229,528	594,759	178,478	773,237	1,912,367	2,685,604	11,138,892	13,824,496
Total		1,430,369	1,430,369	572,922	2,003,291	339,154	2,342,445	2,042,806	4,385,251	11,265,862	15,651,113
Other Production											
	SG	2,920,978	2,920,978	(111,843)	2,809,135	-	2,809,135	-	2,809,135	800,971	3,610,106
	SG - CT	-	-	-	-	-	-	-	-	244,916	244,916
Total		2,920,978	2,920,978	(111,843)	2,809,135	-	2,809,135	-	2,809,135	1,045,886	3,855,021
Other Production - Wind											
	SG-W	4,743	4,743	(5,474)	(732)	1,075,319	1,074,587	631,750	1,706,338	2,373,401	4,079,739
Total		4,743	4,743	(5,474)	(732)	1,075,319	1,074,587	631,750	1,706,338	2,373,401	4,079,739
Transmission Plant											
	SG	9,693,532	9,693,532	14,526,081	24,219,613	8,340,441	32,560,054	6,924,797	39,484,850	5,976,696	45,461,547
Total		9,693,532	9,693,532	14,526,081	24,219,613	8,340,441	32,560,054	6,924,797	39,484,850	5,976,696	45,461,547
Distribution Plant											
	CA	480,182	480,182	726,746	1,206,928	1,861,636	3,068,564	972,907	4,041,471	1,225,253	5,266,724
	ID	621,331	621,331	806,861	1,428,191	950,603	2,378,794	1,180,630	3,559,424	968,439	4,527,863
	OR	5,779,600	5,779,600	8,140,356	13,919,956	3,946,671	17,866,628	4,379,258	22,245,885	7,059,918	29,305,804
	UT	7,738,562	7,738,562	8,556,061	16,294,623	9,289,894	25,584,516	10,266,706	35,851,223	7,959,083	43,810,306
	WA	1,187,192	1,187,192	705,117	1,892,309	1,107,432	2,999,741	44,873	3,044,613	1,714,870	4,759,483
	WYP	4,370,967	4,370,967	4,126,938	8,497,904	3,309,045	11,806,949	6,003,879	17,810,828	3,965,809	21,776,637
Total		20,177,833	20,177,833	23,062,080	43,239,912	20,465,280	63,705,192	22,848,252	86,553,444	22,893,372	109,446,816
General Plant											
	CA	14,029	14,029	32,154	46,184	245,265	291,449	227,340	518,789	106,470	625,259
	ID	1,543,496	1,543,496	71,644	1,615,140	181,850	1,796,990	378,860	2,175,850	219,216	2,395,066
	OR	377,378	377,378	269,555	646,933	3,699,130	4,346,063	2,940,077	7,286,140	2,140,060	9,426,200
	SG	2,761	2,761	1,862,547	1,865,308	1,657,770	3,523,078	633,399	4,156,476	600,964	4,757,440
	SO	1,024,691	1,024,691	476,623	1,501,314	1,656,870	3,158,184	1,180,100	4,338,285	907,470	5,245,755
	UT	6,284,424	6,284,424	582,348	6,866,772	1,328,157	8,194,929	2,130,698	10,325,627	2,463,402	12,789,029
	WA	613,094	613,094	444,838	1,057,932	1,355,219	2,413,151	1,099,318	3,512,469	270,851	3,783,320
	WYP	1,563,622	1,563,622	260,296	1,823,918	2,033,054	3,856,971	1,065,645	4,922,616	1,053,765	5,976,381
Total		11,423,496	11,423,496	4,000,005	15,423,501	12,157,315	27,580,816	9,655,436	37,236,252	7,762,197	44,998,449
Intangible Plant											
	CN	-	-	-	-	-	-	-	-	-	-
	SG	(56,533)	(56,533)	53,313	(3,221)	5,625	2,404	60,523	62,927	1,834	64,761
	SO	874,429	874,429	406,730	1,281,159	1,420,224	2,701,383	1,122,757	3,824,140	660,292	4,484,432
Total		817,896	817,896	460,043	1,277,939	1,425,848	2,703,787	1,183,281	3,887,068	662,126	4,549,193
Mining Plant											
	SE	1,023,602	1,023,602	1,877,433	2,901,035	83,371	2,984,406	2,259,467	5,243,873	178,081	5,421,953
Total		1,023,602	1,023,602	1,877,433	2,901,035	83,371	2,984,406	2,259,467	5,243,873	178,081	5,421,953
Total Plant Additions		61,199,519	61,199,519	61,135,600	122,335,119	47,572,959	169,908,078	59,794,428	229,702,506	260,534,821	490,237,327

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment

Function	Factor	Dec-11 Plant Adds	Dec-11 Cumulative Adds	Jan-12 Plant Adds	Jan-12 Cumulative Adds	Feb-12 Plant Adds	Feb-12 Cumulative Adds	Mar-12 Plant Adds	Mar-12 Cumulative Adds	Apr-12 Plant Adds	Apr-12 Cumulative Adds
Steam Production											
	SG	28,235,084	278,051,619	2,718,305	280,769,924	5,094,105	285,864,029	13,380,737	299,244,767	150,796,024	450,040,790
	SG - Cholla	1,047,102	8,004,062	-	8,004,062	-	8,004,062	276,778	8,280,840	-	8,280,840
Total		29,282,186	286,055,681	2,718,305	288,773,986	5,094,105	293,868,091	13,657,516	307,525,607	150,796,024	458,321,631
Hydro Production											
	SG-U	2,830,854	4,657,471	-	4,657,471	-	4,657,471	-	4,657,471	167,736	4,825,207
	SG-P	26,364,771	40,189,268	478,257	40,667,525	2,939,236	43,606,761	10,945,424	54,552,185	479,612	55,031,796
Total		29,195,625	44,846,739	478,257	45,324,996	2,939,236	48,264,232	10,945,424	59,209,656	647,348	59,857,004
Other Production											
	SG	964,969	4,575,075	119,074	4,694,149	-	4,694,149	-	4,694,149	-	4,694,149
	SG - CT	1,751,629	1,996,545	-	1,996,545	1,052,628	3,049,173	225,055	3,274,228	-	3,274,228
Total		2,716,598	6,571,619	119,074	6,690,694	1,052,628	7,743,322	225,055	7,968,377	-	7,968,377
Other Production - Wind											
	SG-W	2,107,345	6,187,084	-	6,187,084	863,342	7,050,426	-	7,050,426	-	7,050,426
Total		2,107,345	6,187,084	-	6,187,084	863,342	7,050,426	-	7,050,426	-	7,050,426
Transmission Plant											
	SG	17,856,660	63,318,207	16,398,249	79,716,456	4,107,318	83,823,775	29,730,055	113,553,830	16,607,039	130,160,870
Total		17,856,660	63,318,207	16,398,249	79,716,456	4,107,318	83,823,775	29,730,055	113,553,830	16,607,039	130,160,870
Distribution Plant											
	CA	2,755,278	8,022,002	542,499	8,564,501	571,405	9,135,906	662,849	9,798,755	572,784	10,371,539
	ID	848,491	5,376,354	1,092,955	6,469,310	1,069,641	7,538,950	1,138,132	8,677,082	1,225,836	9,902,918
	OR	11,586,848	40,892,652	2,769,549	43,662,201	2,820,626	46,482,827	3,214,499	49,697,326	5,520,572	55,217,898
	UT	18,570,680	62,380,986	3,567,730	65,948,716	3,376,101	69,324,816	5,603,056	74,927,872	3,831,907	78,759,779
	WA	1,900,200	6,659,683	756,136	7,415,819	798,124	8,213,942	925,941	9,139,883	849,883	9,989,766
	WYP	2,631,072	24,407,709	1,346,805	25,754,514	1,310,088	27,064,602	1,361,186	28,425,789	1,432,756	29,858,544
Total		38,292,569	147,739,385	10,075,675	157,815,060	9,945,984	167,761,045	12,905,662	180,666,706	13,433,737	194,100,444
General Plant											
	CA	2,231,388	2,856,646	71,854	2,928,500	110,205	3,038,705	54,244	3,092,949	288,002	3,380,951
	ID	389,937	2,785,003	143,868	2,928,871	556,644	3,485,515	148,541	3,634,055	1,097,623	4,731,678
	OR	6,728,722	16,154,922	1,413,003	17,567,925	3,299,056	20,866,980	608,642	21,475,622	918,619	22,394,242
	SG	6,320,433	11,077,873	9,000	11,086,873	867,104	11,953,977	1,639,301	13,593,279	344,568	13,937,847
	SO	5,154,646	10,400,401	1,376,483	11,776,884	321,651	12,098,535	317,274	12,415,809	395,925	12,811,734
	UT	5,024,139	17,813,168	748,154	18,561,322	2,200,857	20,762,179	1,534,385	22,296,564	1,370,293	23,666,856
	WA	652,514	4,435,834	63,654	4,499,488	585,140	5,084,628	210,333	5,294,962	66,958	5,361,919
	WYP	1,100,880	7,077,262	1,071,342	8,148,604	694,235	8,842,839	871,223	9,714,061	236,819	9,950,880
Total		27,602,659	72,601,109	4,897,358	77,498,467	8,634,891	86,133,357	5,383,944	91,517,301	4,718,806	96,236,107
Intangible Plant											
	CN	-	-	-	-	-	-	-	-	-	-
	SG	1,231,888	1,296,649	-	1,296,649	-	1,296,649	-	1,296,649	-	1,296,649
	SO	3,086,087	7,570,518	1,174,634	8,745,152	274,483	9,019,635	270,749	9,290,384	337,866	9,628,250
Total		4,317,975	8,867,168	1,174,634	10,041,801	274,483	10,316,285	270,749	10,587,033	337,866	10,924,899
Mining Plant											
	SE	3,851,844	9,273,797	2,711,006	11,984,804	813,000	12,797,804	487,840	13,285,643	189,000	13,474,643
Total		3,851,844	9,273,797	2,711,006	11,984,804	813,000	12,797,804	487,840	13,285,643	189,000	13,474,643
Total Plant Additions		155,223,462	645,460,789	38,572,559	684,033,348	33,724,988	717,758,336	73,606,244	791,364,580	186,729,821	978,094,401

PacifiCorp
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Function	Factor	May-12 Plant Adds	May-12 Cumulative Adds	Jun-12 Plant Adds	Jun-12 Cumulative Adds	Jul-12 Plant Adds	Jul-12 Cumulative Adds	Aug-12 Plant Adds	Aug-12 Cumulative Adds	Sep-12 Plant Adds	Sep-12 Cumulative Adds
Steam Production											
	SG	147,387,635	597,428,425	69,568,274	666,996,699	20,042,710	687,039,409	11,174,915	698,214,323	5,810,702	704,025,026
	SG - Cholla	-	8,280,840	317,063	8,597,903	52,487	8,650,390	58,655	8,709,044	59,683	8,768,727
Total		147,387,635	605,709,266	69,885,336	675,594,602	20,095,196	695,689,798	11,233,569	706,923,368	5,870,385	712,793,753
Hydro Production											
	SG-U	-	4,825,207	-	4,825,207	-	4,825,207	-	4,825,207	-	4,825,207
	SG-P	870,034	55,901,831	581,385	56,483,216	852,376	57,335,593	361,264	57,696,856	74,600,885	132,297,742
Total		870,034	60,727,038	581,385	61,308,423	852,376	62,160,800	361,264	62,522,064	74,600,885	137,122,949
Other Production											
	SG	255,746	4,949,895	672,282	5,622,177	571,713	6,193,889	-	6,193,889	-	6,193,889
	SG - CT	-	3,274,228	-	3,274,228	-	3,274,228	-	3,274,228	-	3,274,228
Total		255,746	8,224,122	672,282	8,896,404	571,713	9,468,117	-	9,468,117	-	9,468,117
Other Production - Wind											
	SG-W	-	7,050,426	514,719	7,565,146	2,911	7,568,057	2,911	7,570,967	2,911	7,573,878
Total		-	7,050,426	514,719	7,565,146	2,911	7,568,057	2,911	7,570,967	2,911	7,573,878
Transmission Plant											
	SG	12,372,868	142,533,738	29,269,890	171,803,628	5,845,249	177,648,876	27,391,871	205,040,747	5,920,381	210,961,129
Total		12,372,868	142,533,738	29,269,890	171,803,628	5,845,249	177,648,876	27,391,871	205,040,747	5,920,381	210,961,129
Distribution Plant											
	CA	572,160	10,943,699	593,012	11,536,711	568,146	12,104,856	673,204	12,778,060	585,272	13,363,332
	ID	1,204,659	11,107,577	1,255,136	12,362,712	1,255,091	13,617,804	1,326,391	14,944,195	1,237,361	16,181,556
	OR	2,920,679	58,138,577	2,992,054	61,130,631	2,819,301	63,949,931	3,148,373	67,098,304	2,681,545	69,779,849
	UT	32,576,068	111,335,847	14,358,150	125,693,998	4,702,685	130,396,682	5,115,272	135,511,954	4,598,331	140,110,285
	WA	846,904	10,836,670	879,300	11,715,970	825,680	12,541,650	922,703	13,464,353	796,814	14,261,167
	WYP	1,429,210	31,287,754	1,483,218	32,770,973	1,595,718	34,366,691	1,704,720	36,071,411	1,544,874	37,616,285
Total		39,549,679	233,650,123	21,560,870	255,210,993	11,766,620	266,977,614	12,890,664	279,868,277	11,444,196	291,312,474
General Plant											
	CA	53,613	3,434,563	609,666	4,044,229	53,297	4,097,526	53,903	4,151,429	457,850	4,609,279
	ID	150,985	4,882,663	152,409	5,035,071	242,861	5,277,933	375,825	5,653,758	232,715	5,886,473
	OR	2,049,151	24,443,393	3,171,478	27,614,871	319,521	27,934,392	1,056,183	28,990,575	2,231,318	31,221,893
	SG	328,076	14,265,923	631,915	14,897,838	226,560	15,124,398	959,550	16,083,948	995,849	17,079,797
	SO	338,406	13,150,140	644,192	13,794,332	927,782	14,722,114	610,651	15,332,765	805,579	16,138,344
	UT	789,260	24,456,116	2,877,773	27,333,890	1,019,509	28,353,399	672,729	29,026,128	654,154	29,680,283
	WA	67,127	5,429,046	404,157	5,833,203	67,478	5,900,681	67,682	5,968,362	65,220	6,033,583
	WYP	240,581	10,191,462	469,183	10,660,645	517,104	11,177,749	298,490	11,476,239	627,583	12,103,822
Total		4,017,200	100,253,307	8,960,773	109,214,080	3,374,112	112,588,192	4,095,013	116,683,205	6,070,269	122,753,474
Intangible Plant											
	CN	-	-	-	-	-	-	-	-	-	-
	SG	-	1,296,649	-	1,296,649	-	1,296,649	-	1,296,649	-	1,296,649
	SO	288,782	9,917,032	2,420,667	12,337,698	791,730	13,129,429	521,105	13,650,533	687,448	14,337,981
Total		288,782	11,213,681	2,420,667	13,634,348	791,730	14,426,078	521,105	14,947,183	687,448	15,634,630
Mining Plant											
	SE	997,000	14,471,643	1,203,000	15,674,643	1,417,000	17,091,643	487,000	17,578,643	282,000	17,860,643
Total		997,000	14,471,643	1,203,000	15,674,643	1,417,000	17,091,643	487,000	17,578,643	282,000	17,860,643
Total Plant Additions		205,738,944	1,183,833,345	135,068,922	1,318,902,267	44,716,908	1,363,619,175	56,983,396	1,420,602,571	104,878,476	1,525,481,047

PacifiCorp
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Function	Factor	Oct-12 Plant Adds	Oct-12 Cumulative Adds	Nov-12 Plant Adds	Nov-12 Cumulative Adds	Dec-12 Plant Adds	Dec-12 Cumulative Adds	Year End Plant Adds Dec-12	Factor %	Oregon Allocated Year End Plant Adds Dec. 2012	
Steam Production											
	SG	8,258,677	712,283,703	8,765,694	721,049,397	45,505,867	766,555,263	766,555,263	25.78%	197,596,138	
	SG - Cholla	60,711	8,829,438	54,543	8,883,980	3,549,377	12,433,358	12,433,358	25.78%	3,204,966	
Total		8,319,388	721,113,141	8,820,236	729,933,377	49,055,244	778,988,621	778,988,621		200,801,104	Ref. 8.6.6
Hydro Production											
	SG-U	-	4,825,207	18,821,493	23,646,700	1,152,334	24,799,034	24,799,034	25.78%	6,392,485	
	SG-P	4,363,514	136,661,256	22,751,153	159,412,408	72,597,663	232,010,072	232,010,072	25.78%	59,805,596	
Total		4,363,514	141,486,463	41,572,645	183,059,108	73,749,997	256,809,105	256,809,105		66,198,081	Ref. 8.6.7
Other Production											
	SG	17,641,072	23,834,961	-	23,834,961	3,990,411	27,825,372	27,825,372	25.78%	7,172,589	
	SG - CT	-	3,274,228	-	3,274,228	106,247	3,380,474	3,380,474	25.78%	871,390	
Total		17,641,072	27,109,189	-	27,109,189	4,096,658	31,205,847	31,205,847		8,043,979	Ref. 8.6.8
Other Production - Wind											
	SG-W	2,911	7,576,789	2,911	7,579,700	2,554,626	10,134,326	10,134,326	25.78%	2,612,341	
Total		2,911	7,576,789	2,911	7,579,700	2,554,626	10,134,326	10,134,326		2,612,341	Ref. 8.6.8
Transmission Plant											
	SG	10,127,946	221,089,075	7,919,216	229,008,290	75,394,901	304,403,191	304,403,191	25.78%	78,466,482	
Total		10,127,946	221,089,075	7,919,216	229,008,290	75,394,901	304,403,191	304,403,191		78,466,482	Ref. 8.6.9
Distribution Plant											
	CA	535,640	13,898,972	499,858	14,398,830	620,984	15,019,814	15,019,814	0.00%	-	
	ID	1,168,521	17,350,077	1,131,124	18,481,201	1,195,153	19,676,354	19,676,354	0.00%	-	
	OR	2,612,132	72,391,980	2,489,227	74,881,208	3,006,882	77,888,090	77,888,090	100.00%	77,888,090	
	UT	4,350,740	144,461,026	3,962,755	148,423,781	4,590,400	153,014,181	153,014,181	0.00%	-	
	WA	751,549	15,012,716	619,745	15,632,461	813,463	16,445,924	16,445,924	0.00%	-	
	WYP	1,489,719	39,106,003	1,402,018	40,508,021	2,624,688	43,132,709	43,132,709	0.00%	-	
Total		10,908,301	302,220,774	10,104,727	312,325,501	12,851,570	325,177,071	325,177,071		77,888,090	Ref. 8.6.11
General Plant											
	CA	82,431	4,691,711	53,128	4,744,839	52,561	4,797,399	4,797,399	0.00%	-	
	ID	157,613	6,044,086	331,504	6,375,589	169,224	6,544,813	6,544,813	0.00%	-	
	OR	299,410	31,521,303	499,811	32,021,114	795,836	32,816,950	32,816,950	100.00%	32,816,950	
	SG	1,623,004	18,702,801	12,000	18,714,801	4,865,559	23,580,360	23,580,360	25.78%	6,078,346	
	SO	1,488,157	17,626,501	1,753,746	19,380,247	2,119,283	21,499,530	21,499,530	27.16%	5,840,344	
	UT	1,242,512	30,922,795	695,796	31,618,591	1,984,400	33,602,990	33,602,990	0.00%	-	
	WA	64,945	6,098,527	301,927	6,400,454	63,278	6,463,732	6,463,732	0.00%	-	
	WYP	419,960	12,523,782	634,839	13,158,621	671,444	13,830,065	13,830,065	0.00%	-	
Total		5,378,032	128,131,506	4,282,750	132,414,256	10,721,584	143,135,840	143,135,840		44,735,641	Ref. 8.6.12
Intangible Plant											
	CN	-	-	-	-	-	-	-	29.36%	-	
	SG	751,162	2,047,811	1,836,076	3,883,887	5,703,021	9,586,908	9,586,908	25.78%	2,471,232	
	SO	1,269,931	15,607,912	1,496,574	17,104,487	2,558,549	19,663,036	19,663,036	27.16%	5,341,461	
Total		2,021,093	17,655,723	3,332,651	20,988,374	8,261,570	29,249,944	29,249,944		7,812,693	Ref. 8.6.13
Mining Plant											
	SE	367,000	18,227,643	401,000	18,628,643	4,266,635	22,895,278	22,895,278	24.31%	5,566,648	
Total		367,000	18,227,643	401,000	18,628,643	4,266,635	22,895,278	22,895,278		5,566,648	Ref. 8.6.14
Total Plant Additions		59,129,256	1,584,610,304	76,436,136	1,661,046,439	240,952,785	1,901,999,224	**1,901,999,224**		**492,125,060**	**Ref. 8.6**

PacifiCorp
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Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Naughton U2 Flue Gas Desulfurization Sys	312	SG	Nov-11	154,748,900	25.78%	39,889,864	8.6.15
Naughton U1 Flue Gas Desulfurization Sys	312	SG	May-12	120,749,119	25.78%	31,125,687	8.6.15
DJ U4 SO2 & PM Emission Cntrl Upgrades	312	SG	Apr-12	104,233,252	25.78%	26,868,367	8.6.15
Hunter U1 SO2 Upgrades	312	SG	Jun-12	51,918,028	25.78%	13,382,991	8.6.15
Hunter 303 Turbine Upgrade HP/IP/LP	312	SG	Apr-12	28,237,514	25.78%	7,278,828	8.6.16
302 - Hunter U2 SO2 Project	312	SG	Mar-12	25,068,777	25.78%	6,462,018	8.6.16
Hayden U0 Coal Unloading Facility	312	SG	Oct-11	12,351,711	25.78%	3,183,920	8.6.16
Naughton U1 NOx LNB	312	SG	May-12	8,930,952	25.78%	2,302,145	8.6.16
DJ U4 - Finishing Superheater Replacement	312	SG	Apr-12	8,816,722	25.78%	2,272,700	8.6.16
Huntington U2 Generator Stator Rewind	312	SG	Nov-11	8,657,111	25.78%	2,231,557	8.6.16
Naughton U2 NOx LNB - Clean	312	SG	Nov-11	8,549,495	25.78%	2,203,817	8.6.17
DJ U4 - Platen SSH Replace	312	SG	Apr-12	8,423,781	25.78%	2,171,411	8.6.17
Hunter 300 Adobe Wash Regulating Facility	312	SG	Dec-12	6,201,405	25.78%	1,598,546	8.6.17
Huntington U2 Boiler Finishing SH Pendants Replacem	312	SG	Apr-12	5,791,052	25.78%	1,492,768	8.6.17
DJ U0 - Replace DJ Retro Cooling Tower	312	SG	Apr-12	5,658,604	25.78%	1,458,627	8.6.17
JB U4 Wet Stack Conversion	312	SG	Dec-12	4,415,925	25.78%	1,138,300	
Huntington U2 Steam Inerting for Coal Mills	312	SG	May-12	4,004,827	25.78%	1,032,330	
DJ U0 - Rail Car Thaw Shed	312	SG	Oct-12	3,917,192	25.78%	1,009,741	
Naughton U0 FGD Reagent Loadout Facility	312	SG	Jun-12	3,708,790	25.78%	956,021	
Huntington U1 Steam Inerting for Coal Mills	312	SG	Nov-11	3,663,684	25.78%	944,393	
Huntington U2 Boiler Replace Vertical Low Temp Supe	312	SG	Apr-12	3,504,487	25.78%	903,357	
Hunter 303 Bottom Ash Component Replacement	312	SG	Aug-12	3,217,624	25.78%	829,412	
Naughton U1 OH Turbine Major CY12	312	SG	May-12	3,193,521	25.78%	823,199	
Hunter 303 Hunter 3 Wet Stack Upgrades	312	SG	Apr-12	3,028,455	25.78%	780,650	
Huntington U2 Boiler Waterwall Nose Arch Replacemen	312	SG	Apr-12	2,970,992	25.78%	765,837	
Huntington U2 Generator Field Refurbish/Rewind	312	SG	Nov-11	2,909,674	25.78%	750,031	
Naughton U2 OH HSH Upper Bank Replacement	312	SG	Nov-11	2,883,493	25.78%	743,283	
Hunter 303 ID Fan Replacements	312	SG	Jul-12	2,792,953	25.78%	719,944	
JB U4 APH Baskets 12	312	SG	Jun-12	2,772,313	25.78%	714,623	
Cholla 4: Cooling Tower Structure Imprv	312	SG	Nov-11	2,742,328	25.78%	706,894	
Hunter 300 Gen Coal Handling	312	SG	Dec-11	2,677,121	25.78%	690,086	
Craig 2: HP-IP Turbine Rotor Purchase	312	SG	July11	2,661,902	25.78%	686,163	
Naughton U0 Mine Water Well	312	SG	Jul-11	2,604,192	25.78%	671,287	
Hunter 303 BLR WW Headers and SSH Platen replac	312	SG	Jun-12	2,149,980	25.78%	554,204	
Cholla 4:Cooling Tower Struct Cells-E-L	312	SG	Nov-11	2,044,074	25.78%	526,904	
Naughton U2 OH Generator Field Rewind	312	SG	Nov-11	1,994,375	25.78%	514,093	
Hunter 300 Reverse Osmosis System	312	SG	Dec-12	1,980,627	25.78%	510,549	
Colstrip 3: LP Turbine Repl	312	SG	Jul-11	1,905,338	25.78%	491,142	
Huntington U2 Air Preheater Baskets	312	SG	Nov-11	1,894,044	25.78%	488,231	
Naughton U1 OH Boiler Deflect Arch Replace	312	SG	May-12	1,892,059	25.78%	487,719	
JB New Sewage Treatment Plant or Lagoon	312	SG	Sep-12	1,850,826	25.78%	477,090	
JB U4 Reheater Outlet Terminal Tubes 12	312	SG	May-12	1,830,248	25.78%	471,786	
Huntington U2 Base Turbine Maintenance	312	SG	Nov-11	1,809,328	25.78%	466,393	
Huntington U2 Bottom Ash System Repairs	312	SG	Nov-11	1,799,528	25.78%	463,867	
Wyodak U1 SO2 and PM Emiss Control Upgrade	312	SG	Apr-11	1,759,942	25.78%	453,663	
JB U4 Replace Upper Arch 12	312	SG	Jun-12	1,752,993	25.78%	451,872	
DJ U0 - CY Fire Prot RPLCE -TRPER Decks BST	312	SG	Feb-12	1,729,164	25.78%	445,729	
DJ U0 - Mill - 2012	312	SG	Dec-12	1,515,838	25.78%	390,740	
Hunter 302 Clean Air - PM	312	SG	May-11	1,503,979	25.78%	387,683	
Naughton U1 OH APH Clearflow Baskets	312	SG	May-12	1,486,638	25.78%	383,213	
Hunter 303 FGD Tower Isolation Dampers	312	SG	May-12	1,457,982	25.78%	375,826	
Naughton U1 OH Hot RH Lead Steam Pipe Replacement	312	SG	May-12	1,385,449	25.78%	357,129	
Naughton U2 OH Reheater Tubing Replace	312	SG	Nov-11	1,380,424	25.78%	355,834	
Naughton U2 OH HSH, SH, FSH Replace Tubes	312	SG	Nov-11	1,318,361	25.78%	339,836	
DJ U4 - Water Wall Tube Panel Replacement	312	SG	Apr-12	1,273,107	25.78%	328,171	
Hunter 303 Turbine- Interconnection (Cap Bank)	312	SG	Jun-12	1,235,245	25.78%	318,411	
Huntington U1 Turbine Upgrade- Interconnection	312	SG	Jul-12	1,234,956	25.78%	318,336	
JB U4 Burners - Major 12	312	SG	Jun-12	1,223,882	25.78%	315,482	
Craig 1: Boiler Component Repl	312	SG	Jun-11	1,219,347	25.78%	314,313	
Naughton U2 OH Waterwall Tube Replacement	312	SG	Nov-11	1,209,090	25.78%	311,669	
Huntington U1 SO2 & PM Em Cntrl Upgrades	312	SG	May-11	1,205,477	25.78%	310,738	
DJ U0 - Purchase Ash Haul Truck	312	SG	Jul-12	1,183,030	25.78%	304,952	
Hayden 1: Buckstays Replacement	312	SG	Jul-12	1,179,428	25.78%	304,023	
Hunter U1 Turbine Upgrade- Interconnection	312	SG	Aug-12	1,176,775	25.78%	303,339	
DJ U0 - Pumps And Valves - 2012	312	SG	Dec-12	1,080,719	25.78%	278,579	
DJ U0 - Mills - 2011	312	SG	Sept-11	1,076,558	25.78%	277,506	
JB U4 S02 & PM Em Cntrl Upgrades	312	SG	May-12	1,034,163	25.78%	266,578	
Naughton U1 OH Reheater Tubing Replace	312	SG	May-12	1,009,609	25.78%	260,248	
JB U3 S02 & PM Em Cntrl Upgrades	312	SG	Jun-11	1,007,932	25.78%	259,816	
Huntington U2 Boiler Radiant Reheat Replacement Pha	312	SG	Apr-12	1,005,591	25.78%	259,213	

PacifiCorp
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Pro Forma Plant Additions Adjustment
Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Huntington U0 Lacey's Lake Waste Water Diversion	312	SG	Dec-11	1,003,358	25.78%	258,637	
Projects Less Than $1million	312	SG	Various	99,536,308	25.78%	25,657,628	
Projects Less Than $1million - Cholla	312	SG	Various	7,646,956	25.78%	1,971,168	
				778,988,621		200,801,104	8.6.4

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
Hydro Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
INU 4.1.1/4.1.2 Soda Springs Fish Passag	332	SG-P	Sep-12	74,030,842	25.78%	19,083,045	8.6.18
ILR 4.4 Swift Fish Collector	332	SG-P	Dec-12	62,526,169	25.78%	16,117,467	8.6.18
Ashton Dam Seepage Control	332	SG-U	Nov-12	15,674,929	25.78%	4,040,551	8.6.18
ILR 10.2 Swift Land Fund	332	SG-P	Mar-12	10,591,938	25.78%	2,730,300	8.6.18
IRO Prospect Instream Flow / Automation	332	SG-P	Nov-12	10,204,794	25.78%	2,630,506	8.6.18
Slide Creek Overhaul	332	SG-P	Dec-11	9,941,415	25.78%	2,562,614	8.6.18
INU 4.1.1 (f)/6.9 Slide Tailrace Barrier	332	SG-P	Dec-11	9,124,621	25.78%	2,352,068	8.6.19
INU 6.1 Lemolo 2 Reroute to Toketee	332	SG-P	Nov-11	7,625,825	25.78%	1,965,721	8.6.19
Ashton Stability Improvements	332	SG-U	Nov-12	4,235,590	25.78%	1,091,815	
ILR 4.4.3 Release Ponds	332	SG-P	Dec-12	3,396,793	25.78%	875,597	
North Umpqua Coating Projects (Mandated)	332	SG-P	Nov-12	2,827,731	25.78%	728,909	
Swift 1 Station Service/Generator Breake	332	SG-P	Feb-12	2,779,983	25.78%	716,601	
Merwin Spillway Tainter Gate Rehab	332	SG-P	Oct-12	2,718,940	25.78%	700,865	
ILR 8.7 Lewis River Hatchery Pond 16 Mod	332	SG-P	Dec-11	2,554,511	25.78%	658,480	
ILR 8.7 Speelyai Hat.Water Intake (Dev)	332	SG-P	Nov-12	2,229,988	25.78%	574,828	
Lewis River Portable Spillway Bulkhead	332	SG-P	Dec-11	1,854,299	25.78%	477,985	
Soda Springs Flowline Rehabilitation	332	SG-P	Nov-12	1,775,256	25.78%	457,610	
Swift No.1 Upgrade Dam Monitoring System	332	SG-P	Nov-11	1,735,438	25.78%	447,347	
Toketee TIV Replacements	332	SG-P	Nov-12	1,712,615	25.78%	441,463	
Soda Intake Headgate Rehabilitation	332	SG-U	Dec-11	1,649,365	25.78%	425,159	
Swift 1 Spare Generator Windings	332	SG-P	Dec-12	1,542,838	25.78%	397,700	
Merwin Controls and Metering Replacement	332	SG-P	Oct-11	1,525,547	25.78%	393,243	
Lemolo 2 Flume 12 Bank Stabilization	332	SG-P	Nov-11	1,175,373	25.78%	302,978	
Yale Spillway Tainter Gate Rehab	332	SG-P	Oct-12	1,172,923	25.78%	302,346	
ILR 8.7 Speelyai Hatchery Ponds Mod/Co	332	SG-P	Dec-12	1,092,128	25.78%	281,520	
IBR 3.2.1 Grace Minimum Flow Valve	332	SG-U	Jul-11	1,079,056	25.78%	278,150	
Projects Less Than $1million	332	SG-P	Various	17,870,104	25.78%	4,606,404	
Projects Less Than $1million	332	SG-U	Various	2,160,094	25.78%	556,811	
				256,809,105		66,198,081	8.6.4

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
Other Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Currant Crk U2 CSA Variable fee 24k - CTB MI	343	SG	Oct-12	8,726,476	25.78%	2,249,437	8.6.19
Currant Crk U1 CSA Variable fee 24k - CTA MI	343	SG	Oct-12	8,726,476	25.78%	2,249,437	8.6.19
Hermiston U0 Auxiliary Boiler	343	SG	Dec-12	1,607,513	25.78%	414,371	
W-1799 Replace four gearboxes company wide	343	SG-W	Dec-12	1,275,812	25.78%	328,868	
Lake Side UST1 Install Steam Turbine Valve Seat	343	SG	Jul-11	1,011,624	25.78%	260,768	
Projects Less Than $1million	343	SG	Various	7,753,284	25.78%	1,998,576	
Projects Less Than $1million	343	SG-W	Various	8,858,514	25.78%	2,283,473	
Projects Less Than $1million - Gadsby	343	SG	Various	3,380,474	25.78%	871,390	
				41,340,172		10,656,320	**8.6.4**

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Clover Substation	355	SG	Dec-12	54,705,185	25.78%	14,101,440	8.6.19
Terminal Sub - Replace two 345/138 kV Trans and ten 138 kv breakers	355	SG	Aug-12	46,395,196	25.78%	11,959,362	8.6.20
NERC Facility Rating Project Phase II UT	355	SG	Various	10,570,450	25.78%	2,724,761	
Southwest Wyoming-Silver Creek 138 kV Line Phase I	355	SG	Jan.12	10,518,820	25.78%	2,711,452	8.6.20
Dave Johnston - Casper 230 kV Rebuild	355	SG	Jun-12	9,711,359	25.78%	2,503,312	8.6.20
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	8,691,975	25.78%	2,240,544	
Nibley: New 138-12.5 kV Substation and Rebuild 7 Miles Transmission	355	SG	Mar-12	6,850,785	25.78%	1,765,937	8.6.20
Ben Lomond 345/138 #2 transformer 450 MVA	355	SG	Aug-12	6,460,754	25.78%	1,665,398	8.6.20
NERC Facility Rating Project Phase II WY	355	SG	Various	5,765,700	25.78%	1,486,233	
COPCO II 230-115kV Transformer - TPL002	355	SG	Dec-12	5,211,118	25.78%	1,343,278	8.6.20
MR--Mandated - Regional or National Regulatory	355	SG	Various	4,888,962	25.78%	1,260,235	
Chappel Crk 230kV Cimarex Energy 20 MW	355	SG	Aug-11	4,594,389	25.78%	1,184,303	
City Creek Center: New 40 MW Development for PRI Phase II	355	SG	May-12	4,415,399	25.78%	1,138,164	
Red Butte Sub SVC and Property Acquisiti	355	SG	Jul-11	4,375,150	25.78%	1,127,789	
Union Gap- North Park 115 kV reconductor	355	SG	Aug-12	4,056,681	25.78%	1,045,697	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	3,841,198	25.78%	990,152	
NN - New Revenue - Transmission Expansion Plan	355	SG	Various	3,810,000	25.78%	982,110	
Chehalis U1 GSU replacement	355	SG	Jun-12	3,770,414	25.78%	971,905	
Line 37 Conv to 115kV Bld Nickel Mt Sub - Dist - Canyonville	355	SG	Dec-12	3,370,000	25.78%	868,690	
Meridian Sub 2-230kV Shunt Capacitor	355	SG	Aug-11	3,334,613	25.78%	859,568	
Wyoming - NERC Facility Rating Project	355	SG	Dec-11	3,271,712	25.78%	843,354	
JB U1 Replace / Rewind GSU	355	SG	Oct-12	3,220,140	25.78%	830,060	
M3--Mandated - Environmental	355	SG	Various	3,193,231	25.78%	823,124	
Montana - NERC Facility Rating Project	355	SG	Jul-11	3,017,654	25.78%	777,865	
345-138 kV Spare Transformer	355	SG	Apr-12	3,014,600	25.78%	777,078	
NERC Facility Rating Project Phase II ID	355	SG	Various	2,882,850	25.78%	743,117	
RI--Replace - Storm and Casualty	355	SG	Various	2,763,421	25.78%	712,331	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	2,579,182	25.78%	664,840	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	2,554,135	25.78%	658,383	
Eastside Trans Line Ratings Wave Traps	355	SG	Dec-11	2,537,767	25.78%	654,164	
Wyodak U1 - Generator Step-Up Transformer Spare	355	SG	Nov-12	2,512,050	25.78%	647,535	
R1--Replace - Substation - Switchgear, Breakers, Reclrs	355	SG	Various	2,506,155	25.78%	646,016	
Malin Sub Replace Station Service	355	SG	Nov-11	2,505,234	25.78%	645,778	
Three Peaks Sub: Install 345 kV Sub	355	SG	Dec-11	2,056,215	25.78%	530,034	
RI--Replace - Storm and Casualty	355	SG	Various	2,001,683	25.78%	515,977	
Mona - Limber - Oquirrh 500/345 kV line Phase 1	355	SG	Sep-11	1,964,239	25.78%	506,325	
RF--Replace - Overhead Transmission Lines - Other	355	SG	Various	1,834,486	25.78%	472,878	
RF--Replace - Overhead Transmission Lines - Other	355	SG	Various	1,814,947	25.78%	467,842	
Line 96 Dixonville 500kv to Dixonville Substation-Reconductor 230 kV line	355	SG	Dec-12	1,740,866	25.78%	448,746	
MR--Mandated - Regional or National Regulatory	355	SG	Various	1,732,991	25.78%	446,716	
DJ - Windstar Reconductor 1.5 miles	355	SG	Dec-12	1,700,000	25.78%	438,212	
Purchase spare 230-69 kV transformer	355	SG	May-12	1,609,128	25.78%	414,787	
Cove -Cove Tap 69kV 1.9 Miles Trans Line	355	SG	Mar-12	1,553,444	25.78%	400,434	
Energy Transmission - general interconnections	355	SG	Dec.12	1,500,000	25.78%	386,657	
UDOT Mountain View Corridor Highway Relocation: I-80 to Camp Williams Phase 1	355	SG	Sep-11	1,468,150	25.78%	378,447	
Line 44 Tribal Easement Reroute	355	SG	Jun-12	1,389,132	25.78%	358,079	
U1-1 Main Transformer	355	SG	Dec-12	1,169,473	25.78%	301,457	
R2--Replace - Substation - Meters and Relays	355	SG	Various	1,151,330	25.78%	296,780	
R1--Replace - Substation - Switchgear, Breakers, Reclrs	355	SG	Various	1,144,428	25.78%	295,001	
MR--Mandated - Regional or National Regulatory	355	SG	Various	1,121,596	25.78%	289,116	
M9--Mandated - Public Accommodations & Other	355	SG	Various	1,058,675	25.78%	272,896	
Populus - Borah #1&2 - Transmission Dynamic Rating System	355	SG	Dec-12	1,000,000	25.78%	257,772	
Projects Less Than $1million	355	SG	Various	33,496,129	25.78%	8,634,349	
				304,403,191		78,466,482	**8.6.4**

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Klamath Falls CA - Avian Protection 2011	364	CA	Dec-11	3,615,600	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	CA	Various	1,956,935	0.00%	-	
RI--Replace - Storm and Casualty	364	CA	Various	1,071,675	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	CA	Various	1,034,323	0.00%	-	
Idaho AMR Project	364	ID	Various	5,900,000	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	ID	Various	2,319,338	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	ID	Various	2,099,098	0.00%	-	
M3--Mandated - Environmental	364	ID	Various	2,009,273	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	ID	Various	1,849,191	0.00%	-	
RI--Replace - Storm and Casualty	364	ID	Various	1,487,995	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	OR	Various	10,934,425	100.00%	10,934,425	
N2--N2--New Revenue/Connection - Commercial	364	OR	Various	7,684,914	100.00%	7,684,914	
RC--Replace - Overhead Distribution Lines - Poles	364	OR	Various	6,417,682	100.00%	6,417,682	
RI--Replace - Storm and Casualty	364	OR	Various	6,306,400	100.00%	6,306,400	
RD--Replace - Overhead Distribution Lines - Other	364	OR	Various	4,267,816	100.00%	4,267,816	
RA--Replace - Underground Cable	364	OR	Various	3,645,234	100.00%	3,645,234	
UB--Functional Upgrade - Economically Justified	364	OR	Various	3,510,450	100.00%	3,510,450	
M1--Mandated - Highway Relocations	364	OR	Various	3,474,388	100.00%	3,474,388	
M3--Mandated - Environmental	364	OR	Various	3,150,544	100.00%	3,150,544	
Bend Plant Sub Increase Capacity	364	OR	Jul-11	3,147,464	100.00%	3,147,464	
Deschutes Sub Inc Cap Repl Transformer	364	OR	Apr-12	2,503,043	100.00%	2,503,043	
N7--New Revenue/System Reinforcement - Feeder	364	OR	Various	2,227,069	100.00%	2,227,069	
Humbug Crk Sub Const New 69-12.kv Sub	364	OR	Aug-11	2,013,204	100.00%	2,013,204	
Alderwood Sub Install 2nd Transformer	364	OR	Aug-11	1,963,600	100.00%	1,963,600	
R1--Replace - Substation - Switchgear, Breakers, Reclrs	364	OR	Various	1,884,815	100.00%	1,884,815	
RJ--Replace - Customer Meters	364	OR	Various	1,719,498	100.00%	1,719,498	
M9--Mandated - Public Accommodations & Other	364	OR	Various	1,468,589	100.00%	1,468,589	
RB--Replace - Underground - Vaults & Equipment	364	OR	Various	1,325,094	100.00%	1,325,094	
MR--Mandated - Regional or National Regulatory	364	OR	Various	1,090,212	100.00%	1,090,212	
M4--Mandated - Neutral Extensions	364	OR	Various	1,071,641	100.00%	1,071,641	
N2--N2--New Revenue/Connection - Commercial	364	UT	Various	25,276,110	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	UT	Various	21,066,984	0.00%	-	
City Creek Center: New 40 MW Development for PRI Phase II	364	UT	May-12	16,556,688	0.00%	-	
Nibley: New 138-12.5 kV Substation and Rebuild 7 Miles Transmission	364	UT	Jun-12	10,114,559	0.00%	-	
RI--Replace - Storm and Casualty	364	UT	Various	7,789,471	0.00%	-	
Skypark Build New 138-12 5kV Substation	364	UT	May-12	7,604,324	0.00%	-	
Farmington: Install 2nd Transformer	364	UT	May-12	5,846,710	0.00%	-	
M1--Mandated - Highway Relocations	364	UT	Various	5,567,999	0.00%	-	
Copper Hills New 138-12 5kV Sub	364	UT	Dec-11	5,424,390	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	UT	Various	5,181,946	0.00%	-	
U4--Functional Upgrade - Spare Equipment Addition	364	UT	Various	3,946,557	0.00%	-	
ATK Freeport Expansion	364	UT	Dec-11	3,416,115	0.00%	-	
Utah AMR Project - 2011 (Balance)	364	UT	Various	3,012,159	0.00%	-	
RB--Replace - Underground - Vaults & Equipment	364	UT	Various	2,817,388	0.00%	-	
N7--New Revenue/System Reinforcement - Feeder	364	UT	Various	2,683,153	0.00%	-	
U1--Functional Upgrade - Feeder Improvements	364	UT	Various	2,523,529	0.00%	-	
RD--Replace - Overhead Distribution Lines - Other	364	UT	Various	2,227,027	0.00%	-	
138-26.4 x 13.2 Mobile Transformer	364	UT	Mar-12	2,000,000	0.00%	-	
N3--N3--New Revenue/Connection - Industrial	364	UT	Various	1,972,707	0.00%	-	
RA--Replace - Underground Cable	364	UT	Various	1,949,314	0.00%	-	
RJ--Replace - Customer Meters	364	UT	Various	1,848,798	0.00%	-	
M9--Mandated - Public Accommodations & Other	364	UT	Various	1,550,090	0.00%	-	
M3--Mandated - Environmental	364	UT	Various	1,533,599	0.00%	-	
Smithfield Substation Add New Feeder 13	364	UT	Dec-11	1,383,484	0.00%	-	
Utah SPCC Plans CY2011	364	UT	Various	1,256,400	0.00%	-	
N4--N4--New Revenue/Connection - Irrigation	364	UT	Various	1,077,060	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	WA	Various	3,380,498	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	WA	Various	2,454,433	0.00%	-	
M1--Mandated - Highway Relocations	364	WA	Various	1,949,799	0.00%	-	
M3--Mandated - Environmental	364	WA	Various	1,637,357	0.00%	-	
RA--Replace - Underground Cable	364	WA	Various	1,257,991	0.00%	-	
Wyoming Distribution Reliability Improvements	364	WYP	Various	6,350,206	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	WYP	Various	5,995,683	0.00%	-	
M3--Mandated - Environmental	364	WYP	Various	4,797,434	0.00%	-	
Wyoming AMR Project - 2011	364	WYP	Jul-11	4,023,221	0.00%	-	
Community Park Conv to 115-12 5kV	364	WYP	Oct-11	3,946,054	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	WYP	Various	3,729,788	0.00%	-	
RI--Replace - Storm and Casualty	364	WYP	Various	2,089,010	0.00%	-	
RD--Replace - Overhead Distribution Lines - Other	364	WYP	Various	1,324,933	0.00%	-	
Center Street Substation: Convert to 12.5 kV	364	WYP	Dec-12	1,200,000	0.00%	-	
N3--N3--New Revenue/Connection - Industrial	364	WYP	Various	1,192,204	0.00%	-	
Projects Less Than $1million	364	CA	Various	7,341,280	0.00%	-	
Projects Less Than $1million	364	ID	Various	4,011,459	0.00%	-	
Projects Less Than $1million	364	OR	Various	8,082,007	100.00%	8,082,007	
Projects Less Than $1million	364	UT	Various	7,387,620	0.00%	-	
Projects Less Than $1million	364	WA	Various	5,765,847	0.00%	-	

PacifiCorp
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Pro Forma Plant Additions Adjustment
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Projects Less Than $1million	364	WYP	Various	8,484,176	0.00%	-	
				325,177,071		77,888,090	**8.6.4**

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
General Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
MRR Oregon Mobile Radio Repl Project	397	OR	Various	16,736,429	100.00%	16,736,429	
TOM	397	SO	Various	16,475,937	27.16%	4,475,686	
Utah Mobile Radio Replacement Project	397	UT	Various	13,073,412	0.00%	-	
RV--Replace - Vehicles	397	UT	Various	11,768,715	0.00%	-	
MRRP PacifiCorp Energy	397	SG	Various	11,271,713	25.78%	2,905,527	
RV--Replace - Vehicles	397	OR	Various	7,979,677	100.00%	7,979,677	
Wyoming Mobile Radio Replacement Project	397	WYP	Various	5,747,128	0.00%	-	
RV--Replace - Vehicles	397	WYP	Various	4,720,173	0.00%	-	
RV--Replace - Vehicles	397	ID	Various	3,166,638	0.00%	-	
RT--Replace - Tools	397	UT	Various	3,084,799	0.00%	-	
RQ--Replace - Other General Plant	397	UT	Various	3,075,879	0.00%	-	
Casper Service Center Lease Buy-out	397	SO	Dec-11	2,950,000	27.16%	801,367	
Scipio Pass - Mineral Mountain Microwave	397	SG	Dec-11	2,672,852	25.78%	688,985	
MRR Washington Mobile Radio Repl Project	397	WA	Various	2,650,655	0.00%	-	
MRR California Mobile Radio Repl Project	397	CA	Various	2,590,867	0.00%	-	
Mobile Radio Purch-Implemnt VHF Spectrum	397	OR	Jun-12	2,265,005	100.00%	2,265,005	
RV--Replace - Vehicles	397	WA	Various	2,206,849	0.00%	-	
Idaho Mobile Radio Replacement Project	397	ID	Various	2,187,486	0.00%	-	
RT--Replace - Tools	397	OR	Various	2,112,323	100.00%	2,112,323	
IT Capacity	397	SO	Various	2,073,593	27.16%	563,291	
R8--Replace - Microwave/Fiber Communications	397	OR	Various	1,563,815	100.00%	1,563,815	
Naughton U0 D10 Replacement	397	SG	Dec-11	1,330,697	25.78%	343,016	
Hunter 300 Coal Dozer Replacement	397	SG	Oct-12	1,270,204	25.78%	327,422	
JB Replace Coal Handling Dozer - Accel 12	397	SG	Dec-12	1,196,521	25.78%	308,429	
RV--Replace - Vehicles	397	CA	Various	1,099,076	0.00%	-	
R9--Replace - Other Communications	397	UT	Various	1,086,930	0.00%	-	
Projects Less Than $1million	397	CA	Various	1,107,457	0.00%	-	
Projects Less Than $1million	397	ID	Various	1,190,689	0.00%	-	
Projects Less Than $1million	397	UT	Various	1,513,255	0.00%	-	
Projects Less Than $1million	397	OR	Various	2,159,702	100.00%	2,159,702	
Projects Less Than $1million	397	WA	Various	1,606,228	0.00%	-	
Projects Less Than $1million	397	WYP	Various	3,362,763	0.00%	-	
Projects Less Than $1million	397	SG	Various	5,838,372	25.78%	1,504,966	
				143,135,840		44,735,641	8.6.4

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
Intangible Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Upgrades and Enhancements	303	SO	Various	12,659,001	27.16%	3,438,816	
Generation Compliance Initiative Hardwar	302	SG	Dec-12	4,213,518	25.78%	1,086,125	
Corp Optimization	303	SO	Various	3,170,401	27.16%	861,239	
IT-Mobility Upgrade / Click Replacement	303	SO	Jun-12	1,870,940	27.16%	508,241	
Projects Less Than $1million	302	SG	Various	5,373,390	25.78%	1,385,107	
Projects Less Than $1million	303	SO	Various	1,962,694	27.16%	533,166	
				29,249,944		7,812,693	**8.6.4**

PacifiCorp
Oregon General Rate Case - December 2013
Pro Forma Plant Additions Adjustment
Mining Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2012 Year End Balance	Factor %	OR Allocated CY 2012 Year End Balance	Ref.
Energy West Deer Creek Mine CAP Forecast	399	SE	Various	7,566,655	24.31%	1,839,720	
Cottonwood Prep Plant-System Improvement	399	SE	Dec-12	4,037,635	24.31%	981,691	
Section Extension-2011	399	SE	Mar-11	1,684,887	24.31%	409,655	
Deer Creek-(1) Used Continuous Miner	399	SE	Oct-11	1,575,909	24.31%	383,159	
Deer Creek-Reconstruct Longwall System	399	SE	Jan-12	1,303,958	24.31%	317,038	
Projects Less Than $1million	399	SE	Various	6,726,235	24.31%	1,635,384	
				22,895,278		5,566,648	**8.6.4**

STEAM PLANT ADDITIONS:

Naughton U2 Flue Gas Desulfurization System: **(Reference page 8.6.5)**
This environmental improvement project is the construction of a flue gas desulfurization (FGD) system for Naughton Unit 2. The FGD system involves constructing the following components:

- Interconnection at the electrostatic precipitator
- A flue gas transport system, including ductwork and booster fan
- SO2 absorber systems
- Reagent storage and preparation systems
- Makeup water treatment systems
- Electrical systems, including replacement of the auxiliary and start-up transformers
- Control systems, including upgrade of the existing, interfacing local control networks
- FGD waste disposal systems
- Makeup water supply system modifications
- Boiler reinforcement
- New stack and fiberglass flue (shared with Unit 1)

Naughton U1 Flue Gas Desulfurization System: **(Reference page 8.6.5)**
This environmental improvement project is the construction of a flue gas desulfurization (FGD) system for Naughton Unit 1. The FGD system involves constructing the following components:

- Interconnection at the electrostatic precipitator
- A flue gas transport system, including ductwork and booster fan
- SO2 absorber systems
- Reagent storage and preparation systems
- Makeup water treatment systems
- Electrical systems, including replacement of the auxiliary and start-up transformers
- Control systems, including upgrade of the existing, interfacing local control networks
- FGD waste disposal systems
- Makeup water supply system modifications
- Boiler reinforcement
- New stack and fiberglass flue (shared with Unit 2)

Dave Johnston U4 SO2/PM Emission Controls: **(Reference page 8.6.5)**
This environmental improvement project is to install a dry flue gas desulfurization system with fabric filter on the Dave Johnston Unit 4. This project is in response to the State of Wyoming's review of the Best Available Retrofit Technology (BART). This review requires installation of appropriate emission controls.

Hunter U1 SO2 Upgrades: **(Reference page 8.6.5)**
This project is to convert the existing flue gas desulfurization system to handle higher sulfur coal by adding forced oxidation, reagent preparation and waste disposal equipment.

Hunter U3 Turbine Upgrade HP/IP/LP: **(Reference page 8.6.5)**
This project is to upgrade the high pressure, intermediate pressure and low pressure turbines to increase the turbine/generator output. Increased output with no increase in fuel input or operating cost will improve heat balance and decrease unit cost for electricity produced. Recent advances in steam turbine design technologies have increased the efficiency of new steam turbines. These new design technologies are transferable to steam turbine retrofits. The steam turbine retrofit designs improve turbine efficiency which increases generator output with no increase in boiler heat input or emissions.

Hunter U2 SO2 Project: **(Reference page 8.6.5)**
This environmental improvement project includes the upgrade of the sulfur dioxide (SO_2) removal system, the scrubber waste handling system and the reagent preparation system. A conversion of the electrostatic precipitator into a pulse jet fabric filter or baghouse for the control of particulate matter is in construction under a separate project. PacifiCorp has committed to certain environmental improvement projects to permit Hunter Unit 2 for future operation.

Hayden Coal Unloading Facility: **(Reference page 8.6.5)**
The project scope includes the permitting, design, and construction of a rail spur and a coal unloading facility at the Hayden Station. The project is designed and constructed in accordance with the Routt County Special use Permit and its conditions and mitigation agreements, Union Pacific Railroad Standards and Requirements, and Colorado Department of Transportation Standards, Requirements and agreements.

Naughton U1 Low NOx Burner: **(Reference page 8.6.5)**
This environmental improvement project is for the installation of low nitrogen oxides burners (LNB) and separated over-fired air (SOFA) in the Naughton Unit 1 boiler. This in-furnace combustion modification is designed to reduce NOx emissions produced in the boiler during the coal combustion process. The project consists of design, fabrication and installation of one level of SOFA, modifications of wind box components related to combustion and installation of LNB.

Dave Johnston U4 Finishing Superheater Replacement: **(Reference page 8.6.5)**
This project involves complete replacement of the Dave Johnston Unit 4 finishing superheater assemblies and outlet header. The replacement is based on end of life issues resulting from long term overheat and gas pass pluggage issues due to a fuel change to PRB coal. Oxide scale thickness readings during the two previous overhauls indicate that tube failure rates will increase significantly over the next several years. The finishing superheater redesign will incorporate industry best practices when designing the assembly spacing. The current spacing is 6" which is conducive to pluggage with PRB coal ash; spacing will be increased to approximately 9". Because of the spacing change and the potential for surface area loss, this project must be completed in conjunction with the U4 – Platen Superheater Replacement project in order that the platen superheater can be used to gain back the lost surface area in the finishing superheater.

Huntington U2 Generator Stator Rewind: **(Reference page 8.6.5)**
This project is to rewind the Huntington Unit 2 generator stator windings. These windings are

nearing the end of their life. The stator winding insulation did not pass a recent full voltage DC (direct current) leakage test. The windings have been in-service for approximately 35 years. This project will insure the continued reliability of this generating unit and prevent a forced outage.

Naughton U2 Low NOx Burner: **(Reference page 8.6.5)**
This environmental improvement project is for the installation of low nitrogen oxides burners (LNB) and separated over-fired air (SOFA) in the Naughton Unit 2 boiler. This in-furnace combustion modification is designed to reduce NOx emissions produced in the boiler during the coal combustion process. The project consists of design, fabrication and installation of one level of SOFA, modifications of wind box components related to combustion and installation of LNB.

Dave Johnston U4 Platen SSH Replace: **(Reference page 8.6.5)**
This project involves complete replacement of the Dave Johnston Unit 4 platen superheater assemblies. The replacement is based on end of life issues resulting from long term overheat. Oxide scale thickness readings during the two previous overhauls indicate that tube failure rates will increase significantly over the next several years. Due to a potential surface area change in the finishing superheater a surface area design change may be necessary in the platen superheater area. The platen superheater re-design/replacement must be competed in conjunction with the finishing superheater re-design/replacement in order to maintain fire-side/steam-side compatibility.

Hunter Adobe Wash Regulating Facility: **(Reference page 8.6.5)**
This project provides funding to the Cottonwood Creek Consolidated Irrigation Company for construction of Adobe Wash Regulating Reservoir. This project provides for a firm, long-term and cost effective water supply for the Hunter Plant.

Huntington U2 Boiler Finishing Superheat Pendants Repl: **(Reference page 8.6.5)**
This project is to replace the Huntington Unit 2 boiler finishing superheat pendant assemblies and associated outlet header. These assemblies were supplied as original equipment when the boiler was erected and have been in service since unit startup in 1974. Original design criteria suggest that these assemblies should have a 25 to 30 year life span. In recent years boiler tube failures, particularly those caused by long term overheat and creep, have increased lending credence to the end of life scenario. The outlet header, as with the pendants, has a predicted finite life span. End of life predictions and industry history suggests that this header will not maintain a serviceable life thru the remainder of the projected unit life.

Dave Johnston Replace Retro Cooling Tower: **(Reference page 8.6.5)**
This project is to remove and replace the retro cooling tower at the Dave Johnston plant. The existing structure was built in the early 1970's, with the most recent internal structural repairs being made in 2004, when the fill was replaced by the original equipment manufacturer (OEM). The OEM made the recommendation that the tower be replaced in the near future. The replacement tower will be constructed from fiberglass reinforced plastic which will be resilient to the expansion and contraction encountered annually.

HYDRO PLANT ADDITIONS:

INU 4.1.1/4.1.2 Soda Springs Fish Passage: **(Reference page 8.6.7)**
This project consists of the design and construction of a fish ladder, spillway improvement and fish screen and evaluation facility in order to meet resource agency design criteria to provide upstream and downstream fish passage for anadromous fish at Soda Springs dam. The project fulfills Section 47 of the FERC license that incorporates the North Umpqua Settlement Agreement Sections 4.1.1a-e and 4.1.2.

ILR 4.4 Swift Fish Collector: **(Reference page 8.6.7)**
This project fulfills the conditions specified in Section 4.4 of the Lewis River Settlement Agreement. The agreement stipulates that PacifiCorp must construct and start up a downstream fish collection and transport facility at the Swift Dam to provide: collection, handling, sorting and transportation of juvenile salmonids, adult steelhead and bull trout fish within four and one-half years after the issuance of a new Federal Energy Regulatory Commission license.

Ashton Dam Seepage Control: **(Reference page 8.6.7)**
This project is to reconstruct much of the Ashton dam for the purpose of remediating internal seepage and erosion conditions that threaten the stability and safe operation of the dam. The dam has experienced sinkhole activity at various locations throughout its history which is a result of seepage induced internal erosion of dam materials. The FERC required PacifiCorp Energy to convene and fund a Board of Consultants to review the construction and performance history of the dam and to engage in the identification and development of a satisfactory engineering design for remediation.

ILR 10.2 Swift Land Fund: **(Reference page 8.6.7)**
This project is to acquire interests in land for the protection and management of wildlife habitat. Land purchase actions to be directed per the Lewis River Terrestrial Coordination Committee. This project will comply with the requirements of the Lewis River Settlement Agreement and Section 4(e) of the Federal Power Act as required in the Federal Energy Regulatory Commission license.

IRO Prospect Instream Flow / Automation: **(Reference page 8.6.7)**
This project insures compliance regulatory obligations under Section 401 of the federal Clean Water Act and the new Federal Energy Regulatory Commission license by constructing facilities to reliably release, monitor, and record instream flows below the dams and powerhouses of the Prospect Nos. 1, 2, and 4 hydroelectric projects. The project includes the design, permitting, and construction of automated instream flow release facilities, plant control systems, and associated communications equipment at the Prospect hydroelectric projects.

Slide Creek Overhaul: **(Reference page 8.6.7)**
This project replaces the major operating components at the Slide Creek hydro facility including; turbine runner, generator and station service breakers, exciter, protective relays, governor, control system, station service transformer, generator step-up transformer (GSU), battery bank,

penstock gate actuator, stop log slots, stop logs, hoist and draft tube refurbishment (new concrete).

INU 4.1.1 (f)/6.9 Slide Tailrace Barrier: **(Reference page 8.6.7)**
The design, collaboration, permitting, construction and evaluation of an exclusion barrier across the Slide Creek plant tailrace at the North Umpqua Hydroelectric Project to reduce false attraction, delay and potential injury of anadromous fish. This project includes the design, collaboration, permitting and construction of a plant enhancement for bypassing canal flows during plant unit trips. The Federal Energy Regulatory Commission license identifies these projects as conditions in paragraphs D, E, G, H and I of the commission's orders.

INU 6.1 Lemolo 2 Reroute to Toketee: **(Reference page 8.6.7)**
This project is for the design and construction of a diversion structure, pipeline intake, pipeline, and outfall structure at the Lemolo No. 2 development. The purpose of this project is to eliminate ramping in the full-flow reach of the North Umpqua River between the Lemolo 2 powerhouse and Toketee Lake. The project fulfills Paragraph 47 of the Federal Energy Regulatory Commission license that incorporates the North Umpqua Settlement Agreement Sections 5.4 and 6.1.

OTHER PLANT ADDITIONS:

Currant Creek U2 CSA Variable Fee 24k – CTB MI: **(Reference page 8.6.8)**
This project is to remove and replace the gas turbine combustion, hot gas path section and inspect the compressor section parts in accordance with the long term maintenance plan. The program parts include: baskets, nozzle assemblies, combustor transition parts, support housing components, blades, vanes and ring segments.

Currant Creek U1 CSA Variable Fee 24k – CTA MI: **(Reference page 8.6.8)**
This project is to remove and replace the gas turbine combustion, hot gas path section and inspect the compressor section parts in accordance with the long term maintenance plan. The program parts include: baskets, nozzle assemblies, combustor transition parts, support housing components, blades, vanes and ring segments.

TRANSMISSION PLANT ADDITIONS:

Clover Substation: **(Reference page 8.6.9)**
This projects builds a new 345/138 kV substation approximately three miles south of Mona, Utah. The substation will be constructed in a breaker and a half configuration on the 345 kV bus in a ring configuration on the 138 kV bus. Clover Substation will intercept a number of existing PacifiCorp owned transmission lines; the existing Sigurd - Mona No.1 345 kV line and the Sigurd – Mona No.2 345 kV line will both be looped into the Clover Substation. There will be a short transmission segment connecting the Clover Substation with the Mona-Limber-Oquirrh 500/345 kV transmission line.

Terminal Substation - Replace 345/138 kV Transformers and Breakers: **(Reference page 8.6.9)**
This project replaces the two existing 345-138 kV transformers at Terminal Substation (#9 and #10) and four 138 kV breakers. Specific details of this project include the following:

- Replacement of Terminal transformer #9 (421 MVA) with a 700 MVA transformer
- Replacement of Terminal transformer #10 (448 MVA) with a 700 MVA transformer
- Replacement of breaker L180 with a breaker with continuous rating of 3000A (40 kA fault rating)
- Replacement of 138 kV breakers CB101, CB115, and CB116 with breakers with a fault rating of 63 kA

Southwest Wyoming-Silver Creek 138 kV Line Phase I: **(Reference page 8.6.9)**
This project will rebuild approximately 70 miles of 46 kilovolt transmission line to 138 kilovolts, build the new Croydon substation (near Henefer, Utah), convert the Coalville substation to 138 kilovolts, and convert the remaining single phase 46 kilovolt substations along the route to 12.47 kilovolt (distribution). Phase I includes rebuilding the transmission line from the Evanston, WY area down to the Devils Slide, UT area.

Dave Johnston - Casper 230 kV Rebuild: **(Reference page 8.6.9)**
North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) requirements for path operation are the drivers for rebuilding the Dave Johnston – Casper 230 kilovolt #1 line, and the re-conductor of the Dave Johnston – Casper 230 kilovolt #2 line. The scope of this project will also include installing new breakers at Dave Johnston and Casper Substations along with related equipment for termination of #1 and #2 lines.

Nibley: New 138-12.5 kV Substation and Rebuild 7 Miles Transmission: **(Reference page 8.6.9)**
This project will build a new 138-12.5 kV, 40 MVA substation with three 12.5 kV feeders, rebuild a seven mile section of 46 kV line to 138 kV and add two 138 kV circuit breakers at the Green Canyon substation.

Ben Lomond 345/138 #2 transformer 450 MVA: **(Reference page 8.6.9)**
This project will add a second 345-138 kV 400 MVA transformer at the Ben Lomond substation using a transformer from Terminal substation. The Ogden area is fed by the Ben Lomond and Syracuse substations which feed the 138 and 46 kV sub-transmission systems. The Ben Lomond substation has two 230-138 kV, 299 MVA transformers and one 345-138 kV, 448 MVA transformer. The Syracuse substation has one 345-138 kV, 394 MVA transformer. There are no mobile transformers that can be used to back up these large transformers.

COPCO II 230-115 kV Transformer TPL002: **(Reference page 8.6.9)**
The Copco 2 substation, located in California, presently has two paralleled 230/115-kV transmission transformers, T-3604 rated at 125-MVA, and T-373187, rated at 250-MVA. This project is to replace the 125-MVA rated transformer, T-3604 in order to remain compliant with the NERC Reliability Standard TPL-002.

PacifiCorp
Oregon General Rate Case - December 2013
Plant Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant Retirements	312	3	(30,189,565)	SG	25.777%	(7,782,011)	8.7.4
Steam Plant Retirements	312	3	(21,459,710)	SG	25.777%	(5,531,703)	8.7.4
Steam Plant Retirements	312	3	(39,605,510)	SG	25.777%	(10,209,174)	8.7.4
Steam Plant Retirements	312	3	(32,415,442)	SG	25.777%	(8,355,779)	8.7.4
Hydro Plant Retirements	332	3	(6,502,632)	SG	25.777%	(1,676,194)	8.7.4
Hydro Plant Retirements	332	3	(1,957,851)	SG	25.777%	(504,678)	8.7.4
Hydro Plant Retirements	332	3	(7,527,790)	SG-P	25.777%	(1,940,450)	8.7.4
Hydro Plant Retirements	332	3	(2,411,877)	SG-U	25.777%	(621,713)	8.7.4
Other Plant Retirements	343	3	(1,240,056)	SG	25.777%	(319,651)	8.7.4
Other Plant Retirements	343	3	(43,169,936)	SG	25.777%	(11,127,981)	8.7.4
Other Plant Retirements	343	3	(1,488,577)	SG	25.777%	(383,713)	8.7.4
Other Plant Retirements	343	3	(1,254,239)	SG	25.777%	(323,307)	8.7.4
Transmission Plant Retirements	355	3	(7,429,758)	SG	25.777%	(1,915,180)	8.7.4
Transmission Plant Retirements	355	3	(5,354,181)	SG	25.777%	(1,380,155)	8.7.4
Transmission Plant Retirements	355	3	(35,104,456)	SG	25.777%	(9,048,930)	8.7.4
Distribution Plant Retirements	360	3	(809,311)	OR	Situs	(151,186)	8.7.4
Distribution Plant Retirements	361	3	(1,203,555)	OR	Situs	(224,833)	8.7.4
Distribution Plant Retirements	362	3	(12,489,228)	OR	Situs	(2,333,083)	8.7.4
Distribution Plant Retirements	364	3	(14,478,595)	OR	Situs	(2,704,712)	8.7.4
Distribution Plant Retirements	365	3	(9,919,074)	OR	Situs	(1,852,959)	8.7.4
Distribution Plant Retirements	366	3	(4,621,888)	OR	Situs	(863,404)	8.7.4
Distribution Plant Retirements	367	3	(10,981,859)	OR	Situs	(2,051,495)	8.7.4
Distribution Plant Retirements	368	3	(16,814,263)	OR	Situs	(3,141,032)	8.7.4
Distribution Plant Retirements	369	3	(8,990,663)	OR	Situs	(1,679,524)	8.7.4
Distribution Plant Retirements	370	3	(2,716,554)	OR	Situs	(507,473)	8.7.4
Distribution Plant Retirements	371	3	(133,573)	OR	Situs	(24,953)	8.7.4
Distribution Plant Retirements	373	3	(922,368)	OR	Situs	(172,305)	8.7.4
General Plant Retirements	397	3	(1,080,105)	CA	0.000%	-	8.7.5
General Plant Retirements	397	3	(12,265,899)	OR	100.000%	(12,265,899)	8.7.5
General Plant Retirements	397	3	(2,428,353)	WA	0.000%	-	8.7.5
General Plant Retirements	397	3	(4,309,262)	WYP	0.000%	-	8.7.5
General Plant Retirements	397	3	(11,734,900)	UT	0.000%	-	8.7.5
General Plant Retirements	397	3	(2,683,696)	ID	0.000%	-	8.7.5
General Plant Retirements	397	3	(853,445)	WYU	0.000%	-	8.7.5
General Plant Retirements	397	3	(912,895)	SG	25.777%	(235,318)	8.7.5
General Plant Retirements	397	3	(2,037,936)	SG	25.777%	(525,322)	8.7.5
General Plant Retirements	397	3	(12,199,316)	SG	25.777%	(3,144,636)	8.7.5
General Plant Retirements	397	3	(33,431,694)	SO	27.165%	(9,081,715)	8.7.5
General Plant Retirements	397	3	(538,502)	SG	25.777%	(138,810)	8.7.5
General Plant Retirements	397	3	(11,652)	SG	25.777%	(3,003)	8.7.5
General Plant Retirements	397	3	(2,617,475)	CN	29.363%	(768,566)	8.7.5
General Plant Retirements	397	3	(95,574)	SE	24.314%	(23,237)	8.7.5
Mining Plant Retirements	399	3	(14,987,567)	SE	24.314%	(3,644,005)	8.7.5
			(423,380,783)			(106,658,091)	

Description of Adjustment:

Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through December 31, 2012. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

PacifiCorp PAGE 8.7.1
Oregon General Rate Case - December 2013
Plant Retirements (cont.)

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Plant Retirements	303	3	-	CA	0.000%	-	
Intangible Plant Retirements	303	3	(380,049)	CN	29.363%	(111,593)	
Intangible Plant Retirements	302	3	-	SG	25.777%	-	
Intangible Plant Retirements	303	3	(21,770)	SG	25.777%	(5,612)	
Intangible Plant Retirements	303	3	-	ID	0.000%	-	
Intangible Plant Retirements	303	3	(533,081)	OR	100.000%	(533,081)	
Intangible Plant Retirements	303	3	(116,224)	SE	24.314%	(28,258)	
Intangible Plant Retirements	302	3	(15,547,833)	SG	25.777%	(4,007,789)	
Intangible Plant Retirements	302	3	(4,093,412)	SG-P	25.777%	(1,055,165)	
Intangible Plant Retirements	302	3	(137,827)	SG-U	25.777%	(35,528)	
Intangible Plant Retirements	303	3	(14,074,819)	SO	27.165%	(3,823,423)	
Intangible Plant Retirements	303	3	-	SG	25.777%	-	
Intangible Plant Retirements	303	3	(937)	UT	0.000%	-	
Intangible Plant Retirements	303	3	(175,320)	WA	0.000%	-	
Intangible Plant Retirements	303	3	-	WYP	0.000%	-	
Intangible Plant Retirements	303	3	-	WYU	0.000%	-	
			(35,081,273)			(9,600,449)	8.7.5
	Total:		**(458,462,056)**			**(116,258,540)**	

Description of Adjustment:

Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through December 31, 2012. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

PacifiCorp
Oregon General Rate Case - December 2013
Cumulative Monthly Plant Retirements Summary

Description	Factor	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
Steam Production Plant:											
Pre-merger Pacific	SG	(1,687,650)	(3,375,299)	(5,062,949)	(6,750,598)	(8,438,248)	(10,125,898)	(11,797,870)	(13,469,842)	(15,141,814)	(16,813,787)
Pre-merger Utah	SG	(1,197,003)	(2,394,006)	(3,591,010)	(4,788,013)	(5,985,016)	(7,182,019)	(8,371,827)	(9,561,635)	(10,751,442)	(11,941,250)
Post-merger	SG	(2,065,916)	(4,131,832)	(6,197,748)	(8,263,664)	(10,329,580)	(12,395,497)	(14,521,371)	(16,647,246)	(18,773,120)	(20,898,994)
Renewable - Blundell	SG	(17,367)	(34,734)	(52,101)	(69,468)	(86,835)	(104,202)	(121,628)	(139,053)	(156,479)	(173,905)
Pollution Control Equipment	SG	-	-	-	-	-	-	(115,517)	(231,035)	(346,552)	(462,070)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(1,807,429)	(3,614,859)	(5,422,288)	(7,229,717)	(9,037,147)	(10,844,576)	(12,642,148)	(14,439,720)	(16,237,292)	(18,034,865)
Total Steam Plant		(6,775,365)	(13,550,731)	(20,326,096)	(27,101,461)	(33,876,826)	(40,652,192)	(47,570,361)	(54,488,531)	(61,406,701)	(68,324,870)
Hydro Production Plant:											
Pre-merger Pacific	SG	(163,300)	(326,599)	(489,899)	(653,199)	(4,426,178)	(4,589,478)	(4,748,907)	(4,908,337)	(5,067,766)	(5,227,196)
Pre-merger Utah	SG	(72,500)	(145,000)	(217,501)	(964,933)	(1,037,434)	(1,109,934)	(1,180,594)	(1,251,253)	(1,321,913)	(1,392,573)
Post-merger	SG-P	(213,578)	(427,156)	(640,735)	(854,313)	(4,393,481)	(4,607,059)	(4,850,453)	(5,093,848)	(5,337,242)	(5,580,636)
Post-merger	SG-U	(113,493)	(226,985)	(340,478)	(771,661)	(885,153)	(998,646)	(1,116,415)	(1,234,184)	(1,351,954)	(1,469,723)
Total Hydro Plant		(562,871)	(1,125,741)	(1,688,612)	(3,244,106)	(10,742,246)	(11,305,117)	(11,896,369)	(12,487,622)	(13,078,875)	(13,670,128)
Other Production Plant:											
Pre-merger Utah	SG	(1,809)	(3,618)	(5,427)	(7,236)	(9,045)	(10,854)	(12,647)	(14,439)	(16,232)	(18,025)
Post-merger	SG	(2,166,554)	(4,333,109)	(6,499,663)	(8,666,218)	(10,832,772)	(12,999,327)	(18,976,401)	(21,128,121)	(23,279,842)	(25,431,563)
Post-merger Wind	SG-W	(56,810)	(576,756)	(633,566)	(690,376)	(747,187)	(803,997)	(861,046)	(918,094)	(975,142)	(1,032,190)
Post-merger	SG	(68,760)	(137,521)	(206,281)	(275,042)	(343,802)	(412,563)	(482,702)	(552,842)	(622,982)	(693,122)
Total Other Plant		(2,293,934)	(5,051,004)	(7,344,938)	(9,638,872)	(11,932,806)	(14,226,741)	(20,332,795)	(22,613,497)	(24,894,198)	(27,174,899)
Transmission Plant:											
Pre-merger Pacific	SG	(402,614)	(805,228)	(1,207,842)	(1,610,456)	(2,218,287)	(2,620,901)	(3,021,639)	(3,422,377)	(3,823,115)	(4,223,853)
Pre-merger Utah	SG	(297,993)	(595,987)	(893,980)	(1,191,974)	(1,489,967)	(1,787,961)	(2,085,146)	(2,382,331)	(2,679,516)	(2,976,701)
Post-merger	SG	(1,926,805)	(3,853,609)	(5,780,414)	(7,707,218)	(9,686,230)	(11,613,034)	(13,570,653)	(15,528,271)	(17,485,890)	(19,443,508)
Total Transmission Plant		(2,627,412)	(5,254,824)	(7,882,236)	(10,509,648)	(13,394,484)	(16,021,896)	(18,677,438)	(21,332,979)	(23,988,521)	(26,644,062)
Distribution Plant:											
California	CA	(90,485)	(180,969)	(271,454)	(361,939)	(452,423)	(542,908)	(636,469)	(730,030)	(823,591)	(917,152)
Oregon	OR	(860,715)	(1,721,430)	(2,582,145)	(3,442,860)	(4,303,576)	(5,164,291)	(6,042,846)	(6,921,402)	(7,799,958)	(8,678,513)
Washington	WA	(393,200)	(786,400)	(1,179,600)	(1,572,800)	(1,966,000)	(2,359,200)	(2,756,609)	(3,154,019)	(3,551,429)	(3,948,839)
Eastern Wyoming	WYP	(393,638)	(787,275)	(1,180,913)	(1,574,551)	(1,968,189)	(2,361,826)	(2,773,634)	(3,185,441)	(3,597,249)	(4,009,057)
Utah	UT	(2,584,772)	(5,169,543)	(7,754,315)	(10,374,134)	(12,958,905)	(15,543,677)	(18,179,661)	(20,815,645)	(23,451,628)	(26,087,612)
Idaho	ID	(198,340)	(396,681)	(595,021)	(793,361)	(991,702)	(1,190,042)	(1,391,359)	(1,592,675)	(1,793,991)	(1,995,307)
Western Wyoming	WYU	(68,439)	(136,877)	(205,316)	(273,755)	(342,193)	(410,632)	(478,779)	(546,927)	(615,074)	(683,221)
Total Distribution Plant		(4,589,588)	(9,179,176)	(13,768,764)	(18,393,400)	(22,982,988)	(27,572,576)	(32,259,357)	(36,946,139)	(41,632,920)	(46,319,702)

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Description	Factor	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
General Plant:											
California	CA	(53,258)	(106,517)	(159,775)	(213,033)	(266,291)	(319,550)	(382,929)	(446,309)	(509,688)	(573,068)
Oregon	OR	(646,184)	(1,292,368)	(1,938,553)	(2,584,737)	(3,230,921)	(3,877,105)	(4,576,172)	(5,275,238)	(5,974,304)	(6,673,370)
Washington	WA	(127,518)	(255,037)	(382,555)	(510,073)	(637,592)	(765,110)	(903,714)	(1,042,317)	(1,180,921)	(1,319,524)
Eastern Wyoming	WYP	(224,616)	(449,231)	(673,847)	(898,462)	(1,123,078)	(1,347,693)	(1,594,491)	(1,841,288)	(2,088,085)	(2,334,883)
Utah	UT	(617,308)	(1,234,616)	(1,851,923)	(2,469,231)	(3,086,539)	(3,703,847)	(4,373,101)	(5,042,356)	(5,711,610)	(6,380,865)
Idaho	ID	(143,536)	(287,071)	(430,607)	(574,142)	(717,678)	(861,213)	(1,013,087)	(1,164,961)	(1,316,834)	(1,468,708)
Western Wyoming	WYU	(48,190)	(96,381)	(144,571)	(192,762)	(240,952)	(289,142)	(336,168)	(383,193)	(430,218)	(477,243)
Pre-merger Pacific	SG	(53,738)	(107,475)	(161,213)	(214,951)	(268,689)	(322,426)	(371,632)	(420,838)	(470,044)	(519,249)
Pre-merger Utah	SG	(119,261)	(238,523)	(357,784)	(477,045)	(596,307)	(715,568)	(823,630)	(931,692)	(1,039,754)	(1,147,815)
Post-merger	SG	(647,744)	(1,295,488)	(1,943,231)	(2,590,975)	(3,238,719)	(3,886,463)	(4,559,226)	(5,231,990)	(5,904,754)	(6,577,518)
General Office	SO	(1,861,201)	(3,722,403)	(5,583,604)	(7,444,805)	(9,306,007)	(11,167,208)	(13,022,582)	(14,877,956)	(16,733,329)	(18,588,703)
General Office	SG	(30,869)	(61,738)	(92,607)	(123,476)	(154,345)	(185,214)	(214,654)	(244,095)	(273,536)	(302,976)
General Office	SG	(656)	(1,311)	(1,967)	(2,623)	(3,279)	(3,934)	(4,578)	(5,221)	(5,864)	(6,507)
Customer Service	CN	(148,992)	(297,984)	(446,976)	(595,968)	(744,959)	(893,951)	(1,037,578)	(1,181,205)	(1,324,832)	(1,468,459)
Fuel Related	SE	(5,492)	(10,985)	(16,477)	(21,970)	(27,462)	(32,955)	(38,173)	(43,391)	(48,609)	(53,828)
Total General Plant		(4,728,563)	(9,457,127)	(14,185,690)	(18,914,254)	(23,642,817)	(28,371,380)	(33,251,715)	(38,132,049)	(43,012,383)	(47,892,717)
Mining Plant:											
Coal Mine	SE	(824,346)	(1,648,692)	(2,473,038)	(3,297,383)	(4,121,729)	(4,946,075)	(5,782,866)	(6,619,657)	(7,456,448)	(8,293,239)
Total Mining Plant		(824,346)	(1,648,692)	(2,473,038)	(3,297,383)	(4,121,729)	(4,946,075)	(5,782,866)	(6,619,657)	(7,456,448)	(8,293,239)
Intangible Plant:											
California	CA	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(21,129)	(42,257)	(63,386)	(84,514)	(105,643)	(126,771)	(147,878)	(168,984)	(190,091)	(211,197)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	(1,219)	(2,439)	(3,658)	(4,877)	(6,097)	(7,316)	(8,521)	(9,725)	(10,930)	(12,134)
Idaho	ID	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(31,797)	(63,595)	(95,392)	(127,189)	(158,987)	(190,784)	(219,309)	(247,833)	(276,358)	(304,883)
Fuel Related	SE	(6,503)	(13,006)	(19,510)	(26,013)	(32,516)	(39,019)	(45,453)	(51,887)	(58,320)	(64,754)
Post-merger	SG	(880,309)	(1,760,618)	(2,640,928)	(3,521,237)	(4,401,546)	(5,281,855)	(6,137,353)	(6,992,851)	(7,848,350)	(8,703,848)
Hydro Relicensing	SG-P	(229,530)	(459,059)	(688,589)	(918,118)	(1,147,648)	(1,377,177)	(1,603,530)	(1,829,883)	(2,056,236)	(2,282,589)
Hydro Relicensing	SG-U	(7,683)	(15,365)	(23,048)	(30,731)	(38,414)	(46,096)	(53,741)	(61,385)	(69,029)	(76,673)
General Office	SO	(777,929)	(1,555,858)	(2,333,788)	(3,111,717)	(3,889,646)	(4,667,575)	(5,451,512)	(6,235,449)	(7,019,386)	(7,803,323)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-	-
Utah	UT	(52)	(104)	(156)	(208)	(260)	(312)	(364)	(417)	(469)	(521)
Washington	WA	(10,434)	(20,869)	(31,303)	(41,737)	(52,172)	(62,606)	(71,999)	(81,392)	(90,784)	(100,177)
Eastern Wyoming	WYP	-	-	-	-	-	-	-	-	-	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(1,966,585)	(3,933,171)	(5,899,756)	(7,866,342)	(9,832,927)	(11,799,513)	(13,739,660)	(15,679,806)	(17,619,953)	(19,560,100)
Total		(24,368,665)	(49,200,465)	(73,569,130)	(98,965,466)	(130,526,824)	(154,895,489)	(183,510,561)	(208,300,280)	(233,089,999)	(257,879,717)

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Description	Factor	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	December 2012* Year End Balance
Steam Production Plant:										
Pre-merger Pacific	SG	(18,485,759)	(20,157,731)	(21,829,704)	(23,501,676)	(25,173,648)	(26,845,621)	(28,517,593)	(30,189,565)	(30,189,565)
Pre-merger Utah	SG	(13,131,057)	(14,320,865)	(15,510,673)	(16,700,480)	(17,890,288)	(19,080,095)	(20,269,903)	(21,459,710)	(21,459,710)
Post-merger	SG	(23,024,869)	(25,150,743)	(27,276,618)	(29,402,492)	(31,528,367)	(33,654,241)	(35,780,116)	(37,905,990)	(37,905,990)
Renewable - Blundell	SG	(191,331)	(208,756)	(226,182)	(243,608)	(261,033)	(278,459)	(295,885)	(313,310)	(313,310)
Pollution Control Equipment	SG	(577,587)	(693,105)	(808,622)	(924,139)	(1,039,657)	(1,155,174)	(1,270,692)	(1,386,209)	(1,386,209)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	(19,832,437)	(21,630,009)	(23,427,581)	(25,225,153)	(27,022,726)	(28,820,298)	(30,617,870)	(32,415,442)	(32,415,442)
Total Steam Plant		(75,243,040)	(82,161,210)	(89,079,379)	(95,997,549)	(102,915,718)	(109,833,888)	(116,752,058)	(123,670,227)	(123,670,227)
Hydro Production Plant:										
Pre-merger Pacific	SG	(5,386,625)	(5,546,055)	(5,705,485)	(5,864,914)	(6,024,344)	(6,183,773)	(6,343,203)	(6,502,632)	(6,502,632)
Pre-merger Utah	SG	(1,463,233)	(1,533,892)	(1,604,552)	(1,675,212)	(1,745,871)	(1,816,531)	(1,887,191)	(1,957,851)	(1,957,851)
Post-merger	SG-P	(5,824,031)	(6,067,425)	(6,310,819)	(6,554,213)	(6,797,608)	(7,041,002)	(7,284,396)	(7,527,790)	(7,527,790)
Post-merger	SG-U	(1,587,492)	(1,705,261)	(1,823,031)	(1,940,800)	(2,058,569)	(2,176,339)	(2,294,108)	(2,411,877)	(2,411,877)
Total Hydro Plant		(14,261,381)	(14,852,634)	(15,443,886)	(16,035,139)	(16,626,392)	(17,217,645)	(17,808,898)	(18,400,151)	(18,400,151)
Other Production Plant:										
Pre-merger Utah	SG	(19,817)	(21,610)	(23,403)	(25,195)	(1,234,678)	(1,236,470)	(1,238,263)	(1,240,056)	(1,240,056)
Post-merger	SG	(27,583,283)	(29,735,004)	(31,886,725)	(34,038,445)	(36,714,774)	(38,866,494)	(41,018,215)	(43,169,936)	(43,169,936)
Post-merger Wind	SG-W	(1,089,239)	(1,146,287)	(1,203,335)	(1,260,384)	(1,317,432)	(1,374,480)	(1,431,529)	(1,488,577)	(1,488,577)
Post-merger	SG	(763,261)	(833,401)	(903,541)	(973,680)	(1,043,820)	(1,113,960)	(1,184,100)	(1,254,239)	(1,254,239)
Total Other Plant		(29,455,601)	(31,736,302)	(34,017,004)	(36,297,705)	(40,310,703)	(42,591,405)	(44,872,106)	(47,152,808)	(47,152,808)
Transmission Plant:										
Pre-merger Pacific	SG	(4,624,591)	(5,025,330)	(5,426,068)	(5,826,806)	(6,227,544)	(6,628,282)	(7,029,020)	(7,429,758)	(7,429,758)
Pre-merger Utah	SG	(3,273,886)	(3,571,071)	(3,868,256)	(4,165,441)	(4,462,626)	(4,759,811)	(5,056,996)	(5,354,181)	(5,354,181)
Post-merger	SG	(21,401,127)	(23,358,745)	(25,316,364)	(27,273,982)	(29,231,601)	(31,189,219)	(33,146,838)	(35,104,456)	(35,104,456)
Total Transmission Plant		(29,299,604)	(31,955,146)	(34,610,687)	(37,266,229)	(39,921,770)	(42,577,312)	(45,232,854)	(47,888,395)	(47,888,395)
Distribution Plant:										
California	CA	(1,010,713)	(1,104,274)	(1,197,835)	(1,291,396)	(1,384,957)	(1,478,518)	(1,572,079)	(1,665,640)	(1,665,640)
Oregon	OR	(9,557,069)	(10,435,625)	(11,314,180)	(12,192,736)	(13,071,292)	(13,949,848)	(14,828,403)	(15,706,959)	(15,706,959)
Washington	WA	(4,346,249)	(4,743,658)	(5,141,068)	(5,538,478)	(5,935,888)	(6,333,298)	(6,730,707)	(7,128,117)	(7,128,117)
Eastern Wyoming	WYP	(4,420,864)	(4,832,672)	(5,244,480)	(5,656,287)	(6,068,095)	(6,479,902)	(6,891,710)	(7,303,518)	(7,303,518)
Utah	UT	(28,723,596)	(31,359,580)	(33,995,564)	(36,631,547)	(39,534,508)	(42,170,491)	(44,806,475)	(47,442,459)	(47,442,459)
Idaho	ID	(2,196,624)	(2,397,940)	(2,599,256)	(2,800,573)	(3,001,889)	(3,203,205)	(3,404,522)	(3,605,838)	(3,605,838)
Western Wyoming	WYU	(751,369)	(819,516)	(887,663)	(955,811)	(1,023,958)	(1,092,105)	(1,160,253)	(1,228,400)	(1,228,400)
Total Distribution Plant		(51,006,484)	(55,693,265)	(60,380,047)	(65,066,828)	(70,020,586)	(74,707,368)	(79,394,150)	(84,080,931)	(84,080,931)

*Retirements lag behind by a month

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Description	Factor	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	December 2012* Year End Balance
General Plant:										
California	CA	(636,448)	(699,827)	(763,207)	(826,587)	(889,966)	(953,346)	(1,016,725)	(1,080,105)	(1,080,105)
Oregon	OR	(7,372,436)	(8,071,502)	(8,770,568)	(9,469,635)	(10,168,701)	(10,867,767)	(11,566,833)	(12,265,899)	(12,265,899)
Washington	WA	(1,458,128)	(1,596,731)	(1,735,335)	(1,873,939)	(2,012,542)	(2,151,146)	(2,289,749)	(2,428,353)	(2,428,353)
Eastern Wyoming	WYP	(2,581,680)	(2,828,478)	(3,075,275)	(3,322,072)	(3,568,870)	(3,815,667)	(4,062,465)	(4,309,262)	(4,309,262)
Utah	UT	(7,050,119)	(7,719,373)	(8,388,628)	(9,057,882)	(9,727,137)	(10,396,391)	(11,065,646)	(11,734,900)	(11,734,900)
Idaho	ID	(1,620,581)	(1,772,455)	(1,924,328)	(2,076,202)	(2,228,075)	(2,379,949)	(2,531,822)	(2,683,696)	(2,683,696)
Western Wyoming	WYU	(524,269)	(571,294)	(618,319)	(665,344)	(712,370)	(759,395)	(806,420)	(853,445)	(853,445)
Pre-merger Pacific	SG	(568,455)	(617,661)	(666,867)	(716,072)	(765,278)	(814,484)	(863,690)	(912,895)	(912,895)
Pre-merger Utah	SG	(1,255,877)	(1,363,939)	(1,472,001)	(1,580,062)	(1,713,751)	(1,821,813)	(1,929,875)	(2,037,936)	(2,037,936)
Post-merger	SG	(7,250,282)	(7,923,045)	(8,595,809)	(9,268,573)	(10,181,024)	(10,853,788)	(11,526,552)	(12,199,316)	(12,199,316)
General Office	SO	(20,444,077)	(22,299,451)	(24,154,825)	(26,010,199)	(27,865,573)	(29,720,946)	(31,576,320)	(33,431,694)	(33,431,694)
General Office	SG	(332,417)	(361,858)	(391,298)	(420,739)	(450,180)	(479,620)	(509,061)	(538,502)	(538,502)
General Office	SG	(7,150)	(7,793)	(8,436)	(9,079)	(9,722)	(10,366)	(11,009)	(11,652)	(11,652)
Customer Service	CN	(1,612,086)	(1,755,713)	(1,899,340)	(2,042,967)	(2,186,594)	(2,330,221)	(2,473,848)	(2,617,475)	(2,617,475)
Fuel Related	SE	(59,046)	(64,264)	(69,483)	(74,701)	(79,919)	(85,137)	(90,356)	(95,574)	(95,574)
Total General Plant		(52,773,051)	(57,653,385)	(62,533,719)	(67,414,053)	(72,559,702)	(77,440,036)	(82,320,370)	(87,200,704)	(87,200,704)
Mining Plant:										
Coal Mine	SE	(9,130,030)	(9,966,821)	(10,803,612)	(11,640,403)	(12,477,194)	(13,313,985)	(14,150,776)	(14,987,567)	(14,987,567)
Total Mining Plant		(9,130,030)	(9,966,821)	(10,803,612)	(11,640,403)	(12,477,194)	(13,313,985)	(14,150,776)	(14,987,567)	(14,987,567)
Intangible Plant:										
California	CA	-	-	-	-	-	-	-	-	-
Customer Service	CN	(232,304)	(253,410)	(274,517)	(295,623)	(316,730)	(337,836)	(358,942)	(380,049)	(380,049)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	(13,339)	(14,543)	(15,748)	(16,952)	(18,157)	(19,361)	(20,566)	(21,770)	(21,770)
Idaho	ID	-	-	-	-	-	-	-	-	-
Oregon	OR	(333,408)	(361,932)	(390,457)	(418,982)	(447,507)	(476,031)	(504,556)	(533,081)	(533,081)
Fuel Related	SE	(71,188)	(77,622)	(84,055)	(90,489)	(96,923)	(103,357)	(109,791)	(116,224)	(116,224)
Post-merger	SG	(9,559,346)	(10,414,844)	(11,270,342)	(12,125,840)	(12,981,338)	(13,836,837)	(14,692,335)	(15,547,833)	(15,547,833)
Hydro Relicensing	SG-P	(2,508,942)	(2,735,295)	(2,961,648)	(3,188,001)	(3,414,353)	(3,640,706)	(3,867,059)	(4,093,412)	(4,093,412)
Hydro Relicensing	SG-U	(84,317)	(91,962)	(99,606)	(107,250)	(114,894)	(122,538)	(130,183)	(137,827)	(137,827)
General Office	SO	(8,587,260)	(9,371,197)	(10,155,134)	(10,939,071)	(11,723,008)	(12,506,945)	(13,290,882)	(14,074,819)	(14,074,819)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	(573)	(625)	(677)	(729)	(781)	(833)	(885)	(937)	(937)
Washington	WA	(109,570)	(118,963)	(128,356)	(137,749)	(147,141)	(156,534)	(165,927)	(175,320)	(175,320)
Eastern Wyoming	WYP	-	-	-	-	-	-	-	-	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(21,500,246)	(23,440,393)	(25,380,540)	(27,320,686)	(29,260,833)	(31,200,980)	(33,141,126)	(35,081,273)	(35,081,273)
Total		(282,669,436)	(307,459,155)	(332,248,874)	(357,038,593)	(384,092,899)	(408,882,618)	(433,672,337)	(458,462,056)	**(458,462,056)**

Ref 8.7.1

*Retirements lag behind by a month

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Annual Retirement Rate	Adjusted EPIS Balance Jun 2011	Retirements Jun 2011	Adjustments	Adjusted EPIS Balance Jul 2011	Retirements Jul 2011	Adjustments	Adjusted EPIS Balance Aug 2011	Retirements Aug 2011
Steam Production Plant:										
Pre-merger Pacific	SG	-1.858%	1,090,045,310	(1,687,650)	-	1,088,357,661	(1,687,650)	-	1,086,670,011	(1,687,650)
Pre-merger Utah	SG	-1.202%	1,194,738,007	(1,197,003)	-	1,193,541,004	(1,197,003)	-	1,192,344,001	(1,197,003)
Post-merger	SG	-0.793%	3,125,357,446	(2,065,916)	11,759,582	3,135,051,112	(2,065,916)	3,227,414	3,136,212,609	(2,065,916)
Renewable - Blundell	SG	-0.793%	26,273,155	(17,367)	-	26,255,788	(17,367)	-	26,238,421	(17,367)
Pollution Control Equipment	SG	-0.793%	-	-	1,947,489	1,947,489	-	13,526,940	15,474,429	-
Pollution Control Equipment	SG	-4.164%	-	-	-	-	-	-	-	-
Post-merger	SG	-4.164%	520,843,160	(1,807,429)	-	519,035,731	(1,807,429)	-	517,228,302	(1,807,429)
Total Steam Plant			5,957,257,079	(6,775,365)	13,707,071	5,964,188,785	(6,775,365)	16,754,354	5,974,167,773	(6,775,365)
Hydro Production Plant:										
Pre-merger Pacific	SG	-1.012%	193,652,145	(163,300)	-	193,488,846	(163,300)	-	193,325,546	(163,300)
Pre-merger Utah	SG	-1.990%	43,721,885	(72,500)	-	43,649,384	(72,500)	-	43,576,884	(72,500)
Post-merger	SG-P	-1.006%	254,882,001	(213,578)	365,231	255,033,653	(213,578)	229,528	255,049,604	(213,578)
Post-merger	SG-U	-1.403%	97,096,458	(113,493)	1,065,138	98,048,104	(113,493)	343,394	98,278,005	(113,493)
Total Hydro Plant			589,352,489	(562,871)	1,430,369	590,219,987	(562,871)	572,922	590,230,039	(562,871)
Other Production Plant:										
Pre-merger Utah	SG	-1.797%	1,207,690	(1,809)	-	1,205,881	(1,809)	-	1,204,072	(1,809)
Post-merger	SG	-2.113%	1,230,406,793	(2,166,554)	2,920,978	1,231,161,216	(2,166,554)	(111,843)	1,228,882,819	(2,166,554)
Post-merger Wind	SG-W	-0.053%	1,285,286,816	(56,810)	4,743	1,285,234,748	(519,945)	(5,474)	1,284,709,328	(56,810)
Post-merger	SG	-1.045%	78,966,675	(68,760)	-	78,897,914	(68,760)	-	78,829,154	(68,760)
Total Other Plant			2,595,867,973	(2,293,934)	2,925,721	2,596,499,760	(2,757,069)	(117,317)	2,593,625,373	(2,293,934)
Transmission Plant:										
Pre-merger Pacific	SG	-0.859%	562,508,283	(402,614)	-	562,105,669	(402,614)	-	561,703,055	(402,614)
Pre-merger Utah	SG	-0.543%	659,011,430	(297,993)	-	658,713,437	(297,993)	-	658,415,443	(297,993)
Post-merger	SG	-0.715%	3,233,142,263	(1,926,805)	9,693,532	3,240,908,990	(1,926,805)	14,526,081	3,253,508,267	(1,926,805)
Total Transmission Plant			4,454,661,976	(2,627,412)	9,693,532	4,461,728,096	(2,627,412)	14,526,081	4,473,626,765	(2,627,412)
Distribution Plant:										
California	CA	-0.494%	219,979,421	(90,485)	480,182	220,369,118	(90,485)	726,746	221,005,379	(90,485)
Oregon	OR	-0.599%	1,723,708,872	(860,715)	5,779,600	1,728,627,757	(860,715)	8,140,356	1,735,907,398	(860,715)
Washington	WA	-1.175%	401,662,069	(393,200)	1,187,192	402,456,061	(393,200)	705,117	402,767,978	(393,200)
Eastern Wyoming	WYP	-0.989%	477,607,666	(393,638)	4,370,967	481,584,995	(393,638)	4,126,938	485,318,295	(393,638)
Utah	UT	-1.312%	2,363,965,358	(2,584,772)	7,738,562	2,369,119,149	(2,584,772)	8,556,061	2,375,090,438	(2,584,772)
Idaho	ID	-0.853%	279,009,730	(198,340)	621,331	279,432,720	(198,340)	806,861	280,041,241	(198,340)
Western Wyoming	WYU	-0.851%	96,464,758	(68,439)	-	96,396,319	(68,439)	-	96,327,881	(68,439)
Total Distribution Plant			5,562,397,875	(4,589,588)	20,177,833	5,577,986,119	(4,589,588)	23,062,080	5,596,458,611	(4,589,588)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Annual Retirement Rate	Adjusted EPIS Balance Jun 2011	Retirements Jun 2011	Adjustments	Adjusted EPIS Balance Jul 2011	Retirements Jul 2011	Adjustments	Adjusted EPIS Balance Aug 2011	Retirements Aug 2011
General Plant:										
California	CA	-4.787%	13,350,121	(53,258)	14,029	13,310,892	(53,258)	32,154	13,289,788	(53,258)
Oregon	OR	-5.169%	150,027,310	(646,184)	377,378	149,758,505	(646,184)	269,555	149,381,875	(646,184)
Washington	WA	-3.624%	42,225,870	(127,518)	613,094	42,711,446	(127,518)	444,838	43,028,766	(127,518)
Eastern Wyoming	WYP	-4.646%	58,018,046	(224,616)	1,563,622	59,357,052	(224,616)	260,296	59,392,732	(224,616)
Utah	UT	-4.418%	167,668,277	(617,308)	6,284,424	173,335,393	(617,308)	582,348	173,300,433	(617,308)
Idaho	ID	-5.201%	33,117,528	(143,536)	1,543,496	34,517,488	(143,536)	71,644	34,445,597	(143,536)
Western Wyoming	WYU	-4.836%	11,958,614	(48,190)	-	11,910,423	(48,190)	-	11,862,233	(48,190)
Pre-merger Pacific	SG	-16.867%	3,823,163	(53,738)	-	3,769,426	(53,738)	-	3,715,688	(53,738)
Pre-merger Utah	SG	-18.782%	7,619,888	(119,261)	-	7,500,627	(119,261)	-	7,381,365	(119,261)
Post-merger	SG	-4.175%	186,178,898	(647,744)	2,761	185,533,915	(647,744)	1,862,547	186,748,719	(647,744)
General Office	SO	-9.120%	244,906,361	(1,861,201)	1,024,691	244,069,850	(1,861,201)	476,623	242,685,272	(1,861,201)
General Office	SG	-9.254%	4,002,876	(30,869)	-	3,972,007	(30,869)	-	3,941,138	(30,869)
General Office	SG	-3.854%	204,151	(656)	-	203,495	(656)	-	202,839	(656)
Customer Service	CN	-7.202%	24,826,321	(148,992)	-	24,677,329	(148,992)	-	24,528,337	(148,992)
Fuel Related	SE	-9.983%	660,194	(5,492)	-	654,702	(5,492)	-	649,209	(5,492)
Total General Plant			948,587,619	(4,728,563)	11,423,496	955,282,551	(4,728,563)	4,000,005	954,553,993	(4,728,563)
Mining Plant:										
Coal Mine	SE	-3.451%	286,661,904	(824,346)	1,023,602	286,861,160	(824,346)	1,877,433	287,914,247	(824,346)
Total Mining Plant			286,661,904	(824,346)	1,023,602	286,861,160	(824,346)	1,877,433	287,914,247	(824,346)
Intangible Plant:										
California	CA	0.000%	216,407	-	-	216,407	-	-	216,407	-
Customer Service	CN	-0.209%	121,077,156	(21,129)	-	121,056,027	(21,129)	-	121,034,899	(21,129)
Pre-merger Pacific	SG	-39.831%	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	-2.435%	600,993	(1,219)	-	599,774	(1,219)	-	598,554	(1,219)
Idaho	ID	0.000%	1,427,593	-	-	1,427,593	-	-	1,427,593	-
Oregon	OR	-20.584%	1,853,709	(31,797)	-	1,821,912	(31,797)	-	1,790,115	(31,797)
Fuel Related	SE	-2.135%	3,654,416	(6,503)	-	3,647,913	(6,503)	-	3,641,409	(6,503)
Post-merger	SG	-7.471%	141,397,273	(880,309)	(56,533)	140,460,431	(880,309)	53,313	139,633,434	(880,309)
Hydro Relicensing	SG-P	-2.768%	99,510,474	(229,530)	-	99,280,945	(229,530)	-	99,051,415	(229,530)
Hydro Relicensing	SG-U	-1.003%	9,189,363	(7,683)	-	9,181,680	(7,683)	-	9,173,997	(7,683)
General Office	SO	-2.483%	375,888,954	(777,929)	874,429	375,985,454	(777,929)	406,730	375,614,255	(777,929)
Cholla Intangible	SG	0.000%	-	-	-	-	-	-	-	-
Utah	UT	-0.021%	3,003,131	(52)	-	3,003,079	(52)	-	3,003,027	(52)
Washington	WA	-19.963%	627,214	(10,434)	-	616,779	(10,434)	-	606,345	(10,434)
Eastern Wyoming	WYP	0.000%	1,379,644	-	-	1,379,644	-	-	1,379,644	-
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-
Total Intangible Plant			759,826,327	(1,966,585)	817,896	758,677,637	(1,966,585)	460,043	757,171,094	(1,966,585)
Total			21,154,613,241	(24,368,665)	61,199,519	21,191,444,095	(24,831,800)	61,135,600	21,227,747,895	(24,368,665)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Sep 2011	Retirements Sep 2011	Adjustments	Adjusted EPIS Balance Oct 2011	Retirements Oct 2011	Adjustments	Adjusted EPIS Balance Nov 2011	Retirements Nov 2011
Steam Production Plant:										
Pre-merger Pacific	SG	-	1,084,982,362	(1,687,650)	-	1,083,294,712	(1,687,650)	-	1,081,607,062	(1,687,650)
Pre-merger Utah	SG	-	1,191,146,998	(1,197,003)	-	1,189,949,995	(1,197,003)	-	1,188,752,991	(1,197,003)
Post-merger	SG	2,378,711	3,136,525,404	(2,065,916)	13,740,163	3,148,199,651	(2,065,916)	52,127,586	3,198,261,321	(2,065,916)
Renewable - Blundell	SG	-	26,221,054	(17,367)	-	26,203,687	(17,367)	-	26,186,320	(17,367)
Pollution Control Equipment	SG	1,307,520	16,781,949	-	388,419	17,170,368	-	149,412,712	166,583,080	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	-	515,420,872	(1,807,429)	120,058	513,733,502	(1,807,429)	6,836,901	518,762,974	(1,807,429)
Total Steam Plant		3,686,231	5,971,078,639	(6,775,365)	14,248,640	5,978,551,913	(6,775,365)	208,377,199	6,180,153,747	(6,775,365)
Hydro Production Plant:										
Pre-merger Pacific	SG	-	193,162,246	(163,300)	-	192,998,946	(3,772,979)	-	189,225,967	(163,300)
Pre-merger Utah	SG	-	43,504,384	(747,433)	-	42,756,951	(72,500)	-	42,684,451	(72,500)
Post-merger	SG-P	178,478	255,014,503	(213,578)	1,912,367	256,713,292	(3,539,168)	11,138,892	264,313,016	(213,578)
Post-merger	SG-U	160,676	98,325,188	(431,183)	130,439	98,024,445	(113,493)	126,970	98,037,922	(113,493)
Total Hydro Plant		339,154	590,006,322	(1,555,493)	2,042,806	590,493,635	(7,498,140)	11,265,862	594,261,357	(562,871)
Other Production Plant:										
Pre-merger Utah	SG	-	1,202,263	(1,809)	-	1,200,454	(1,809)	-	1,198,645	(1,809)
Post-merger	SG	-	1,226,716,265	(2,166,554)	-	1,224,549,710	(2,166,554)	800,971	1,223,184,126	(2,166,554)
Post-merger Wind	SG-W	1,075,319	1,285,727,837	(56,810)	631,750	1,286,302,777	(56,810)	2,373,401	1,288,619,368	(56,810)
Post-merger	SG	-	78,760,393	(68,760)	-	78,691,633	(68,760)	244,916	78,867,788	(68,760)
Total Other Plant		1,075,319	2,592,406,758	(2,293,934)	631,750	2,590,744,574	(2,293,934)	3,419,287	2,591,869,927	(2,293,934)
Transmission Plant:										
Pre-merger Pacific	SG	-	561,300,441	(402,614)	-	560,897,827	(607,831)	-	560,289,996	(402,614)
Pre-merger Utah	SG	-	658,117,450	(297,993)	-	657,819,456	(297,993)	-	657,521,463	(297,993)
Post-merger	SG	8,340,441	3,259,921,903	(1,926,805)	6,924,797	3,264,919,895	(1,979,012)	5,976,696	3,268,917,580	(1,926,805)
Total Transmission Plant		8,340,441	4,479,339,794	(2,627,412)	6,924,797	4,483,637,179	(2,884,836)	5,976,696	4,486,729,039	(2,627,412)
Distribution Plant:										
California	CA	1,861,636	222,776,531	(90,485)	972,907	223,658,953	(90,485)	1,225,253	224,793,721	(90,485)
Oregon	OR	3,946,671	1,738,993,355	(860,715)	4,379,258	1,742,511,897	(860,715)	7,059,918	1,748,711,100	(860,715)
Washington	WA	1,107,432	403,482,210	(393,200)	44,873	403,133,883	(393,200)	1,714,870	404,455,552	(393,200)
Eastern Wyoming	WYP	3,309,045	488,233,702	(393,638)	6,003,879	493,843,943	(393,638)	3,965,809	497,416,115	(393,638)
Utah	UT	9,289,894	2,381,795,560	(2,619,819)	10,266,706	2,389,442,447	(2,584,772)	7,959,083	2,394,816,759	(2,584,772)
Idaho	ID	950,603	280,793,503	(198,340)	1,180,630	281,775,793	(198,340)	968,439	282,545,891	(198,340)
Western Wyoming	WYU	-	96,259,442	(68,439)	-	96,191,003	(68,439)	-	96,122,565	(68,439)
Total Distribution Plant		20,465,280	5,612,334,302	(4,624,635)	22,848,252	5,630,557,919	(4,589,588)	22,893,372	5,648,861,703	(4,589,588)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Sep 2011	Retirements Sep 2011	Adjustments	Adjusted EPIS Balance Oct 2011	Retirements Oct 2011	Adjustments	Adjusted EPIS Balance Nov 2011	Retirements Nov 2011
General Plant:										
California	CA	245,265	13,481,795	(53,258)	227,340	13,655,877	(53,258)	106,470	13,709,089	(53,258)
Oregon	OR	3,699,130	152,434,821	(646,184)	2,940,077	154,728,714	(646,184)	2,140,060	156,222,589	(646,184)
Washington	WA	1,355,219	44,256,467	(127,518)	1,099,318	45,228,266	(127,518)	270,851	45,371,598	(127,518)
Eastern Wyoming	WYP	2,033,054	61,201,171	(224,616)	1,065,645	62,042,200	(224,616)	1,053,765	62,871,349	(224,616)
Utah	UT	1,328,157	174,011,282	(617,308)	2,130,698	175,524,672	(617,308)	2,463,402	177,370,766	(617,308)
Idaho	ID	181,850	34,483,912	(143,536)	378,860	34,719,236	(143,536)	219,216	34,794,916	(143,536)
Western Wyoming	WYU	-	11,814,042	(48,190)	-	11,765,852	(48,190)	-	11,717,661	(48,190)
Pre-merger Pacific	SG	-	3,661,950	(53,738)	-	3,608,212	(53,738)	-	3,554,475	(53,738)
Pre-merger Utah	SG	-	7,262,104	(119,261)	-	7,142,842	(119,261)	-	7,023,581	(119,261)
Post-merger	SG	1,657,770	187,758,745	(647,744)	633,399	187,744,400	(647,744)	600,964	187,697,620	(647,744)
General Office	SO	1,656,870	242,480,941	(1,861,201)	1,180,100	241,799,840	(1,861,201)	907,470	240,846,109	(1,861,201)
General Office	SG	-	3,910,269	(30,869)	-	3,879,400	(30,869)	-	3,848,531	(30,869)
General Office	SG	-	202,184	(656)	-	201,528	(656)	-	200,872	(656)
Customer Service	CN	-	24,379,345	(148,992)	-	24,230,353	(148,992)	-	24,081,362	(148,992)
Fuel Related	SE	-	643,717	(5,492)	-	638,225	(5,492)	-	632,732	(5,492)
Total General Plant		12,157,315	961,982,745	(4,728,563)	9,655,436	966,909,617	(4,728,563)	7,762,197	969,943,251	(4,728,563)
Mining Plant:										
Coal Mine	SE	83,371	287,173,272	(824,346)	2,259,467	288,608,393	(824,346)	178,081	287,962,128	(824,346)
Total Mining Plant		83,371	287,173,272	(824,346)	2,259,467	288,608,393	(824,346)	178,081	287,962,128	(824,346)
Intangible Plant:										
California	CA	-	216,407	-	-	216,407	-	-	216,407	-
Customer Service	CN	-	121,013,770	(21,129)	-	120,992,641	(21,129)	-	120,971,513	(21,129)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	-	597,335	(1,219)	-	596,116	(1,219)	-	594,896	(1,219)
Idaho	ID	-	1,427,593	-	-	1,427,593	-	-	1,427,593	-
Oregon	OR	-	1,758,317	(31,797)	-	1,726,520	(31,797)	-	1,694,723	(31,797)
Fuel Related	SE	-	3,634,906	(6,503)	-	3,628,403	(6,503)	-	3,621,900	(6,503)
Post-merger	SG	5,625	138,758,750	(880,309)	60,523	137,938,964	(880,309)	1,834	137,060,489	(880,309)
Hydro Relicensing	SG-P	-	98,821,886	(229,530)	-	98,592,356	(229,530)	-	98,362,827	(229,530)
Hydro Relicensing	SG-U	-	9,166,315	(7,683)	-	9,158,632	(7,683)	-	9,150,949	(7,683)
General Office	SO	1,420,224	376,256,550	(777,929)	1,122,757	376,601,378	(777,929)	660,292	376,483,740	(777,929)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	-	3,002,975	(52)	-	3,002,923	(52)	-	3,002,871	(52)
Washington	WA	-	595,911	(10,434)	-	585,476	(10,434)	-	575,042	(10,434)
Eastern Wyoming	WYP	-	1,379,644	-	-	1,379,644	-	-	1,379,644	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,425,848	756,630,357	(1,966,585)	1,183,281	755,847,052	(1,966,585)	662,126	754,542,592	(1,966,585)
Total		47,572,959	21,250,952,188	(25,396,335)	59,794,428	21,285,350,282	(31,561,358)	260,534,821	21,514,323,744	(24,368,665)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Dec 2011	Retirements Dec 2011	Adjustments	Adjusted EPIS Balance Jan 2012	Retirements Jan 2012	Adjustments	Adjusted EPIS Balance Feb 2012	Retirements Feb 2012
Steam Production Plant:										
Pre-merger Pacific	SG	-	1,079,919,413	(1,671,972)	-	1,078,247,440	(1,671,972)	-	1,076,575,468	(1,671,972)
Pre-merger Utah	SG	-	1,187,555,988	(1,189,808)	-	1,186,366,180	(1,189,808)	-	1,185,176,373	(1,189,808)
Post-merger	SG	19,868,220	3,216,063,624	(2,125,874)	1,035,774	3,214,973,524	(2,125,874)	2,029,675	3,214,877,325	(2,125,874)
Renewable - Blundell	SG	192,957	26,361,910	(17,426)	-	26,344,484	(17,426)	-	26,327,059	(17,426)
Pollution Control Equipment	SG	8,173,906	174,756,986	(115,517)	1,682,531	176,324,000	(115,517)	3,064,430	179,272,912	(115,517)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	1,047,102	518,002,647	(1,797,572)	-	516,205,074	(1,797,572)	-	514,407,502	(1,797,572)
Total Steam Plant		29,282,186	6,202,660,568	(6,918,170)	2,718,305	6,198,460,703	(6,918,170)	5,094,105	6,196,636,639	(6,918,170)
Hydro Production Plant:										
Pre-merger Pacific	SG	-	189,062,668	(159,430)	-	188,903,238	(159,430)	-	188,743,809	(159,430)
Pre-merger Utah	SG	-	42,611,951	(70,660)	-	42,541,291	(70,660)	-	42,470,631	(70,660)
Post-merger	SG-P	26,364,771	290,464,209	(243,394)	478,257	290,699,072	(243,394)	2,939,236	293,394,914	(243,394)
Post-merger	SG-U	2,830,854	100,755,284	(117,769)	-	100,637,514	(117,769)	-	100,519,745	(117,769)
Total Hydro Plant		29,195,625	622,894,111	(591,253)	478,257	622,781,115	(591,253)	2,939,236	625,129,099	(591,253)
Other Production Plant:										
Pre-merger Utah	SG	-	1,196,836	(1,793)	-	1,195,043	(1,793)	-	1,193,250	(1,793)
Post-merger	SG	964,969	1,221,982,541	(5,977,074)	119,074	1,216,124,541	(2,151,721)	-	1,213,972,821	(2,151,721)
Post-merger Wind	SG-W	2,107,345	1,290,669,902	(57,048)	-	1,290,612,854	(57,048)	863,342	1,291,419,148	(57,048)
Post-merger	SG	1,751,629	80,550,657	(70,140)	-	80,480,517	(70,140)	1,052,628	81,463,005	(70,140)
Total Other Plant		4,823,943	2,594,399,936	(6,106,055)	119,074	2,588,412,955	(2,280,701)	1,915,970	2,588,048,224	(2,280,701)
Transmission Plant:										
Pre-merger Pacific	SG	-	559,887,382	(400,738)	-	559,486,644	(400,738)	-	559,085,906	(400,738)
Pre-merger Utah	SG	-	657,223,469	(297,185)	-	656,926,284	(297,185)	-	656,629,099	(297,185)
Post-merger	SG	17,856,660	3,284,847,436	(1,957,618)	16,398,249	3,299,288,067	(1,957,618)	4,107,318	3,301,437,767	(1,957,618)
Total Transmission Plant		17,856,660	4,501,958,287	(2,655,542)	16,398,249	4,515,700,995	(2,655,542)	4,107,318	4,517,152,772	(2,655,542)
Distribution Plant:										
California	CA	2,755,278	227,458,514	(93,561)	542,499	227,907,453	(93,561)	571,405	228,385,297	(93,561)
Oregon	OR	11,586,848	1,759,437,233	(878,556)	2,769,549	1,761,328,227	(878,556)	2,820,626	1,763,270,297	(878,556)
Washington	WA	1,900,200	405,962,552	(397,410)	756,136	406,321,278	(397,410)	798,124	406,721,992	(397,410)
Eastern Wyoming	WYP	2,631,072	499,653,549	(411,808)	1,346,805	500,588,547	(411,808)	1,310,088	501,486,827	(411,808)
Utah	UT	18,570,680	2,410,802,667	(2,635,984)	3,567,730	2,411,734,413	(2,635,984)	3,376,101	2,412,474,530	(2,635,984)
Idaho	ID	848,491	283,196,042	(201,316)	1,092,955	284,087,681	(201,316)	1,069,641	284,956,005	(201,316)
Western Wyoming	WYU	-	96,054,126	(68,147)	-	95,985,979	(68,147)	-	95,917,831	(68,147)
Total Distribution Plant		38,292,569	5,682,564,684	(4,686,782)	10,075,675	5,687,953,578	(4,686,782)	9,945,984	5,693,212,780	(4,686,782)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Dec 2011	Retirements Dec 2011	Adjustments	Adjusted EPIS Balance Jan 2012	Retirements Jan 2012	Adjustments	Adjusted EPIS Balance Feb 2012	Retirements Feb 2012
General Plant:										
California	CA	2,231,388	15,887,218	(63,380)	71,854	15,895,692	(63,380)	110,205	15,942,517	(63,380)
Oregon	OR	6,728,722	162,305,127	(699,066)	1,413,003	163,019,064	(699,066)	3,299,056	165,619,053	(699,066)
Washington	WA	652,514	45,896,594	(138,604)	63,654	45,821,644	(138,604)	585,140	46,268,181	(138,604)
Eastern Wyoming	WYP	1,100,880	63,747,614	(246,797)	1,071,342	64,572,159	(246,797)	694,235	65,019,596	(246,797)
Utah	UT	5,024,139	181,777,597	(669,254)	748,154	181,856,497	(669,254)	2,200,857	183,388,100	(669,254)
Idaho	ID	389,937	35,041,317	(151,874)	143,868	35,033,312	(151,874)	556,644	35,438,082	(151,874)
Western Wyoming	WYU	-	11,669,471	(47,025)	-	11,622,446	(47,025)	-	11,575,421	(47,025)
Pre-merger Pacific	SG	-	3,500,737	(49,206)	-	3,451,531	(49,206)	-	3,402,325	(49,206)
Pre-merger Utah	SG	-	6,904,320	(108,062)	-	6,796,258	(108,062)	-	6,688,196	(108,062)
Post-merger	SG	6,320,433	193,370,309	(672,764)	9,000	192,706,545	(672,764)	867,104	192,900,886	(672,764)
General Office	SO	5,154,646	244,139,554	(1,855,374)	1,376,483	243,660,664	(1,855,374)	321,651	242,126,940	(1,855,374)
General Office	SG	-	3,817,663	(29,441)	-	3,788,222	(29,441)	-	3,758,781	(29,441)
General Office	SG	-	200,216	(643)	-	199,573	(643)	-	198,930	(643)
Customer Service	CN	-	23,932,370	(143,627)	-	23,788,743	(143,627)	-	23,645,116	(143,627)
Fuel Related	SE	-	627,240	(5,218)	-	622,021	(5,218)	-	616,803	(5,218)
Total General Plant		27,602,659	992,817,347	(4,880,334)	4,897,358	992,834,371	(4,880,334)	8,634,891	996,588,928	(4,880,334)
Mining Plant:										
Coal Mine	SE	3,851,844	290,989,625	(836,791)	2,711,006	292,863,841	(836,791)	813,000	292,840,050	(836,791)
Total Mining Plant		3,851,844	290,989,625	(836,791)	2,711,006	292,863,841	(836,791)	813,000	292,840,050	(836,791)
Intangible Plant:										
California	CA	-	216,407	-	-	216,407	-	-	216,407	-
Customer Service	CN	-	120,950,384	(21,106)	-	120,929,278	(21,106)	-	120,908,171	(21,106)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	-	593,677	(1,205)	-	592,472	(1,205)	-	591,268	(1,205)
Idaho	ID	-	1,427,593	-	-	1,427,593	-	-	1,427,593	-
Oregon	OR	-	1,662,925	(28,525)	-	1,634,401	(28,525)	-	1,605,876	(28,525)
Fuel Related	SE	-	3,615,397	(6,434)	-	3,608,963	(6,434)	-	3,602,529	(6,434)
Post-merger	SG	1,231,888	137,412,067	(855,498)	-	136,556,569	(855,498)	-	135,701,071	(855,498)
Hydro Relicensing	SG-P	-	98,133,297	(226,353)	-	97,906,944	(226,353)	-	97,680,591	(226,353)
Hydro Relicensing	SG-U	-	9,143,267	(7,644)	-	9,135,622	(7,644)	-	9,127,978	(7,644)
General Office	SO	3,086,087	378,791,897	(783,937)	1,174,634	379,182,594	(783,937)	274,483	378,673,140	(783,937)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	-	3,002,819	(52)	-	3,002,767	(52)	-	3,002,715	(52)
Washington	WA	-	564,608	(9,393)	-	555,215	(9,393)	-	545,822	(9,393)
Eastern Wyoming	WYP	-	1,379,644	-	-	1,379,644	-	-	1,379,644	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		4,317,975	756,893,981	(1,940,147)	1,174,634	756,128,468	(1,940,147)	274,483	754,462,805	(1,940,147)
Total		155,223,462	21,645,178,541	(28,615,072)	38,572,559	21,655,136,028	(24,789,719)	33,724,988	21,664,071,297	(24,789,719)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Mar 2012	Retirements Mar 2012	Adjustments	Adjusted EPIS Balance Apr 2012	Retirements Apr 2012	Adjustments	Adjusted EPIS Balance May 2012	Retirements May 2012
Steam Production Plant:										
Pre-merger Pacific	SG	-	1,074,903,496	(1,671,972)	-	1,073,231,524	(1,671,972)	-	1,071,559,551	(1,671,972)
Pre-merger Utah	SG	-	1,183,986,565	(1,189,808)	-	1,182,796,758	(1,189,808)	-	1,181,606,950	(1,189,808)
Post-merger	SG	840,142	3,213,591,593	(2,125,874)	50,500,754	3,261,966,472	(2,125,874)	20,400,832	3,280,241,430	(2,125,874)
Renewable - Blundell	SG	-	26,309,633	(17,426)	-	26,292,207	(17,426)	-	26,274,781	(17,426)
Pollution Control Equipment	SG	12,540,595	191,697,990	(115,517)	100,295,270	291,877,743	(115,517)	126,986,803	418,749,028	(115,517)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	276,778	512,886,708	(1,797,572)	-	511,089,136	(1,797,572)	-	509,291,564	(1,797,572)
Total Steam Plant		13,657,516	6,203,375,985	(6,918,170)	150,796,024	6,347,253,839	(6,918,170)	147,387,635	6,487,723,304	(6,918,170)
Hydro Production Plant:										
Pre-merger Pacific	SG	-	188,584,379	(159,430)	-	188,424,949	(159,430)	-	188,265,520	(159,430)
Pre-merger Utah	SG	-	42,399,971	(70,660)	-	42,329,312	(70,660)	-	42,258,652	(70,660)
Post-merger	SG-P	10,945,424	304,096,944	(243,394)	479,612	304,333,161	(243,394)	870,034	304,959,801	(243,394)
Post-merger	SG-U	-	100,401,976	(117,769)	167,736	100,451,943	(117,769)	-	100,334,173	(117,769)
Total Hydro Plant		10,945,424	635,483,270	(591,253)	647,348	635,539,365	(591,253)	870,034	635,818,146	(591,253)
Other Production Plant:										
Pre-merger Utah	SG	-	1,191,458	(1,793)	-	1,189,665	(1,793)	-	1,187,872	(1,793)
Post-merger	SG	-	1,211,821,100	(2,151,721)	-	1,209,669,379	(2,151,721)	255,746	1,207,773,404	(2,151,721)
Post-merger Wind	SG-W	-	1,291,362,100	(57,048)	-	1,291,305,052	(57,048)	-	1,291,248,003	(57,048)
Post-merger	SG	225,055	81,617,921	(70,140)	-	81,547,781	(70,140)	-	81,477,641	(70,140)
Total Other Plant		225,055	2,585,992,578	(2,280,701)	-	2,583,711,877	(2,280,701)	255,746	2,581,686,921	(2,280,701)
Transmission Plant:										
Pre-merger Pacific	SG	-	558,685,168	(400,738)	-	558,284,430	(400,738)	-	557,883,692	(400,738)
Pre-merger Utah	SG	-	656,331,914	(297,185)	-	656,034,729	(297,185)	-	655,737,544	(297,185)
Post-merger	SG	29,730,055	3,329,210,203	(1,957,618)	16,607,039	3,343,859,624	(1,957,618)	12,372,868	3,354,274,874	(1,957,618)
Total Transmission Plant		29,730,055	4,544,227,286	(2,655,542)	16,607,039	4,558,178,784	(2,655,542)	12,372,868	4,567,896,110	(2,655,542)
Distribution Plant:										
California	CA	662,849	228,954,585	(93,561)	572,784	229,433,807	(93,561)	572,160	229,912,406	(93,561)
Oregon	OR	3,214,499	1,765,606,240	(878,556)	5,520,572	1,770,248,257	(878,556)	2,920,679	1,772,290,380	(878,556)
Washington	WA	925,941	407,250,523	(397,410)	849,883	407,702,996	(397,410)	846,904	408,152,490	(397,410)
Eastern Wyoming	WYP	1,361,186	502,436,206	(411,808)	1,432,756	503,457,154	(411,808)	1,429,210	504,474,556	(411,808)
Utah	UT	5,603,056	2,415,441,602	(2,635,984)	3,831,907	2,416,637,526	(2,635,984)	32,576,068	2,446,577,610	(2,635,984)
Idaho	ID	1,138,132	285,892,821	(201,316)	1,225,836	286,917,340	(201,316)	1,204,659	287,920,683	(201,316)
Western Wyoming	WYU	-	95,849,684	(68,147)	-	95,781,537	(68,147)	-	95,713,389	(68,147)
Total Distribution Plant		12,905,662	5,701,431,661	(4,686,782)	13,433,737	5,710,178,616	(4,686,782)	39,549,679	5,745,041,514	(4,686,782)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Mar 2012	Retirements Mar 2012	Adjustments	Adjusted EPIS Balance Apr 2012	Retirements Apr 2012	Adjustments	Adjusted EPIS Balance May 2012	Retirements May 2012
General Plant:										
California	CA	54,244	15,933,382	(63,380)	288,002	16,158,004	(63,380)	53,613	16,148,237	(63,380)
Oregon	OR	608,642	165,528,629	(699,066)	918,619	165,748,182	(699,066)	2,049,151	167,098,268	(699,066)
Washington	WA	210,333	46,339,911	(138,604)	66,958	46,268,265	(138,604)	67,127	46,196,789	(138,604)
Eastern Wyoming	WYP	871,223	65,644,022	(246,797)	236,819	65,634,043	(246,797)	240,581	65,627,827	(246,797)
Utah	UT	1,534,385	184,253,230	(669,254)	1,370,293	184,954,268	(669,254)	789,260	185,074,274	(669,254)
Idaho	ID	148,541	35,434,749	(151,874)	1,097,623	36,380,499	(151,874)	150,985	36,379,610	(151,874)
Western Wyoming	WYU	-	11,528,395	(47,025)	-	11,481,370	(47,025)	-	11,434,345	(47,025)
Pre-merger Pacific	SG	-	3,353,120	(49,206)	-	3,303,914	(49,206)	-	3,254,708	(49,206)
Pre-merger Utah	SG	-	6,580,134	(108,062)	-	6,472,073	(108,062)	-	6,364,011	(108,062)
Post-merger	SG	1,639,301	193,867,423	(672,764)	344,568	193,539,227	(672,764)	328,076	193,194,540	(672,764)
General Office	SO	317,274	240,588,841	(1,855,374)	395,925	239,129,392	(1,855,374)	338,406	237,612,424	(1,855,374)
General Office	SG	-	3,729,341	(29,441)	-	3,699,900	(29,441)	-	3,670,459	(29,441)
General Office	SG	-	198,287	(643)	-	197,644	(643)	-	197,001	(643)
Customer Service	CN	-	23,501,489	(143,627)	-	23,357,862	(143,627)	-	23,214,235	(143,627)
Fuel Related	SE	-	611,585	(5,218)	-	606,367	(5,218)	-	601,148	(5,218)
Total General Plant		5,383,944	997,092,537	(4,880,334)	4,718,806	996,931,009	(4,880,334)	4,017,200	996,067,875	(4,880,334)
Mining Plant:										
Coal Mine	SE	487,840	292,491,099	(836,791)	189,000	291,843,308	(836,791)	997,000	292,003,517	(836,791)
Total Mining Plant		487,840	292,491,099	(836,791)	189,000	291,843,308	(836,791)	997,000	292,003,517	(836,791)
Intangible Plant:										
California	CA	-	216,407	-	-	216,407	-	-	216,407	-
Customer Service	CN	-	120,887,065	(21,106)	-	120,865,958	(21,106)	-	120,844,852	(21,106)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	-	590,063	(1,205)	-	588,859	(1,205)	-	587,654	(1,205)
Idaho	ID	-	1,427,593	-	-	1,427,593	-	-	1,427,593	-
Oregon	OR	-	1,577,351	(28,525)	-	1,548,826	(28,525)	-	1,520,302	(28,525)
Fuel Related	SE	-	3,596,095	(6,434)	-	3,589,662	(6,434)	-	3,583,228	(6,434)
Post-merger	SG	-	134,845,573	(855,498)	-	133,990,075	(855,498)	-	133,134,577	(855,498)
Hydro Relicensing	SG-P	-	97,454,238	(226,353)	-	97,227,885	(226,353)	-	97,001,532	(226,353)
Hydro Relicensing	SG-U	-	9,120,334	(7,644)	-	9,112,690	(7,644)	-	9,105,045	(7,644)
General Office	SO	270,749	378,159,952	(783,937)	337,866	377,713,881	(783,937)	288,782	377,218,726	(783,937)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	-	3,002,663	(52)	-	3,002,611	(52)	-	3,002,559	(52)
Washington	WA	-	536,429	(9,393)	-	527,037	(9,393)	-	517,644	(9,393)
Eastern Wyoming	WYP	-	1,379,644	-	-	1,379,644	-	-	1,379,644	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		270,749	752,793,407	(1,940,147)	337,866	751,191,126	(1,940,147)	288,782	749,539,761	(1,940,147)
Total		73,606,244	21,712,887,822	(24,789,719)	186,729,821	21,874,827,924	(24,789,719)	205,738,944	22,055,777,149	(24,789,719)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Jun 2012	Retirements Jun 2012	Adjustments	Adjusted EPIS Balance Jul 2012	Retirements Jul 2012	Adjustments	Adjusted EPIS Balance Aug 2012	Retirements Aug 2012
Steam Production Plant:										
Pre-merger Pacific	SG	-	1,069,887,579	(1,671,972)	-	1,068,215,607	(1,671,972)	-	1,066,543,634	(1,671,972)
Pre-merger Utah	SG	-	1,180,417,143	(1,189,808)	-	1,179,227,335	(1,189,808)	-	1,178,037,527	(1,189,808)
Post-merger	SG	20,733,703	3,298,849,258	(2,125,874)	18,081,455	3,314,804,839	(2,125,874)	7,166,759	3,319,845,723	(2,125,874)
Renewable - Blundell	SG	-	26,257,356	(17,426)	-	26,239,930	(17,426)	-	26,222,504	(17,426)
Pollution Control Equipment	SG	48,834,571	467,468,081	(115,517)	1,961,255	469,313,818	(115,517)	4,008,155	473,206,456	(115,517)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	317,063	507,811,054	(1,797,572)	52,487	506,065,969	(1,797,572)	58,655	504,327,051	(1,797,572)
Total Steam Plant		69,885,336	6,550,690,471	(6,918,170)	20,095,196	6,563,867,498	(6,918,170)	11,233,569	6,568,182,897	(6,918,170)
Hydro Production Plant:										
Pre-merger Pacific	SG	-	188,106,090	(159,430)	-	187,946,661	(159,430)	-	187,787,231	(159,430)
Pre-merger Utah	SG	-	42,187,992	(70,660)	-	42,117,333	(70,660)	-	42,046,673	(70,660)
Post-merger	SG-P	581,385	305,297,792	(243,394)	852,376	305,906,774	(243,394)	361,264	306,024,644	(243,394)
Post-merger	SG-U	-	100,216,404	(117,769)	-	100,098,635	(117,769)	-	99,980,866	(117,769)
Total Hydro Plant		581,385	635,808,279	(591,253)	852,376	636,069,403	(591,253)	361,264	635,839,413	(591,253)
Other Production Plant:										
Pre-merger Utah	SG	-	1,186,080	(1,793)	-	1,184,287	(1,793)	-	1,182,494	(1,209,482)
Post-merger	SG	672,282	1,206,293,966	(2,151,721)	571,713	1,204,713,958	(2,151,721)	-	1,202,562,237	(2,676,328)
Post-merger Wind	SG-W	514,719	1,291,705,674	(57,048)	2,911	1,291,651,537	(57,048)	2,911	1,291,597,399	(57,048)
Post-merger	SG	-	81,407,502	(70,140)	-	81,337,362	(70,140)	-	81,267,222	(70,140)
Total Other Plant		1,187,001	2,580,593,221	(2,280,701)	574,624	2,578,887,143	(2,280,701)	2,911	2,576,609,353	(4,012,998)
Transmission Plant:										
Pre-merger Pacific	SG	-	557,482,954	(400,738)	-	557,082,215	(400,738)	-	556,681,477	(400,738)
Pre-merger Utah	SG	-	655,440,359	(297,185)	-	655,143,175	(297,185)	-	654,845,990	(297,185)
Post-merger	SG	29,269,890	3,381,587,145	(1,957,618)	5,845,249	3,385,474,776	(1,957,618)	27,391,871	3,410,909,028	(1,957,618)
Total Transmission Plant		29,269,890	4,594,510,459	(2,655,542)	5,845,249	4,597,700,166	(2,655,542)	27,391,871	4,622,436,495	(2,655,542)
Distribution Plant:										
California	CA	593,012	230,411,857	(93,561)	568,146	230,886,442	(93,561)	673,204	231,466,084	(93,561)
Oregon	OR	2,992,054	1,774,403,878	(878,556)	2,819,301	1,776,344,623	(878,556)	3,148,373	1,778,614,440	(878,556)
Washington	WA	879,300	408,634,380	(397,410)	825,680	409,062,650	(397,410)	922,703	409,587,944	(397,410)
Eastern Wyoming	WYP	1,483,218	505,545,967	(411,808)	1,595,718	506,729,877	(411,808)	1,704,720	508,022,790	(411,808)
Utah	UT	14,358,150	2,458,299,776	(2,635,984)	4,702,685	2,460,366,477	(2,635,984)	5,115,272	2,462,845,765	(2,902,960)
Idaho	ID	1,255,136	288,974,502	(201,316)	1,255,091	290,028,277	(201,316)	1,326,391	291,153,352	(201,316)
Western Wyoming	WYU	-	95,645,242	(68,147)	-	95,577,095	(68,147)	-	95,508,947	(68,147)
Total Distribution Plant		21,560,870	5,761,915,603	(4,686,782)	11,766,620	5,768,995,442	(4,686,782)	12,890,664	5,777,199,324	(4,953,758)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Jun 2012	Retirements Jun 2012	Adjustments	Adjusted EPIS Balance Jul 2012	Retirements Jul 2012	Adjustments	Adjusted EPIS Balance Aug 2012	Retirements Aug 2012
General Plant:										
California	CA	609,666	16,694,523	(63,380)	53,297	16,684,440	(63,380)	53,903	16,674,964	(63,380)
Oregon	OR	3,171,478	169,570,679	(699,066)	319,521	169,191,134	(699,066)	1,056,183	169,548,251	(699,066)
Washington	WA	404,157	46,462,342	(138,604)	67,478	46,391,216	(138,604)	67,682	46,320,294	(138,604)
Eastern Wyoming	WYP	469,183	65,850,213	(246,797)	517,104	66,120,520	(246,797)	298,490	66,172,212	(246,797)
Utah	UT	2,877,773	187,282,793	(669,254)	1,019,509	187,633,048	(669,254)	672,729	187,636,523	(669,254)
Idaho	ID	152,409	36,380,145	(151,874)	242,861	36,471,132	(151,874)	375,825	36,695,084	(151,874)
Western Wyoming	WYU	-	11,387,320	(47,025)	-	11,340,294	(47,025)	-	11,293,269	(47,025)
Pre-merger Pacific	SG	-	3,205,502	(49,206)	-	3,156,297	(49,206)	-	3,107,091	(49,206)
Pre-merger Utah	SG	-	6,255,949	(108,062)	-	6,147,887	(108,062)	-	6,039,825	(133,689)
Post-merger	SG	631,915	193,153,691	(672,764)	226,560	192,707,487	(672,764)	959,550	192,994,274	(912,451)
General Office	SO	644,192	236,401,242	(1,855,374)	927,782	235,473,650	(1,855,374)	610,651	234,228,927	(1,855,374)
General Office	SG	-	3,641,019	(29,441)	-	3,611,578	(29,441)	-	3,582,137	(29,441)
General Office	SG	-	196,358	(643)	-	195,715	(643)	-	195,072	(643)
Customer Service	CN	-	23,070,608	(143,627)	-	22,926,981	(143,627)	-	22,783,354	(143,627)
Fuel Related	SE	-	595,930	(5,218)	-	590,712	(5,218)	-	585,493	(5,218)
Total General Plant		8,960,773	1,000,148,314	(4,880,334)	3,374,112	998,642,091	(4,880,334)	4,095,013	997,856,771	(5,145,649)
Mining Plant:										
Coal Mine	SE	1,203,000	292,369,726	(836,791)	1,417,000	292,949,935	(836,791)	487,000	292,600,144	(836,791)
Total Mining Plant		1,203,000	292,369,726	(836,791)	1,417,000	292,949,935	(836,791)	487,000	292,600,144	(836,791)
Intangible Plant:										
California	CA	-	216,407	-	-	216,407	-	-	216,407	-
Customer Service	CN	-	120,823,746	(21,106)	-	120,802,639	(21,106)	-	120,781,533	(21,106)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	-	586,450	(1,205)	-	585,245	(1,205)	-	584,041	(1,205)
Idaho	ID	-	1,427,593	-	-	1,427,593	-	-	1,427,593	-
Oregon	OR	-	1,491,777	(28,525)	-	1,463,252	(28,525)	-	1,434,728	(28,525)
Fuel Related	SE	-	3,576,794	(6,434)	-	3,570,360	(6,434)	-	3,563,927	(6,434)
Post-merger	SG	-	132,279,079	(855,498)	-	131,423,580	(855,498)	-	130,568,082	(855,498)
Hydro Relicensing	SG-P	-	96,775,179	(226,353)	-	96,548,827	(226,353)	-	96,322,474	(226,353)
Hydro Relicensing	SG-U	-	9,097,401	(7,644)	-	9,089,757	(7,644)	-	9,082,113	(7,644)
General Office	SO	2,420,667	378,855,455	(783,937)	791,730	378,863,249	(783,937)	521,105	378,600,416	(783,937)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	-	3,002,507	(52)	-	3,002,455	(52)	-	3,002,402	(52)
Washington	WA	-	508,251	(9,393)	-	498,858	(9,393)	-	489,465	(9,393)
Eastern Wyoming	WYP	-	1,379,644	-	-	1,379,644	-	-	1,379,644	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		2,420,667	750,020,281	(1,940,147)	791,730	748,871,865	(1,940,147)	521,105	747,452,823	(1,940,147)
Total		135,068,922	22,166,056,353	(24,789,719)	44,716,908	22,185,983,542	(24,789,719)	56,983,396	22,218,177,220	(27,054,307)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Sep 2012	Retirements Sep 2012	Adjustments	Adjusted EPIS Balance Oct 2012	Retirements Oct 2012	Adjustments	Adjusted EPIS Balance Nov 2012	Retirements Nov 2012
Steam Production Plant:										
Pre-merger Pacific	SG	-	1,064,871,662	(1,671,972)	-	1,063,199,690	(1,671,972)	-	1,061,527,717	(1,671,972)
Pre-merger Utah	SG	-	1,176,847,720	(1,189,808)	-	1,175,657,912	(1,189,808)	-	1,174,468,105	(1,189,808)
Post-merger	SG	3,533,046	3,321,252,895	(2,125,874)	5,730,842	3,324,857,863	(2,125,874)	7,912,925	3,330,644,913	(2,125,874)
Renewable - Blundell	SG	-	26,205,079	(17,426)	210,072	26,397,725	(17,426)	-	26,380,299	(17,426)
Pollution Control Equipment	SG	2,277,656	475,368,595	(115,517)	2,317,763	477,570,841	(115,517)	852,769	478,308,093	(115,517)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	59,683	502,589,162	(1,797,572)	60,711	500,852,300	(1,797,572)	54,543	499,109,271	(1,797,572)
Total Steam Plant		5,870,385	6,567,135,113	(6,918,170)	8,319,388	6,568,536,331	(6,918,170)	8,820,236	6,570,438,398	(6,918,170)
Hydro Production Plant:										
Pre-merger Pacific	SG	-	187,627,802	(159,430)	-	187,468,372	(159,430)	-	187,308,942	(159,430)
Pre-merger Utah	SG	-	41,976,013	(70,660)	-	41,905,353	(70,660)	-	41,834,694	(70,660)
Post-merger	SG-P	74,600,885	380,382,135	(243,394)	4,363,514	384,502,255	(243,394)	22,751,153	407,010,013	(243,394)
Post-merger	SG-U	-	99,863,096	(117,769)	-	99,745,327	(117,769)	18,821,493	118,449,050	(117,769)
Total Hydro Plant		74,600,885	709,849,046	(591,253)	4,363,514	713,621,307	(591,253)	41,572,645	754,602,700	(591,253)
Other Production Plant:										
Pre-merger Utah	SG	-	(26,988)	(1,793)	-	(28,781)	(1,793)	-	(30,574)	(1,793)
Post-merger	SG	-	1,199,885,909	(2,151,721)	17,641,072	1,215,375,260	(2,151,721)	-	1,213,223,540	(2,151,721)
Post-merger Wind	SG-W	2,911	1,291,543,262	(57,048)	2,911	1,291,489,124	(57,048)	2,911	1,291,434,987	(57,048)
Post-merger	SG	-	81,197,082	(70,140)	-	81,126,943	(70,140)	-	81,056,803	(70,140)
Total Other Plant		2,911	2,572,599,265	(2,280,701)	17,643,983	2,587,962,547	(2,280,701)	2,911	2,585,684,756	(2,280,701)
Transmission Plant:										
Pre-merger Pacific	SG	-	556,280,739	(400,738)	-	555,880,001	(400,738)	-	555,479,263	(400,738)
Pre-merger Utah	SG	-	654,548,805	(297,185)	-	654,251,620	(297,185)	-	653,954,435	(297,185)
Post-merger	SG	5,920,381	3,414,871,791	(1,957,618)	10,127,946	3,423,042,119	(1,957,618)	7,919,216	3,429,003,716	(1,957,618)
Total Transmission Plant		5,920,381	4,625,701,335	(2,655,542)	10,127,946	4,633,173,739	(2,655,542)	7,919,216	4,638,437,413	(2,655,542)
Distribution Plant:										
California	CA	585,272	231,957,795	(93,561)	535,640	232,399,874	(93,561)	499,858	232,806,171	(93,561)
Oregon	OR	2,681,545	1,780,417,429	(878,556)	2,612,132	1,782,151,005	(878,556)	2,489,227	1,783,761,677	(878,556)
Washington	WA	796,814	409,987,348	(397,410)	751,549	410,341,487	(397,410)	619,745	410,563,822	(397,410)
Eastern Wyoming	WYP	1,544,874	509,155,856	(411,808)	1,489,719	510,233,767	(411,808)	1,402,018	511,223,977	(411,808)
Utah	UT	4,598,331	2,464,541,136	(2,635,984)	4,350,740	2,466,255,893	(2,635,984)	3,962,755	2,467,582,664	(2,635,984)
Idaho	ID	1,237,361	292,189,397	(201,316)	1,168,521	293,156,602	(201,316)	1,131,124	294,086,409	(201,316)
Western Wyoming	WYU	-	95,440,800	(68,147)	-	95,372,653	(68,147)	-	95,304,505	(68,147)
Total Distribution Plant		11,444,196	5,783,689,762	(4,686,782)	10,908,301	5,789,911,281	(4,686,782)	10,104,727	5,795,329,227	(4,686,782)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Sep 2012	Retirements Sep 2012	Adjustments	Adjusted EPIS Balance Oct 2012	Retirements Oct 2012	Adjustments	Adjusted EPIS Balance Nov 2012	Retirements Nov 2012
General Plant:										
California	CA	457,850	17,069,434	(63,380)	82,431	17,088,486	(63,380)	53,128	17,078,234	(63,380)
Oregon	OR	2,231,318	171,080,503	(699,066)	299,410	170,680,847	(699,066)	499,811	170,481,592	(699,066)
Washington	WA	65,220	46,246,911	(138,604)	64,945	46,173,252	(138,604)	301,927	46,336,575	(138,604)
Eastern Wyoming	WYP	627,583	66,552,998	(246,797)	419,960	66,726,161	(246,797)	634,839	67,114,202	(246,797)
Utah	UT	654,154	187,621,423	(669,254)	1,242,512	188,194,680	(669,254)	695,796	188,221,222	(669,254)
Idaho	ID	232,715	36,775,926	(151,874)	157,613	36,781,665	(151,874)	331,504	36,961,295	(151,874)
Western Wyoming	WYU	-	11,246,244	(47,025)	-	11,199,219	(47,025)	-	11,152,193	(47,025)
Pre-merger Pacific	SG	-	3,057,885	(49,206)	-	3,008,679	(49,206)	-	2,959,474	(49,206)
Pre-merger Utah	SG	-	5,906,137	(108,062)	-	5,798,075	(108,062)	-	5,690,013	(108,062)
Post-merger	SG	995,849	193,077,671	(672,764)	1,623,004	194,027,911	(672,764)	12,000	193,367,148	(672,764)
General Office	SO	805,579	233,179,132	(1,855,374)	1,488,157	232,811,915	(1,855,374)	1,753,746	232,710,287	(1,855,374)
General Office	SG	-	3,552,697	(29,441)	-	3,523,256	(29,441)	-	3,493,815	(29,441)
General Office	SG	-	194,428	(643)	-	193,785	(643)	-	193,142	(643)
Customer Service	CN	-	22,639,727	(143,627)	-	22,496,100	(143,627)	-	22,352,473	(143,627)
Fuel Related	SE	-	580,275	(5,218)	-	575,057	(5,218)	-	569,839	(5,218)
Total General Plant		6,070,269	998,781,391	(4,880,334)	5,378,032	999,279,089	(4,880,334)	4,282,750	998,681,505	(4,880,334)
Mining Plant:										
Coal Mine	SE	282,000	292,045,353	(836,791)	367,000	291,575,562	(836,791)	401,000	291,139,771	(836,791)
Total Mining Plant		282,000	292,045,353	(836,791)	367,000	291,575,562	(836,791)	401,000	291,139,771	(836,791)
Intangible Plant:										
California	CA	-	216,407	-	-	216,407	-	-	216,407	-
Customer Service	CN	-	120,760,426	(21,106)	-	120,739,320	(21,106)	-	120,718,213	(21,106)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	SG	-	582,836	(1,205)	-	581,632	(1,205)	-	580,427	(1,205)
Idaho	ID	-	1,427,593	-	-	1,427,593	-	-	1,427,593	-
Oregon	OR	-	1,406,203	(28,525)	-	1,377,678	(28,525)	-	1,349,153	(28,525)
Fuel Related	SE	-	3,557,493	(6,434)	-	3,551,059	(6,434)	-	3,544,625	(6,434)
Post-merger	SG	-	129,712,584	(855,498)	751,162	129,608,247	(855,498)	1,836,076	130,588,825	(855,498)
Hydro Relicensing	SG-P	-	96,096,121	(226,353)	-	95,869,768	(226,353)	-	95,643,415	(226,353)
Hydro Relicensing	SG-U	-	9,074,469	(7,644)	-	9,066,824	(7,644)	-	9,059,180	(7,644)
General Office	SO	687,448	378,503,927	(783,937)	1,269,931	378,989,921	(783,937)	1,496,574	379,702,559	(783,937)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	-	3,002,350	(52)	-	3,002,298	(52)	-	3,002,246	(52)
Washington	WA	-	480,072	(9,393)	-	470,680	(9,393)	-	461,287	(9,393)
Eastern Wyoming	WYP	-	1,379,644	-	-	1,379,644	-	-	1,379,644	-
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		687,448	746,200,124	(1,940,147)	2,021,093	746,281,070	(1,940,147)	3,332,651	747,673,574	(1,940,147)
Total		104,878,476	22,296,001,389	(24,789,719)	59,129,256	22,330,340,926	(24,789,719)	76,436,136	22,381,987,343	(24,789,719)

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Dec 2012
Steam Production Plant:			
Pre-merger Pacific	SG	-	1,059,855,745
Pre-merger Utah	SG	-	1,173,278,297
Post-merger	SG	36,265,083	3,364,784,121
Renewable - Blundell	SG	112,028	26,474,902
Pollution Control Equipment	SG	9,128,756	487,321,331
Pollution Control Equipment	SG	-	-
Post-merger	SG	3,549,377	500,861,076
Total Steam Plant		49,055,244	6,612,575,472
Hydro Production Plant:			
Pre-merger Pacific	SG	-	187,149,513
Pre-merger Utah	SG	-	41,764,034
Post-merger	SG-P	72,597,663	479,364,282
Post-merger	SG-U	1,152,334	119,483,615
Total Hydro Plant		73,749,997	827,761,444
Other Production Plant:			
Pre-merger Utah	SG	-	(32,366)
Post-merger	SG	3,990,411	1,215,062,230
Post-merger Wind	SG-W	2,554,626	1,293,932,564
Post-merger	SG	106,247	81,092,910
Total Other Plant		6,651,283	2,590,055,338
Transmission Plant:			
Pre-merger Pacific	SG	-	555,078,525
Pre-merger Utah	SG	-	653,657,250
Post-merger	SG	75,394,901	3,502,440,998
Total Transmission Plant		75,394,901	4,711,176,773
Distribution Plant:			
California	CA	620,984	233,333,594
Oregon	OR	3,006,882	1,785,890,003
Washington	WA	813,463	410,979,876
Eastern Wyoming	WYP	2,624,688	513,436,857
Utah	UT	4,590,400	2,469,537,080
Idaho	ID	1,195,153	295,080,246
Western Wyoming	WYU	-	95,236,358
Total Distribution Plant		12,851,570	5,803,494,015

PacifiCorp
Oregon General Rate Case - December 2013
June 2011 - Dec 2012 Retirements

Description	Factor	Adjustments	Adjusted EPIS Balance Dec 2012
General Plant:			
California	CA	52,561	17,067,415
Oregon	OR	795,836	170,578,362
Washington	WA	63,278	46,261,249
Eastern Wyoming	WYP	671,444	67,538,848
Utah	UT	1,984,400	189,536,367
Idaho	ID	169,224	36,978,645
Western Wyoming	WYU	-	11,105,168
Pre-merger Pacific	SG	-	2,910,268
Pre-merger Utah	SG	-	5,581,952
Post-merger	SG	4,865,559	197,559,943
General Office	SO	2,119,283	232,974,197
General Office	SG	-	3,464,375
General Office	SG	-	192,499
Customer Service	CN	-	22,208,846
Fuel Related	SE	-	564,620
Total General Plant		10,721,584	1,004,522,755
Mining Plant:			
Coal Mine	SE	4,266,635	294,569,615
Total Mining Plant		4,266,635	294,569,615
Intangible Plant:			
California	CA	-	216,407
Customer Service	CN	-	120,697,107
Pre-merger Pacific	SG	-	-
Pre-merger Utah	SG	-	579,223
Idaho	ID	-	1,427,593
Oregon	OR	-	1,320,629
Fuel Related	SE	-	3,538,192
Post-merger	SG	5,703,021	135,436,348
Hydro Relicensing	SG-P	-	95,417,062
Hydro Relicensing	SG-U	-	9,051,536
General Office	SO	2,558,549	381,477,170
Cholla Intangible	SG	-	-
Utah	UT	-	3,002,194
Washington	WA	-	451,894
Eastern Wyoming	WYP	-	1,379,644
Western Wyoming	WYU	-	-
Total Intangible Plant		8,261,570	753,994,997
Total		240,952,785	22,598,150,409

PacifiCorp
Oregon General Rate Case - December 2013
Plant Retirements
Known Retirements

Snake Creek Hydro Plant

September 2011		
Hydro Plant	DGU	(674,933)
Hydro Plant	SG-U	(317,690)
Distribution Plant	UT	(35,047)
		(1,027,670)

Condit Hydro Plant

October 2011		
Hydro Plant	DGP	(3,609,679)
Hydro Plant	SG-P	(3,325,590)
Transmission Plant	DGP	(205,217)
Transmission Plant	SG	(52,207)
		(7,192,693)

Little Mountain

December 2011 & August 2012		
Other Plant	DGU	(1,207,690)
Other Plant	SG	(4,349,961)
Distribution Plant	UT	(266,977)
General Plant	DGU	(25,627)
General Plant	SG	(239,688)
		(6,089,941)

Foote Creek Wind Plant

July 2011		
Other Plant	SG-W	(463,135)
		(463,135)

PacifiCorp
Oregon General Rate Case - December 2013
Miscellaneous Rate Base

Adjustment to Rate Base:	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
1 - Fuel Stock - Pro Forma	151	3	(4,230,548)	SE	24.314%	(1,028,595)	
1 - Fuel Stock - Pro Forma	151	3	(3,918,475)	SE	24.314%	(952,719)	
			(8,149,023)			(1,981,314)	8.8.1
1 - Fuel Stock - Working Capital Deposit	25316	3	(640,000)	SE	24.314%	(155,607)	8.8.1
1 - Fuel Stock - Working Capital Deposit	25317	3	(600,495)	SE	24.314%	(146,001)	8.8.1
2 - Prepaid Overhauls	186M	3	12,833,312	SG	25.777%	3,308,063	8.8.1

Description of Adjustment:

1 - This adjustment reflects the change in the fuel stock balance from the base period to the test period. This adjustment also reflects the working capital deposits which are an offset to fuel stock costs.

2 - Balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked forward to reflect payments and transfers of capital to electric plant in service during the 12 months ending December 2012.

PacifiCorp
Oregon General Rate Case - December 2013
Miscellaneous Rate Base
Average Balances - Summary

1 - Coal Fuel Stock Balances by Plant	Account	Factor	Actuals Jun-2011 Balance	Pro Forma Dec-2012 Balance	Pro Forma Dec-2013 Balance	Dec 2012/2013 Beg/End Avg Balance	Adjustment to Avg Balance	
Bridger	151	SE	33,738,717	28,022,132	19,764,889	23,893,511	(9,845,206)	
Carbon	151	SE	2,194,834	2,535,436	2,604,363	2,569,899	375,065	
Cholla	151	SSECH	10,592,137	8,299,297	5,048,025	6,673,661	(3,918,475)	
Colstrip	151	SE	1,391,926	1,180,480	1,277,496	1,228,988	(162,939)	
Craig	151	SE	6,028,708	6,337,028	4,659,216	5,498,122	(530,586)	
Hayden	151	SE	2,230,924	2,478,824	2,522,370	2,500,597	269,673	
Hunter	151	SE	62,957,864	58,503,067	44,618,244	51,560,655	(11,397,209)	
Huntington	151	SE	25,574,365	31,104,218	26,547,953	28,826,086	3,251,721	
Johnston	151	SE	8,712,443	7,348,109	6,278,792	6,813,450	(1,898,993)	
Naughton	151	SE	9,005,283	14,840,091	4,955,610	9,897,850	892,567	
Deer Creek	151	SE	31,102	496,184	551,555	523,870	492,767	
Prep Plant	151	SE	35,710,483	46,746,700	32,688,823	39,717,761	4,007,279	
Rock Garden	151	SE	17,121,325	27,436,637	27,436,637	27,436,637	10,315,312	
Total			215,290,111	235,328,205	178,953,972	207,141,088	**(8,149,023)**	To 8.8
1 - Working Capital Deposits								
UAMPS Working Capital Deposit	25316	SE	(2,777,000)	(3,235,000)	(3,599,000)	(3,417,000)	**(640,000)**	To 8.8
DPEC Working Capital Deposit	25317	SE	(2,023,136)	(2,489,934)	(2,757,328)	(2,623,631)	**(600,495)**	To 8.8

2 - Overhaul Prepayments by Plant	Account	Factor	Actuals Jun-2011 Balance	Pro Forma Dec-2012 Balance		Adjustment to Ending Balance	
Lake Side	186M	SG	8,230,641	22,051,735		13,821,093	
Chehalis	186M	SG	5,926,927	12,539,892		6,612,965	
Currant Creek	186M	SG	8,523,236	922,490		(7,600,746)	
Total			22,680,804	35,514,116		**12,833,312**	To 8.8

PacifiCorp PAGE 8.9
Oregon General Rate Case - December 2013
Powerdale Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove O&M Expense	535	3	(7,065)	SG-P	25.777%	(1,821)	
	537	3	(10,198)	SG-P	25.777%	(2,629)	
	539	3	(12,863)	SG-P	25.777%	(3,316)	
	540	3	(151)	SG-P	25.777%	(39)	
	545	3	(7,715)	SG-P	25.777%	(1,989)	
			(37,993)			(9,793)	8.9.1
Adjustment to Unrecovered Plant:							
Remove Booked Amortization	407	3	(1,327,321)	SG-P	25.777%	(342,146)	8.9.1
Adjustment to Decommissioning Reg Asset:							
Remove Booked Decom Reg Asset	182M	3	(265,470)	OR	100.000%	(265,470)	B-16
Tax Adjustments							
Beg/End ADIT Balance	283	3	841,418	SG	25.777%	216,894	
Beg/End ADIT Balance	283	3	(10,337)	OR	100.000%	(10,337)	

Description of Adjustment:

This adjustment removes costs related to the Powerdale hydroelectric plant from results. Powerdale was decommissioned after it was damaged by a flood in November 2006. Deferred accounting for the unrecovered plant balance was authorized by the Commission in Docket No. UM 1298 and was fully amortized December 2010. Consistent with Dockets UE-210 and UE-217, the Company amortized the decommissioning regulatory asset beginning January 1, 2010, which will be fully amortized before the beginning of the rate effective period in this case. Accordingly, this adjustment removes the O&M expense associated with the plant, the amortization expense related to the unrecovered plant regulatory asset and the decommissioning regulatory asset balance.

PacifiCorp
Oregon General Rate Case - December 2013
Powerdale Removal
Powerdale Expense

Operation & Maintenance Expense

Description	Account	Factor	12 Months Ended June 2011 Expense	Escalation Factor	Escalated Expense
Operation & Maintenance Expense	535	SG-P	6,553	7.81%	7,065
Hydraulic Expense	537	SG-P	9,459	7.81%	10,198
Misc. Hydro Expense	539	SG-P	11,931	7.81%	12,863
Rents (Hydro Generation)	540	SG-P	140	7.81%	151
Maintenance of Misc. Hydro Plant	545	SG-P	7,375	4.61%	7,715
			35,459		**37,993**
			Ref 8.9	**Ref 4.12.8**	**Ref 8.9**

Unrecovered Plant Amortization Expense

Date	Amortization
July 2010	221,220
Aug 2010	221,220
Sept 2010	221,220
Oct 2010	221,220
Nov 2010	221,220
Dec 2010	221,220
Jan 2011	-
Feb 2011	-
Mar 2011	-
Apr 2011	-
May 2011	-
June 2011	-
Total	**1,327,321**
	Ref 8.9

Unrecovered Plant Amortization Schedule:

Beg Balance	8,796,061
Amort May 07 - Dec 07	(832,136)
Balance Remaining to Amortize	7,963,925
Monthly Amort Exp	221,220

	Amort	Balance
May-07	104,017	8,692,044
Jun-07	104,017	8,588,027
Jul-07	104,017	8,484,010
Aug-07	104,017	8,379,993
Sep-07	104,017	8,275,976
Oct-07	104,017	8,171,959
Nov-07	104,017	8,067,942
Dec-07	104,017	7,963,925
Jan-08	221,220	7,742,705
Feb-08	221,220	7,521,485
Mar-08	221,220	7,300,265
Apr-08	221,220	7,079,044
May-08	221,220	6,857,824
Jun-08	221,220	6,636,604
Jul-08	221,220	6,415,384
Aug-08	221,220	6,194,164
Sep-08	221,220	5,972,944
Oct-08	221,220	5,751,724
Nov-08	221,220	5,530,503
Dec-08	221,220	5,309,283
Jan-09	221,220	5,088,063
Feb-09	221,220	4,866,843
Mar-09	221,220	4,645,623
Apr-09	221,220	4,424,403
May-09	221,220	4,203,183
Jun-09	221,220	3,981,963
Jul-09	221,220	3,760,742
Aug-09	221,220	3,539,522
Sep-09	221,220	3,318,302
Oct-09	221,220	3,097,082
Nov-09	221,220	2,875,862
Dec-09	221,220	2,654,642
Jan-10	221,220	2,433,422
Feb-10	221,220	2,212,201
Mar-10	221,220	1,990,981
Apr-10	221,220	1,769,761
May-10	221,220	1,548,541
Jun-10	221,220	1,327,321
Jul-10	221,220	1,106,101
Aug-10	221,220	884,881
Sep-10	221,220	663,660
Oct-10	221,220	442,440
Nov-10	221,220	221,220
Dec-10	221,220	(0)
	8,796,061	

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Adjust amortization expense from base period to pro forma period							
Trojan Unrecovered Plant	407	3	(465,882)	TROJP	25.555%	(119,055)	8.10.1
Trojan Unrecov. Plant Contra - OR	407	3	39,640	OR	100.000%	39,640	8.10.2
Trojan Decommissioning	407	3	(697,992)	TROJP	25.555%	(178,371)	8.10.3
Cholla Transaction costs	557	3	(91,007)	SGCT	25.862%	(23,536)	8.10.4
Cholla Trans costs - OR Disallow	557	3	4,363	OR	100.000%	4,363	8.10.5
Pension and Post-retirement Curtail	920	3	57,755	OR	100.000%	57,755	8.10.6
Electric Plant Acq Adj - Amort Exp	406	3	(330,925)	SG	25.777%	(85,303)	8.10.7
Remove amortization expense of Reg Assets that have been collected under Tariff Riders							
GRID West - Oregon	904	1	(391,980)	OR	100.000%	(391,980)	
Transition Plan - 2000	930	1	(155,424)	OR	100.000%	(155,424)	
MEHC Transition Plan - 2006	920	1	(2,095,915)	OR	100.000%	(2,095,915)	
OR Independent Evaluator Fees	557	1	(844,878)	SG	25.777%	(217,786)	
Adjustment to Rate Base:							
Adjust amortization expense from base period to pro forma period							
Cholla Transaction costs	182M	3	(2,244,850)	SGCT	25.862%	(580,559)	8.10.4
Cholla Trans costs - OR Disallow	182M	3	107,626	OR	100.000%	107,626	8.10.5
Elec Plant Acq Adj - Accum Amort	115	3	(10,882,477)	SG	25.777%	(2,805,193)	8.10.7
Adjustment to Tax:							
Trojan	190	3	(1,917,975)	TROJD	25.516%	(489,382)	
Pension MMT & CTG	283	3	(2,695,444)	OR	100.000%	(2,695,444)	
Retirement MMT - OR	283	3	512,810	OR	100.000%	512,810	
RTO Grid West Notes Rec - OR	283	3	(309,117)	OR	100.000%	(309,117)	
Accrued CIC Severance	190	3	9,806	SO	27.165%	2,664	
OR Independent Evaluator Fee	283	3	(72,825)	OTHER	0.000%	-	
Electric Plant Acq Adj	282	3	2,989,659	SG	25.777%	770,649	

Description of Adjustment:

This adjustment normalizes regulatory assets from the base period to the pro forma period. In addition, in UE 210, the Company agreed to set up tariff riders to collect the balance of the GRID - West Reg Asset, the 2000 Transition Plan Reg Asset and the Oregon MEHC Transition Plan Reg Asset. These tariff riders are credited to revenues when collected and removed from revenues in the Pro Forma Revenue adjustment 3.1. These regulatory assets are amortized in unadjusted results by charging expense. This adjustment removes that expense.

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Trojan Unrecovered Plant
Account 185801 and 185802

	Unrecovered Plant Account 185801	Unrec Plant - Amortization Account 185802	
	Rate Base	Amortization Expense	Accm Amort YE Rate Base
Pro Forma (Rate Base B/E Avg)	-	-	-
Base Period (Rate Base YE)	-	465,882	-
Adjustment	-	**(465,882)**	-
		Ref 8.10	

	Account 185801	Amortization of 185802			
	End Balance	Beg Balance	Adjustment	Amortization	End Balance
2010 January	15,211,535	(14,326,270)		(68,097)	(14,394,368)
February	15,211,535	(14,394,368)		(68,097)	(14,462,465)
March	15,211,535	(14,462,465)		(68,097)	(14,530,562)
April	15,211,535	(14,530,562)		(68,097)	(14,598,660)
May	15,211,535	(14,598,660)		(68,097)	(14,666,757)
June	15,211,535	(14,666,757)		(68,097)	(14,734,854)
July	15,211,535	(14,734,854)		(68,097)	(14,802,951)
August	15,211,535	(14,802,951)		(68,097)	(14,871,049)
September	15,211,535	(14,871,049)		(68,097)	(14,939,146)
October	15,211,535	(14,939,146)	(10,799) (1)	(68,097)	(15,018,042)
November	15,211,535	(15,018,042)		(64,498)	(15,082,540)
December	15,211,535	(15,082,540)		(64,498)	(15,147,037)
2011 January		(15,147,037)	15,211,535 (2)	(64,498)	(0)
February					-
March					-
April					-
May					-
June					-
			Base Period Amortization =	(465,882)	

(1) Trojan Water Rights sale
(2) Close Trojan Accounts

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Trojan Unrecovered Plant Disallowance - Oregon
Account 185809

	Unrec Plant - Amortization Account 185809	
	Amortization Expense	Rate Base
Pro Forma (Rate Base B/E Avg)	-	-
Base Period (Rate Base YE)	(39,640)	-
Adjustment	**39,640**	**-**
	Ref 8.10	

		Amortization of 185804		
		Beg Balance	Amortization	End Balance
2009	December	(79,279)	5,663	(73,617)
2010	January	(73,617)	5,663	(67,954)
	February	(67,954)	5,663	(62,291)
	March	(62,291)	5,663	(56,628)
	April	(56,628)	5,663	(50,966)
	May	(50,966)	5,663	(45,303)
	June	(45,303)	5,663	(39,640)
	July	(39,640)	5,663	(33,977)
	August	(33,977)	5,663	(28,314)
	September	(28,314)	5,663	(22,652)
	October	(22,652)	5,663	(16,989)
	November	(16,989)	5,663	(11,326)
	December	(11,326)	5,663	(5,663)
2011	January	(5,663)	5,663	-
	February	-		-
	March	-		-
	April	-		-
	May	-		-
	June	-		-
	Base Period Amortization =		39,640	

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Trojan Decommissioning
Account 185803 and 185804

	Decommissioning Account 185803	Decommissioning - Amortization Account 185804	
	Rate Base	Amortization Expense	Rate Base
Pro Forma (Rate Base B/E Avg)	-	-	-
Base Period (Rate Base YE)	-	697,992	-
Adjustment	**-**	**(697,992)**	**-**
		Ref 8.10	

	Account 185803	Amortization of 185804			
	End Balance	Beg Balance	Adjustment	Amortization	End Balance
2010 January	17,980,541	(16,684,270)		(99,713)	(16,783,983)
February	17,980,541	(16,783,983)		(99,713)	(16,883,696)
March	17,980,541	(16,883,696)		(99,713)	(16,983,409)
April	17,980,541	(16,983,409)		(99,713)	(17,083,123)
May	17,980,541	(17,083,123)		(99,713)	(17,182,836)
June	17,980,541	(17,182,836)		(99,713)	(17,282,549)
July	17,980,541	(17,282,549)		(99,713)	(17,382,262)
August	17,980,541	(17,382,262)		(99,713)	(17,481,975)
September	17,980,541	(17,481,975)		(99,713)	(17,581,688)
October	17,980,541	(17,581,688)		(99,713)	(17,681,401)
November	17,980,541	(17,681,401)		(99,713)	(17,781,115)
December	17,980,541	(17,781,115)		(99,713)	(17,880,828)
2011 January		(17,880,828)	17,980,541 (1)	(99,713)	(0)
February					-
March					-
April					-
May					-
June					-
			Base Period Amortization =	(697,992)	

(1) Close Trojan Accounts

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Cholla Transaction Costs
Account 187050

	Amortization Expense	Rate Base
Pro Forma (Rate Base B/E Avg)	1,122,425	4,583,236
Base Period (Rate Base YE)	1,213,432	6,828,086
Adjustment	**(91,007)**	**(2,244,850)**
	8.10	**8.10**

		Beg Balance	Amortization	End Balance	Avg Balance
2010	July	7,950,511	(93,535)	7,856,975	
	August	7,856,975	(93,535)	7,763,440	
	September	7,763,440	(93,535)	7,669,904	
	October	7,669,904	(93,535)	7,576,369	
	November	7,576,369	(93,535)	7,482,834	
	December	7,482,834	(93,535)	7,389,298	
2011	January	7,389,298	(93,535)	7,295,763	
	February	7,295,763	(93,535)	7,202,227	
	March	7,202,227	(93,535)	7,108,692	
	April	7,108,692	(93,535)	7,015,157	
	May	7,015,157	(93,535)	6,921,621	
	June	6,921,621	(93,535)	6,828,086	
	Base Period Amortization =		(1,122,425)		
	Escalation Rate =		108.11%		
			(1,213,432)		
	July	6,828,086	(93,535)	6,734,550	
	August	6,734,550	(93,535)	6,641,015	
	September	6,641,015	(93,535)	6,547,479	
	October	6,547,479	(93,535)	6,453,944	
	November	6,453,944	(93,535)	6,360,409	
	December	6,360,409	(93,535)	6,266,873	
2012	January	6,266,873	(93,535)	6,173,338	
	February	6,173,338	(93,535)	6,079,802	
	March	6,079,802	(93,535)	5,986,267	
	April	5,986,267	(93,535)	5,892,731	
	May	5,892,731	(93,535)	5,799,196	
	June	5,799,196	(93,535)	5,705,661	
	July	5,705,661	(93,535)	5,612,125	
	August	5,612,125	(93,535)	5,518,590	
	September	5,518,590	(93,535)	5,425,054	
	October	5,425,054	(93,535)	5,331,519	
	November	5,331,519	(93,535)	5,237,984	
	December	5,237,984	(93,535)	5,144,448	
2013	January	5,144,448	(93,535)	5,050,913	
	February	5,050,913	(93,535)	4,957,377	
	March	4,957,377	(93,535)	4,863,842	
	April	4,863,842	(93,535)	4,770,306	
	May	4,770,306	(93,535)	4,676,771	
	June	4,676,771	(93,535)	4,583,236	
	July	4,583,236	(93,535)	4,489,700	
	August	4,489,700	(93,535)	4,396,165	
	September	4,396,165	(93,535)	4,302,629	
	October	4,302,629	(93,535)	4,209,094	
	November	4,209,094	(93,535)	4,115,558	
	December	4,115,558	(93,535)	4,022,023	4,583,236
	Pro Forma Amortization =		(1,122,425)		
	Tax Effected		(425,972)		

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Cholla Transaction Costs - Oregon Disallowance
Account 187060

	Amortization Expense	Rate Base
Pro Forma (Rate Base B/E Avg)	(53,813)	(219,737)
Base Period (Rate Base YE)	(58,176)	(327,363)
Adjustment	**4,363**	**107,626**
	Ref 8.10	**Ref 8.10**

		Beg Balance	Amortization	End Balance	Avg Balance
2010	July	(381,176)	4,484	(376,692)	
	August	(376,692)	4,484	(372,207)	
	September	(372,207)	4,484	(367,723)	
	October	(367,723)	4,484	(363,238)	
	November	(363,238)	4,484	(358,754)	
	December	(358,754)	4,484	(354,270)	
2011	January	(354,270)	4,484	(349,785)	
	February	(349,785)	4,484	(345,301)	
	March	(345,301)	4,484	(340,816)	
	April	(340,816)	4,484	(336,332)	
	May	(336,332)	4,484	(331,847)	
	June	(331,847)	4,484	(327,363)	
	Base Period Amortization =		53,813		
	Escalation Rate =		108.11%		
			58,176		
	July	(327,363)	4,484	(322,879)	
	August	(322,879)	4,484	(318,394)	
	September	(318,394)	4,484	(313,910)	
	October	(313,910)	4,484	(309,425)	
	November	(309,425)	4,484	(304,941)	
	December	(304,941)	4,484	(300,456)	
2012	January	(300,456)	4,484	(295,972)	
	February	(295,972)	4,484	(291,488)	
	March	(291,488)	4,484	(287,003)	
	April	(287,003)	4,484	(282,519)	
	May	(282,519)	4,484	(278,034)	
	June	(278,034)	4,484	(273,550)	
	July	(273,550)	4,484	(269,066)	
	August	(269,066)	4,484	(264,581)	
	September	(264,581)	4,484	(260,097)	
	October	(260,097)	4,484	(255,612)	
	November	(255,612)	4,484	(251,128)	
	December	(251,128)	4,484	(246,643)	
2013	January	(246,643)	4,484	(242,159)	
	February	(242,159)	4,484	(237,675)	
	March	(237,675)	4,484	(233,190)	
	April	(233,190)	4,484	(228,706)	
	May	(228,706)	4,484	(224,221)	
	June	(224,221)	4,484	(219,737)	
	July	(219,737)	4,484	(215,252)	
	August	(215,252)	4,484	(210,768)	
	September	(210,768)	4,484	(206,284)	
	October	(206,284)	4,484	(201,799)	
	November	(201,799)	4,484	(197,315)	
	December	(197,315)	4,484	(192,830)	(219,737)
	Pro Forma Amortization =		53,813		
	Tax Effected		20,423		

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Pension and Postretirement Curtailment and Date Change

Deferral and Amortization of Pension Curtailment and Pension and Postretirement Date Change

	Original Amount	Additional Local 127
Oregon Portion	(7,558,051)	(586,649)
Amortization Period	120 months	107 months

	Amortization Expense
Pro Forma Period	(821,597)
Base Period	(879,352)
	57,755

Ref 8.10

		Beginning Balance	Amortization	Ending Balance
2010	July	(6,983,578)	68,466	(6,915,112)
	August	(6,915,112)	68,466	(6,846,646)
	September	(6,846,646)	68,466	(6,778,179)
	October	(6,778,179)	68,466	(6,709,713)
	November	(6,709,713)	68,466	(6,641,246)
	December	(6,641,246)	68,466	(6,572,780)
2011	January	(6,572,780)	68,466	(6,504,313)
	February	(6,504,313)	68,466	(6,435,847)
	March	(6,435,847)	68,466	(6,367,380)
	April	(6,367,380)	68,466	(6,298,914)
	May	(6,298,914)	68,466	(6,230,447)
	June	(6,230,447)	68,466	(6,161,981)
		Base Period Amort =	821,597	
		Escalation Rate =	107.03%	
			879,352	
	July	(6,161,981)	68,466	(6,093,515)
	August	(6,093,515)	68,466	(6,025,048)
	September	(6,025,048)	68,466	(5,956,582)
	October	(5,956,582)	68,466	(5,888,115)
	November	(5,888,115)	68,466	(5,819,649)
	December	(5,819,649)	68,466	(5,751,182)
2012	January	(5,751,182)	68,466	(5,682,716)
	February	(5,682,716)	68,466	(5,614,249)
	March	(5,614,249)	68,466	(5,545,783)
	April	(5,545,783)	68,466	(5,477,316)
	May	(5,477,316)	68,466	(5,408,850)
	June	(5,408,850)	68,466	(5,340,384)
	July	(5,340,384)	68,466	(5,271,917)
	August	(5,271,917)	68,466	(5,203,451)
	September	(5,203,451)	68,466	(5,134,984)
	October	(5,134,984)	68,466	(5,066,518)
	November	(5,066,518)	68,466	(4,998,051)
	December	(4,998,051)	68,466	(4,929,585)
2013	January	(4,929,585)	68,466	(4,861,118)
	February	(4,861,118)	68,466	(4,792,652)
	March	(4,792,652)	68,466	(4,724,185)
	April	(4,724,185)	68,466	(4,655,719)
	May	(4,655,719)	68,466	(4,587,253)
	June	(4,587,253)	68,466	(4,518,786)
	July	(4,518,786)	68,466	(4,450,320)
	August	(4,450,320)	68,466	(4,381,853)
	September	(4,381,853)	68,466	(4,313,387)
	October	(4,313,387)	68,466	(4,244,920)
	November	(4,244,920)	68,466	(4,176,454)
	December	(4,176,454)	68,466	(4,107,987)
		Pro Forma Amort =	821,597	

PacifiCorp
Oregon General Rate Case - December 2013
Regulatory Asset Amortization
Electric Plant Acquisition Adjustment
Account 115

	Account 115	Amortization of Account 114 Amort Expense	Amortization of Account 114 Accum Amort
Pro Forma (Rate Base B/E Avg)	159,175,508	5,193,044	(115,489,726)
Base Period (Rate Base YE)	159,175,508	5,523,970	(104,607,250)
Adjustment	-	**(330,925)**	**(10,882,477)**
		Ref 8.10	**Ref 8.10**

		Account 115 End Balance	Beg Balance	Amortization	End Balance	Avg Balance
2010	January	157,193,780	(96,326,873)	(456,613)	(96,783,485)	
	February	159,175,508	(96,783,485)	(458,472)	(97,241,957)	
	March	159,175,508	(97,241,957)	(460,331)	(97,702,288)	
	April	159,175,508	(97,702,288)	(460,331)	(98,162,619)	
	May	159,175,508	(98,162,619)	(460,331)	(98,622,949)	
	June	159,175,508	(98,622,949)	(460,331)	(99,083,280)	
	July	159,175,508	(99,083,280)	(460,331)	(99,543,611)	
	August	159,175,508	(99,543,611)	(460,331)	(100,003,942)	
	September	159,175,508	(100,003,942)	(460,331)	(100,464,273)	
	October	159,175,508	(100,464,273)	(460,331)	(100,924,603)	
	November	159,175,508	(100,924,603)	(460,331)	(101,384,934)	
	December	159,175,508	(101,384,934)	(460,331)	(101,845,265)	
2011	January	159,175,508	(101,845,265)	(460,331)	(102,305,596)	
	February	159,175,508	(102,305,596)	(460,331)	(102,765,927)	
	March	159,175,508	(102,765,927)	(460,331)	(103,226,257)	
	April	159,175,508	(103,226,257)	(460,331)	(103,686,588)	
	May	159,175,508	(103,686,588)	(460,331)	(104,146,919)	
	June	159,175,508	(104,146,919)	(460,331)	(104,607,250)	
			Base Period Amort =	(5,523,970)		
	July	159,175,508	(104,607,250)	(460,331)	(105,067,581)	
	August	159,175,508	(105,067,581)	(460,331)	(105,527,911)	
	September	159,175,508	(105,527,911)	(460,331)	(105,988,242)	
	October	159,175,508	(105,988,242)	(460,331)	(106,448,573)	
	November	159,175,508	(106,448,573)	(460,331)	(106,908,904)	
	December	159,175,508	(106,908,904)	(460,331)	(107,369,235)	
2012	January	159,175,508	(107,369,235)	(460,331)	(107,829,565)	
	February	159,175,508	(107,829,565)	(460,331)	(108,289,896)	
	March	159,175,508	(108,289,896)	(460,331)	(108,750,227)	
	April	159,175,508	(108,750,227)	(460,331)	(109,210,558)	
	May	159,175,508	(109,210,558)	(460,331)	(109,670,889)	
	June	159,175,508	(109,670,889)	(460,331)	(110,131,219)	
	July	159,175,508	(110,131,219)	(460,331)	(110,591,550)	
	August	159,175,508	(110,591,550)	(460,331)	(111,051,881)	
	September	159,175,508	(111,051,881)	(460,331)	(111,512,212)	
	October	159,175,508	(111,512,212)	(460,331)	(111,972,543)	
	November	159,175,508	(111,972,543)	(460,331)	(112,432,873)	
	December	159,175,508	(112,432,873)	(460,331)	(112,893,204)	
2013	January	159,175,508	(112,893,204)	(460,331)	(113,353,535)	
	February	159,175,508	(113,353,535)	(460,331)	(113,813,866)	
	March	159,175,508	(113,813,866)	(460,331)	(114,274,197)	
	April	159,175,508	(114,274,197)	(460,331)	(114,734,527)	
	May	159,175,508	(114,734,527)	(460,331)	(115,194,858)	
	June	159,175,508	(115,194,858)	(460,331)	(115,655,189)	
	July	159,175,508	(115,655,189)	(405,177)	(116,060,366)	
	August	159,175,508	(116,060,366)	(405,177)	(116,465,542)	
	September	159,175,508	(116,465,542)	(405,177)	(116,870,719)	
	October	159,175,508	(116,870,719)	(405,177)	(117,275,895)	
	November	159,175,508	(117,275,895)	(405,177)	(117,681,072)	
	December	159,175,508	(117,681,072)	(405,177)	(118,086,249)	(115,489,726)
			Pro Forma Amort =	(5,193,044)		

TAX IMPACTS FOR ADIT		
Amort CY 2012	(5,523,970) X .37951=	(2,096,402)
Amort CY 2013	(5,193,044) X .37951=	(1,970,812)
Less: Tax Depr for 2013	485,621 X .37951=	184,298
Balance at 2013		(3,882,916)
Beg/End Average	Net adjustment to Account 282	(2,989,659)

PacifiCorp
Oregon General Rate Case - December 2013
Klamath Hydroelectric Settlement Agreement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Operation & Maintenance (see note 1)	537	3	530,537	SG-P	25.777%	136,757	8.11.1
Facilities Removal Costs (see note 1)	557	3	15,824,000	SG	25.777%	4,078,977	
Facilities Removal Costs (see note 1)	557	3	1,376,000	SG	25.777%	354,694	
Adjustment to Revenue:							
Oregon Customer Surcharge (see note 1)	440	3	15,824,000	OR	100.000%	15,824,000	
California Customer Surcharge (see note 1)	440	3	1,376,000	CA	0.000%	-	
Adjustment to Rate Base:							
Existing Klamath	332	3	2,150,303	SG-P	25.777%	554,287	8.11.2
Klamath Relicensing & Settlement Costs	302	3	-	SG-P	25.777%	-	8.11.3
Adjustment to Depreciation Expense:							
Existing Klamath	403HP	3	2,607,231	SG-P	25.777%	672,070	8.11.2
Klamath Relicensing & Settlement Costs	404IP	3	4,136,115	SG-P	25.777%	1,066,173	8.11.3
Adjustment to Depreciation Reserve:							
Existing Klamath	108HP	3	(9,398,362)	SG-P	25.777%	(2,422,630)	8.11.2
Klamath Relicensing & Settlement Costs	111IP	3	(12,409,338)	SG-P	25.777%	(3,198,774)	8.11.3

Description of Adjustment:

This adjustment accounts for the total test period costs related to the Klamath Hydroelectric Settlement Agreement (KHSA). Depreciation of existing Klamath facilities is accelerated so that assets are fully depreciated by December 31, 2019. Relicensing and settlement process costs are also amortized at a rate that will achieve a zero net book value by December 31, 2019. This treatment was approved in Docket UE-219.

Note 1: Additional general business revenues reflected in this adjustment are for purposes of the calculation of the 2010 Protocol allocation method only. These revenues offset the facility removal costs included through this adjustment to FERC account 557.

PacifiCorp
Oregon General Rate Case - December 2013
Klamath Hydroelectric Settlement Agreement Adjustment
O&M

	12ME Jun 2011 Actuals	12ME Dec13 Forecast	Increase to Test Period	Inflation*	Adjustment	
	(A)	(B)	(C = B - A)	(D)	(E = C - D)	
Administration/Management	485,806	621,838	136,032	35,231	100,801	
Aquatic Habitat/Hatcheries	1,521,203	2,606,020	1,084,817	110,320	974,497	
Terrestrial Improvements	35,000	48,711	13,711	2,538	11,172	
Water Measurement/Monitoring	820,584	550,327	(270,257)	59,510	(329,767)	
Water Quality Improvement	452,690	259,354	(193,336)	32,830	(226,165)	
Klamath Implementation Total	3,315,283	4,086,250	770,967	240,430	**530,537**	**Ref 8.11**

** Inflation is included in Adjustment 4.12*
The escalation factor used in this adjustment is an average based on operations and maintenance FERC account balances at June 2011.
Hydro average: 7.252%

Existing Klamath:	June 2011	Y/E	
Gross EPIS	84,295,830	84,295,830	(A)
Depreciation Reserve	(31,331,379)	(31,331,379)	(B)
Depreciation Expense	3,705,240	(C)	

	Capital Additions	EPIS Balance		Depreciation Expense		Depreciation Reserve	
				7.302%	(D)		
Jun-11		84,295,830	(A)			(31,331,379)	(B)
Jul-11	-	84,295,830		512,954		(31,844,333)	
Aug-11	-	84,295,830		512,954		(32,357,287)	
Sep-11	-	84,295,830		512,954		(32,870,242)	
Oct-11	-	84,295,830		512,954		(33,383,196)	
Nov-11	808,761	85,104,591		515,415		(33,898,611)	
Dec-11	257,200	85,361,792		518,658		(34,417,269)	
Jan-12	-	85,361,792		519,441		(34,936,710)	
Feb-12	1,038	85,362,830		519,444		(35,456,154)	
Mar-12	2,076	85,364,906		519,454		(35,975,608)	
Apr-12	2,076	85,366,982		519,466		(36,495,074)	
May-12	283,654	85,650,636		520,336		(37,015,409)	
Jun-12	-	85,650,636		521,199		(37,536,608)	
Jul-12	144,441	85,795,077		521,638		(38,058,246)	
Aug-12	760	85,795,837		522,080		(38,580,326)	
Sep-12	-	85,795,837		522,082		(39,102,408)	
Oct-12	-	85,795,837		522,082		(39,624,490)	
Nov-12	-	85,795,837		522,082		(40,146,572)	
Dec-12	650,297	86,446,133		524,061		(40,670,633)	
	2,150,303	86,446,133	(E)	6,253,364	(F)	(40,670,633)	(G)
		Year End		Year End Dec.12		Year End	
				6,312,472	(H = D * E)	(59,108)	(I = F - H)
				Annualized Dec.12		Incremental Reserve	
						(40,729,741)	(J = G + I)
						Adjusted Reserve	
	Adjustments:	**2,150,303**	(K = E - A)	**2,607,231**	(L = H - C)	**(9,398,362)**	(M = J - B)
		Ref. 8.11		**Ref. 8.11**		**Ref. 8.11**	

Projects related to Klamath Implementation:

Project	RP Factor	In-Service	Amount (July11-Dec12)
IKL IM8 JC Boyle Bypass Barrier Removal	SG-P	Dec-12	541,914
IKL IM4 IG Hatchery Bogus Creek Weir Installation	SG-P	Dec-12	108,383
IKL IM7 JC Boyle Gravel Enhancement	SG-P	Nov-11	272,608
Copco 1 Spillway Tainter Gate Rehab	SG-P	Nov-11	237,218
Copco Reach Forklift	SG-P	Nov-11	148,375
Iron Gate Klamath River Flow Protection	SG-P	May-12	262,894
Iron Gate Penstock Failure Detection	SG-P	Jul-12	145,201
IKL IM4 IG Egg Rearing Moist Air Incubat	SG-P	Dec-11	119,780
JC Boyle Instream Flow Augmentation	SG-P	Nov-11	186,371
JC Boyle Spillgate Rehab	SG-P	Dec-11	127,559
			2,150,303

Klamath Relicensing & Settlement Process Costs

In-Service Date Dec-10

	June 2011	Y/E	
Gross EPIS	74,111,750	74,111,750	(A)
Amortization Reserve	(4,136,777)	(4,136,777)	(B)
Amortization Expense	4,136,777	(C)	

	EPIS Balance		Depreciation Expense		Depreciation Reserve	
			11.163%	(D)		
Jun-11	74,111,750	(A)			(4,136,777)	(B)
Jul-11	74,111,750		689,408		(4,826,185)	
Aug-11	74,111,750		689,408		(5,515,592)	
Sep-11	74,111,750		689,408		(6,205,000)	
Oct-11	74,111,750		689,408		(6,894,407)	
Nov-11	74,111,750		689,408		(7,583,815)	
Dec-11	74,111,750		689,408		(8,273,223)	
Jan-12	74,111,750		689,408		(8,962,630)	
Feb-12	74,111,750		689,408		(9,652,038)	
Mar-12	74,111,750		689,408		(10,341,446)	
Apr-12	74,111,750		689,408		(11,030,853)	
May-12	74,111,750		689,408		(11,720,261)	
Jun-12	74,111,750		689,408		(12,409,669)	
Jul-12	74,111,750		689,408		(13,099,076)	
Aug-12	74,111,750		689,408		(13,788,484)	
Sep-12	74,111,750		689,408		(14,477,892)	
Oct-12	74,111,750		689,408		(15,167,299)	
Nov-12	74,111,750		689,408		(15,856,707)	
Dec-12	74,111,750		689,408		(16,546,115)	
	74,111,750	(E)	8,272,892	(F)	(16,546,115)	(G)
	Year End		Year End Dec.12		Year End	
			8,272,892	(H = D * E)	-	(I = F - H)
			Annualized Dec.12		Incremental Reserve	
					(16,546,115)	(J = G + I)
					Adjusted Reserve	
Adjustments:	-	(K = E - A)	**4,136,115**	(L = H - C)	**(12,409,338)**	(M = J - B)
	Ref. 8.11		**Ref. 8.11**		**Ref. 8.11**	

PacifiCorp PAGE 8.12
Oregon General Rate Case - December 2013
Misc. Asset Sales and Removals

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Black Hills O&M Expense	560	1	(53,959)	SG	25.777%	(13,909)	8.12.1
Adjustment to Rate Base:							
Remove Deseret Power's June 2011 Bal	312	1	(2,725,222)	SG	25.777%	(702,485)	8.12.1
Remove Deseret Power's June 2011 Bal	314	1	(7,678,354)	SG	25.777%	(1,979,261)	8.12.1
Remove Deseret Power's Dep Res	108SP	1	13,120	SG	25.777%	3,382	8.12.1
Adjustment to Expense:							
Adjust Snake Creek O&M Exp to Dec 2013	539	3	(93,841)	SG-U	25.777%	(24,190)	8.12.1
Adjust Condit O&M Exp to Dec 2013	539	3	(415,118)	SG-P	25.777%	(107,006)	8.12.1
Adjustment to Rate Base:							
Remove Goose Creek:							
Transmission Plant In Service	350	1	(422,880)	SG	25.777%	(109,006)	8.12.2
Accum. Prov. for Depr	108TP	1	256,093	SG	25.777%	66,013	8.12.2

Description of Adjustment:

This adjusts the Company's filing for various assets that were sold or removed, including the sale of transmission assets to Black Hills Power, the sale of Snake Creek hydroelectric plant to Heber Light and Power Company, the removal of Deseret Power's portion of the Hunter unit two scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the removal of the Goose Creek switching station. Asset balances for Snake Creek and Condit are removed in the adjustment to plant retirements, page 8.7. The Oregon allocated proceeds related to the gain on the sale of Snake Creek will be placed in the property sales balancing account and passed through to customers in Schedule 96 as outlined in Docket UP-275, Commission Order 11-331.

PacifiCorp
Oregon General Rate Case - December 2013
Misc Asset Sales and Removals

	12 ME June 2011	12 ME December 2013	Adjustment	
Black Hills				
O&M Expense	53,959	-	**(53,959)**	**Ref. 8.12**

	June 2011 Year-End Balance	December 2013 Year-End Balance	Adjustment	
Deseret Power - Hunter Projects				
EPIS - 312	2,725,222	-	**(2,725,222)**	**Ref. 8.12**
EPIS - 314	7,678,354	-	**(7,678,354)**	**Ref. 8.12**
Depreciation Reserve	(13,120)	-	**13,120**	**Ref. 8.12**

Snake Creek		12 ME June 2011	Escalation Rate	Escalated Amount	12 ME December 2013	Adjustment	
O&M Expense	539	79,455	7.81%	85,663	-	(85,663)	
	543	1,376	4.61%	1,439	-	(1,439)	
	544	5,752	4.61%	6,016	-	(6,016)	
	545	691	4.61%	723	-	(723)	
		87,273		93,841	-	**(93,841)**	**Ref. 8.12**
Condit Hydroelectric Project							
O&M Expense	535	5,795	7.81%	6,248	-	(6,248)	
	537	41,524	7.81%	44,769	-	(44,769)	
	539	273,121	7.81%	294,460	-	(294,460)	
	542	3,956	4.61%	4,139	-	(4,139)	
	543	(303)	4.61%	(317)	-	317	
	544	31,084	4.61%	32,516	-	(32,516)	
	545	31,837	4.61%	33,304	-	(33,304)	
		387,015		415,118	-	**(415,118)**	**Ref. 8.12**

PacifiCorp
Oregon General Rate Case - December 2013
Misc Asset Sales and Removals

Goose Creek (Assets Retired)

	FERC Acct	Factor	June 2011 Balance	
Switching Station	350	SG	**422,880**	**Ref. 8.12**
Switching Station Accum Depr	108TP	SG	**(256,093)**	**Ref. 8.12**
Switching Station Book Value			166,787	

PacifiCorp
Oregon General Rate Case - December 2013
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Plant	341	1	(3,045,740)	SG	25.777%	(785,105)	
Other Plant	343	1	(178,830,073)	SG	25.777%	(46,097,305)	
Other Plant	344	1	(5,850,373)	SG	25.777%	(1,508,060)	
Other Plant	345	1	(12,048,682)	SG	25.777%	(3,105,807)	
Other Plant	346	1	(659,497)	SG	25.777%	(170,000)	
General Plant	392	1	(28,254)	SG	25.777%	(7,283)	8.13.1
			(200,462,618)			(51,673,560)	
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	17,045,720	SG	25.777%	4,393,902	
General Plant	108GP	1	5,265	SG	25.777%	1,357	8.13.1
			17,050,985			4,395,259	
Adjustment to O&M Expense:							
Rolling Hills	549	1	(903,082)	SG	25.777%	(232,789)	8.13.1
Rolling Hills	929	1	(451,580)	SO	27.165%	(122,672)	8.13.1
			(1,354,661)			(355,460)	
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	(6,588,076)	SCHMDEXP	27.513%	(1,812,601)	
Schedule M Adjustment	SCHMDT	1	(21,331,398)	TAXDEPR	26.149%	(5,577,917)	
Deferred Tax Expense	41110	1	2,500,241	SCHMDEXP	27.513%	687,900	
Deferred Tax Expense	41010	1	(8,095,479)	TAXDEPR	26.149%	(2,116,875)	
Deferred Tax Expense	41110	1	8,345	OR	100.000%	8,345	
Accumulated Def Inc Tax Balance	282	1	14,471,106	OR	100.000%	14,471,106	

Description of Adjustment:

This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the 12 months ended June 2011. This treatment is consistent with Commission Order No. 08-548.

Rate Base Amounts	Balance as of June 2011	Ref.
Capital		
Other Plant - 341	3,045,740	
Other Plant - 343	178,830,073	
Other Plant - 344	5,850,373	
Other Plant - 345	12,048,682	
Other Plant - 346	659,497	
General Plant - 392	28,254	
	200,462,618	8.13
Depreciation Reserve		
Other Plant	(17,045,720)	
General Plant	(5,265)	
	(17,050,985)	8.13

Expense Amounts	Amount in Yr Ended June 2011	Ref.
Operation & Maintenance Expense		
Account 549	903,082	8.13
Account 929	451,580	8.13
	1,354,661	

PacifiCorp PAGE 8.14
Oregon General Rate Case - December 2013
FERC 105 (PHFU)

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove PHFU	105	1	(11,867,819)	SG	25.777%	(3,059,186)	
Remove PHFU	105	1	(2,920,237)	UT	0.000%	-	
Remove PHFU	105	1	(4,254,106)	OR	100.000%	(4,254,106)	
Remove PHFU	105	1	(25,979,316)	SE	24.314%	(6,316,486)	
			(45,021,478)			(13,629,778)	8.14.1

Description of Adjustment:

This adjustment removes all Plant Held for Future Use (PHFU) assets from FERC account 105. The company is making this adjustment in compliance with UE 116, Order No. 01-787, Appendix A, page 4 of 5.

PacifiCorp
Oregon General Rate Case - December 2013
FERC 105 (PHFU)
From BW Report (SAP)

Primary Account		Secondary Account		Alloc	Jun-11
1050000	EL PLT HLD FTR USE	3401000	LAND OWNED IN FEE	SG	8,923,302
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEE	SG	2,788,412
1050000	EL PLT HLD FTR USE	3502000	LAND OWNED IN FEE	SG	156,105
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	OR	746,268
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	UT	2,920,237
1050000	EL PLT HLD FTR USE	3891000	LAND OWNED IN FEE	OR	3,507,838
1050000	EL PLT HLD FTR USE	3992200	LAND RIGHTS	SE	953,014
1059000	EL PLT HLD FTR USE-O	0	ELECTRIC PHFU -OTHER	SE	25,026,303
Total					**45,021,478**

SG	11,867,819	
UT	2,920,237	
OR	4,254,106	
SE	25,979,316	
Total	**45,021,478**	**Ref. 8.14**

PacifiCorp PAGE 8.15
Oregon General Rate Case - December 2013
Carbon Plant Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Carbon Plant	312	3	1,505,930	SG	25.777%	388,186	Conf. Ex. PAC/1105
Adjustment to Depreciation Expense:							
Carbon Plant	403SP	3	41,145,553	SG	25.777%	10,606,153	Conf. Ex. PAC/1105
Adjustment to Depreciation Reserve:							
Carbon Plant	108SP	3	(51,596,447)	SG	25.777%	(13,300,096)	Conf. Ex. PAC/1105
Tax Adjustments:							
Schedule M Adjustment	SCHMAT	3	41,145,553	SG	25.777%	10,606,153	
Deferred Income Tax Expense	41110	3	(15,615,149)	SG	25.777%	(4,025,141)	
ADIT Balance	282	3	15,615,149	SG	25.777%	4,025,141	

Description of Adjustment:

This adjustment includes accelerated depreciation for the Carbon plant. Depreciation of the Carbon plant is accelerated so that assets are fully depreciated by April 2015. The Carbon plant is depreciated using approved rates through December 31, 2012, but the annualized level of depreciation included in this adjustment uses the accelerated rate.

The Company currently anticipates that the Carbon plant will discontinue operations as early as April 2015. Compliance with recently promulgated EPA mercury and air toxics standards (MATS) will likely require significant investment in emissions control equipment for the Carbon units. Such emissions control equipment is likely uneconomical to retrofit at Carbon. Alternatives to such emissions control equipment at the Carbon plant, such as conversion of the units to natural gas, will also likely not be economic for customers. Nonetheless, the Company continues to evaluate compliance options and transmission system impacts that will ultimately contribute to the Company's decision-making process regarding this facility.

It is important to note that the MATS regulations currently include provisions for requesting extension of compliance deadlines under certain system reliability and compliance project timing scenarios. There is also the potential that the MATS regulations driving an accelerated plant closure may be subject to a series of delays from appeals, thereby prolonging the closure.

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DEC 31, 2013
FILE:	OR JAM Dec 2013 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/27/2012
TIME:	8:27:47 AM
TYPE OF RATE BASE:	Year End
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	1.660
FEDERAL/STATE COMBINED RATE	37.951%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	46.90%	5.372%	2.519%
PREFERRED	0.30%	5.427%	0.016%
COMMON	52.80%	10.200%	5.386%
	100.00%		7.921%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see the testimony of Mr. Bruce N. Williams.
For information and support regarding return on common equity, see the testimony of Dr. Samuel C. Hadaway.

REVISED PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1	Operating Revenues					
2	General Business Revenues	2.3	3,762,226,028	1,057,442,897	4,261,379,301	1,198,198,666
3	Interdepartmental	2.3	0	0	0	0
4	Special Sales	2.3	379,179,495	96,385,126	470,484,400	119,935,205
5	Other Operating Revenues	2.4	323,231,828	82,320,482	146,133,018	39,568,762
6	Total Operating Revenues	2.4	4,464,637,351	1,236,148,505	4,877,996,718	1,357,702,634
7						
8	Operating Expenses:					
9	Steam Production	2.5	991,002,147	245,975,227	1,128,949,413	279,765,299
10	Nuclear Production	2.6	0	0	0	0
11	Hydro Production	2.7	43,249,454	11,148,479	50,399,087	12,991,451
12	Other Power Supply	2.9	900,802,841	211,827,635	1,187,016,092	309,196,350
13	Embedded Cost Differential (ECD)		0	(8,734,872)	0	(4,348,707)
14	Transmission	2.10	203,395,397	52,337,448	199,472,285	51,375,843
15	Distribution	2.12	211,900,030	67,278,537	222,653,494	70,646,415
16	Customer Accounting	2.12	95,209,362	33,934,000	99,289,759	35,339,085
17	Customer Service & Infor	2.13	113,969,877	25,306,096	20,536,835	4,061,969
18	Sales	2.13	0	0	0	0
19	Administrative & General	2.14	153,962,449	46,225,173	143,057,189	45,507,206
20						
21	Total O & M Expenses	2.14	2,713,491,556	685,297,723	3,051,374,154	804,534,911
22						
23	Depreciation	2.16	515,564,333	145,480,763	648,623,871	178,556,841
24	Amortization	2.17	48,399,074	13,240,235	51,678,159	13,811,422
25	Taxes Other Than Income	2.17	146,842,558	57,033,205	167,755,580	65,254,394
26	Income Taxes - Federal	2.20	(618,009,956)	(127,426,047)	(88,481,998)	(4,651,063)
27	Income Taxes - State	2.20	(76,306,032)	(15,337,836)	(3,872,858)	1,468,901
28	Income Taxes - Def Net	2.19	922,130,589	227,736,260	284,396,170	71,477,555
29	Investment Tax Credit Adj.	2.17	(1,874,204)	0	(1,874,204)	0
30	Misc Revenue & Expense	2.4	(1,689,284)	(217,486)	(2,364,567)	(346,249)
31						
32	Total Operating Expenses	2.20	3,648,548,635	985,806,817	4,107,234,308	1,130,106,713
33						
34	Operating Revenue for Return		816,088,716	250,341,688	770,762,410	227,595,921
35						
36	Rate Base:					
37	Electric Plant in Service	2.30	22,157,283,708	6,042,320,934	23,586,997,425	6,411,672,676
38	Plant Held for Future Use	2.31	45,021,478	13,629,778	0	0
39	Misc Deferred Debits	2.33	213,788,714	20,005,179	224,219,332	22,574,838
40	Elec Plant Acq Adj	2.31	54,568,258	14,066,144	43,685,781	11,260,952
41	Nuclear Fuel	2.31	0	0	0	0
42	Prepayments	2.32	28,443,124	7,668,739	28,443,124	7,668,739
43	Fuel Stock	2.32	218,254,887	53,126,671	208,865,369	50,821,098
44	Material & Supplies	2.32	190,997,513	54,183,873	190,997,513	54,183,873
45	Working Capital	2.33	71,452,139	22,816,250	85,403,234	28,005,358
46	Weatherization Loans	2.31	(35,682)	(1,210)	(35,682)	(1,210)
47	Miscellaneous Rate Base	2.34	0	0	0	0
48						
49	Total Electric Plant		22,979,774,139	6,227,816,357	24,368,576,097	6,586,186,324
50						
51	Rate Base Deductions:					
52	Accum Prov For Depr	2.38	(6,903,348,317)	(2,013,730,903)	(7,548,558,148)	(2,199,790,441)
53	Accum Prov For Amort	2.39	(471,314,196)	(131,052,265)	(506,182,675)	(140,152,858)
54	Accum Def Income Taxes	2.35	(3,103,714,231)	(836,200,317)	(3,627,014,527)	(960,748,582)
55	Unamortized ITC	2.35	(4,857,544)	(3,084,689)	(1,899,596)	(1,115,967)
56	Customer Adv for Const	2.34	(27,863,920)	(11,273,844)	(27,863,920)	(11,392,393)
57	Customer Service Deposits	2.34	0	0	0	0
58	Misc. Rate Base Deductions	2.34	(63,364,442)	(15,791,340)	(64,194,166)	(15,993,075)
59						
60	Total Rate Base Deductions		(10,574,462,650)	(3,011,133,359)	(11,775,713,032)	(3,329,193,315)
61						
62	Total Rate Base		12,405,311,489	3,216,682,999	12,592,863,065	3,256,993,008
63						
64	Return on Rate Base		6.579%	7.783%	6.121%	6.988%
65						
66	Return on Equity		7.657%	9.937%	6.790%	8.432%
67	Net Power Costs		1,242,802,122	304,971,288	1,504,095,928	370,482,581
68	100 Basis Points in Equity:					
69	Revenue Requirement Impact		105,561,805	27,372,055	107,157,758	27,715,069
70	Rate Base Decrease		(921,686,497)	(204,366,457)	(1,000,060,590)	(228,806,763)

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
71	Sales to Ultimate Customers								
72	440	Residential Sales							
73			0	S		1,437,482,984	525,297,185	1,594,603,193	580,219,963
74									
75					B1	1,437,482,984	525,297,185	1,594,603,193	580,219,963
76									
77	442	Commercial & Industrial Sales							
78			0	S		2,284,357,284	526,413,455	2,626,335,543	612,827,521
79			P	SE		-	-	-	-
80			PT	SG		-	-	-	-
81									
82									
83					B1	2,284,357,284	526,413,455	2,626,335,543	612,827,521
84									
85	444	Public Street & Highway Lighting							
86			0	S		20,614,685	5,732,257	19,191,288	5,151,182
87			0	SO		-	-	-	-
88					B1	20,614,685	5,732,257	19,191,288	5,151,182
89									
90	445	Other Sales to Public Authority							
91			0	S		19,771,075	-	21,249,276	-
92									
93					B1	19,771,075	-	21,249,276	-
94									
95	448	Interdepartmental							
96			DPW	S		-	-	-	-
97			GP	SO		-	-	-	-
98					B1	-	-	-	-
99									
100	**Total Sales to Ultimate Customers**				**B1**	**3,762,226,028**	**1,057,442,897**	**4,261,379,301**	**1,198,198,666**
101									
102									
103									
104	447	Sales for Resale-Non NPC							
105			P	S		9,158,552	1,018,526	9,158,552	1,018,526
106						9,158,552	1,018,526	9,158,552	1,018,526
107									
108	447NPC	Sales for Resale-NPC							
109			P	SG		369,045,839	95,129,518	461,325,848	118,916,679
110			P	SE		975,104	237,082	-	-
111			P	SG		-	-	-	-
112						370,020,943	95,366,600	461,325,848	118,916,679
113									
114		Total Sales for Resale			B1	379,179,495	96,385,126	470,484,400	119,935,205
115									
116	449	Provision for Rate Refund							
117			P	S		-	-	-	-
118			P	SG		-	-	-	-
119									
120									
121					B1	-	-	-	-
122									
123	**Total Sales from Electricity**				**B1**	**4,141,405,523**	**1,153,828,023**	**4,731,863,701**	**1,318,133,871**
124	450	Forfeited Discounts & Interest							
125			CUST	S		8,064,749	3,149,119	8,064,749	3,149,119
126			CUST	SO		-	-	-	-
127					B1	8,064,749	3,149,119	8,064,749	3,149,119
128									
129	451	Misc Electric Revenue							
130			CUST	S		5,941,041	1,140,452	5,941,041	1,140,452
131			CUST	SG		-	-	-	-
132			CUST	SO		1,151	313	1,151	313
133					B1	5,942,192	1,140,765	5,942,192	1,140,765
134									
135	453	Water Sales							
136			P	SG		85,842	22,128	85,842	22,128
137					B1	85,842	22,128	85,842	22,128
138									
139	454	Rent of Electric Property							
140			DPW	S		10,629,119	5,103,258	10,629,119	5,103,258
141			T	SG		5,697,494	1,468,652	5,697,494	1,468,652
142			GP	SO		3,501,221	951,740	3,501,221	951,740
143					B1	19,827,834	7,523,649	19,827,834	7,523,649
144									
145									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
146									
147	456	Other Electric Revenue							
148			DMSC	S		98,316,742	21,405,134	4,021,198	(81)
149			CUST	CN		-	-	-	-
150			OTHSE	SE		10,745,276	2,612,555	10,894,140	2,648,749
151			OTHSO	SO		285,872	77,709	285,872	77,709
152			OTHSGR	SG		179,963,321	46,389,424	97,011,191	25,006,725
153									
154									
155					B1	289,311,211	70,484,821	112,212,401	27,733,101
156									
157	**Total Other Electric Revenues**				**B1**	**323,231,828**	**82,320,482**	**146,133,018**	**39,568,762**
158									
159	**Total Electric Operating Revenues**				**B1**	**4,464,637,351**	**1,236,148,505**	**4,877,996,718**	**1,357,702,634**
160									
161	Summary of Revenues by Factor								
162		S				3,894,336,230	1,089,259,385	4,299,193,959	1,208,609,940
163		CN				-	-	-	-
164		SE				11,720,380	2,849,637	10,894,140	2,648,749
165		SO				3,788,245	1,029,762	3,788,245	1,029,762
166		SG				554,792,496	143,009,722	564,120,374	145,414,183
167		DGP				-	-	-	-
168									
169	Total Electric Operating Revenues					4,464,637,351	1,236,148,505	4,877,996,718	1,357,702,634
170	Miscellaneous Revenues								
171	41160	Gain on Sale of Utility Plant - CR							
172			DPW	S		-	-	-	-
173			T	SG		-	-	-	-
174			G	SO		-	-	-	-
175			T	SG		-	-	-	-
176			P	SG		-	-	-	-
177					B1	-	-	-	-
178									
179	41170	Loss on Sale of Utility Plant							
180			DPW	S		-	-	-	-
181			T	SG		-	-	-	-
182					B1	-	-	-	-
183									
184	4118	Gain from Emission Allowances							
185			P	S		-	-	-	-
186			P	SE		(559,750)	(136,095)	(1,235,033)	(300,280)
187					B1	(559,750)	(136,095)	(1,235,033)	(300,280)
188									
189	41181	Gain from Disposition of NOX Credits							
190			P	SE		-	-	-	-
191					B1	-	-	-	-
192									
193	4194	Impact Housing Interest Income							
194			P	SG		-	-	-	-
195					B1	-	-	-	-
196									
197	421	(Gain) / Loss on Sale of Utility Plant							
198			DPW	S		233,226	275,201	77,137	265,014
199			T	SG		(761,976)	(196,416)	(761,976)	(196,416)
200			T	SG		(170,995)	(44,078)	(170,995)	(44,078)
201			CUST	CN		899	264	899	264
202			PTD	SO		(380,083)	(103,318)	2,099	571
203			P	SG		(50,606)	(13,045)	(276,699)	(71,325)
204					B1	(1,129,534)	(81,391)	(1,129,534)	(45,969)
205									
206	**Total Miscellaneous Revenues**					**(1,689,284)**	**(217,486)**	**(2,364,567)**	**(346,249)**
207	Miscellaneous Expenses								
208	4311	Interest on Customer Deposits							
209			CUST	S		-	-	-	-
210					B1	-	-	-	-
211	**Total Miscellaneous Expenses**					-	-	-	-
212									
213	**Net Misc Revenue and Expense**				**B1**	**(1,689,284)**	**(217,486)**	**(2,364,567)**	**(346,249)**
214									

REVISED PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
215	500	Operation Supervision & Engineering							
216			P	SG		17,434,919	4,494,226	18,163,498	4,682,033
217			P	SSGCH		2,217,593	589,996	2,403,391	639,429
218					B2	19,652,512	5,084,223	20,566,889	5,321,461
219									
220	501	Fuel Related-Non NPC							
221			P	SE		18,028,765	4,383,427	19,539,898	4,750,837
222			P	SE		-	-	-	-
223			P	SE		-	-	-	-
224			P	SSECT		-	-	-	-
225			P	SSECH		3,225,441	802,863	3,495,680	870,129
226					B2	21,254,205	5,186,290	23,035,578	5,620,966
227									
228	501NPC	Fuel Related-NPC							
229			P	S		(409,282)	-	-	-
230			P	SE		614,495,568	149,405,496	724,243,273	176,089,025
231			P	SE		-	-	-	-
232			P	SE		-	-	-	-
233			P	SSECT		-	-	-	-
234			P	SSECH		49,297,564	12,270,935	56,457,816	14,053,234
235					B2	663,383,851	161,676,431	780,701,089	190,142,259
236									
237		Total Fuel Related				684,638,056	166,862,721	803,736,667	195,763,225
238									
239	502	Steam Expenses							
240			P	SG		31,637,199	8,155,170	33,473,246	8,628,451
241			P	SSGCH		7,646,027	2,034,246	8,286,640	2,204,683
242					B2	39,283,226	10,189,416	41,759,887	10,833,133
243									
244	503	Steam From Other Sources-Non-NPC							
245			P	SE		-	-	(3,411)	(829)
246					B2	-	-	(3,411)	(829)
247									
248	503NPC	Steam From Other Sources-NPC							
249			P	SE		3,321,608	807,600	4,183,520	1,017,161
250					B2	3,321,608	807,600	4,183,520	1,017,161
251									
252	505	Electric Expenses							
253			P	SG		3,108,226	801,212	3,282,389	846,106
254			P	SSGCH		1,137,586	302,658	1,232,897	328,016
255					B2	4,245,811	1,103,870	4,515,286	1,174,122
256									
257	506	Misc. Steam Expense							
258			P	SG		48,802,848	12,579,986	50,795,673	13,093,679
259			P	SE		-	-	-	-
260			P	SSGCH		1,904,602	506,724	2,064,357	549,228
261					B2	50,707,450	13,086,710	52,860,030	13,642,907
262									
263	507	Rents							
264			P	SG		286,514	73,855	310,520	80,043
265			P	SSGCH		623	166	675	180
266					B2	287,138	74,021	311,195	80,223
267									
268	510	Maint Supervision & Engineering							
269			P	SG		4,593,089	1,183,968	2,210,861	569,897
270			P	SSGCH		1,999,843	532,063	2,174,725	578,591
271					B2	6,592,932	1,716,031	4,385,586	1,148,488
272									
273									
274									
275	511	Maintenance of Structures							
276			P	SG		23,720,364	6,114,435	24,725,131	6,373,435
277			P	SSGCH		424,329	112,894	443,447	117,980
278					B2	24,144,693	6,227,329	25,168,578	6,491,416
279									
280	512	Maintenance of Boiler Plant							
281			P	SG		101,673,678	26,208,582	108,957,994	28,086,271
282			P	SSGCH		4,835,272	1,286,437	8,690,223	2,312,057
283					B2	106,508,950	27,495,019	117,648,217	30,398,328
284									
285	513	Maintenance of Electric Plant							
286			P	SG		38,873,335	10,020,440	40,521,249	10,445,225
287			P	SSGCH		643,842	171,296	672,834	179,009
288					B2	39,517,177	10,191,736	41,194,083	10,624,234
289									
290	514	Maintenance of Misc. Steam Plant							
291			P	SG		10,067,965	2,595,235	10,496,512	2,705,702
292			P	SSGCH		2,034,629	541,319	2,126,376	565,728
293					B2	12,102,595	3,136,554	12,622,887	3,271,430
294									
295	**Total Steam Power Generation**				**B2**	**991,002,147**	**245,975,227**	**1,128,949,413**	**279,765,299**

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
296	517	Operation Super & Engineering							
297			P	SG		-	-	-	-
298					B2	-	-	-	-
299									
300	518	Nuclear Fuel Expense							
301			P	SE		-	-	-	-
302									
303					B2	-	-	-	-
304									
305	519	Coolants and Water							
306			P	SG		-	-	-	-
307					B2	-	-	-	-
308									
309	520	Steam Expenses							
310			P	SG		-	-	-	-
311					B2	-	-	-	-
312									
313									
314									
315	523	Electric Expenses							
316			P	SG		-	-	-	-
317					B2	-	-	-	-
318									
319	524	Misc. Nuclear Expenses							
320			P	SG		-	-	-	-
321					B2	-	-	-	-
322									
323	528	Maintenance Super & Engineering							
324			P	SG		-	-	-	-
325					B2	-	-	-	-
326									
327	529	Maintenance of Structures							
328			P	SG		-	-	-	-
329					B2	-	-	-	-
330									
331	530	Maintenance of Reactor Plant							
332			P	SG		-	-	-	-
333					B2	-	-	-	-
334									
335	531	Maintenance of Electric Plant							
336			P	SG		-	-	-	-
337					B2	-	-	-	-
338									
339	532	Maintenance of Misc Nuclear							
340			P	SG		-	-	-	-
341					B2	-	-	-	-
342									
343	**Total Nuclear Power Generation**				**B2**	-	-	-	-
344									
345	535	Operation Super & Engineering							
346			P	DGP		-	-	-	-
347			P	SG		5,436,999	1,401,504	9,912,764	2,555,228
348			P	SG		(924,196)	(238,231)	(505,379)	(130,272)
349									
350					B2	4,512,803	1,163,272	9,407,384	2,424,956
351									
352	536	Water For Power							
353			P	DGP		-	-	-	-
354			P	SG		199,930	51,536	212,164	54,690
355			P	SG		-	-	-	-
356									
357					B2	199,930	51,536	212,164	54,690
358									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
359	537	Hydraulic Expenses							
360			P	DGP		-	-	-	-
361			P	SG		3,376,626	870,398	4,143,554	1,068,090
362			P	SG		259,907	66,997	277,962	71,651
363									
364					B2	3,636,533	937,395	4,421,516	1,139,741
365									
366	538	Electric Expenses							
367			P	DGP		-	-	-	-
368			P	SG		-	-	-	-
369			P	SG		-	-	-	-
370									
371					B2	-	-	-	-
372									
373	539	Misc. Hydro Expenses							
374			P	DGP		-	-	-	-
375			P	SG		19,787,089	5,100,549	20,640,604	5,320,560
376			P	SG		7,388,753	1,904,610	7,670,423	1,977,217
377									
378									
379					B2	27,175,842	7,005,159	28,311,027	7,297,777
380									
381	540	Rents (Hydro Generation)							
382			P	DGP		-	-	-	-
383			P	SG		158,963	40,976	178,124	45,915
384			P	SG		983	253	1,060	273
385									
386					B2	159,947	41,230	179,184	46,188
387									
388	541	Maint Supervision & Engineering							
389			P	DGP		-	-	-	-
390			P	SG		1,691	436	1,755	452
391			P	SG		-	-	-	-
392									
393					B2	1,691	436	1,755	452
394									
395	542	Maintenance of Structures							
396			P	DGP		-	-	-	-
397			P	SG		1,028,908	265,223	1,071,488	276,199
398			P	SG		22,386	5,770	22,567	5,817
399									
400					B2	1,051,293	270,994	1,094,055	282,016
401									
402									
403									
404									
405	543	Maintenance of Dams & Waterways							
406			P	DGP		-	-	-	-
407			P	SG		1,391,013	358,564	1,451,174	374,071
408			P	SG		637,041	164,211	661,402	170,491
409									
410					B2	2,028,054	522,775	2,112,576	544,562
411									
412	544	Maintenance of Electric Plant							
413			P	DGP		-	-	-	-
414			P	SG		1,280,143	329,985	1,330,455	342,953
415			P	SG		361,514	93,188	375,294	96,740
416									
417					B2	1,641,657	423,172	1,705,749	439,693
418									
419	545	Maintenance of Misc. Hydro Plant							
420			P	DGP		-	-	-	-
421			P	SG		1,978,265	509,940	2,053,304	529,283
422			P	SG		863,439	222,570	900,373	232,090
423									
424					B2	2,841,704	732,511	2,953,677	761,374
425									
426	**Total Hydraulic Power Generation**				**B2**	**43,249,454**	**11,148,479**	**50,399,087**	**12,991,451**

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
427									
428	546	Operation Super & Engineering							
429			P	SG		398,439	102,706	430,688	111,019
430			P	SSGCT		-	-	-	-
431					B2	398,439	102,706	430,688	111,019
432									
433	547	Fuel-Non-NPC							
434			P	SE		-	-	-	-
435			P	SSECT		-	-	-	-
436					B2	-	-	-	-
437									
438	547NPC	Fuel-NPC							
439			P	SE		365,731,151	88,922,112	349,046,222	84,865,419
440			P	SSECT		16,065,664	3,904,072	17,197,901	4,179,214
441					B2	381,796,815	92,826,185	366,244,123	89,044,633
442									
443	548	Generation Expense							
444			P	SG		12,707,631	3,275,666	12,387,370	3,193,112
445			P	SSGCT		1,195,095	307,776	1,247,708	321,326
446					B2	13,902,725	3,583,442	13,635,078	3,514,438
447									
448	549	Miscellaneous Other							
449			P	S		-	-	-	-
450			P	SG		21,482,053	5,537,462	21,654,734	5,581,974
451			P	SSGCT		-	-	-	-
452					B2	21,482,053	5,537,462	21,654,734	5,581,974
453									
454									
455									
456									
457	550	Rents							
458			P	S		-	-	502,584	502,584
459			P	SG		3,846,936	991,631	4,158,849	1,072,033
460			P	SSGCT		-	-	-	-
461					B2	3,846,936	991,631	4,661,433	1,574,617
462									
463	551	Maint Supervision & Engineering							
464			P	SG		-	-	-	-
465					B2	-	-	-	-
466									
467	552	Maintenance of Structures							
468			P	SG		2,539,068	654,499	2,667,827	687,690
469			P	SSGCT		141,863	36,534	145,949	37,587
470					B2	2,680,930	691,034	2,813,776	725,277
471									
472	553	Maint of Generation & Electric Plant							
473			P	SG		9,506,139	2,450,412	9,729,443	2,507,974
474			P	SSGCT		517,185	133,192	536,452	138,154
475					B2	10,023,323	2,583,604	10,265,896	2,646,128
476									
477	554	Maintenance of Misc. Other							
478			P	SG		2,583,613	665,982	2,718,026	700,630
479			P	SSGCT		133,251	34,317	136,469	35,145
480					B2	2,716,865	700,299	2,854,495	735,775
481									
482	**Total Other Power Generation**				**B2**	**436,848,086**	**107,016,362**	**422,560,223**	**103,933,861**
483									
484									
485	555	Purchased Power-Non NPC							
486			DMSC	S		(30,986,809)	(22,356,044)	-	-
487						(30,986,809)	(22,356,044)	-	-
488									
489	555NPC	Purchased Power-NPC							
490			P	S		-	-	(145,921)	(145,921)
491			P	SG		402,775,436	103,824,048	644,944,800	166,248,421
492			P	SE		23,644,780	5,748,878	37,962,219	9,229,951
493		Seasonal Co	P	SSGC		-	-	-	-
494				DGP		-	-	-	-
495						426,420,216	109,572,927	682,761,098	175,332,451
496									
497		Total Purchased Power			B2	395,433,407	87,216,882	682,761,098	175,332,451
498									
499	556	System Control & Load Dispatch							
500			P	SG		1,200,430	309,437	1,272,275	327,956
501									
502					B2	1,200,430	309,437	1,272,275	327,956
503									
504									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
505									
506	557	Other Expenses							
507			P	S		(183,792)	(53,813)	26,766,674	15,770,187
508			P	SG		62,079,483	16,002,325	52,533,396	13,541,615
509			P	SGCT		1,122,425	290,280	1,122,425	290,280
510			P	SE		4,302,803	1,046,163	-	-
511			P	SSGCT		-	-	-	-
512			P	TROJP		-	-	-	-
513									
514					B2	67,320,919	17,284,954	80,422,496	29,602,081
515									
516	**Total Other Power Supply**				**B2**	**463,954,755**	**104,811,273**	**764,455,869**	**205,262,489**
517									
518	**Total Production Expense**				**B2**	**1,935,054,442**	**468,951,341**	**2,366,364,592**	**601,953,100**
519									
520	Embedded Cost Differentials								
521	Company Owned Hyc		P	DGP		(37,527,138)	(20,387,995)	(22,719,268)	(12,343,076)
522	Company Owned Hyc		P	SG		37,527,138	9,673,429	22,719,268	5,856,381
523	Mid-C Contract		P	MC		(14,215,023)	(5,885,814)	(16,711,783)	(6,919,612)
524	Mid-C Contract		P	SG		14,215,023	3,664,229	16,711,783	4,307,822
525	Existing QF Contracts		P	S		17,568,373	8,729,907	13,082,809	8,122,154
526	Existing QF Contracts		P	SG		(17,568,373)	(4,528,627)	(13,082,809)	(3,372,376)
527									
528					**B2**	-	(8,734,872)	-	(4,348,707)
529									
530	2010 Protocol Stipulated Embedded Cost Differential and Adjustment								
531	Company Owned Hyc		P	DGP		-	-	-	-
532	Company Owned Hyc		P	SG		-	-	-	-
533	Mid-C Contract		P	MC		-	-	-	-
534	Mid-C Contract		P	SG		-	-	-	-
535	Klamath Dam Remov		P	S		-	-	-	-
536						-	-	-	-
537									
538									
539	Summary of Production Expense by Factor								
540		S				(14,011,511)	(13,679,951)	40,206,146	24,249,004
541		SG				876,740,608	225,998,786	1,122,181,812	289,266,545
542		SE				1,029,524,674	250,313,676	1,134,971,721	275,951,564
543		SNPPH				-	-	-	-
544		TROJP				-	-	-	-
545		SGCT				1,122,425	290,280	1,122,425	290,280
546		DGP				(37,527,138)	(20,387,995)	(22,719,268)	(12,343,076)
547		DEU				-	-	-	-
548		DEP				-	-	-	-
549		SNPPS				-	-	-	-
550		SNPPO				-	-	-	-
551		DGU				-	-	-	-
552		MC				(14,215,023)	(5,885,814)	(16,711,783)	(6,919,612)
553		SSGCT				1,987,393	511,820	2,066,578	532,212
554		SSECT				16,065,664	3,904,072	17,197,901	4,179,214
555		SSGC				-	-	-	-
556		SSGCH				22,844,345	6,077,799	28,095,565	7,474,899
557		SSECH				52,523,005	13,073,798	59,953,496	14,923,363
558	Total Production Expense by Factor					1,935,054,442	460,216,469	2,366,364,592	597,604,393
559	560	Operation Supervision & Engineering							
560			T	SG		6,080,103	1,567,278	6,260,781	1,613,851
561									
562					B2	6,080,103	1,567,278	6,260,781	1,613,851
563									
564	561	Load Dispatching							
565			T	SG		10,809,557	2,786,396	11,237,083	2,896,600
566									
567					B2	10,809,557	2,786,396	11,237,083	2,896,600
568	562	Station Expense							
569			T	SG		2,821,129	727,207	2,965,446	764,408
570									
571					B2	2,821,129	727,207	2,965,446	764,408
572									
573	563	Overhead Line Expense							
574			T	SG		117,236	30,220	122,245	31,511
575									
576					B2	117,236	30,220	122,245	31,511
577									
578	564	Underground Line Expense							
579			T	SG		-	-	-	-
580									
581					B2	-	-	-	-
582									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
583	565	Transmission of Electricity by Others							
584			T	SG		-	-	-	-
585			T	SE		-	-	-	-
586						-	-	-	-
587									
588	565NPC	Transmission of Electricity by Others-NPC							
589			T	SG		131,608,086	33,924,820	128,632,545	33,157,810
590			T	SE		6,292,490	1,529,926	2,899,400	704,946
591						137,900,576	35,454,746	131,531,945	33,862,757
592									
593		Total Transmission of Electricity by Others			B2	137,900,576	35,454,746	131,531,945	33,862,757
594									
595	566	Misc. Transmission Expense							
596			T	SG		4,256,727	1,097,263	3,583,415	923,703
597									
598					B2	4,256,727	1,097,263	3,583,415	923,703
599									
600	567	Rents - Transmission							
601			T	SG		1,837,478	473,649	1,949,783	502,599
602									
603					B2	1,837,478	473,649	1,949,783	502,599
604									
605	568	Maint Supervision & Engineering							
606			T	SG		2,286,817	589,476	2,376,593	612,618
607									
608					B2	2,286,817	589,476	2,376,593	612,618
609									
610	569	Maintenance of Structures							
611			T	SG		4,806,788	1,239,053	5,030,496	1,296,719
612									
613					B2	4,806,788	1,239,053	5,030,496	1,296,719
614									
615	570	Maintenance of Station Equipment							
616			T	SG		11,187,555	2,883,833	11,668,160	3,007,720
617									
618					B2	11,187,555	2,883,833	11,668,160	3,007,720
619									
620	571	Maintenance of Overhead Lines							
621			T	SG		20,881,692	5,382,706	22,314,037	5,751,924
622									
623					B2	20,881,692	5,382,706	22,314,037	5,751,924
624									
625	572	Maintenance of Underground Lines							
626			T	SG		140,683	36,264	147,248	37,956
627									
628					B2	140,683	36,264	147,248	37,956
629									
630	573	Maint of Misc. Transmission Plant							
631			T	SG		269,056	69,355	285,051	73,478
632									
633					B2	269,056	69,355	285,051	73,478
634									
635	**Total Transmission Expense**				**B2**	**203,395,397**	**52,337,448**	**199,472,285**	**51,375,843**
636									
637	Summary of Transmission Expense by Factor								
638		SE				6,292,490	1,529,926	2,899,400	704,946
639		SG				197,102,907	50,807,522	196,572,884	50,670,897
640		SNPT				-	-	-	-
641	Total Transmission Expense by Factor					203,395,397	52,337,448	199,472,285	51,375,843
642	580	Operation Supervision & Engineering							
643			DPW	S		42,004	-	44,700	(22)
644			DPW	SNPD		13,876,912	3,733,700	14,375,480	3,867,843
645					B2	13,918,916	3,733,700	14,420,180	3,867,822
646									
647	581	Load Dispatching							
648			DPW	S		-	-	0	0
649			DPW	SNPD		13,794,410	3,711,502	14,295,255	3,846,258
650					B2	13,794,410	3,711,502	14,295,255	3,846,258
651									
652	582	Station Expense							
653			DPW	S		4,039,699	1,101,897	4,231,352	1,151,914
654			DPW	SNPD		33,605	9,042	34,972	9,410
655					B2	4,073,304	1,110,939	4,266,324	1,161,324
656									

REVISED PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
657	583	Overhead Line Expenses							
658			DPW	S		5,982,127	2,969,038	6,218,589	3,085,147
659			DPW	SNPD		30,145	8,111	31,400	8,449
660					B2	6,012,272	2,977,149	6,249,990	3,093,596
661									
662	584	Underground Line Expense							
663			DPW	S		278	-	295	-
664			DPW	SNPD		-	-	-	-
665					B2	278	-	295	-
666									
667	585	Street Lighting & Signal Systems							
668			DPW	S		-	-	-	-
669			DPW	SNPD		221,438	59,580	229,230	61,676
670					B2	221,438	59,580	229,230	61,676
671									
672	586	Meter Expenses							
673			DPW	S		5,747,285	2,841,470	5,975,389	2,954,255
674			DPW	SNPD		1,338,372	360,100	1,392,549	374,677
675					B2	7,085,657	3,201,570	7,367,938	3,328,932
676									
677	587	Customer Installation Expenses							
678			DPW	S		12,706,959	4,336,385	13,210,598	4,507,068
679			DPW	SNPD		-	-	-	-
680					B2	12,706,959	4,336,385	13,210,598	4,507,068
681									
682	588	Misc. Distribution Expenses							
683			DPW	S		1,163,371	271,373	1,218,437	285,912
684			DPW	SNPD		4,035,067	1,085,669	4,242,428	1,141,461
685					B2	5,198,437	1,357,042	5,460,866	1,427,373
686									
687	589	Rents							
688			DPW	S		3,105,864	1,725,844	3,294,557	1,830,943
689			DPW	SNPD		64,337	17,311	68,316	18,381
690					B2	3,170,201	1,743,154	3,362,873	1,849,324
691									
692	590	Maint Supervision & Engineering							
693			DPW	S		822,461	318,747	856,965	332,395
694			DPW	SNPD		3,963,420	1,066,391	4,105,506	1,104,621
695					B2	4,785,882	1,385,139	4,962,471	1,437,016
696									
697	591	Maintenance of Structures							
698			DPW	S		1,693,542	482,824	1,812,437	516,721
699			DPW	SNPD		81,577	21,949	87,304	23,490
700					B2	1,775,119	504,773	1,899,740	540,210
701									
702	592	Maintenance of Station Equipment							
703			DPW	S		13,321,109	4,794,255	13,967,934	5,031,020
704			DPW	SNPD		1,453,956	391,199	1,506,447	405,322
705					B2	14,775,064	5,185,454	15,474,381	5,436,343
706	593	Maintenance of Overhead Lines							
707			DPW	S		87,567,530	28,822,221	92,850,975	30,523,061
708			DPW	SNPD		935,245	251,635	993,680	267,358
709					B2	88,502,774	29,073,856	93,844,655	30,790,419
710									
711	594	Maintenance of Underground Lines							
712			DPW	S		23,367,197	5,828,439	24,519,542	6,102,548
713			DPW	SNPD		202	54	216	58
714					B2	23,367,399	5,828,493	24,519,758	6,102,606
715									
716	595	Maintenance of Line Transformers							
717			DPW	S		-	-	-	-
718			DPW	SNPD		863,979	232,461	902,135	242,727
719					B2	863,979	232,461	902,135	242,727
720									
721	596	Maint of Street Lighting & Signal Sys.							
722			DPW	S		4,084,095	1,172,787	4,301,512	1,223,327
723			DPW	SNPD		-	-	-	-
724					B2	4,084,095	1,172,787	4,301,512	1,223,327
725									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
726	597	Maintenance of Meters							
727			DPW	S		4,756,900	1,020,485	4,955,527	1,062,137
728			DPW	SNPD		1,013,733	272,753	1,053,667	283,498
729					B2	5,770,633	1,293,239	6,009,193	1,345,635
730									
731	598	Maint of Misc. Distribution Plant							
732			DPW	S		2,085,687	450,008	2,227,633	479,343
733			DPW	SNPD		(292,473)	(78,692)	(351,531)	(94,582)
734					B2	1,793,214	371,316	1,876,101	384,760
735									
736	**Total Distribution Expense**				**B2**	**211,900,030**	**67,278,537**	**222,653,494**	**70,646,415**
737									
738									
739	Summary of Distribution Expense by Factor								
740		S				170,486,107	56,135,774	179,686,441	59,085,769
741		SNPD				41,413,923	11,142,764	42,967,053	11,560,646
742									
743	Total Distribution Expense by Factor					211,900,030	67,278,537	222,653,494	70,646,415
744									
745	901	Supervision							
746			CUST	S		2,542	1,014	2,671	1,054
747			CUST	CN		2,624,795	770,715	2,729,363	801,419
748					B2	2,627,337	771,729	2,732,034	802,473
749									
750	902	Meter Reading Expense							
751			CUST	S		20,676,876	9,820,883	21,488,525	10,203,950
752			CUST	CN		2,206,147	647,788	2,295,146	673,921
753					B2	22,883,023	10,468,671	23,783,671	10,877,871
754									
755	903	Customer Receipts & Collections							
756			CUST	S		7,837,725	2,224,477	8,168,746	2,318,208
757			CUST	CN		48,674,989	14,292,370	50,746,013	14,900,482
758					B2	56,512,714	16,516,847	58,914,759	17,218,690
759									
760	904	Uncollectible Accounts							
761			CUST	S		12,598,658	5,996,810	13,239,348	6,250,186
762			P	SG		-	-	-	-
763			CUST	CN		390,827	114,758	413,756	121,491
764					B2	12,989,486	6,111,568	13,653,105	6,371,676
765									
766	905	Misc. Customer Accounts Expense							
767			CUST	S		10,473	10,473	11,087	11,087
768			CUST	CN		186,329	54,712	195,103	57,288
769					B2	196,802	65,184	206,190	68,375
770									
771	**Total Customer Accounts Expense**				**B2**	**95,209,362**	**33,934,000**	**99,289,759**	**35,339,085**
772									
773	Summary of Customer Accts Exp by Factor								
774		S				41,126,274	18,053,658	42,910,378	18,784,485
775		CN				54,083,088	15,880,343	56,379,381	16,554,600
776		SG				-	-	-	-
777	Total Customer Accounts Expense by Factor					95,209,362	33,934,000	99,289,759	35,339,085
778									
779	907	Supervision							
780			CUST	S		-	-	-	-
781			CUST	CN		279,527	82,077	289,796	85,093
782					B2	279,527	82,077	289,796	85,093
783									
784	908	Customer Assistance							
785			CUST	S		106,251,795	22,984,962	12,474,522	1,637,007
786			CUST	CN		2,500,498	734,218	2,591,349	760,894
787									
788									
789					B2	108,752,293	23,719,180	15,065,871	2,397,902
790									

REVISED PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
791	909	Informational & Instructional Adv							
792			CUST	S		546,516	215,357	575,866	226,726
793			CUST	CN		4,158,696	1,221,112	4,359,846	1,280,175
794					B2	4,705,212	1,436,469	4,935,711	1,506,902
795									
796	910	Misc. Customer Service							
797			CUST	S		-	-	-	-
798			CUST	CN		232,845	68,370	245,457	72,073
799									
800					B2	232,845	68,370	245,457	72,073
801									
802	**Total Customer Service Expense**				**B2**	**113,969,877**	**25,306,096**	**20,536,835**	**4,061,969**
803									
804									
805	Summary of Customer Service Exp by Factor								
806		S				106,798,311	23,200,319	13,050,387	1,863,734
807		CN				7,171,566	2,105,777	7,486,448	2,198,235
808									
809	Total Customer Service Expense by Factor				B2	113,969,877	25,306,096	20,536,835	4,061,969
810									
811									
812	911	Supervision							
813			CUST	S		-	-	-	-
814			CUST	CN		-	-	-	-
815					B2	-	-	-	-
816									
817	912	Demonstration & Selling Expense							
818			CUST	S		-	-	-	-
819			CUST	CN		-	-	-	-
820					B2	-	-	-	-
821									
822	913	Advertising Expense							
823			CUST	S		-	-	-	-
824			CUST	CN		-	-	-	-
825					B2	-	-	-	-
826									
827	916	Misc. Sales Expense							
828			CUST	S		-	-	-	-
829			CUST	CN		-	-	-	-
830					B2	-	-	-	-
831									
832	**Total Sales Expense**				**B2**	-	-	-	-
833									
834									
835	Total Sales Expense by Factor								
836		S				-	-	-	-
837		CN				-	-	-	-
838	Total Sales Expense by Factor					-	-	-	-
839									
840	**Total Customer Service Exp Including Sales**				**B2**	**113,969,877**	**25,306,096**	**20,536,835**	**4,061,969**
841	920	Administrative & General Salaries							
842			PTD	S		(5,902,057)	1,274,323	(8,510,215)	(821,591)
843			CUST	CN		-	-	-	-
844			PTD	SO		76,070,259	20,678,240	78,936,527	21,457,380
845					B2	70,168,202	21,952,564	70,426,313	20,635,789
846									
847	921	Office Supplies & expenses							
848			PTD	S		818,712	302,041	863,989	318,745
849			CUST	CN		-	-	-	-
850			PTD	SO		8,822,483	2,398,223	9,243,641	2,512,706
851					B2	9,641,195	2,700,264	10,107,629	2,831,451
852									
853	922	A&G Expenses Transferred							
854			PTD	S		-	-	-	-
855			CUST	CN		-	-	-	-
856			PTD	SO		(31,726,905)	(8,624,350)	(34,862,827)	(9,476,791)
857					B2	(31,726,905)	(8,624,350)	(34,862,827)	(9,476,791)
858									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
859	923	Outside Services							
860			PTD	S		20,106	12,958	21,290	13,721
861			CUST	CN		-	-	-	-
862			PTD	SO		14,126,182	3,839,932	14,861,865	4,039,913
863					B2	14,146,288	3,852,890	14,883,154	4,053,634
864									
865	924	Property Insurance							
866			DPW	S		2,036,678	1,307,800	5,994,676	5,265,799
867			PT	SG		-	-	-	-
868			PTD	SO		23,348,780	6,346,918	9,748,399	2,649,915
869					B2	25,385,458	7,654,718	15,743,075	7,915,714
870									
871	925	Injuries & Damages							
872			PTD	S		-	-	248,469	248,469
873			PTD	SO		8,314,977	2,260,267	7,013,752	1,906,554
874					B2	8,314,977	2,260,267	7,262,221	2,155,023
875									
876	926	Employee Pensions & Benefits							
877			LABOR	S		-	-	-	-
878			CUST	CN		-	-	-	-
879			LABOR	SO		-	-	-	-
880					B2	-	-	-	-
881									
882	927	Franchise Requirements							
883			DMSC	S		-	-	-	-
884			DMSC	SG		-	-	-	-
885					B2	-	-	-	-
886									
887	928	Regulatory Commission Expense							
888			DMSC	S		14,959,078	3,046,402	15,795,520	3,255,051
889			CUST	CN		-	-	-	-
890			DMSC	SO		1,799,757	489,230	1,862,611	506,315
891			FERC	SG		1,657,049	427,140	1,755,117	452,419
892					B2	18,415,884	3,962,771	19,413,248	4,213,785
893									
894	929	Duplicate Charges							
895			LABOR	S		-	-	-	-
896			LABOR	SO		(6,811,639)	(1,851,613)	(7,736,639)	(2,103,057)
897					B2	(6,811,639)	(1,851,613)	(7,736,639)	(2,103,057)
898									
899	930	Misc General Expenses							
900			PTD	S		1,654,367	1,359,479	2,197,149	2,031,324
901			CUST	CN		-	-	-	-
902			LABOR	SO		14,551,845	3,955,640	14,311,679	3,890,355
903					B2	16,206,212	5,315,119	16,508,828	5,921,679
904									
905	931	Rents							
906			PTD	S		1,085,852	1,056,225	1,172,227	1,140,243
907			PTD	SO		5,322,451	1,446,806	5,745,828	1,561,893
908					B2	6,408,304	2,503,031	6,918,055	2,702,136
909									
910	935	Maintenance of General Plant							
911			G	S		235,679	90,071	241,201	92,331
912			CUST	CN		-	-	-	-
913			G	SO		23,578,792	6,409,442	24,152,930	6,565,511
914					B2	23,814,472	6,499,513	24,394,131	6,657,842
915									
916	**Total Administrative & General Expense**				**B2**	**153,962,449**	**46,225,173**	**143,057,189**	**45,507,206**
917									
918	Summary of A&G Expense by Factor								
919		S				14,908,416	8,449,299	18,024,307	11,544,092
920		SO				137,396,984	37,348,734	123,277,765	33,510,695
921		SG				1,657,049	427,140	1,755,117	452,419
922		CN				-	-	-	-
923	Total A&G Expense by Factor					153,962,449	46,225,173	143,057,189	45,507,206
924									
925	**Total O&M Expense**				**B2**	**2,713,491,556**	**685,297,723**	**3,051,374,154**	**804,534,911**

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
926	403SP	Steam Depreciation							
927			P	SG		21,699,385	5,593,484	30,086,982	7,755,568
928			P	SG		25,254,801	6,509,969	30,498,129	7,861,550
929			P	SG		71,555,236	18,444,904	161,045,747	41,513,012
930			P	SSGCH		7,849,360	2,088,343	11,577,816	3,080,309
931					B3	126,358,782	32,636,700	233,208,674	60,210,438
932									
933	403NP	Nuclear Depreciation							
934			P	SG		-	-	-	-
935					B3	-	-	-	-
936									
937	403HP	Hydro Depreciation							
938			P	SG		3,614,050	931,599	6,185,025	1,594,324
939			P	SG		1,004,089	258,826	931,287	240,059
940			P	SG		9,959,593	2,567,300	14,361,224	3,701,915
941			P	SG		3,695,335	952,552	4,616,029	1,189,881
942					B3	18,273,067	4,710,277	26,093,565	6,726,179
943									
944	403OP	Other Production Depreciation							
945			P	S		-	-	-	-
946			P	SG		123,593	31,859	(3,312)	(854)
947			P	SG		109,925,386	28,335,637	104,654,323	26,976,907
948			P	SSGCT		2,625,250	676,089	2,692,774	693,478
949			P	SSGCH		-	-	-	-
950					B3	112,674,229	29,043,585	107,343,785	27,669,532
951									
952	403TP	Transmission Depreciation							
953			T	S		-	-	-	-
954			T	SG		11,173,740	2,880,272	10,788,283	2,780,912
955			T	SG		12,421,176	3,201,826	12,398,498	3,195,980
956			T	SG		55,933,484	14,418,061	66,201,741	17,064,925
957					B3	79,528,400	20,500,159	89,388,522	23,041,818
958									
959									
960									
961	403	Distribution Depreciation							
962	360	Land & Land Rights	DPW	S		314,458	68,465	442,878	90,290
963	361	Structures	DPW	S		1,224,317	290,449	1,415,294	322,906
964	362	Station Equipment	DPW	S		12,591,896	4,332,463	14,573,663	4,669,271
965	363	Storage Battery Eq	DPW	S		1,854	-	1,854	-
966	364	Poles & Towers	DPW	S		34,968,334	12,562,380	37,265,769	12,952,836
967	365	OH Conductors	DPW	S		19,443,714	6,903,560	21,017,653	7,171,056
968	366	UG Conduit	DPW	S		7,883,127	2,153,638	8,616,519	2,278,280
969	367	UG Conductor	DPW	S		17,848,103	3,737,039	19,590,683	4,033,197
970	368	Line Trans	DPW	S		28,003,627	11,077,108	30,671,681	11,530,553
971	369	Services	DPW	S		12,028,084	4,494,872	13,454,704	4,737,331
972	370	Meters	DPW	S		6,354,816	2,175,541	6,785,873	2,248,801
973	371	Inst Cust Prem	DPW	S		489,912	118,152	511,107	121,754
974	372	Leased Property	DPW	S		-	-	-	-
975	373	Street Lighting	DPW	S		2,156,362	666,810	2,302,721	691,685
976					B3	143,308,604	48,580,477	156,650,401	50,847,961
977									
978	403GP	General Depreciation							
979			G-SITUS	S		12,138,484	3,740,188	13,476,566	4,019,896
980			G-DGP	SG		248,887	64,156	110,098	28,380
981			G-DGU	SG		376,406	97,027	138,646	35,739
982			P	SE		21,246	5,166	16,878	4,104
983			CUST	CN		1,706,446	501,062	1,516,791	445,373
984			G-SG	SG		6,152,699	1,585,991	6,639,755	1,711,540
985			PTD	SO		14,631,939	3,977,412	13,932,877	3,787,385
986			P	SSGCT		6,010	1,548	6,328	1,630
987			P	SSGCH		139,134	37,017	100,984	26,867
988					B3	35,421,251	10,009,565	35,938,924	10,060,914
989									
990	403GV0	General Vehicles							
991			G-SG	SG		-	-	-	-
992					B3	-	-	-	-
993									
994	403MP	Mining Depreciation							
995			P	SE		-	-	-	-
996					B3	-	-	-	-
997									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
998	403EP	Experimental Plant Depreciation							
999			P	SG		-	-	-	-
1000			P	SG		-	-	-	-
1001					B3	-	-	-	-
1002	4031	ARO Depreciation							
1003			P	S		-	-	-	-
1004					B3	-	-	-	-
1005									
1006									
1007	**Total Depreciation Expense**				**B3**	**515,564,333**	**145,480,763**	**648,623,871**	**178,556,841**
1008									
1009	Summary	S				155,447,088	52,320,665	170,126,967	54,867,856
1010		DGP				-	-	-	-
1011		DGU				-	-	-	-
1012		SG				333,137,859	85,873,462	448,652,456	115,649,839
1013		SO				14,631,939	3,977,412	13,932,877	3,787,385
1014		CN				1,706,446	501,062	1,516,791	445,373
1015		SE				21,246	5,166	16,878	4,104
1016		SSGCH				7,988,494	2,125,360	11,678,799	3,107,175
1017		SSGCT				2,631,260	677,637	2,699,102	695,108
1018	Total Depreciation Expense By Factor					515,564,333	145,480,763	648,623,871	178,556,841
1019									
1020	404GP	Amort of LT Plant - Capital Lease Gen							
1021			I-SITUS	S		1,672,595	777,880	1,108,765	248,068
1022			I-SG	SG		-	-	-	-
1023			PTD	SO		1,265,577	344,023	1,259,258	342,305
1024			I-DGU	SG		-	-	-	-
1025			CUST	CN		270,082	79,304	273,367	80,268
1026			I-DGP	SG		-	-	-	-
1027					B4	3,208,254	1,201,207	2,641,390	670,641
1028									
1029	404SP	Amort of LT Plant - Cap Lease Steam							
1030			P	SG		-	-	-	-
1031			P	SG		-	-	-	-
1032					B4	-	-	-	-
1033									
1034	404IP	Amort of LT Plant - Intangible Plant							
1035			I-SITUS	S		195,942	14,532	185,661	8,962
1036			P	SE		13,653	3,320	336,447	81,802
1037			I-SG	SG		9,025,509	2,326,519	5,317,923	1,370,809
1038			PTD	SO		15,076,510	4,098,260	20,971,360	5,700,662
1039			CUST	CN		5,695,883	1,672,474	5,801,059	1,703,357
1040			I-SG	SG		6,752,316	1,740,555	10,780,267	2,778,846
1041			I-SG	SG		307,800	79,342	302,172	77,891
1042			I-DGP	SG		-	-	-	-
1043			I-SG	SSGCT		-	-	-	-
1044			I-SG	SSGCH		77,056	20,501	-	-
1045			I-DGU	SG		16,758	4,320	16,151	4,163
1046					B4	37,161,427	9,959,823	43,711,041	11,726,493
1047									
1048	404MP	Amort of LT Plant - Mining Plant							
1049			P	SE		-	-	-	-
1050					B4	-	-	-	-
1051									
1052	404OP	Amort of LT Plant - Other Plant							
1053			P	SSGCT		-	-	-	-
1054					B4	-	-	-	-
1055									
1056									
1057	404HP	Amortization of Other Electric Plant							
1058			P	SG		168,315	43,387	249,015	64,189
1059			P	SG		46,417	11,965	44,532	11,479
1060			P	SG		-	-	-	-
1061					B4	214,732	55,352	293,548	75,668
1062									
1063	**Total Amortization of Limited Term Plant**				**B4**	**40,584,413**	**11,216,382**	**46,645,979**	**12,472,803**
1064									
1065									
1066	405	Amortization of Other Electric Plant							
1067			GP	S		-	-	-	-
1068									
1069					B4	-	-	-	-
1070									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1071	406	Amortization of Plant Acquisition Adj							
1072			P	S		-	-	-	-
1073			P	SG		-	-	-	-
1074			P	SG		-	-	-	-
1075			P	SG		5,523,970	1,423,922	5,193,044	1,338,619
1076			P	SO		-	-	-	-
1077					B4	5,523,970	1,423,922	5,193,044	1,338,619
1078	407	Amort of Prop Losses, Unrec Plant, etc							
1079			DPW	S		(200,504)	(39,640)	(160,864)	-
1080			GP	SO		-	-	-	-
1081			P	SG-P		1,327,321	342,146	(0)	(0)
1082			P	SE		-	-	-	-
1083			P	SG		-	-	-	-
1084			P	TROJP		1,163,874	297,426	(0)	(0)
1085					B4	2,290,691	599,931	(160,864)	(0)
1086									
1087	**Total Amortization Expense**				**B4**	**48,399,074**	**13,240,235**	**51,678,159**	**13,811,422**
1088									
1089									
1090									
1091	Summary of Amortization Expense by Factor								
1092		S				1,668,033	752,772	1,133,562	257,030
1093		SE				13,653	3,320	336,447	81,802
1094		TROJP				1,163,874	297,426	(0)	(0)
1095		DGP				-	-	-	-
1096		SG-P				1,327,321	342,146	(0)	(0)
1097		SO				16,342,088	4,442,283	22,230,619	6,042,967
1098		SSGCT				-	-	-	-
1099		SSGCH				77,056	20,501	-	-
1100		CN				5,965,965	1,751,778	6,074,426	1,783,625
1101		SG				21,841,085	5,630,010	21,903,105	5,645,997
1102	Total Amortization Expense by Factor					48,399,074	13,240,235	51,678,159	13,811,422
1103	408	Taxes Other Than Income							
1104			DMSC	S		27,545,791	24,628,661	31,057,647	28,140,517
1105			GP	GPS		108,846,556	29,587,596	124,768,000	33,915,498
1106			GP	SO		9,622,896	2,615,800	9,622,896	2,615,800
1107			P	SE		827,316	201,150	827,316	201,150
1108			P	SG		-	-	1,479,722	381,430
1109			DMSC	OPRV-ID		-	-	-	-
1110			GP	EXCTAX		-	-	-	-
1111			GP	SG		-	-	-	-
1112									
1113									
1114									
1115	**Total Taxes Other Than Income**				**B5**	**146,842,558**	**57,033,205**	**167,755,580**	**65,254,394**
1116									
1117									
1118	41140	Deferred Investment Tax Credit - Fed							
1119			PTD	DGU		(1,874,204)	-	(1,874,204)	-
1120									
1121					B7	(1,874,204)	-	(1,874,204)	-
1122									
1123	41141	Deferred Investment Tax Credit - Idaho							
1124			PTD	DGU		-	-	-	-
1125									
1126					B7	-	-	-	-
1127									
1128	**Total Deferred ITC**				**B7**	**(1,874,204)**	**-**	**(1,874,204)**	**-**
1129									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1130									
1131	427	Interest on Long-Term Debt							
1132			GP	S		312,146,084	81,043,299	317,137,627	82,058,897
1133			GP	SNP		-	-	-	-
1134					B6	312,146,084	81,043,299	317,137,627	82,058,897
1135									
1136	428	Amortization of Debt Disc & Exp							
1137			GP	SNP		-	-	-	-
1138					B6	-	-	-	-
1139									
1140	429	Amortization of Premium on Debt							
1141			GP	SNP		-	-	-	-
1142					B6	-	-	-	-
1143									
1144	431	Other Interest Expense							
1145			NUTIL	OTH		-	-	-	-
1146			GP	SO		-	-	-	-
1147			GP	SNP		-	-	-	-
1148					B6	-	-	-	-
1149									
1150	432	AFUDC - Borrowed							
1151			GP	SNP		-	-	-	-
1152						-	-	-	-
1153									
1154		Total Elec. Interest Deductions for Tax			B6	312,146,084	81,043,299	317,137,627	82,058,897
1155									
1156		Non-Utility Portion of Interest							
1157		427	NUTIL	NUTIL		-	-	-	-
1158		428	NUTIL	NUTIL		-	-	-	-
1159		429	NUTIL	NUTIL		-	-	-	-
1160		431	NUTIL	NUTIL		-	-	-	-
1161									
1162		Total Non-utility Interest				-	-	-	-
1163									
1164		Total Interest Deductions for Tax			B6	312,146,084	81,043,299	317,137,627	82,058,897
1165									
1166									
1167	419	Interest & Dividends							
1168			GP	S		-	-	-	-
1169			GP	SNP		(59,310,129)	(15,547,742)	(53,488,675)	(14,021,688)
1170		Total Operating Deductions for Tax			B6	(59,310,129)	(15,547,742)	(53,488,675)	(14,021,688)
1171									
1172									
1173	41010	Deferred Income Tax - Federal-DR							
1174			GP	S		47,440,799	339,759	1,292,220	20,423
1175			P	SCHMDEXP		-	-	-	-
1176			PT	SSGCH		31,324	8,334	31,324	8,334
1177			LABOR	SO		7,830,895	2,128,679	(15,554)	(4,228)
1178			GP	SNP		33,713,788	8,837,837	32,439,546	8,503,803
1179			P	SE		18,367,716	4,465,838	1,130,007	274,745
1180			PT	SG		23,560,496	6,073,226	45,491,826	11,726,499
1181			GP	GPS		26,018,718	7,072,629	21,164,533	5,753,123
1182			TAXDEPR	TAXDEPR		1,080,616,640	282,568,931	503,656,213	131,700,357
1183			CUST	BADDEBT		-	-	-	-
1184			CUST	CN		18,276	5,366	0	0
1185			IBT	IBT		-	-	-	-
1186			DPW	SNPD		-	-	-	-
1187					B7	1,237,598,652	311,500,598	605,190,115	157,983,056
1188									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1189									
1190									
1191	41110	Deferred Income Tax - Federal-CR							
1192			GP	S		(26,227,663)	(5,015,484)	(10,150,074)	(1,773,344)
1193			P	SE		(12,433,468)	(3,023,014)	-	-
1194			CUST	BADDEBT		(499,023)	(232,886)	-	-
1195			GP	SNP		(19,232,707)	(5,041,722)	(27,638,492)	(7,245,240)
1196			PT	SG		(8,206,952)	(2,115,519)	(15,642,792)	(4,032,267)
1197			DPW	CIAC		(10,561,420)	(2,841,639)	(19,266,440)	(5,183,797)
1198			LABOR	SO		(17,184,714)	(4,671,335)	(4,237,506)	(1,151,885)
1199			PT	SNPD		(3,638,499)	(978,969)	-	-
1200			P	SG-P		-	-	-	-
1201			P	SGCT		(425,972)	(110,164)	(425,972)	(110,164)
1202			GP	SCHMDEXP		(215,825,162)	(59,413,569)	(242,921,943)	(66,872,924)
1203			P	TROJD		(721,757)	(184,160)	-	-
1204			IBT	IBT		-	-	-	-
1205			0	DGP		-	-	-	-
1206			0	DGU		-	-	-	-
1207			0	SG-U		-	-	-	-
1208			0	SSGCH		(510,725)	(135,880)	(510,725)	(135,880)
1209			0	SSGCT		-	-	-	-
1210					B7	(315,468,063)	(83,764,339)	(320,793,945)	(86,505,501)
1211									
1212	**Total Deferred Income Taxes**				**B7**	**922,130,589**	**227,736,260**	**284,396,170**	**71,477,555**
1213	SCHMAF	Additions - Flow Through							
1214			SCHMAF	S		-	-	-	-
1215			SCHMAF	SNP		-	-	-	-
1216			SCHMAF	SO		-	-	-	-
1217			SCHMAF	SE		-	-	-	-
1218			SCHMAF	TROJP		-	-	-	-
1219			SCHMAF	SG		-	-	-	-
1220					B6	-	-	-	-
1221									
1222	SCHMAP	Additions - Permanent							
1223			P	S		28,808	-	-	-
1224			P	SE		130,031	31,615	16,000	3,890
1225			LABOR	SNP		-	-	-	-
1226			SCHMAP-SO	SO		14,206,873	3,861,866	(2,502,079)	(680,142)
1227			SCHMAP	SG		-	-	-	-
1228			DPW	SCHMDEXP		(535,912)	(147,529)	(240,884)	(66,312)
1229					B6	13,829,800	3,745,952	(2,726,963)	(742,564)
1230									
1231	SCHMAT	Additions - Temporary							
1232			SCHMAT-SITUS	S		52,139,597	11,691,014	3,084,839	(36,000)
1233			P	SG-P		-	-	-	-
1234			DPW	CIAC		27,829,092	7,487,651	50,766,618	13,659,185
1235			SCHMAT-SNP	SNP		50,677,736	13,284,819	72,826,783	19,091,039
1236			P	TROJD		1,901,813	485,258	-	-
1237			CUST	BADDEBT		1,314,913	613,648	-	-
1238			SCHMAT-SE	SE		32,761,900	7,965,571	-	-
1239			P	SG		16,882,886	4,351,928	41,145,553	10,606,153
1240			SCHMAT-GPS	CN		-	-	-	-
1241			SCHMAT-SO	SO		45,281,318	12,308,857	11,165,730	3,035,189
1242			SCHMAT-SNP	SNPD		9,587,358	2,579,559	-	-
1243			P	SGCT		1,122,425	290,280	1,122,425	290,280
1244			TAXDEPR	DGP		-	-	-	-
1245			BOOKDEPR	SCHMDEXP		568,694,270	156,553,369	640,093,658	176,208,596
1246			0	DGU		-	-	-	-
1247			0	SG-U		-	-	-	-
1248			0	SSGCH		-	-	-	-
1249			0	SSGCT		-	-	-	-
1250					B6	808,193,308	217,611,954	820,205,606	222,854,442
1251									
1252	TOTAL SCHEDULE - M ADDITIONS				B6	822,023,108	221,357,906	817,478,643	222,111,878
1253									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1254	SCHMDF	Deductions - Flow Through							
1255			SCHMDF	S		-	-	-	-
1256			SCHMDF	DGP		-	-	-	-
1257			SCHMDF	DGU		-	-	-	-
1258					B6	-	-	-	-
1259	SCHMDP	Deductions - Permanent							
1260			SCHMDP	S		-	-	-	-
1261			P	SE		574,264	139,624	477,991	116,216
1262			PTD	SNP		361,498	94,764	381,062	99,893
1263			SCHMDEXP	IBT		109,247	(49,195)	-	-
1264			P	SG		-	-	-	-
1265			SCHMDP-SO	SO		20,811,550	5,657,221	(4,100,000)	(1,114,506)
1266					B6	21,856,559	5,842,413	(3,240,947)	(898,397)
1267									
1268	SCHMDT	Deductions - Temporary							
1269			GP	S		125,005,401	895,255	3,404,965	53,813
1270			CUST	BADDEBT		-	-	-	-
1271			SCHMDT-SNP	SNP		88,835,043	23,287,494	85,477,445	22,407,323
1272			SCHMDT	CN		48,156	14,140	0	0
1273			SCHMDT	SSGCH		82,539	21,960	82,539	21,960
1274			P	DGP		-	-	-	-
1275			P	SE		48,398,501	11,767,379	2,977,542	723,945
1276			SCHMDT-SG	SG		62,081,357	16,002,808	119,869,900	30,899,050
1277			SCHMDT-GPS	GPS		68,558,717	18,636,213	55,768,052	15,159,346
1278			SCHMDT-SO	SO		23,344,458	6,345,743	(40,985)	(11,141)
1279			TAXDEPR	TAXDEPR		2,847,399,647	744,562,543	1,327,122,376	347,027,370
1280			DPW	SNPD		-	-	-	-
1281					B6	3,263,753,819	821,533,534	1,594,661,834	416,281,666
1282									
1283	TOTAL SCHEDULE - M DEDUCTIONS				B6	3,285,610,378	827,375,948	1,591,420,887	415,383,269
1284									
1285	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(2,463,587,270)**	**(606,018,041)**	**(773,942,244)**	**(193,271,391)**
1286									
1287									
1288									
1289	40911	State Income Taxes							
1290			IBT	IBT		(76,017,493)	(15,263,459)	(3,480,440)	1,570,055
1291			IBT	IBT		-	-	-	-
1292		REC	P	SG		(288,539)	(74,377)	(392,418)	(101,154)
1293			IBT	IBT		-	-	-	-
1294	**Total State Tax Expense**					**(76,306,032)**	**(15,337,836)**	**(3,872,858)**	**1,468,901**
1295									
1296									
1297	Calculation of Taxable Income:								
1298		Operating Revenues				4,464,637,351	1,236,148,505	4,877,996,718	1,357,702,634
1299		Operating Deductions:							
1300		O & M Expenses				2,713,491,556	685,297,723	3,051,374,154	804,534,911
1301		Depreciation Expense				515,564,333	145,480,763	648,623,871	178,556,841
1302		Amortization Expense				48,399,074	13,240,235	51,678,159	13,811,422
1303		Taxes Other Than Income				146,842,558	57,033,205	167,755,580	65,254,394
1304		Interest & Dividends (AFUDC-Equity)				(59,310,129)	(15,547,742)	(53,488,675)	(14,021,688)
1305		Misc Revenue & Expense				(1,689,284)	(217,486)	(2,364,567)	(346,249)
1306		Total Operating Deductions				3,363,298,107	885,286,699	3,863,578,523	1,047,789,632
1307		Other Deductions:							
1308		Interest Deductions				312,146,084	81,043,299	317,137,627	82,058,897
1309		Interest on PCRBS				-	-	-	-
1310		Schedule M Adjustments				(2,463,587,270)	(606,018,041)	(773,942,244)	(193,271,391)
1311									
1312		Income Before State Taxes				(1,674,394,110)	(336,199,534)	(76,661,675)	34,582,714
1313									
1314		State Income Taxes				(76,306,032)	(15,337,836)	(3,872,858)	1,468,901
1315									
1316	Total Taxable Income					(1,598,088,079)	(320,861,698)	(72,788,818)	33,113,813
1317									
1318	Tax Rate					35.0%	35.0%	35.0%	35.0%
1319									
1320	Federal Income Tax - Calculated					(559,330,828)	(112,301,594)	(25,476,086)	11,589,835
1321									
1322	Adjustments to Calculated Tax:								
1323	40910	PMI	P	SE		(120,409)	(29,276)	(16,000)	(3,890)
1324	40910	REC	P	SG		(58,529,911)	(15,087,346)	(62,989,912)	(16,237,007)
1325	40911	State Energy Cr	P	SO		(28,808)	(7,831)	-	-
1326	40910	IRS Settle	LABOR	S		-	-	-	-
1327	**Federal Income Tax Expense**					**(618,009,956)**	**(127,426,047)**	**(88,481,998)**	**(4,651,063)**
1328									
1329	**Total Operating Expenses**					**3,648,548,635**	**985,806,817**	**4,107,234,308**	**1,130,106,713**

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1330	310	Land and Land Rights							
1331			P	SG		2,328,228	600,151	2,328,228	600,151
1332			P	SG		34,798,446	8,970,049	34,798,446	8,970,049
1333			P	SG		56,303,435	14,513,424	56,303,435	14,513,424
1334			P	S		-	-	-	-
1335			P	SSGCH		2,468,743	656,816	2,468,743	656,816
1336					B8	95,898,852	24,740,440	95,898,852	24,740,440
1337									
1338	311	Structures and Improvements							
1339			P	SG		233,585,247	60,211,631	233,585,247	60,211,631
1340			P	SG		324,837,488	83,733,863	324,837,488	83,733,863
1341			P	SG		306,366,663	78,972,610	306,366,663	78,972,610
1342			P	SSGCH		58,737,692	15,627,319	58,737,692	15,627,319
1343					B8	923,527,091	238,545,422	923,527,091	238,545,422
1344									
1345	312	Boiler Plant Equipment							
1346			P	SG		635,449,135	163,800,708	605,259,570	156,018,697
1347			P	SG		586,564,644	151,199,678	565,104,934	145,667,975
1348			P	SG		2,138,721,828	551,301,641	2,864,452,289	738,374,307
1349			P	SSGCH		325,216,222	86,524,638	305,234,138	81,208,352
1350					B8	3,685,951,829	952,826,665	4,340,050,930	1,121,269,330
1351									
1352	314	Turbogenerator Units							
1353			P	SG		127,038,148	32,746,820	127,038,148	32,746,820
1354			P	SG		143,662,395	37,032,078	143,662,395	37,032,078
1355			P	SG		591,402,331	152,446,696	583,723,978	150,467,435
1356			P	SSGCH		63,736,456	16,957,253	63,736,456	16,957,253
1357					B8	925,839,330	239,182,847	918,160,977	237,203,586
1358									
1359	315	Accessory Electric Equipment							
1360			P	SG		86,928,888	22,407,794	86,928,888	22,407,794
1361			P	SG		137,455,589	35,432,140	137,455,589	35,432,140
1362			P	SG		126,540,752	32,618,606	126,540,752	32,618,606
1363			P	SSGCH		66,647,509	17,731,746	66,647,509	17,731,746
1364					B8	417,572,737	108,190,286	417,572,737	108,190,286
1365									
1366									
1367									
1368	316	Misc Power Plant Equipment							
1369			P	SG		4,715,664	1,215,564	4,715,664	1,215,564
1370			P	SG		5,085,197	1,310,819	5,085,197	1,310,819
1371			P	SG		19,517,661	5,031,098	19,517,661	5,031,098
1372			P	SSGCH		4,036,539	1,073,932	4,036,539	1,073,932
1373					B8	33,355,061	8,631,413	33,355,061	8,631,413
1374									
1375	317	Steam Plant ARO							
1376			P	S		-	-	-	-
1377					B8	-	-	-	-
1378									
1379	SP	Unclassified Steam Plant - Account 300							
1380			P	SG		5,221,058	1,345,840	5,221,058	1,345,840
1381					B8	5,221,058	1,345,840	5,221,058	1,345,840
1382									
1383									
1384	**Total Steam Production Plant**				**B8**	**6,087,365,959**	**1,573,462,914**	**6,733,786,706**	**1,739,926,318**
1385									
1386									
1387	Summary of Steam Production Plant by Factor								
1388		S				-	-	-	-
1389		DGP				-	-	-	-
1390		DGU				-	-	-	-
1391		SG				5,566,522,798	1,434,891,210	6,232,925,630	1,606,670,901
1392		SSGCH				520,843,160	138,571,704	500,861,076	133,255,417
1393	Total Steam Production Plant by Factor					6,087,365,959	1,573,462,914	6,733,786,706	1,739,926,318
1394	320	Land and Land Rights							
1395			P	SG		-	-	-	-
1396			P	SG		-	-	-	-
1397					B8	-	-	-	-
1398									
1399	321	Structures and Improvements							
1400			P	SG		-	-	-	-
1401			P	SG	B8	-	-	-	-
1402						-	-	-	-

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1403									
1404	322	Reactor Plant Equipment							
1405			P	SG		-	-	-	-
1406			P	SG		-	-	-	-
1407					B8	-	-	-	-
1408									
1409	323	Turbogenerator Units							
1410			P	SG		-	-	-	-
1411			P	SG		-	-	-	-
1412					B8	-	-	-	-
1413									
1414	324	Land and Land Rights							
1415			P	SG		-	-	-	-
1416			P	SG		-	-	-	-
1417					B8	-	-	-	-
1418									
1419	325	Misc. Power Plant Equipment							
1420			P	SG		-	-	-	-
1421			P	SG		-	-	-	-
1422					B8	-	-	-	-
1423									
1424									
1425	NP	Unclassified Nuclear Plant - Acct 300							
1426			P	SG		-	-	-	-
1427					B8	-	-	-	-
1428									
1429									
1430	**Total Nuclear Production Plant**				**B8**	-	-	-	-
1431									
1432									
1433									
1434	Summary of Nuclear Production Plant by Factor								
1435		DGP				-	-	-	-
1436		DGU				-	-	-	-
1437		SG				-	-	-	-
1438									
1439	Total Nuclear Plant by Factor					-	-	-	-
1440									
1441	330	Land and Land Rights							
1442			P	SG		10,537,839	2,716,355	10,537,839	2,716,355
1443			P	SG		5,269,427	1,358,308	5,269,427	1,358,308
1444			P	SG		9,571,216	2,467,187	9,571,216	2,467,187
1445			P	SG		672,873	173,448	672,873	173,448
1446					B8	26,051,355	6,715,298	26,051,355	6,715,298
1447									
1448	331	Structures and Improvements							
1449			P	SG		20,799,391	5,361,491	20,799,391	5,361,491
1450			P	SG		5,274,527	1,359,623	5,274,527	1,359,623
1451			P	SG		80,369,624	20,717,003	80,369,624	20,717,003
1452			P	SG		8,245,496	2,125,454	8,245,496	2,125,454
1453					B8	114,689,039	29,563,571	114,689,039	29,563,571
1454									
1455	332	Reservoirs, Dams & Waterways							
1456			P	SG		150,783,539	38,867,706	146,431,209	37,745,800
1457			P	SG		19,969,848	5,147,659	18,011,998	4,642,981
1458			P	SG		115,440,304	29,757,226	339,922,585	87,622,372
1459			P	SG		49,681,299	12,806,426	72,068,456	18,577,198
1460					B8	335,874,990	86,579,017	576,434,248	148,588,350
1461									
1462	333	Water Wheel, Turbines, & Generators							
1463			P	SG		31,234,511	8,051,368	31,234,511	8,051,368
1464			P	SG		8,597,048	2,216,074	8,597,048	2,216,074
1465			P	SG		45,210,605	11,654,008	45,210,605	11,654,008
1466			P	SG		30,461,484	7,852,104	30,461,484	7,852,104
1467					B8	115,503,647	29,773,554	115,503,647	29,773,554
1468									
1469	334	Accessory Electric Equipment							
1470			P	SG		4,342,020	1,119,249	4,342,020	1,119,249
1471			P	SG		3,626,864	934,902	3,626,864	934,902
1472			P	SG		45,034,974	11,608,735	45,034,974	11,608,735
1473			P	SG		7,348,480	1,894,229	7,348,480	1,894,229
1474					B8	60,352,339	15,557,116	60,352,339	15,557,116
1475									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1476									
1477									
1478	335	Misc. Power Plant Equipment							
1479			P	SG		1,145,813	295,358	1,145,813	295,358
1480			P	SG		161,332	41,587	161,332	41,587
1481			P	SG		992,216	255,765	992,216	255,765
1482			P	SG		12,582	3,243	12,582	3,243
1483					B8	2,311,942	595,953	2,311,942	595,953
1484									
1485	336	Roads, Railroads & Bridges							
1486			P	SG		4,632,223	1,194,055	4,632,223	1,194,055
1487			P	SG		822,839	212,104	822,839	212,104
1488			P	SG		10,344,503	2,666,519	10,344,503	2,666,519
1489			P	SG		674,244	173,801	674,244	173,801
1490					B8	16,473,809	4,246,479	16,473,809	4,246,479
1491									
1492	337	Hydro Plant ARO							
1493			P	S		-	-	-	-
1494					B8	-	-	-	-
1495									
1496	HP	Unclassified Hydro Plant - Acct 300							
1497			P	S		-	-	-	-
1498			P	SG		-	-	-	-
1499			P	SG		-	-	-	-
1500			P	SG		-	-	-	-
1501					B8	-	-	-	-
1502									
1503	**Total Hydraulic Production Plant**				**B8**	**671,257,121**	**173,030,989**	**911,816,379**	**235,040,321**
1504									
1505	Summary of Hydraulic Plant by Factor								
1506		S				-	-	-	-
1507		SG				671,257,121	173,030,989	911,816,379	235,040,321
1508		DGP				-	-	-	-
1509		DGU				-	-	-	-
1510	Total Hydraulic Plant by Factor					671,257,121	173,030,989	911,816,379	235,040,321
1511									
1512	340	Land and Land Rights							
1513			P	S		-	-	75,000	75,000
1514			P	SG		28,912,692	7,452,870	28,912,692	7,452,870
1515			P	SG		-	-	-	-
1516			P	SSGCT		-	-	-	-
1517					B8	28,912,692	7,452,870	28,987,692	7,527,870
1518									
1519	341	Structures and Improvements							
1520			P	SG		158,822,988	40,940,048	155,777,248	40,154,943
1521			P	SG		163,512	42,149	163,512	42,149
1522			P	SSGCT		4,240,304	1,092,019	4,240,304	1,092,019
1523					B8	163,226,804	42,074,215	160,181,064	41,289,110
1524									
1525	342	Fuel Holders, Producers & Accessories							
1526			P	SG		8,424,526	2,171,603	8,424,526	2,171,603
1527			P	SG		121,339	31,278	121,339	31,278
1528			P	SSGCT		2,284,126	588,238	2,284,126	588,238
1529					B8	10,829,991	2,791,119	10,829,991	2,791,119
1530									
1531	343	Prime Movers							
1532			P	S		-	-	-	-
1533			P	SG		754,440	194,473	(485,616)	(125,178)
1534			P	SG		2,438,440,767	628,560,656	2,252,911,880	580,736,588
1535			P	SSGCT		53,648,952	13,816,380	55,775,187	14,363,956
1536					B8	2,492,844,159	642,571,509	2,308,201,451	594,975,365
1537									
1538	344	Generators							
1539			P	S		-	-	-	-
1540			P	SG		-	-	-	-
1541			P	SG		338,102,743	87,153,268	332,252,370	85,645,208
1542			P	SSGCT		15,873,643	4,087,988	15,873,643	4,087,988
1543					B8	353,976,386	91,241,256	348,126,013	89,733,197

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1544									
1545	345	Accessory Electric Plant							
1546			P	SG		244,333,275	62,982,167	232,284,593	59,876,360
1547			P	SG		156,586	40,363	156,586	40,363
1548			P	SSGCT		2,919,649	751,906	2,919,649	751,906
1549					B8	247,409,510	63,774,437	235,360,828	60,668,629
1550									
1551									
1552									
1553	346	Misc. Power Plant Equipment							
1554			P	SG		12,359,491	3,185,925	11,699,994	3,015,925
1555			P	SG		11,813	3,045	11,813	3,045
1556					B8	12,371,304	3,188,970	11,711,807	3,018,971
1557									
1558	347	Other Production ARO							
1559			P	S		-	-	-	-
1560					B8	-	-	-	-
1561									
1562	OP	Unclassified Other Prod Plant-Acct 300							
1563			P	S		-	-	-	-
1564			P	SG		-	-	-	-
1565						-	-	-	-
1566									
1567	**Total Other Production Plant**				**B8**	**3,309,570,847**	**853,094,376**	**3,103,398,847**	**800,004,260**
1568									
1569	Summary of Other Production Plant by Factor								
1570		S				-	-	75,000	75,000
1571		DGU				-	-	-	-
1572		SG				3,230,604,172	832,757,845	3,022,230,938	779,045,153
1573		SSGCT				78,966,675	20,336,531	81,092,910	20,884,107
1574	Total of Other Production Plant by Factor					3,309,570,847	853,094,376	3,103,398,847	800,004,260
1575									
1576	Experimental Plant								
1577	103	Experimental Plant							
1578			P	SG		-	-	-	-
1579	**Total Experimental Production Plant**				**B8**	-	-	-	-
1580									
1581	**Total Production Plant**				**B8**	**10,068,193,926**	**2,599,588,278**	**10,749,001,932**	**2,774,970,900**
1582	350	Land and Land Rights							
1583			T	SG		21,116,232	5,443,164	21,116,232	5,443,164
1584			T	SG		48,488,152	12,498,866	48,488,152	12,498,866
1585			T	SG		117,882,430	30,386,737	117,459,550	30,277,730
1586					B8	187,486,813	48,328,766	187,063,933	48,219,760
1587									
1588	352	Structures and Improvements							
1589			T	S		-	-	-	-
1590			T	SG		7,437,017	1,917,051	7,437,017	1,917,051
1591			T	SG		18,158,628	4,680,778	18,158,628	4,680,778
1592			T	SG		111,471,491	28,734,179	111,471,491	28,734,179
1593					B8	137,067,135	35,332,008	137,067,135	35,332,008
1594									
1595	353	Station Equipment							
1596			T	SG		124,774,520	32,163,321	124,774,520	32,163,321
1597			T	SG		183,031,133	47,180,219	183,031,133	47,180,219
1598			T	SG		1,286,199,080	331,545,531	1,286,199,080	331,545,531
1599					B8	1,594,004,732	410,889,071	1,594,004,732	410,889,071
1600									
1601	354	Towers and Fixtures							
1602			T	SG		155,436,532	40,067,116	155,436,532	40,067,116
1603			T	SG		133,296,819	34,360,128	133,296,819	34,360,128
1604			T	SG		663,705,120	171,084,298	663,705,120	171,084,298
1605					B8	952,438,471	245,511,541	952,438,471	245,511,541
1606									
1607	355	Poles and Fixtures							
1608			T	S		-	-	-	-
1609			T	SG		66,359,912	17,105,697	58,930,153	15,190,517
1610			T	SG		116,744,670	30,093,455	111,390,489	28,713,299
1611			T	SG		442,373,423	114,031,283	711,672,158	183,448,835
1612					B8	625,478,004	161,230,435	881,992,800	227,352,651
1613									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1614	356	Clearing and Grading							
1615			T	SG		185,514,669	47,820,404	185,514,669	47,820,404
1616			T	SG		157,672,314	40,643,437	157,672,314	40,643,437
1617			T	SG		540,276,301	139,267,859	540,276,301	139,267,859
1618					B8	883,463,283	227,731,700	883,463,283	227,731,700
1619									
1620	357	Underground Conduit							
1621			T	SG		6,371	1,642	6,371	1,642
1622			T	SG		91,651	23,625	91,651	23,625
1623			T	SG		3,161,431	814,927	3,161,431	814,927
1624					B8	3,259,452	840,194	3,259,452	840,194
1625									
1626	358	Underground Conductors							
1627			T	SG		-	-	-	-
1628			T	SG		1,087,552	280,340	1,087,552	280,340
1629			T	SG		6,387,543	1,646,527	6,387,543	1,646,527
1630					B8	7,475,095	1,926,867	7,475,095	1,926,867
1631									
1632	359	Roads and Trails							
1633			T	SG		1,863,032	480,237	1,863,032	480,237
1634			T	SG		440,513	113,552	440,513	113,552
1635			T	SG		9,295,159	2,396,027	9,295,159	2,396,027
1636					B8	11,598,703	2,989,816	11,598,703	2,989,816
1637									
1638	TP	Unclassified Trans Plant - Acct 300							
1639			T	SG		52,813,167	13,613,732	52,813,167	13,613,732
1640					B8	52,813,167	13,613,732	52,813,167	13,613,732
1641									
1642	TS0	Unclassified Trans Sub Plant - Acct 300							
1643			T	SG		-	-	-	-
1644					B8	-	-	-	-
1645									
1646	**Total Transmission Plant**				**B8**	**4,455,084,856**	**1,148,394,129**	**4,711,176,773**	**1,214,407,339**
1647	Summary of Transmission Plant by Factor								
1648		DGP				-	-	-	-
1649		DGU				-	-	-	-
1650		SG				4,455,084,856	1,148,394,129	4,711,176,773	1,214,407,339
1651	Total Transmission Plant by Factor					4,455,084,856	1,148,394,129	4,711,176,773	1,214,407,339
1652	360	Land and Land Rights							
1653			DPW	S		53,310,709	12,659,445	55,631,353	13,257,962
1654					B8	53,310,709	12,659,445	55,631,353	13,257,962
1655									
1656	361	Structures and Improvements							
1657			DPW	S		79,280,201	19,644,752	82,731,310	20,534,828
1658					B8	79,280,201	19,644,752	82,731,310	20,534,828
1659									
1660	362	Station Equipment							
1661			DPW	S		822,686,594	201,249,126	858,498,574	210,485,397
1662					B8	822,686,594	201,249,126	858,498,574	210,485,397
1663									
1664	363	Storage Battery Equipment							
1665			DPW	S		-	-	-	-
1666					B8	-	-	-	-
1667									
1668	364	Poles, Towers & Fixtures							
1669			DPW	S		953,729,554	322,560,427	995,245,904	333,267,914
1670					B8	953,729,554	322,560,427	995,245,904	333,267,914
1671									
1672	365	Overhead Conductors							
1673			DPW	S		653,386,179	231,283,187	681,828,424	238,618,730
1674					B8	653,386,179	231,283,187	681,828,424	238,618,730
1675									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1676	366	Underground Conduit							
1677			DPW	S		304,451,586	83,119,613	317,704,524	86,537,680
1678					B8	304,451,586	83,119,613	317,704,524	86,537,680
1679									
1680									
1681									
1682									
1683	367	Underground Conductors							
1684			DPW	S		723,393,642	154,354,890	754,883,348	162,476,403
1685					B8	723,393,642	154,354,890	754,883,348	162,476,403
1686									
1687	368	Line Transformers							
1688			DPW	S		1,107,583,957	387,652,357	1,155,797,670	400,087,161
1689					B8	1,107,583,957	387,652,357	1,155,797,670	400,087,161
1690									
1691	369	Services							
1692			DPW	S		592,230,200	221,950,830	618,010,293	228,599,776
1693					B8	592,230,200	221,950,830	618,010,293	228,599,776
1694									
1695	370	Meters							
1696			DPW	S		178,944,014	59,949,532	186,733,541	61,958,530
1697					B8	178,944,014	59,949,532	186,733,541	61,958,530
1698									
1699	371	Installations on Customers' Premises							
1700			DPW	S		8,798,701	2,469,615	9,181,713	2,568,397
1701					B8	8,798,701	2,469,615	9,181,713	2,568,397
1702									
1703	372	Leased Property							
1704			DPW	S		-	-	-	-
1705					B8	-	-	-	-
1706									
1707	373	Street Lights							
1708			DPW	S		60,757,949	21,964,678	63,402,774	22,646,805
1709					B8	60,757,949	21,964,678	63,402,774	22,646,805
1710									
1711	DP	Unclassified Dist Plant - Acct 300							
1712			DPW	S		23,844,586	4,850,420	23,844,586	4,850,420
1713					B8	23,844,586	4,850,420	23,844,586	4,850,420
1714									
1715	DS0	Unclassified Dist Sub Plant - Acct 300							
1716			DPW	S		-	-	-	-
1717					B8	-	-	-	-
1718									
1719									
1720	**Total Distribution Plant**				**B8**	**5,562,397,875**	**1,723,708,872**	**5,803,494,015**	**1,785,890,003**
1721									
1722	Summary of Distribution Plant by Factor								
1723		S				5,562,397,875	1,723,708,872	5,803,494,015	1,785,890,003
1724									
1725	Total Distribution Plant by Factor					5,562,397,875	1,723,708,872	5,803,494,015	1,785,890,003

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1726	389	Land and Land Rights							
1727			G-SITUS	S		9,472,275	3,046,462	9,472,275	3,046,462
1728			CUST	CN		1,128,506	331,362	1,128,506	331,362
1729			G-DGU	SG		332	86	332	86
1730			G-SG	SG		1,228	316	1,228	316
1731			PTD	SO		5,596,700	1,521,356	5,596,700	1,521,356
1732					B8	16,199,041	4,899,581	16,199,041	4,899,581
1733									
1734	390	Structures and Improvements							
1735			G-SITUS	S		112,740,950	33,831,192	112,740,950	33,831,192
1736			G-DGP	SG		356,327	91,851	356,327	91,851
1737			G-DGU	SG		1,638,043	422,241	1,638,043	422,241
1738			CUST	CN		12,312,990	3,615,446	12,312,990	3,615,446
1739			G-SG	SG		5,341,588	1,376,909	5,341,588	1,376,909
1740			PTD	SO		103,941,406	28,254,477	103,941,406	28,254,477
1741					B8	236,331,305	67,592,117	236,331,305	67,592,117
1742									
1743	391	Office Furniture & Equipment							
1744			G-SITUS	S		10,991,809	3,251,346	10,991,809	3,251,346
1745			G-DGP	SG		-	-	-	-
1746			G-DGU	SG		5,295	1,365	5,295	1,365
1747			CUST	CN		8,316,863	2,442,069	8,316,863	2,442,069
1748			G-SG	SG		4,603,865	1,186,746	4,603,865	1,186,746
1749			P	SE		68,033	16,541	68,033	16,541
1750			PTD	SO		54,794,019	14,894,703	54,794,019	14,894,703
1751			P	SSGCH		89,734	23,874	89,734	23,874
1752			P	SSGCT		-	-	-	-
1753					B8	78,869,618	21,816,643	78,869,618	21,816,643
1754									
1755	392	Transportation Equipment							
1756			G-SITUS	S		72,819,065	21,181,722	72,819,065	21,181,722
1757			PTD	SO		7,289,686	1,981,561	7,289,686	1,981,561
1758			G-SG	SG		17,294,590	4,458,053	17,266,336	4,450,770
1759			CUST	CN		-	-	-	-
1760			G-DGU	SG		779,129	200,837	779,129	200,837
1761			P	SE		404,148	98,263	404,148	98,263
1762			G-DGP	SG		120,286	31,006	120,286	31,006
1763			P	SSGCH		343,984	91,518	343,984	91,518
1764			P	SSGCT		44,655	11,500	44,655	11,500
1765					B8	99,095,543	28,054,461	99,067,289	28,047,178
1766									
1767	393	Stores Equipment							
1768			G-SITUS	S		8,443,634	2,672,691	8,443,634	2,672,691
1769			G-DGP	SG		69,750	17,980	69,750	17,980
1770			G-DGU	SG		268,272	69,153	268,272	69,153
1771			PTD	SO		324,919	88,323	324,919	88,323
1772			G-SG	SG		4,127,356	1,063,915	4,127,356	1,063,915
1773			P	SSGCT		53,971	13,899	53,971	13,899
1774					B8	13,287,902	3,925,961	13,287,902	3,925,961

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1775									
1776	394	Tools, Shop & Garage Equipment							
1777			G-SITUS	S		31,738,287	10,248,972	31,738,287	10,248,972
1778			G-DGP	SG		1,339,090	345,179	1,339,090	345,179
1779			G-SG	SG		20,900,830	5,387,639	20,900,830	5,387,639
1780			PTD	SO		3,801,735	1,033,429	3,801,735	1,033,429
1781			P	SE		7,106	1,728	7,106	1,728
1782			G-DGU	SG		907,807	234,007	907,807	234,007
1783			P	SSGCH		1,697,140	451,529	1,697,140	451,529
1784			P	SSGCT		89,913	23,156	89,913	23,156
1785					B8	60,481,908	17,725,638	60,481,908	17,725,638
1786									
1787	395	Laboratory Equipment							
1788			G-SITUS	S		23,516,426	9,316,206	23,516,426	9,316,206
1789			G-DGP	SG		1,518	391	1,518	391
1790			G-DGU	SG		5,371	1,384	5,371	1,384
1791			PTD	SO		5,705,503	1,550,932	5,705,503	1,550,932
1792			P	SE		7,593	1,846	7,593	1,846
1793			G-SG	SG		6,322,239	1,629,693	6,322,239	1,629,693
1794			P	SSGCH		253,001	67,311	253,001	67,311
1795			P	SSGCT		14,022	3,611	14,022	3,611
1796					B8	35,825,672	12,571,375	35,825,672	12,571,375
1797									
1798	396	Power Operated Equipment							
1799			G-SITUS	S		94,699,232	29,310,166	94,699,232	29,310,166
1800			G-DGP	SG		845,108	217,845	845,108	217,845
1801			G-SG	SG		31,187,550	8,039,263	31,187,550	8,039,263
1802			PTD	SO		1,137,422	309,186	1,137,422	309,186
1803			G-DGU	SG		1,634,205	421,252	1,634,205	421,252
1804			P	SE		45,031	10,949	45,031	10,949
1805			P	SSGCT		-	-	-	-
1806			P	SSGCH		999,837	266,009	999,837	266,009
1807					B8	130,548,386	38,574,670	130,548,386	38,574,670
1808	397	Communication Equipment							
1809			DPW	S		110,422,697	36,498,469	173,122,987	57,049,520
1810			G-DGP	SG		1,471,243	379,245	558,348	143,926
1811			G-DGU	SG		2,381,434	613,866	343,497	88,544
1812			PTD	SO		57,841,983	15,723,233	45,909,819	12,479,703
1813			CUST	CN		2,855,125	838,346	237,650	69,781
1814			G-SG	SG		96,581,869	24,896,058	107,962,913	27,829,767
1815			P	SE		126,615	30,784	31,041	7,547
1816			G-SG	SSGCH		619,180	164,735	80,679	21,465
1817			G-SG	SSGCT		1,590	410	(10,062)	(2,591)
1818					B8	272,301,737	79,145,146	328,236,873	97,687,663
1819									
1820	398	Misc. Equipment							
1821			G-SITUS	S		1,521,391	670,085	1,521,391	670,085
1822			G-DGP	SG		-	-	-	-
1823			G-DGU	SG		-	-	-	-
1824			CUST	CN		212,837	62,495	212,837	62,495
1825			PTD	SO		2,924,199	794,887	2,924,199	794,887
1826			P	SE		1,668	405	1,668	405
1827			G-SG	SG		1,910,599	492,498	1,910,599	492,498
1828			G-SG	SSGCT		-	-	-	-
1829					B8	6,570,694	2,020,371	6,570,694	2,020,371
1830									
1831	399	Coal Mine							
1832			P	SE		286,661,904	69,697,596	488,304,005	118,723,886
1833	MP		P	SE		-	-	-	-
1834					B8	286,661,904	69,697,596	488,304,005	118,723,886
1835									
1836	399L	WIDCO Capital Lease							
1837			P	SE	Tab 8	-	-	-	-
1838						-	-	-	-
1839									
1840		Remove Capital Leases				-	-	-	-
1841					Tab 8	-	-	-	-
1842									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1843	1011390	General Capital Leases							
1844			G-SITUS	S		18,984,156	5,882,166	18,984,156	5,882,166
1845			P	SG		33,744,912	8,698,478	33,744,912	8,698,478
1846			PTD	SO		12,664,054	3,442,480	12,664,054	3,442,480
1847					B9	65,393,121	18,023,125	65,393,121	18,023,125
1848									
1849		Remove Capital Leases				(65,393,121)	(18,023,125)	(65,393,121)	(18,023,125)
1850						-	-	-	-
1851									
1852	1011346	General Gas Line Capital Leases							
1853			P	SG		-	-	-	-
1854					B9	-	-	-	-
1855									
1856		Remove Capital Leases				-	-	-	-
1857						-	-	-	-
1858									
1859	GP	Unclassified Gen Plant - Acct 300							
1860			G-SITUS	S		-	-	-	-
1861			PTD	SO		1,548,788	421,008	1,548,788	421,008
1862			CUST	CN		-	-	-	-
1863			G-SG	SG		(53,522)	(13,796)	(53,522)	(13,796)
1864			G-DGP	SG		-	-	-	-
1865			G-DGU	SG		-	-	-	-
1866					B8	1,495,266	407,212	1,495,266	407,212
1867									
1868	399G	Unclassified Gen Plant - Acct 300							
1869			G-SITUS	S		-	-	-	-
1870			PTD	SO		-	-	-	-
1871			G-SG	SG		-	-	-	-
1872			G-DGP	SG		-	-	-	-
1873			G-DGU	SG		-	-	-	-
1874					B8	-	-	-	-
1875									
1876	**Total General Plant**				**B8**	**1,237,668,975**	**346,430,770**	**1,495,217,958**	**413,992,294**
1877									
1878	Summary of General Plant by Factor								
1879		S				495,349,922	155,909,477	558,050,211	176,460,528
1880		DGP				-	-	-	-
1881		DGU				-	-	-	-
1882		SG				233,786,314	60,263,460	242,188,272	62,429,246
1883		SO				257,570,415	70,015,575	245,638,251	66,772,045
1884		SE				287,322,098	69,858,112	488,868,625	118,861,165
1885		CN				24,826,321	7,289,718	22,208,846	6,521,153
1886		DEU				-	-	-	-
1887		SSGCT				204,151	52,576	192,499	49,575
1888		SSGCH				4,002,876	1,064,976	3,464,375	921,706
1889		Less Capital Leases				(65,393,121)	(18,023,125)	(65,393,121)	(18,023,125)
1890	Total General Plant by Factor					1,237,668,975	346,430,770	1,495,217,958	413,992,294
1891	301	Organization							
1892			I-SITUS	S		-	-	-	-
1893			PTD	SO		-	-	-	-
1894			I-SG	SG		-	-	-	-
1895					B8	-	-	-	-
1896	302	Franchise & Consent							
1897			I-SITUS	S		1,000,000	-	1,000,000	-
1898			I-SG	SG		10,265,665	2,646,196	4,304,740	1,109,640
1899			I-SG	SG		173,622,224	44,754,870	169,528,812	43,699,705
1900			I-SG	SG		9,189,363	2,368,756	9,051,536	2,333,228
1901			I-DGP	SG		-	-	-	-
1902			I-DGU	SG		600,993	154,919	600,993	154,919
1903					B8	194,678,245	49,924,741	184,486,081	47,297,491
1904									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1905	303	Miscellaneous Intangible Plant							
1906			I-SITUS	S		7,507,698	1,853,709	6,798,360	1,320,629
1907			I-SG	SG		131,131,608	33,801,998	131,109,838	33,796,386
1908			PTD	SO		375,888,954	102,178,200	381,477,170	103,697,249
1909			P	SE		3,654,416	888,517	3,538,192	860,259
1910			CUST	CN		121,077,156	35,551,719	120,697,107	35,440,125
1911			P	SG		-	-	-	-
1912			I-DGP	SSGCT		-	-	-	-
1913					B8	639,259,832	174,274,143	643,620,666	175,114,648
1914	303	Less Non-Utility Plant							
1915			I-SITUS	S		-	-	-	-
1916						639,259,832	174,274,143	643,620,666	175,114,648
1917	IP	Unclassified Intangible Plant - Acct 300							
1918			I-SITUS	S		-	-	-	-
1919			I-SG	SG		-	-	-	-
1920			I-DGU	SG		-	-	-	-
1921			PTD	SO		-	-	-	-
1922						-	-	-	-
1923									
1924	**Total Intangible Plant**				**B8**	**833,938,076**	**224,198,884**	**828,106,747**	**222,412,140**
1925									
1926	Summary of Intangible Plant by Factor								
1927		S				8,507,698	1,853,709	7,798,360	1,320,629
1928		DGP				-	-	-	-
1929		DGU				-	-	-	-
1930		SG				324,809,853	83,726,739	314,595,919	81,093,878
1931		SO				375,888,954	102,178,200	381,477,170	103,697,249
1932		CN				121,077,156	35,551,719	120,697,107	35,440,125
1933		SSGCT				-	-	-	-
1934		SSGCH				-	-	-	-
1935		SE				3,654,416	888,517	3,538,192	860,259
1936	Total Intangible Plant by Factor					833,938,076	224,198,884	828,106,747	222,412,140
1937	Summary of Unclassified Plant (Account 106)								
1938		DP				23,844,586	4,850,420	23,844,586	4,850,420
1939		DS0				-	-	-	-
1940		GP				1,495,266	407,212	1,495,266	407,212
1941		HP				-	-	-	-
1942		NP				-	-	-	-
1943		OP				-	-	-	-
1944		TP				52,813,167	13,613,732	52,813,167	13,613,732
1945		TS0				-	-	-	-
1946		IP				-	-	-	-
1947		MP							
1948		SP				5,221,058	1,345,840	5,221,058	1,345,840
1949	Total Unclassified Plant by Factor					83,374,078	20,217,205	83,374,078	20,217,205
1950									
1951	**Total Electric Plant In Service**				**B8**	**22,157,283,708**	**6,042,320,934**	**23,586,997,425**	**6,411,672,676**

REVISED PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
1952	Summary of Electric Plant by Factor								
1953		S				6,066,255,494	1,881,472,059	6,369,417,586	1,963,746,160
1954		SE				290,976,514	70,746,630	492,406,816	119,721,424
1955		DGU				-	-	-	-
1956		DGP				-	-	-	-
1957		SG				14,482,065,114	3,733,064,372	15,434,933,910	3,978,686,839
1958		SO				633,459,369	172,193,775	627,115,421	170,469,294
1959		CN				145,903,477	42,841,437	142,905,953	41,961,278
1960		DEU				-	-	-	-
1961		SSGCH				524,846,037	139,636,680	504,325,451	134,177,123
1962		SSGCT				79,170,826	20,389,107	81,285,409	20,933,682
1963		Less Capital Leases				(65,393,121)	(18,023,125)	(65,393,121)	(18,023,125)
1964						22,157,283,708	6,042,320,934	23,586,997,425	6,411,672,676
1965	105	Plant Held For Future Use							
1966			DPW	S		7,174,343	4,254,106	-	-
1967			P	SG		-	-	-	-
1968			P	SG		2,944,517	759,013	-	-
1969			P	SG		8,923,302	2,300,173	-	-
1970			P	SE		25,979,316	6,316,486	-	-
1971			G	SG		-	-	-	-
1972									
1973									
1974	**Total Plant Held For Future Use**				**B10**	**45,021,478**	**13,629,778**	-	-
1975									
1976	114	Electric Plant Acquisition Adjustments							
1977			P	S		-	-	-	-
1978			P	SG		144,614,797	37,277,580	144,614,797	37,277,580
1979			P	SG		14,560,711	3,753,337	14,560,711	3,753,337
1980	**Total Electric Plant Acquisition Adjustment**				**B15**	**159,175,508**	**41,030,917**	**159,175,508**	**41,030,917**
1981									
1982	115	Accum Provision for Asset Acquisition Adjustments							
1983			P	S		-	-	-	-
1984			P	SG		(91,388,309)	(23,557,306)	(102,270,785)	(26,362,499)
1985			P	SG		(13,218,942)	(3,407,467)	(13,218,942)	(3,407,467)
1986					B15	(104,607,250)	(26,964,773)	(115,489,727)	(29,769,966)
1987									
1988	120	Nuclear Fuel							
1989			P	SE		-	-	-	-
1990	**Total Nuclear Fuel**				**B15**	-	-	-	-
1991									
1992	124	Weatherization							
1993			DMSC	S		1,969,468	0	1,969,468	0
1994			DMSC	SO		(4,454)	(1,211)	(4,454)	(1,211)
1995					B16	1,965,015	(1,210)	1,965,015	(1,210)
1996									
1997	182W	Weatherization							
1998			DMSC	S		(2,000,697)	-	(2,000,697)	-
1999			DMSC	SG		-	-	-	-
2000			DMSC	SGCT		-	-	-	-
2001			DMSC	SO		-	-	-	-
2002					B16	(2,000,697)	-	(2,000,697)	-
2003									
2004	186W	Weatherization							
2005			DMSC	S		-	-	-	-
2006			DMSC	CN		-	-	-	-
2007			DMSC	CNP		-	-	-	-
2008			DMSC	SG		-	-	-	-
2009			DMSC	SO		-	-	-	-
2010					B16	-	-	-	-
2011									
2012	**Total Weatherization**				**B16**	**(35,682)**	**(1,210)**	**(35,682)**	**(1,210)**

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2013									
2014	151	Fuel Stock							
2015			P	DEU		-	-	-	-
2016			P	SE		212,462,887	51,657,204	208,232,339	50,628,609
2017			P	SSECT		-	-	-	-
2018			P	SSECH		10,592,137	2,636,548	6,673,661	1,661,179
2019	**Total Fuel Stock**				**B13**	**223,055,023**	**54,293,752**	**214,906,000**	**52,289,788**
2020									
2021	152	Fuel Stock - Undistributed							
2022			P	SE		-	-	-	-
2023						-	-	-	-
2024									
2025	25316	DG&T Working Capital Deposit							
2026			P	SE		(2,777,000)	(675,186)	(3,417,000)	(830,793)
2027					B13	(2,777,000)	(675,186)	(3,417,000)	(830,793)
2028									
2029	25317	DG&T Working Capital Deposit							
2030			P	SE		(2,023,136)	(491,896)	(2,623,631)	(637,897)
2031					B13	(2,023,136)	(491,896)	(2,623,631)	(637,897)
2032									
2033	25319	Provo Working Capital Deposit							
2034			P	SE		-	-	-	-
2035						-	-	-	-
2036									
2037		Total Fuel Stock			B13	218,254,887	53,126,671	208,865,369	50,821,098
2038	154	Materials and Supplies							
2039			MSS	S		88,641,997	27,856,546	88,641,997	27,856,546
2040			MSS	SG		4,703,417	1,212,407	4,703,417	1,212,407
2041			MSS	SE		6,159,125	1,497,500	6,159,125	1,497,500
2042			MSS	SO		51,819	14,086	51,819	14,086
2043			MSS	SNPPS		87,220,162	22,543,326	87,220,162	22,543,326
2044			MSS	SNPPH		(1,860)	(479)	(1,860)	(479)
2045			MSS	SNPD		(2,478,050)	(666,740)	(2,478,050)	(666,740)
2046			MSS	SG		-	-	-	-
2047			MSS	SG		-	-	-	-
2048			MSS	SG		-	-	-	-
2049			MSS	SSGCT		-	-	-	-
2050			MSS	SNPPO		6,973,902	1,797,788	6,973,902	1,797,788
2051			MSS	SSGCH		-	-	-	-
2052	**Total Materials and Supplies**				**B13**	**191,270,513**	**54,254,434**	**191,270,513**	**54,254,434**
2053									
2054	163	Stores Expense Undistributed							
2055			MSS	SO		-	-	-	-
2056									
2057					B13	-	-	-	-
2058									
2059	25318	Provo Working Capital Deposit							
2060			MSS	SNPPS		(273,000)	(70,561)	(273,000)	(70,561)
2061									
2062					B13	(273,000)	(70,561)	(273,000)	(70,561)
2063									
2064		Total Materials & Supplies			B13	190,997,513	54,183,873	190,997,513	54,183,873
2065									
2066	165	Prepayments							
2067			DMSC	S		7,868,243	2,209,516	7,868,243	2,209,516
2068			GP	GPS		283,539	77,074	283,539	77,074
2069			PT	SG		2,643,389	681,391	2,643,389	681,391
2070			P	SE		3,362,821	817,620	3,362,821	817,620
2071			PTD	SO		14,285,132	3,883,139	14,285,132	3,883,139
2072	**Total Prepayments**				**B15**	**28,443,124**	**7,668,739**	**28,443,124**	**7,668,739**
2073									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2074	182M	Misc Regulatory Assets							
2075			DDS2	S		121,949,207	(61,893)	121,791,362	(219,737)
2076			DEFSG	SG		-	-	-	-
2077			P	SGCT		6,828,086	1,765,867	4,583,236	1,185,308
2078			DEFSG	SG-P		-	-	-	-
2079			P	SE		-	-	-	-
2080			P	SSGCT		-	-	-	-
2081			DDSO2	SO		8,841,299	2,403,338	8,841,299	2,403,338
2082					B11	137,618,592	4,107,312	135,215,897	3,368,909
2083									
2084	186M	Misc Deferred Debits							
2085			LABOR	S		13,749,962	-	13,749,962	-
2086			P	SG		-	-	-	-
2087			P	SG		-	-	-	-
2088			DEFSG	SG		49,283,351	12,703,846	62,116,663	16,011,908
2089			LABOR	SO		-	-	-	-
2090			P	SE		13,136,810	3,194,021	13,136,810	3,194,021
2091			P	SNPPS		-	-	-	-
2092			GP	EXCTAX		-	-	-	-
2093	**Total Misc. Deferred Debits**				**B11**	**76,170,123**	**15,897,867**	**89,003,435**	**19,205,929**
2094									
2095	Working Capital								
2096	CWC	Cash Working Capital							
2097			CWC	S		33,965,050	12,240,121	48,310,814	17,525,188
2098			CWC	SO		-	-	-	-
2099			CWC	SE		-	-	-	-
2100					B14	33,965,050	12,240,121	48,310,814	17,525,188
2101									
2102	OWC	Other Work. Cap.							
2103	131	Cash	GP	SNP		-	-	-	-
2104	135	Working Funds	P	SG		-	-	-	-
2105	141	Notes Receivabl	GP	SO		-	-	-	-
2106	143	Other A/R	GP	SO		55,756,133	15,156,235	55,756,133	15,156,235
2107	232	A/P	PTD	S		-	-	-	-
2108	232	A/P	PTD	SO		(4,730,325)	(1,285,848)	(4,730,325)	(1,285,848)
2109	232	A/P	P	SE		(3,588,481)	(872,486)	(3,588,481)	(872,486)
2110	232	A/P	T	SG		(172,140)	(44,373)	(172,140)	(44,373)
2111	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2112	2533	Other Msc. Df. Crd.	P	SE		(6,363,956)	(1,547,302)	(6,758,625)	(1,643,260)
2113	230	Asset Retir. Oblig.	P	SE		(2,516,092)	(611,750)	(2,516,092)	(611,750)
2114	230	Asset Retir. Oblig.	P	S		-	-	-	-
2115	254105	ARO Reg Liability	P	S		-	-	-	-
2116	254105	ARO Reg Liability	P	SE		(898,049)	(218,347)	(898,049)	(218,347)
2117	2533	Cholla Reclamation	P	SSECH		-	-	-	-
2118					B14	37,487,090	10,576,128	37,092,420	10,480,170
2119									
2120	**Total Working Capital**				**B14**	**71,452,139**	**22,816,250**	**85,403,234**	**28,005,358**
2121	Miscellaneous Rate Base								
2122	18221	Unrec Plant & Reg Study Costs							
2123			P	S		-	-	-	-
2124									
2125					B15	-	-	-	-
2126									
2127	18222	Nuclear Plant - Trojan							
2128			P	S		-	-	-	-
2129			P	TROJP		-	-	-	-
2130			P	TROJD		-	-	-	-
2131					B15	-	-	-	-
2132									
2133									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2134									
2135	1869	Misc Deferred Debits-Trojan							
2136			P	S		-	-	-	-
2137			P	SNPPN		-	-	-	-
2138					B15	-	-	-	-
2139									
2140	**Total Miscellaneous Rate Base**				**B15**	-	-	-	-
2141									
2142	**Total Rate Base Additions**				**B15**	**822,490,431**	**185,495,423**	**781,578,672**	**174,513,647**
2143	235	Customer Service Deposits							
2144			CUST	S		-	-	-	-
2145			CUST	CN		-	-	-	-
2146	**Total Customer Service Deposits**				B15	-	-	-	-
2147									
2148	2281	Prop Ins	PTD	SO		-	-	-	-
2149	2282	Inj & Dam	PTD	SO		(6,485,000)	(1,762,823)	(6,485,000)	(1,762,823)
2150	2283	Pen & Ben	PTD	SO		(25,325,928)	(6,884,368)	(25,325,928)	(6,884,368)
2151	254	Ins Prov	PTD	SO		-	-	-	-
2152	254	Reg Liabilitie	P	SE		-	-	-	-
2153					B15	(31,810,928)	(8,647,190)	(31,810,928)	(8,647,190)
2154									
2155	22844	Accum Hydro Relicensing Obligation							
2156			P	S		-	-	-	-
2157			P	SG		-	-	-	-
2158					B15	-	-	-	-
2159									
2160	22841	Chehalis Rat	P	SG		(1,500,000)	(386,657)	(1,500,000)	(386,657)
2161	230	ARO	P	TROJP		(1,660,934)	(424,449)	(1,660,934)	(424,449)
2162	254105	ARO	P	TROJP		(3,463,650)	(885,130)	(3,463,650)	(885,130)
2163	254		P	S		(9,715,443)	(1,313,427)	(9,715,443)	(1,313,427)
2164					B15	(16,340,028)	(3,009,663)	(16,340,028)	(3,009,663)
2165									
2166	252	Customer Advances for Construction							
2167			DPW	S		(11,658,859)	(7,096,641)	(12,562,616)	(7,448,152)
2168			DPW	SE		-	-	-	-
2169			T	SG		(16,205,061)	(4,177,204)	(15,301,304)	(3,944,241)
2170			DPW	SO		-	-	-	-
2171			CUST	CN		-	-	-	-
2172	**Total Customer Advances for Construction**				**B19**	**(27,863,920)**	**(11,273,844)**	**(27,863,920)**	**(11,392,393)**
2173									
2174	25398	SO2 Emissions							
2175			P	SE		-	-	(829,723)	(201,735)
2176					B19	-	-	(829,723)	(201,735)
2177									
2178	25399	Other Deferred Credits							
2179			P	S		(1,300,240)	(621,782)	(1,300,240)	(621,782)
2180			LABOR	SO		-	-	-	-
2181			P	SG		(8,875,492)	(2,287,849)	(8,875,492)	(2,287,849)
2182			P	SE		(5,037,754)	(1,224,855)	(5,037,754)	(1,224,855)
2183					B19	(15,213,487)	(4,134,487)	(15,213,487)	(4,134,487)

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2184									
2185	190	Accumulated Deferred Income Taxes							
2186			P	S		19,032,602	962,923	32,739,158	2,194,422
2187			CUST	CN		47,212	13,863	28,936	8,496
2188			LABOR	SO		78,987,023	21,471,107	83,158,212	22,604,964
2189			P	GPS		-	-	-	-
2190			IBT	IBT		-	-	-	-
2191			P	SG-P		-	-	-	-
2192			P	SG-U		-	-	-	-
2193			CUST	BADDEBT		3,844,157	1,794,004	5,515,134	2,573,821
2194			P	TROJD		1,912,922	488,093	-	-
2195			P	SG		39,603,970	10,208,777	7,372,994	1,900,548
2196			P	SE		(15,479,212)	(3,763,541)	(13,979,690)	(3,398,954)
2197			PTD	SNP		-	-	-	-
2198			DPW	SNPD		1,793,564	482,573	806,637	217,032
2199			P	SSGCT		-	-	-	-
2200	**Total Accum Deferred Income Taxes**				**B19**	**129,742,238**	**31,657,798**	**115,641,381**	**26,100,330**
2201									
2202	281	Accumulated Deferred Income Taxes							
2203			P	S		-	-	-	-
2204			PT	SG		(121,387,549)	(31,290,257)	-	-
2205			T	SG		-	-	-	-
2206					B19	(121,387,549)	(31,290,257)	-	-
2207									
2208	282	Accumulated Deferred Income Taxes							
2209			GP	S		-	-	(3,658,835,895)	(985,558,965)
2210			GP	CN		-	-	-	-
2211			TAXDEPR	DGU		-	-	-	-
2212			ACCMDIT	DITBAL		(3,031,107,795)	(832,740,314)	2	1
2213			P	DGP		-	-	-	-
2214			DPW	SG-P		-	-	-	-
2215			P	SSGCH		-	-	-	-
2216			PT	SG-U		-	-	-	-
2217			LABOR	SO		26,404,262	7,177,492	23,436,640	6,370,801
2218			GP	SSGCT		-	-	-	-
2219			P	SE		(5,491,795)	(1,335,249)	(5,083,668)	(1,236,019)
2220			P	SG		(4,961,751)	(1,278,998)	14,715,157	3,793,149
2221					B19	(3,015,157,079)	(828,177,069)	(3,625,767,764)	(976,631,033)
2222									
2223	283	Accumulated Deferred Income Taxes							
2224			GP	S		(56,399,874)	2,046,121	(78,631,297)	(339,034)
2225			P	SG		(9,100,661)	(2,345,891)	(1,946,183)	(501,671)
2226			P	SE		(12,837,744)	(3,121,307)	(15,145,533)	(3,682,412)
2227			LABOR	SO		(3,864,666)	(1,050,535)	(9,931,871)	(2,699,788)
2228			GP	GPS		(7,560,429)	(2,055,140)	(5,821,397)	(1,582,422)
2229			PTD	SNP		(4,344,154)	(1,138,790)	(3,672,481)	(962,716)
2230			P	TROJD		-	-	-	-
2231			P	SSGCT		-	-	-	-
2232			P	SGCT		(2,804,313)	(725,246)	(1,739,383)	(449,836)
2233			P	IBT		-	-	-	-
2234					B19	(96,911,841)	(8,390,790)	(116,888,144)	(10,217,878)
2235									
2236	**Total Accum Deferred Income Tax**				**B19**	**(3,103,714,231)**	**(836,200,317)**	**(3,627,014,527)**	**(960,748,582)**
2237	255	Accumulated Investment Tax Credit							
2238			PTD	S		-	-	-	-
2239			PTD	ITC84		(872,621)	(619,351)	-	-
2240			PTD	ITC85		(2,026,144)	(1,371,497)	(668,689)	(452,636)
2241			PTD	ITC86		(1,109,823)	(717,034)	(616,575)	(398,357)
2242			PTD	ITC88		(177,804)	(108,816)	(118,548)	(72,551)
2243			PTD	ITC89		(398,410)	(224,527)	(280,594)	(158,131)
2244			PTD	ITC90		(272,742)	(43,463)	(215,190)	(34,292)
2245			PTD	DGU		-	-	-	-
2246	**Total Accumlated ITC**				**B19**	(4,857,544)	(3,084,689)	(1,899,596)	(1,115,967)
2247									
2248	**Total Rate Base Deductions**					**(3,199,800,137)**	**(866,350,191)**	**(3,720,972,208)**	**(989,250,016)**
2249									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2250									
2251									
2252	108SP	Steam Prod Plant Accumulated Depr							
2253			P	S		-	-	-	-
2254			P	SG		(764,758,175)	(197,132,900)	(780,055,729)	(201,076,174)
2255			P	SG		(855,622,229)	(220,555,068)	(878,481,702)	(226,447,590)
2256			P	SG		(634,543,934)	(163,567,373)	(928,281,792)	(239,284,636)
2257			P	SSGCH		(168,303,056)	(44,777,474)	(167,834,615)	(44,652,844)
2258					B17	(2,423,227,394)	(626,032,816)	(2,754,653,837)	(711,461,245)
2259									
2260	108NP	Nuclear Prod Plant Accumulated Depr							
2261			P	SG		-	-	-	-
2262			P	SG		-	-	-	-
2263			P	SG		-	-	-	-
2264					B17	-	-	-	-
2265									
2266									
2267	108HP	Hydraulic Prod Plant Accum Depr							
2268			P	S		-	-	-	-
2269			P	SG		(154,767,475)	(39,894,652)	(162,043,005)	(41,770,076)
2270			P	SG		(29,241,674)	(7,537,672)	(28,697,021)	(7,397,276)
2271			P	SG		(67,412,046)	(17,376,908)	(54,558,705)	(14,063,682)
2272			P	SG		(17,589,885)	(4,534,172)	(21,810,471)	(5,622,119)
2273					B17	(269,011,080)	(69,343,403)	(267,109,202)	(68,853,153)
2274									
2275	108OP	Other Production Plant - Accum Depr							
2276			P	S		-	-	-	-
2277			P	SG		(1,548,574)	(399,178)	(366,724)	(94,531)
2278			P	SG		-	-	-	-
2279			P	SG		(412,359,088)	(106,294,441)	(506,567,557)	(130,578,704)
2280			P	SSGCT		(21,791,105)	(5,611,930)	(24,540,740)	(6,320,052)
2281					B17	(435,698,768)	(112,305,550)	(531,475,021)	(136,993,288)
2282									
2283	108EP	Experimental Plant - Accum Depr							
2284			P	SG		-	-	-	-
2285			P	SG		-	-	-	-
2286						-	-	-	-
2287									
2288	**Total Production Plant Accum Depreciation**				**B17**	**(3,127,937,242)**	**(807,681,769)**	**(3,553,238,060)**	**(917,307,686)**
2289									
2290	Summary of Prod Plant Depreciation by Factor								
2291		S				-	-	-	-
2292		DGP				-	-	-	-
2293		DGU				-	-	-	-
2294		SG				(2,937,843,080)	(757,292,365)	(3,360,862,705)	(866,334,789)
2295		SSGCH				(168,303,056)	(44,777,474)	(167,834,615)	(44,652,844)
2296		SSGCT				(21,791,105)	(5,611,930)	(24,540,740)	(6,320,052)
2297	Total of Prod Plant Depreciation by Factor					(3,127,937,242)	(807,681,769)	(3,553,238,060)	(917,307,686)
2298									
2299									
2300	108TP	Transmission Plant Accumulated Depr							
2301			T	S		-	-	-	-
2302			T	SG		(369,436,693)	(95,230,269)	(378,249,324)	(97,501,915)
2303			T	SG		(398,038,617)	(102,603,031)	(411,324,484)	(106,027,750)
2304			T	SG		(428,771,884)	(110,525,193)	(490,402,478)	(126,411,807)
2305	**Total Trans Plant Accum Depreciation**				**B17**	**(1,196,247,194)**	**(308,358,493)**	**(1,279,976,286)**	**(329,941,471)**

REVISED PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2306	108360	Land and Land Rights							
2307			DPW	S		(7,602,613)	(2,374,363)	(9,030,795)	(2,950,952)
2308					B17	(7,602,613)	(2,374,363)	(9,030,795)	(2,950,952)
2309									
2310	108361	Structures and Improvements							
2311			DPW	S		(15,035,110)	(3,599,321)	(17,159,008)	(4,456,786)
2312					B17	(15,035,110)	(3,599,321)	(17,159,008)	(4,456,786)
2313									
2314	108362	Station Equipment							
2315			DPW	S		(214,712,020)	(58,097,426)	(236,751,601)	(66,995,304)
2316					B17	(214,712,020)	(58,097,426)	(236,751,601)	(66,995,304)
2317									
2318	108363	Storage Battery Equipment							
2319			DPW	S		-	-	-	-
2320					B17	-	-	-	-
2321									
2322	108364	Poles, Towers & Fixtures							
2323			DPW	S		(514,475,720)	(209,418,127)	(540,025,911)	(219,733,317)
2324					B17	(514,475,720)	(209,418,127)	(540,025,911)	(219,733,317)
2325									
2326	108365	Overhead Conductors							
2327			DPW	S		(277,148,700)	(127,166,293)	(294,652,762)	(134,233,080)
2328					B17	(277,148,700)	(127,166,293)	(294,652,762)	(134,233,080)
2329									
2330	108366	Underground Conduit							
2331			DPW	S		(127,942,936)	(35,884,487)	(136,099,123)	(39,177,324)
2332					B17	(127,942,936)	(35,884,487)	(136,099,123)	(39,177,324)
2333									
2334	108367	Underground Conductors							
2335			DPW	S		(295,078,722)	(59,114,033)	(314,458,268)	(66,937,995)
2336					B17	(295,078,722)	(59,114,033)	(314,458,268)	(66,937,995)
2337									
2338	108368	Line Transformers							
2339			DPW	S		(382,284,169)	(168,090,440)	(411,956,083)	(180,069,664)
2340					B17	(382,284,169)	(168,090,440)	(411,956,083)	(180,069,664)
2341									
2342	108369	Services							
2343			DPW	S		(179,783,834)	(67,712,510)	(195,649,542)	(74,117,855)
2344					B17	(179,783,834)	(67,712,510)	(195,649,542)	(74,117,855)
2345									
2346	108370	Meters							
2347			DPW	S		(74,912,498)	(32,858,656)	(79,706,366)	(34,794,049)
2348					B17	(74,912,498)	(32,858,656)	(79,706,366)	(34,794,049)
2349									
2350									
2351									
2352	108371	Installations on Customers' Premises							
2353			DPW	S		(7,778,672)	(2,493,265)	(8,014,388)	(2,588,428)
2354					B17	(7,778,672)	(2,493,265)	(8,014,388)	(2,588,428)
2355									
2356	108372	Leased Property							
2357			DPW	S		-	-	-	-
2358					B17	-	-	-	-
2359									
2360	108373	Street Lights							
2361			DPW	S		(27,338,303)	(8,583,788)	(28,965,994)	(9,240,924)
2362					B17	(27,338,303)	(8,583,788)	(28,965,994)	(9,240,924)
2363									
2364	108D00	Unclassified Dist Plant - Acct 300							
2365			DPW	S		-	-	-	-
2366					B17	-	-	-	-
2367									
2368	108DS	Unclassified Dist Sub Plant - Acct 300							
2369			DPW	S		-	-	-	-
2370					B17	-	-	-	-
2371									
2372	108DP	Unclassified Dist Sub Plant - Acct 300							
2373			DPW	S		1,183,546	(224,187)	1,183,546	(224,187)
2374					B17	1,183,546	(224,187)	1,183,546	(224,187)
2375									
2376									
2377	**Total Distribution Plant Accum Depreciation**				**B17**	**(2,122,909,752)**	**(775,616,895)**	**(2,271,286,293)**	**(835,519,865)**
2378									
2379	Summary of Distribution Plant Depr by Factor								
2380		S				(2,122,909,752)	(775,616,895)	(2,271,286,293)	(835,519,865)
2381									
2382	Total Distribution Depreciation by Factor					(2,122,909,752)	(775,616,895)	(2,271,286,293)	(835,519,865)

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2383	108GP	General Plant Accumulated Depr							
2384			G-SITUS	S		(154,405,355)	(45,213,577)	(153,946,618)	(43,367,585)
2385			G-DGP	SG		(2,773,800)	(715,007)	(2,097,281)	(540,619)
2386			G-DGU	SG		(4,558,040)	(1,174,933)	(2,969,084)	(765,345)
2387			G-SG	SG		(53,387,293)	(13,761,725)	(55,301,048)	(14,255,037)
2388			CUST	CN		(7,761,004)	(2,278,853)	(7,506,237)	(2,204,046)
2389			PTD	SO		(74,737,799)	(20,316,037)	(63,288,399)	(17,203,737)
2390			P	SE		(309,947)	(75,359)	(281,847)	(68,527)
2391			P	SSGCT		(44,066)	(11,349)	(46,139)	(11,882)
2392			P	SSGCH		(1,930,396)	(513,587)	(1,672,452)	(444,960)
2393					B17	(299,907,700)	(84,060,426)	(287,109,106)	(78,861,739)
2394									
2395									
2396	108MP	Mining Plant Accumulated Depr.							
2397			P	S		-	-	-	-
2398			P	SE		(156,346,430)	(38,013,319)	(156,948,403)	(38,159,679)
2399					B17	(156,346,430)	(38,013,319)	(156,948,403)	(38,159,679)
2400	108MP	Less Centralia Situs Depreciation							
2401			P	S		-	-	-	-
2402					B17	(156,346,430)	(38,013,319)	(156,948,403)	(38,159,679)
2403									
2404	1081390	Accum Depr - Capital Lease							
2405			PTD	SO	B17	-	-	-	-
2406						-	-	-	-
2407									
2408		Remove Capital Leases				-	-	-	-
2409					B17	-	-	-	-
2410									
2411	1081399	Accum Depr - Capital Lease							
2412			P	S		-	-	-	-
2413			P	SE	B17	-	-	-	-
2414						-	-	-	-
2415									
2416		Remove Capital Leases				-	-	-	-
2417					B17	-	-	-	-
2418									
2419									
2420	**Total General Plant Accum Depreciation**				**B17**	**(456,254,130)**	**(122,073,745)**	**(444,057,508)**	**(117,021,419)**
2421									
2422									
2423									
2424	Summary of General Depreciation by Factor								
2425		S				(154,405,355)	(45,213,577)	(153,946,618)	(43,367,585)
2426		DGP				-	-	-	-
2427		DGU				-	-	-	-
2428		SE				(156,656,378)	(38,088,678)	(157,230,250)	(38,228,206)
2429		SO				(74,737,799)	(20,316,037)	(63,288,399)	(17,203,737)
2430		CN				(7,761,004)	(2,278,853)	(7,506,237)	(2,204,046)
2431		SG				(60,719,132)	(15,651,665)	(60,367,413)	(15,561,002)
2432		DEU				-	-	-	-
2433		SSGCT				(44,066)	(11,349)	(46,139)	(11,882)
2434		SSGCH				(1,930,396)	(513,587)	(1,672,452)	(444,960)
2435		Remove Capital Leases				-	-	-	-
2436	Total General Depreciation by Factor					(456,254,130)	(122,073,745)	(444,057,508)	(117,021,419)
2437									
2438									
2439	**Total Accum Depreciation - Plant In Service**				**B17**	**(6,903,348,317)**	**(2,013,730,903)**	**(7,548,558,148)**	**(2,199,790,441)**
2440	111SP	Accum Prov for Amort-Steam							
2441			P	SSGCH		-	-	-	-
2442			P	SSGCT		-	-	-	-
2443					B18	-	-	-	-
2444									
2445									
2446	111GP	Accum Prov for Amort-General							
2447			G-SITUS	S		(16,369,840)	(6,518,199)	(18,032,987)	(6,890,301)
2448			CUST	CN		(2,861,226)	(840,138)	(3,271,277)	(960,540)
2449			I-SG	SG		-	-	-	-
2450			PTD	SO		(11,320,920)	(3,077,375)	(13,209,808)	(3,590,833)
2451			P	SE		-	-	-	-
2452					B18	(30,551,986)	(10,435,712)	(34,514,072)	(11,441,674)
2453									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2011 UNADJUSTED RESULTS TOTAL	JUNE 2011 UNADJUSTED RESULTS OREGON	DECEMBER 2013 PRO FORMA RESULTS TOTAL	DECEMBER 2013 PRO FORMA RESULTS OREGON
2454									
2455	111HP	Accum Prov for Amort-Hydro							
2456			P	SG		-	-	-	-
2457			P	SG		-	-	-	-
2458			P	SG		(240,880)	(62,092)	(614,404)	(158,376)
2459			P	SG		(460,259)	(118,642)	(527,058)	(135,860)
2460					B18	(701,139)	(180,734)	(1,141,461)	(294,236)
2461									
2462									
2463	111IP	Accum Prov for Amort-Intangible Plant							
2464			I-SITUS	S		(1,127,555)	(51,762)	(698,196)	466,390
2465			I-DGP	SG		-	-	-	-
2466			I-DGU	SG		(357,775)	(92,224)	(360,485)	(92,923)
2467			P	SE		(1,452,677)	(353,197)	(1,845,722)	(448,760)
2468			I-SG	SG		(49,291,670)	(12,705,990)	(41,781,003)	(10,769,954)
2469			I-SG	SG		(19,514,437)	(5,030,267)	(31,636,160)	(8,154,902)
2470			I-SG	SG		(3,523,610)	(908,286)	(3,840,958)	(990,090)
2471			CUST	CN		(97,854,280)	(28,732,817)	(106,183,429)	(31,178,494)
2472			P	SSGCT		-	-	-	-
2473			P	SSGCH		(171,088)	(45,518)	(171,088)	(45,518)
2474			PTD	SO		(266,767,979)	(72,515,756)	(284,010,102)	(77,202,697)
2475					B18	(440,061,070)	(120,435,819)	(470,527,143)	(128,416,948)
2476	111IP	Less Non-Utility Plant							
2477			NUTIL	OTH		-	-	-	-
2478						(440,061,070)	(120,435,819)	(470,527,143)	(128,416,948)
2479									
2480	111390	Accum Amtr - Capital Lease							
2481			G-SITUS	S		(5,492,566)	(2,003,233)	(5,492,566)	(2,003,233)
2482			P	SG		(4,390,814)	(1,131,827)	(4,390,814)	(1,131,827)
2483			PTD	SO		1,055,993	287,051	1,055,993	287,051
2484						(8,827,387)	(2,848,008)	(8,827,387)	(2,848,008)
2485									
2486		Remove Capital Lease Amtr				8,827,387	2,848,008	8,827,387	2,848,008
2487									
2488	**Total Accum Provision for Amortization**				**B18**	**(471,314,196)**	**(131,052,265)**	**(506,182,675)**	**(140,152,858)**
2489									
2490									
2491									
2492									
2493	Summary of Amortization by Factor								
2494		S				(22,989,961)	(8,573,194)	(24,223,749)	(8,427,143)
2495		DGP				-	-	-	-
2496		DGU				-	-	-	-
2497		SE				(1,452,677)	(353,197)	(1,845,722)	(448,760)
2498		SO				(277,032,906)	(75,306,080)	(296,163,917)	(80,506,478)
2499		CN				(100,715,506)	(29,572,955)	(109,454,706)	(32,139,035)
2500		SSGCT				-	-	-	-
2501		SSGCH				(171,088)	(45,518)	(171,088)	(45,518)
2502		SG				(77,779,445)	(20,049,328)	(83,150,881)	(21,433,932)
2503		Less Capital Lease				8,827,387	2,848,008	8,827,387	2,848,008
2504	Total Provision For Amortization by Factor					(471,314,196)	(131,052,265)	(506,182,675)	(140,152,858)

Oregon General Rate Case
Pro Forma Factors December 31, 2013
2010 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S		-	-	-	-	-	-	-			Situs
System Generation	SG		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 11.17
System Generation (Pac. Power Costs on SG)	SG-P		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 11.17
System Generation (R.M.P. Costs on SG)	SG-U		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 11.17
Divisional Generation - Pac. Power	DGP		3.5470%	54.3287%	16.5606%	0.0000%	0.0000%	25.5638%	0.0000%			Pg 11.17
Divisional Generation - R.M.P.	DGU		0.0000%	0.0000%	0.0000%	82.4723%	10.6915%	6.2132%	0.6230%			Pg 11.17
System Capacity	SC		1.7249%	26.2650%	8.0206%	43.4237%	5.3886%	14.8650%	0.3121%			Pg 11.17
System Energy	SE		1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%			Pg 11.17
System Energy (Pac. Power Costs on SE)	SE-P		1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%			Pg 11.17
System Energy (R.M.P. Costs on SE)	SE-U		1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%			Pg 11.17
Divisional Energy - Pac. Power	DEP		3.3508%	52.3252%	15.8568%	0.0000%	0.0000%	28.4672%	0.0000%			Pg 10.17
Divisional Energy - R.M.P.	DEU		0.0000%	0.0000%	0.0000%	80.5036%	11.7852%	7.0142%	0.6970%			Pg 10.17
System Overhead	SO		2.3104%	27.1650%	7.6601%	42.9878%	5.5204%	14.1204%	0.2358%			Pg 10.8
System Overhead (Pac. Power Costs on SO)	SO-P		2.3104%	27.1650%	7.6601%	42.9878%	5.5204%	14.1204%	0.2358%			Pg 10.8
System Overhead (R.M.P. Costs on SO)	SO-U		2.3104%	27.1650%	7.6601%	42.9878%	5.5204%	14.1204%	0.2358%			Pg 10.8
Divisional Overhead - Pac. Power	DOP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Divisional Overhead - R.M.P.	DOU		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Gross Plant-System	GPS		2.3104%	27.1648%	7.6601%	42.9879%	5.5205%	14.1205%	0.2358%			Pg 10.7
System Gross Plant - Pac. Power	SGPP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
System Gross Plant - R.M.P.	SGPU		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
System Net Plant	SNP		2.1535%	26.1963%	7.4791%	44.2636%	5.4786%	14.1850%	0.2440%			Pg 10.7
Seasonal System Capacity Combustion Turbine	SSCCT		1.7238%	26.2375%	8.0211%	43.4570%	5.3890%	14.8593%	0.3123%			Pg 10.19
Seasonal System Energy Combustion Turbine	SSECT		1.5566%	24.3007%	7.3656%	43.1123%	6.3156%	16.9759%	0.3734%			Pg 10.18
Seasonal System Capacity Cholla	SSCCH		1.7564%	27.1765%	8.2701%	42.0334%	5.3748%	15.0883%	0.3006%			Pg 10.20
Seasonal System Energy Cholla	SSECH		1.5593%	24.8916%	7.6399%	42.4173%	6.0012%	17.1265%	0.3642%			Pg 10.19
Seasonal System Generation Cholla	SSGCH		1.7071%	26.6053%	8.1126%	42.1293%	5.5314%	15.5978%	0.3165%			Pg 10.20
Seasonal System Capacity Purchases	SSCP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Pg 10.21
Seasonal System Energy Purchases	SSEP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Pg 10.20
Seasonal System Generation Contracts	SSGC		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Pg 10.21
Seasonal System Generation Combustion Turbine	SSGCT		1.6820%	25.7533%	7.8573%	43.3708%	5.6206%	15.3884%	0.3275%			Pg 10.19
Mid-Columbia	MC		1.2483%	41.4056%	9.3665%	32.1498%	4.1678%	11.4191%	0.2428%			Pg 10.18
Division Net Plant Distribution	SNPD		3.5615%	26.9058%	6.3244%	48.1018%	4.7829%	10.3236%	0.0000%			Pg 10.6
Divisional Generation - Huntington	DGUH		0.0000%	0.0000%	0.0000%	82.4723%	10.6915%	6.2132%	0.6230%			Pg 10.17
Divisional Energy - Huntington	DEUH		0.0000%	0.0000%	0.0000%	80.5036%	11.7852%	7.0142%	0.6970%			Pg 10.17
Division Net Plant General-Mine - Pac. Power	DNPGMP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant General-Mine - R.M.P.	DNPGMU		1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%			Pg 10.6
Division Net Plant Intangible - Pac. Power	DNPIP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Intangible - R.M.P.	DNPIU		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Steam - Pac. Power	DNPPSP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Steam - R.M.P.	DNPPSU		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Hydro - Pac. Power	DNPPHP		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Hydro - R.M.P.	DNPPHU		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
System Net Hydro Plant-Pac. Power	SNPPH-P		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 10.4
System Net Hydro Plant-R.M.P.	SNPPH-U		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 10.4
Customer - System	CN		2.4026%	29.3629%	6.7070%	50.4639%	3.7625%	7.3011%	0.0000%	0.0000%	0.0000%	Pg 10.11
Customer - Pac. Power	CNP		5.3468%	65.3434%	14.9256%	0.0000%	0.0000%	14.3843%	0.0000%	0.0000%	0.0000%	Pg 10.11
Customer - R.M.P.	CNU		0.0000%	0.0000%	0.0000%	91.6463%	6.8330%	1.5207%	0.0000%	0.0000%	0.0000%	Pg 10.11
Washington Business Tax	WBTAX		0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Situs
Operating Revenue - Idaho	OPRV-ID		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Operating Revenue - Wyoming	OPRVWY		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Excise Tax - superfund	EXCTAX		-10.4527%	-46.6436%	14.5860%	74.8583%	18.2194%	27.1229%	5.2838%	5.7273%	11.2987%	Pg 10.12
Interest	INT		2.1535%	26.1963%	7.4791%	44.2636%	5.4786%	14.1850%	0.2440%		0.0000%	Pg 10.8
CIAC	CIAC		3.5615%	26.9058%	6.3244%	48.1018%	4.7829%	10.3236%	0.0000%			Pg 10.11

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Idaho State Income Tax	IDSIT		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%		0.0000%	Pg 10.11
Blank	DONOTUSE		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Bad Debt Expense	BADDEBT		4.0266%	46.6683%	13.1376%	27.6692%	3.3671%	5.1312%	0.0000%	0.0000%	0.0000%	Pg 10.10
Blank	DONOTUSE		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Blank	DONOTUSE		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Accumulated Investment Tax Credit 1984	ITC84		3.2870%	70.9760%	14.1800%			10.9460%			0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85		5.4200%	67.6900%	13.3600%			11.6100%			1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86		4.7890%	64.6080%	13.1260%			15.5000%			1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88		4.2700%	61.2000%	14.9600%			16.7100%			2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89		4.8806%	56.3558%	15.2688%			20.6776%			2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90		1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%			0.3860%	Fixed
Other Electric	OTHER		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 10.4
System Net Transmission Plant	SNPT		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 10.5
System Net Production Plant	SNPP		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 10.5
System Net Hydro Plant	SNPPH		1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%			Pg 10.4
System Net Nuclear Plant	SNPPN		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Pg 10.4
System Net Other Production Plant	SNPPO		1.6829%	25.7793%	7.8572%	43.3407%	5.6186%	15.3940%	0.3274%			Pg 10.5
System Net General Plant	SNPG		2.6089%	29.9029%	7.4637%	39.7339%	6.4352%	13.7298%	0.1257%			Pg 10.6
System Net Intangible Plant	SNPI		1.9097%	26.2820%	7.7735%	43.4976%	5.5845%	14.6699%	0.2829%			Pg 10.7
Trojan Plant Allocator	TROJP		1.6638%	25.5548%	7.7831%	43.3047%	5.7236%	15.6357%	0.3343%			Pg 10.13
Trojan Decommissioning Allocator	TROJD		1.6604%	25.5155%	7.7700%	43.2981%	5.7421%	15.6783%	0.3356%			Pg 10.13
Income Before Taxes	IBT		-10.3705%	-46.1800%	14.5251%	74.5616%	18.1211%	27.0137%	5.2484%	5.8623%	11.2182%	Pg 10.8
DIT Expense	DITEXP		1.8715%	25.8651%	3.6799%	43.5936%	5.0036%	14.7421%	0.2403%	0.0000%	5.0040%	Pg 10.9
DIT Balance	DITBAL		2.2537%	27.4731%	6.0229%	42.8782%	5.6374%	13.8724%	0.2827%	0.0000%	1.5794%	Pg 10.10
Tax Depreciation	TAXDEPR		2.0843%	26.1489%	6.9635%	44.1398%	5.4343%	14.3136%	0.2576%	0.0000%	0.6581%	Pg 10.14
Blank	DONOTUSE		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Blank	DONOTUSE		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Blank	DONOTUSE		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
SCHMAT Depreciation Expense	SCHMDEXP		2.3459%	27.5134%	7.9971%	42.0828%	5.4381%	14.3840%	0.2388%	0.0000%	0.0000%	Pg 10.14
SCHMDT Amortization Expense	SCHMAEXP		2.1461%	26.7181%	7.3853%	43.1008%	5.2792%	15.1279%	0.2426%	0.0000%	0.0000%	Pg 10.13
System Generation Cholla Transaction	SGCT		1.6885%	25.8618%	7.8832%	43.4843%	5.6372%	15.4450%				Pg 10.17

CALCULATION OF INTERNAL FACTORS
Pro Forma Factors December 31, 2013

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other
STEAM :									
STEAM PRODUCTION PLANT									
	DGP	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	
	SG	6,733,786,706	113,324,819	1,735,778,637	529,103,058	2,918,554,301	378,354,240	22,045,379	
	SSGCH	0	0	0	0	0	0	0	
		6,733,786,706	113,324,819	1,735,778,637	529,103,058	2,918,554,301	378,354,240	22,045,379	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
LESS ACCUMULATED DEPRECIATION												
	DGP	(780,055,729)	(13,127,781)	(201,076,174)	(61,292,389)	(338,091,345)	(43,829,335)	(2,553,782)				
	DGU	(878,481,702)	(14,784,219)	(226,447,590)	(69,026,148)	(380,751,078)	(49,359,638)	(2,876,014)				
	SG	(928,281,792)	(15,622,319)	(239,284,636)	(72,939,158)	(402,335,407)	(52,157,778)	(3,039,051)				
	SSGCH	(167,834,615)	(2,824,537)	(43,262,989)	(13,187,499)	(72,742,791)	(9,430,197)	(549,465)				
		(2,754,653,837)	(46,358,856)	(710,071,390)	(216,445,194)	(1,193,920,621)	(154,776,949)	(9,018,312)				
TOTAL NET STEAM PLANT		3,979,132,869	66,965,963	1,025,707,247	312,657,864	1,724,633,680	223,577,292	13,027,067				
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	0.3274%				
NUCLEAR :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
NUCLEAR PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	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				
	DGU	0	0	0	0	0	0	0				
	SG	0	0	0	0	0	0	0				
		0	0	0	0	0	0	0				
TOTAL NUCLEAR PLANT		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%				
HYDRO :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
HYDRO PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	911,816,379	15,345,218	235,040,321	71,645,399	395,198,977	51,232,629	2,985,146				
		911,816,379	15,345,218	235,040,321	71,645,399	395,198,977	51,232,629	2,985,146				
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	DGP	(162,043,005)	(2,727,068)	(41,770,076)	(12,732,427)	(70,232,594)	(9,104,782)	(530,504)				
	DGU	(28,697,021)	(482,950)	(7,397,276)	(2,254,850)	(12,437,848)	(1,612,412)	(93,950)				
	SG	(77,510,637)	(1,304,449)	(19,980,037)	(6,090,350)	(33,594,620)	(4,355,124)	(253,758)				
		(268,250,663)	(4,514,467)	(69,147,389)	(21,077,627)	(116,265,062)	(15,072,318)	(878,211)				
TOTAL NET HYDRO PRODUCTION PLANT		643,565,716	10,830,751	165,892,932	50,567,772	278,933,915	36,160,310	2,106,935				
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	0.3274%				
OTHER :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												
	S	75000	0	75000	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	3,103,323,847	52,226,723	799,948,598	243,841,721	1,345,040,994	174,367,824	10,159,804				
	SSGCT	0	0	0	0	0	0	0				
		3,103,398,847	52,226,723	800,023,598	243,841,721	1,345,040,994	174,367,824	10,159,804				

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
LESS ACCUMULATED DEPRECIATION												
	S	0	0	0	0	0	0	0				
	DGU	(366,724)	(6,172)	(94,531)	(28,815)	(158,945)	(20,605)	(1,201)				
	SG	(506,567,557)	(8,525,170)	(130,578,704)	(39,803,227)	(219,556,245)	(28,462,734)	(1,658,424)				
	SSGCT	(24,540,740)	(413,003)	(6,325,905)	(1,928,273)	(10,636,435)	(1,378,881)	(80,343)				
		(531,475,021)	(8,944,345)	(136,999,140)	(41,760,316)	(230,351,625)	(29,862,221)	(1,739,967)				
TOTAL NET OTHER PRODUCTION PLANT		2,571,923,826	43,282,378	663,024,458	202,081,405	1,114,689,369	144,505,603	8,419,836				
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.6829%	25.7793%	7.8572%	43.3407%	5.6186%	0.3274%				
PRODUCTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
TOTAL PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	10,748,926,932	180,896,761	2,770,767,557	844,590,177	4,658,794,272	603,954,693	35,190,329				
	SSGCH	0	0	0	0	0	0	0				
	SSGCT	0	0	0	0	0	0	0				
		10,748,926,932	180,896,761	2,770,767,557	844,590,177	4,658,794,272	603,954,693	35,190,329				
LESS ACCUMULATED DEPRECIATION												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	(3,554,379,521)	(59,817,668)	(916,217,919)	(279,283,137)	(1,540,537,307)	(199,711,488)	(11,636,490)				
	SSGCH	0	0	0	0	0	0	0				
	SSGCT	0	0	0	0	0	0	0				
		(3,554,379,521)	(59,817,668)	(916,217,919)	(279,283,137)	(1,540,537,307)	(199,711,488)	(11,636,490)				
TOTAL NET PRODUCTION PLANT		7,194,547,411	121,079,093	1,854,549,638	565,307,040	3,118,256,964	404,243,205	23,553,838				
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	0.3274%				
TRANSMISSION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
TRANSMISSION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	4,711,176,773	79,285,739	1,214,407,339	370,177,754	2,041,915,765	264,708,965	15,423,666				
		4,711,176,773	79,285,739	1,214,407,339	370,177,754	2,041,915,765	264,708,965	15,423,666				
LESS ACCUMULATED DEPRECIATION												
	DGP	(378,249,324)	(6,365,666)	(97,501,915)	(29,720,703)	(163,940,624)	(21,252,861)	(1,238,330)				
	DGU	(411,324,484)	(6,922,297)	(106,027,750)	(32,319,563)	(178,276,042)	(23,111,270)	(1,346,613)				
	SG	(490,402,478)	(8,253,123)	(126,411,807)	(38,533,066)	(212,549,985)	(27,554,460)	(1,605,502)				
		(1,279,976,286)	(21,541,086)	(329,941,471)	(100,573,332)	(554,766,650)	(71,918,591)	(4,190,445)				
TOTAL NET TRANSMISSION PLANT		3,431,200,486	57,744,653	884,465,868	269,604,421	1,487,149,115	192,790,373	11,233,221				
SNPT												
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	0.3274%				
DISTRIBUTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
DISTRIBUTION PLANT - PACIFIC POWER												
	S	2,942,411,930	233,333,594	1,785,890,003	410,979,876	0	0	0				
LESS ACCUMULATED DEPRECIATION												
	S	(1,337,867,439)	(107,534,773)	(835,519,865)	(187,589,890)	0	0	-				
		1,604,544,492	125,798,821	950,370,138	223,389,986	0	0	0				

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DNPDP												
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	7.8402%	59.2299%	13.9223%	0.0000%	0.0000%	0.0000%				
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	2,861,082,085	0	0	0	2,469,537,080	295,080,246	0				
LESS ACCUMULATED DEPRECIATION												
	S	(933,418,854)	0	0	0	(770,481,140)	(126,139,855)	0				
		1,927,663,230	0	0	0	1,699,055,940	168,940,391	0				
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	88.1407%	8.7640%	0.0000%				
TOTAL NET DISTRIBUTION PLANT		3,532,207,722	125,798,821	950,370,138	223,389,986	1,699,055,940	168,940,391	0				
DNPD & SNPD												
SYSTEM NET PLANT DISTRIBUTION		100.0000%	3.5615%	26.9058%	6.3244%	48.1018%	4.7829%	0.0000%				
GENERAL :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
GENERAL PLANT												
	S	558,050,211	17,067,415	176,460,528	46,261,249	201,250,601	36,978,645	0				
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SE	564,620	8,791	137,279	41,602	243,332	35,622	2,107				
	SG	245,845,146	4,137,398	63,371,884	19,317,128	106,554,074	13,813,410	804,859				
	SO	245,638,251	5,675,294	66,727,596	18,816,043	105,594,485	13,560,326	579,284				
	CN	22,208,846	533,600	6,521,153	1,489,547	11,207,448	835,611	0				
	DEU	0	0	0	0	0	0	0				
	SSGCT	0	0	0	0	0	0	0				
	SSGCH	0	0	0	0	0	0	0				
	Remove Capital Lease	(65,393,121)	(860,497)	(18,020,833)	(3,621,560)	(31,783,934)	(2,595,152)	(140,341)				
		1,006,913,953	26,562,002	295,197,608	82,304,009	393,066,006	62,628,462	1,245,909				
LESS ACCUMULATED DEPRECIATION												
	S	(171,979,604)	(5,608,057)	(50,257,885)	(19,673,913)	(55,419,115)	(10,393,889)	0				
	DGP	(2,097,281)	(35,296)	(540,619)	(164,793)	(909,002)	(117,841)	(6,866)				
	DGU	(2,969,084)	(49,968)	(765,345)	(233,294)	(1,286,859)	(166,825)	(9,720)				
	SE	(281,847)	(4,388)	(68,527)	(20,767)	(121,467)	(17,782)	(1,052)				
	SG	(55,301,048)	(930,677)	(14,255,037)	(4,345,245)	(23,968,551)	(3,107,224)	(181,047)				
	SO	(76,498,207)	(1,767,436)	(20,780,727)	(5,859,810)	(32,884,898)	(4,223,042)	(180,404)				
	CN	(10,777,514)	(258,946)	(3,164,587)	(722,848)	(5,438,753)	(405,505)	0				
	SSGCT	(46,139)	(776)	(11,893)	(3,625)	(19,998)	(2,592)	(151)				
	SSGCH	(1,672,452)	(28,146)	(431,111)	(131,412)	(724,873)	(93,971)	(5,475)				
		(321,623,177)	(8,683,689)	(90,275,732)	(31,155,706)	(120,773,516)	(18,528,672)	(384,716)				
TOTAL NET GENERAL PLANT		685,290,776	17,878,313	204,921,876	51,148,302	272,292,490	44,099,789	861,193				
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	2.6089%	29.9029%	7.4637%	39.7339%	6.4352%	0.1257%				
MINING :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
GENERAL MINING PLANT												
	SE	488,304,005	7,602,794	118,723,886	35,978,527	210,442,515	30,807,369	1,822,106				
LESS ACCUMULATED DEPRECIATION												
	SE	(156,948,403)	(2,443,655)	(38,159,679)	(11,564,051)	(67,639,454)	(9,901,961)	(585,653)				
		331,355,602	5,159,139	80,564,207	24,414,476	142,803,060	20,905,408	1,236,453				
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	0.3731%				

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
INTANGIBLE :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
INTANGIBLE PLANT												
	S	7,798,360	216,407	1,320,629	451,894	3,002,194	1,427,593	0				
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SE	3,538,192	55,089	860,259	260,696	1,524,841	223,226	13,203				
	CN	120,697,107	2,899,926	35,440,125	8,095,153	60,908,456	4,541,245	0				
	SG	314,595,919	5,294,425	81,093,878	24,719,177	136,351,998	17,676,339	1,029,939				
	SO	381,477,170	8,813,754	103,628,219	29,221,388	163,988,651	21,059,240	899,631				
	SSGCT	0	0	0	0	0	0	0				
	SSGCH	0	0	0	0	0	0	0				
		828,106,747	17,279,599	222,343,110	62,748,307	365,776,140	44,927,643	1,942,772				
LESS ACCUMULATED AMORTIZATION												
	S	(698,196)	0	466,390	173,498	(52,526)	(797,736)	0				
	DGP	0	0	0	0	0	0	0				
	DGU	(360,485)	(6,067)	(92,923)	(28,325)	(156,241)	(20,255)	(1,180)				
	SE	(1,845,722)	(28,738)	(448,760)	(135,994)	(795,444)	(116,448)	(6,887)				
	CN	(106,183,429)	(2,551,213)	(31,178,494)	(7,121,721)	(53,584,289)	(3,995,166)	0				
	SG	(77,258,121)	(1,300,199)	(19,914,946)	(6,070,508)	(33,485,174)	(4,340,936)	(252,931)				
	SO	(284,010,102)	(6,561,848)	(77,151,304)	(21,755,350)	(122,089,701)	(15,678,623)	(669,776)				
	SSGCT	0	0	0	0	0	0	0				
	SSGCH	(171,088)	(2,879)	(44,102)	(13,443)	(74,153)	(9,613)	(560)				
		(470,527,143)	(10,450,943)	(128,364,138)	(34,951,843)	(210,237,528)	(24,958,777)	(931,335)				
TOTAL NET INTANGIBLE PLANT		357,579,605	6,828,656	93,978,972	27,796,465	155,538,613	19,968,867	1,011,437				
SNPI												
SYSTEM NET INTANGIBLE PLANT		100.0000%	1.9097%	26.2820%	7.7735%	43.4976%	5.5845%	0.2829%				

GROSS PLANT :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**
PRODUCTION PLANT		10,748,926,932	180,896,761	2,770,767,557	844,590,177	4,658,794,272	603,954,693	35,190,329
TRANSMISSION PLANT		4,711,176,773	79,285,739	1,214,407,339	370,177,754	2,041,915,765	264,708,965	15,423,666
DISTRIBUTION PLANT		5,803,494,015	233,333,594	1,785,890,003	410,979,876	2,469,537,080	295,080,246	0
GENERAL PLANT		1,495,217,958	34,164,796	413,921,494	118,282,535	603,508,521	93,435,830	3,068,015
INTANGIBLE PLANT		828,106,747	17,279,599	222,343,110	62,748,307	365,776,140	44,927,643	1,942,772
TOTAL GROSS PLANT		23,586,922,425	544,960,489	6,407,329,503	1,806,778,649	10,139,531,778	1,302,107,378	55,624,782
GPS								
GROSS PLANT-SYSTEM FACTOR		100.0000%	2.3104%	27.1648%	7.6601%	42.9879%	5.5205%	0.2358%
ACCUMULATED DEPRECIATION AND AMORTIZATION								
PRODUCTION PLANT		(3,554,379,521)	(59,817,668)	(916,217,919)	(279,283,137)	(1,540,537,307)	(199,711,488)	(11,636,490)
TRANSMISSION PLANT		(1,279,976,286)	(21,541,086)	(329,941,471)	(100,573,332)	(554,766,650)	(71,918,591)	(4,190,445)
DISTRIBUTION PLANT		(2,271,286,293)	(107,534,773)	(835,519,865)	(187,589,890)	(770,481,140)	(126,139,855)	0
GENERAL PLANT		(478,571,580)	(11,127,344)	(128,435,411)	(42,719,757)	(188,412,971)	(28,430,633)	(970,369)
INTANGIBLE PLANT		(470,527,143)	(10,450,943)	(128,364,138)	(34,951,843)	(210,237,528)	(24,958,777)	(931,335)
		(8,054,740,823)	(210,471,815)	(2,338,478,804)	(645,117,959)	(3,264,435,596)	(451,159,344)	(17,728,639)
NET PLANT		15,532,181,602	334,488,674	4,068,850,698	1,161,660,690	6,875,096,182	850,948,034	37,896,143
SNP								
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	2.1535%	26.1963%	7.4791%	44.2636%	5.4786%	0.2440%

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	2.1535%	26.1963%	7.4791%	44.2636%	5.4786%	0.2440%				
TOTAL GROSS PLANT (LESS SO FACTOR)		22,959,882,004	530,471,442	6,237,048,688	1,758,741,218	9,869,948,642	1,267,487,812	54,145,867				
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.3104%	27.1650%	7.6601%	42.9878%	5.5204%	0.2358%				

IBT

INCOME BEFORE TAXES	TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Adjustment to 10.5% Target ROE	0	=-(UTCR!K150-(U	=-(UTCR!L150-(UTC	=-(UTCR!M150-(UTC	=-(UTCR!P150-(UTC	=-(UTCR!Q150-(UTCR!Q178*Report!J96))*(1/NetToGross)			
INCOME BEFORE STATE TAXES	(77,704,867)	8,072,407	35,946,655	(11,306,373)	(58,039,007)	(14,105,540)	(4,085,412)	(4,426,811)	(8,733,222)
Interest Synchronization	(135,477)	-	-	-	-	-	-	(136,413)	936
INCOME BEFORE TAXES AT 10.5% ROE	(77,840,345)	8,072,407	35,946,655	(11,306,373)	(58,039,007)	(14,105,540)	(4,085,412)	(4,563,224)	(8,732,286)
INCOME BEFORE TAXES (FACTOR)	100.0000%	-10.3705%	-46.1800%	14.5251%	74.5616%	18.1211%	5.2484%	5.8623%	11.2182%

See Calculation of EXCTAX

DITEXP:		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Pre-Merger - PPL										
Prod / Hydro	S	(3,033,484)	(105,487)	(1,599,499)	(415,040)	(124,851)	0	0	0	0
Transmission	S	(803,012)	(29,729)	(431,265)	(115,820)	(36,383)	0	0	0	0
Distribution	S	(3,927,317)	(250,186)	(2,528,615)	(397,928)	0	0	0	0	0
General	S	52,373	0	33,965	0	6,074	0	19	0	0
Mining	S	0	0	0	0	0	0	0	0	0
Non Utility	NUTIL	4,098,667	0	0	0	0	0	0	0	4,098,667
Total PPL		(3,612,773)	(385,402)	(4,525,414)	(928,788)	(155,160)	0	19	0	4,098,667
Pre-Merger - UPL										
Production	S	(6,518,742)	0	0	0	(4,832,238)	(1,216,735)	(55,161)	0	0
Transmission	S	(2,162,631)	0	0	0	(1,762,538)	(278,336)	(12,990)	0	0
Distribution	S	(3,248,624)	0	0	0	(2,532,966)	(527,723)	0	0	0
General	S	73,937	130	7,329	423	4,536	41,317	685	0	0
Mining Plant	S	0	0	0	0	0	0	0	0	0
Non-Utility	NUTIL	0								
Total UPL		(11,856,060)	130	7,329	423	(9,123,206)	(1,981,477)	(67,466)	0	0
Post-Merger (Vintages beginning 2006 and forward except for WCA which is 2007 and forward)										
Prod / Other Prod	S	11,496,381	178,203	2,665,460	994,394	5,082,133	702,184	30,562	0	0
Cholla Unit 4	S	2,028,843	30,096	512,958	0	881,191	114,386	6,010	0	162,067
Gadsby Unit 4, 5 & 6	S	408,344	6,587	104,318	0	172,319	22,870	1,053	0	32,868
Hydro-PPL	S	370,184	4,914	62,130	34,467	183,683	29,242	1,093	0	0
Hydro-UPL	S	324,682	5,114	81,376	25,795	141,621	17,917	970	0	0

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Transmission	S	8,777,359	107,702	2,463,748	686,652	3,635,553	397,820	28,543	0	0		
Distribution	S	102,173,400	3,080,862	29,321,481	6,781,057	47,997,706	4,498,501	0	0	185		
General/ Intangibles	S	(12,063,658)	(324,943)	(4,006,412)	(669,996)	(4,707,903)	(715,403)	(17,350)	0	(2,248)		
Mining	S	(1,380,690)	(18,234)	(458,226)	(79,987)	(513,164)	(55,676)	(4,747)	0	0		
WCA - CAEE 2007+	S	7,052,222	112,597	1,663,775	0	3,048,586	453,092	23,397	0	527,972		
WCA - CAGE 2007+	S	365,423,014	5,921,410	93,327,988	0	158,001,435	19,641,305	1,104,198	0	29,769,723		
WCA - CAGW 2007+	S	37,759,974	608,022	9,699,537	8,415,900	16,320,491	2,060,282	114,826	0	(5,452,268)		
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0	0	0		
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0		
WCA - General 2007+	S	41,736,140	959,248	11,018,096	3,755,404	18,207,799	2,235,071	93,266	0	(454,396)		
WCA - JBG 2007+	S	6,755,042	108,354	1,725,251	1,423,814	2,960,394	371,566	20,168	0	(929,524)		
Non Utility	NUTIL	40,813	0	0	0	0	0	0	0	40,813		
Total PC (Post Merger)		570,902,050	10,779,932	148,181,480	21,367,500	251,411,844	29,773,157	1,401,989	0	23,695,192		
Total Deferred Taxes		555,433,217	10,394,660	143,663,395	20,439,135	242,133,478	27,791,680	1,334,542	0	27,793,859		
Percentage of Total (DITEXP)		100.0000%	1.8715%	25.8651%	3.6799%	43.5936%	5.0036%	0.2403%	0.0000%	5.0040%		

DITBAL :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Pre-Merger - PPL										
Prod / Hydro	S	50,406,693	1,750,807	27,733,265	6,920,653	2,046,531	0	0		0
Transmission	S	20,517,318	781,759	11,146,292	3,051,508	901,636	0	0		0
Distribution	S	36,769,179	3,310,124	21,600,461	5,264,808	0	0	0		0
General	S	(511,917)	221	(333,084)	297	(57,681)	16	(174)		0
Mining	S	2,278	38	585	179	939	133	8		0
Non Utility	NUTIL	3,109,531	0	0	0	0	0	0		3,109,531
Total PPL		110,293,082	5,842,949	60,147,519	15,237,445	2,891,425	149	(166)	0	3,109,531
Pre-Merger - UPL										
Prod / Hydro	S	84,319,238	0	0	0	66,395,025	13,000,213	587,942		0
Transmission	S	48,709,089	0	0	0	40,868,456	5,686,172	256,629		0
Distribution	S	41,976,387	0	0	0	33,790,280	5,977,888	0		0
General	S	(695,447)	978	(79,247)	3,083	(83,631)	(351,815)	(5,485)		0
Mining	S	6,056	100	1,555	476	2,497	354	21		0
Non-Utility Plant	NUTIL	0								
Total UPL		174,315,323	1,078	(77,692)	3,559	140,972,627	24,312,812	839,107	0	0
Post-Merger (Vintages beginning 2006 and forward except for WCA which is 2007 and forward)										
Prod / Other Prod	S	501,329,323	9,272,270	146,027,992	40,124,982	202,484,337	26,804,432	1,792,629	0	0
OREGON EXTRA BOOK DEPR	S	(11,868,370)	0	(11,868,370)	0	0	0	0		0
Cholla Unit 4	S	(5,149,283)	(138,482)	(2,398,910)	0	(2,913,619)	(745,894)	(37,659)		1,813,906
Gadsby Unit 4, 5 & 6	S	3,314,227	55,905	815,558	0	1,512,280	189,924	15,039		266,411
Hydro-PPL	S	38,015,974	750,151	11,573,557	3,145,955	14,894,085	1,899,820	119,078		0
Hydro-UPL	S	10,284,908	223,626	3,199,485	915,290	3,966,153	508,981	28,401		0

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
Transmission	S	247,524,214	4,913,360	73,369,558	19,898,806	99,790,403	13,249,624	786,061		0	
Distribution	S	654,998,767	25,680,365	189,945,619	41,139,159	306,314,862	33,782,350	0		6,299	
General/ Intangibles	S	124,337,275	2,972,049	39,824,613	9,348,576	47,137,490	7,007,037	217,549		7,841	
Mining	S	11,096,466	174,883	3,318,767	794,614	4,227,181	603,530	40,854		0	
WCA - CAEE 2007+	S	22,596,894	326,245	5,964,994	0	9,061,344	1,234,277	82,586		1,857,764	
WCA - CAGE 2007+	S	1,127,066,592	19,402,919	302,269,983	0	466,452,607	61,410,437	4,320,259		94,275,351	
WCA - CAGW 2007+	S	268,796,560	4,642,746	75,154,717	57,133,693	111,968,082	14,836,292	1,055,315		(38,654,021)	
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0		0	
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0		0	
WCA - General 2007+	S	103,611,705	2,354,180	31,279,005	7,014,979	41,076,506	5,597,483	232,735		533,555	
WCA - JBG 2007+	S	59,998,517	1,049,529	16,493,765	12,424,394	25,120,260	3,229,258	232,532		(8,194,680)	
Non Utility	NUTIL	(691,969)	0	0	0	0	0	0		(691,969)	
Total PC (Post Merger)		3,155,261,800	71,679,746	884,970,333	191,940,448	1,331,091,971	169,607,551	8,885,379	0	51,220,457	
Total Deferred Taxes		3,439,870,205	77,523,773	945,040,160	207,181,452	1,474,956,023	193,920,512	9,724,320	0	54,329,988	
Percentage of Total (DITBAL)		100.0000%	2.2537%	27.4731%	6.0229%	42.8782%	5.6374%	0.2827%	0.0000%	1.5794%	

OPRV-WY

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

OPRV-ID

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Interstate Sales for Resale			
Montana Power	0	0	0
Portland General Electric	0	0	0
Puget Sound Power & Light	0	0	0
Washington Water Power Co.	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

BADDEBT

Account 904 Balance	13,653,105	549,756	6,371,676	1,793,688	3,777,704	459,711	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100%	4.0266%	46.6683%	13.1376%	27.6692%	3.3671%	0.0000%	0.0000%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Customer Factors		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Total Electric Customers		1,981,824	47,616	581,920	132,921	1,000,106	74,566	0	0	0		
CN												
Customer System factor - CN			2.4026%	29.3629%	6.7070%	50.4639%	3.7625%	0.0000%	0.0000%	0.0000%		
Pacific Power Customers		890,557	47,616	581,920	132,921	0	0	0	0	0		
CNP												
Customer Service Pacific Power factor - CNP			5.35%	65.34%	14.93%	0.00%	0.00%	0.00%	0.00%	0.00%		
Rocky Mountain Power Customers		1,091,267	0	0	0	1,000,106	74,566	0	0	0		
CNU												
Customer Service R.M.P. factor - CNU			0.00%	0.00%	0.00%	91.65%	6.83%	0.00%	0.00%	0.00%		

CIAC	**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**
TOTAL NET DISTRIBUTION PLANT	3,532,207,722	125,798,821	950,370,138	223,389,986	1,699,055,940	168,940,391	0	0	0
CIAC FACTOR: Same as (SNPD Factor)	100.00%	3.56%	26.91%	6.32%	48.10%	4.78%	0.00%	0.00%	0.00%

IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total
	Payroll	0	0	0	0
Idaho State Income Tax Allocation			0.00%	0.00%	0.00%
	Property	0	0	0	0
			0.00%	0.00%	0.00%
	Sales	0	0	0	0
			0.00%	0.00%	0.00%
	Average		0.00%	0.00%	
		Idaho - PPL Factor	0.00%	0.00%	
		Idaho - UPL Factor	0.00%	0.00%	
			0.00%	0.00%	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION		2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
EXCTAX													
Excise Tax (Superfund)			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Total Taxable Income			(73,784,649)	7,712,524	34,415,831	(10,762,230)	(55,233,955)	(13,443,099)	(3,898,649)	(4,225,833)	(8,336,734)		
Less Other Electric Items:													
	419	OTH	0	0	0	0	0	0	0	0	0		
	432	OTH	0	0	0	0	0	0	0	0	0		
	40910	OTH	0	0	0	0	0	0	0	0	0		
	SCHMDT	OTH	0	0	0	0	0	0	0	0	0		
	SCHMDT (Steam)	OTH											
Total Taxable Income Excluding Other			(73,784,649)	7,712,524	34,415,831	(10,762,230)	(55,233,955)	(13,443,099)	(3,898,649)	(4,225,833)	(8,336,734)		
Excise Tax (Superfund) Factor - EXCTAX			100.0000%	-10.4527%	-46.6436%	14.5860%	74.8583%	18.2194%	5.2838%	5.7273%	11.2987%		
Trojan Allocators			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Premerger													
Dec 1991 Plant			16,918,976										
Dec 1992 Plant			17,094,202										
Average		SG	17,006,589	286,209	4,383,815	1,336,282	7,370,987	955,557	55,677	0	0		
Dec 1991 Reserve			(7,851,432)										
Dec 1992 Reserve			(8,434,030)										
Average		SG	(8,142,731)	(137,036)	(2,098,964)	(639,810)	(3,529,218)	(457,519)	(26,658)	0	0		
Postmerger													
Dec 1991 Plant			4,284,960										
Dec 1992 Plant			3,485,613										
Average		SG	3,885,287	65,387	1,001,516	305,284	1,683,959	218,304	12,720	0	0		
Dec 1991 Reserve			(129,394)										
Dec 1992 Reserve			(240,609)										
Average		SG	(185,002)	(3,113)	(47,688)	(14,536)	(80,183)	(10,395)	(606)	0	0		
Net Plant			12,564,143	211,446	3,238,679	987,220	5,445,544	705,947	41,133	0	0		
Division Net Plant Nuclear Pacific Power		**DNPPNP**	100.0000%	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	0.3274%	0.0000%	0.0000%		
Division Net Plant Nuclear Rocky Mountain Power		**DNPPNP**	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%	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	0.3274%	0.0000%	0.0000%		
Account 182.22			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Pre-merger	(101)	SG	17,094,202	287,683	4,406,399	1,343,166	7,408,960	960,479	55,964	0	0		
		(108) SG	(8,434,030)	(141,939)	(2,174,053)	(662,699)	(3,655,473)	(473,887)	(27,612)	0	0		
Post-merger	(101)	SG	3,485,613	58,660	898,492	273,880	1,510,733	195,848	11,411	0	0		
		(108) SG	(240,609)	(4,049)	(62,022)	(18,906)	(104,285)	(13,519)	(788)	0	0		
		(107) SG	1,778,549	29,932	458,459	139,748	770,858	99,932	5,823	0	0		
		(120) SE	1,975,759	30,762	480,377	145,575	851,485	124,652	7,373	0	0		

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION		2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
	(228)	SG	7,220,849	121,522	1,861,329	567,374	3,129,657	405,721	23,640	0	0		
	(228)	SG	1,472,376	24,779	379,537	115,691	638,156	82,729	4,820	0	0		
	(228)	SNNP	3,531,000	59,424	910,191	277,446	1,530,404	198,398	11,560	0	0		
	(228)	SE	1,743,025	27,139	423,791	128,427	751,185	109,968	6,504	0	0		
Total Acct 182.22			29,626,734	493,913	7,582,500	2,309,703	12,831,680	1,690,322	98,695	0	0		
Revised Study	(228)	SNNP	112,680	1,896	29,046	8,854	48,838	6,331	369	0	0		
	(228)	SE	941,950	14,666	229,021	69,403	405,949	59,428	3,515	0	0		
December 1993 Adj.			1,054,630	16,562	258,067	78,257	454,786	65,759	3,884	0	0		
Adjusted Acct 182.22			30,681,364	510,475	7,840,567	2,387,960	13,286,467	1,756,081	102,579	0	0		
TROJP			100.0000%	1.6638%	25.5548%	7.7831%	43.3047%	5.7236%	0.3343%	0.0000%	0.0000%		
Trojan Plant Allocator													
Account 228.42			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Plant - Premerger		SG	7,220,849	121,522	1,861,329	567,374	3,129,657	405,721	23,640	0	0		
- Postmerger		SG	1,472,376	24,779	379,537	115,691	638,156	82,729	4,820	0	0		
Storage Facility		SE	1,743,025	27,139	423,791	128,427	751,185	109,968	6,504	0	0		
Transition Costs		SNNP	3,531,000	59,424	910,191	277,446	1,530,404	198,398	11,560	0	0		
Total Acct 228.42			13,967,250	232,864	3,574,848	1,088,938	6,049,402	796,816	46,524	0	0		
Transition Costs		SNNP	112,680	1,896	29,046	8,854	48,838	6,331	369	0	0		
Storage Facility		SE	941,950	14,666	229,021	69,403	405,949	59,428	3,515	0	0		
December 1993 Adj.			1,054,630	16,562	258,067	78,257	454,786	65,759	3,884	0	0		
Adjusted Acct 228.42			15,021,880	249,426	3,832,915	1,167,195	6,504,188	862,576	50,408	0	0		
TROJD			100.0000%	1.6604%	25.5155%	7.7700%	43.2981%	5.7421%	0.3356%	0.0000%	0.0000%		
Trojan Decommissioning Allocator													
SCHMA			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Amortization Expense :													
Amortization of Limited Term Plant		Acct 404	46,645,979	1,021,674	12,468,780	3,569,428	20,022,922	2,436,418	108,388	0	0		
Amortization of Other Electric Plant		Acct 405	0	0	0	0	0	0	0	0	0		
Amortization of Plant Acquisitions		Acct 406	5,193,044	87,395	1,338,619	408,040	2,250,767	291,784	17,001	0	0		
Amort of Prop. Losses, Unrecovered Plant, etc.		Acct 407	(160,864)	(0)	(0)	(160,864)	(0)	(0)	(0)	0	0		
Total Amortization Expense :			51,678,159	1,109,070	13,807,399	3,816,604	22,273,689	2,728,201	125,389	0	0		
Schedule M Amortization Factor			100.0000%	2.1461%	26.7181%	7.3853%	43.1008%	5.2792%	0.2426%	0.0000%	0.0000%		
SCHMD			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**		
Depreciation Expense :													
Steam		Acct 403.1	233,208,674	3,924,735	60,114,561	18,324,225	101,077,181	13,103,398	763,489	0	0		
Nuclear		Acct 403.2	0	0	0	0	0	0	0	0	0		
Hydro		Acct 403.3	26,093,565	439,136	6,726,179	2,050,285	11,309,459	1,466,131	85,426	0	0		
Other		Acct 403.4	107,343,785	1,806,519	27,670,174	8,434,470	46,524,887	6,031,373	351,427	0	0		
Transmission		Acct 403.5	89,388,522	1,504,345	23,041,818	7,023,647	38,742,726	5,022,512	292,644	0	0		
Distribution		Acct 403.6	156,650,401	6,721,753	50,847,961	12,825,736	61,305,861	7,584,857	0	0	0		
General		Acct 403.7&8	35,938,924	819,439	10,057,558	3,212,677	13,998,709	2,064,703	55,824	0	0		
Mining		Acct 403.9	0	0	0	0	0	0	0	0	0		
Experimental		Acct 403.4	0	0	0	0	0	0	0	0	0		

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2013

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Postmerger Hydro Step I Adjustment		0	0	0	0	0	0	0	0	0		
Total Depreciation Expense :		648,623,871	15,215,928	178,458,250	51,871,041	272,958,824	35,272,974	1,548,811	0	0		
Schedule M Depreciation Factor		100.0000%	2.3459%	27.5134%	7.9971%	42.0828%	5.4381%	0.2388%	0.0000%	0.0000%		

Tax Depreciation by Function	**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**	**Other**	**Non-Utility**
Based on Tax Depreciation Schedule M Differences	1,350,141,991	28,140,941	353,046,737	94,017,051	595,950,577	73,370,301	3,477,470	-	8,884,704
Tax Depr factor	100.0000%	2.0843%	26.1489%	6.9635%	44.1398%	5.4343%	0.2576%	0.0000%	0.6581%

Pro Forma Factors December 31, 2013
Oregon General Rate Case - December 2013
COINCIDENTAL PEAKS

			FORECAST LOADS (CP)							
			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-13	10	8	166	2,626	829	3,212	450	1,274	23	8,580
Feb-13	5	8	155	2,455	681	3,204	429	1,260	26	8,210
Mar-13	7	8	152	2,271	660	3,090	410	1,259	21	7,863
Apr-13	3	8	139	2,166	572	3,044	408	1,218	20	7,567
May-13	14	14	125	1,805	560	3,981	484	1,193	26	8,175
Jun-13	20	15	146	1,981	673	4,303	631	1,247	24	9,005
Jul-13	15	15	157	2,262	739	4,698	699	1,298	43	9,896
Aug-13	22	15	151	2,328	728	4,742	547	1,257	34	9,787
Sep-13	5	15	133	2,076	637	4,311	470	1,232	27	8,886
Oct-13	31	8	134	2,159	658	3,347	442	1,256	20	8,015
Nov-13	20	18	142	2,236	701	3,699	461	1,307	25	8,572
Dec-13	11	18	155	2,377	729	3,724	480	1,336	28	8,830
			1,756	26,744	8,167	45,355	5,910	15,136	318	103,385

- (less)

Subtract: DSM programs, MagCorp Buy-through (UT) - Grossed up for Line Losses

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-13	10	8	-	-	-	89	-	-	-	89
Feb-13	5	8	-	-	-	-	-	-	-	-
Mar-13	7	8	-	-	-	-	-	-	-	-
Apr-13	3	8	-	-	-	-	-	-	-	-
May-13	14	14	-	-	-	-	-	-	-	-
Jun-13	20	15	-	-	-	261	116	-	-	377
Jul-13	15	15	-	-	-	288	164	-	-	452
Aug-13	22	15	-	-	-	282	142	-	-	425
Sep-13	5	15	-	-	-	120	-	-	-	120
Oct-13	31	8	-	-	-	-	-	-	-	-
Nov-13	20	18	-	-	-	-	-	-	-	-
Dec-13	11	18	-	-	-	99	-	-	-	99
			-	-	-	1,139	423	-	-	1,562

= equals

COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES										
			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-13	10	8	166	2,626	829	3,123	450	1,274	23	8,491
Feb-13	5	8	155	2,455	681	3,204	429	1,260	26	8,210
Mar-13	7	8	152	2,271	660	3,090	410	1,259	21	7,863
Apr-13	3	8	139	2,166	572	3,044	408	1,218	20	7,567
May-13	14	14	125	1,805	560	3,981	484	1,193	26	8,175
Jun-13	20	15	146	1,981	673	4,042	514	1,247	24	8,628
Jul-13	15	15	157	2,262	739	4,410	535	1,298	43	9,444
Aug-13	22	15	151	2,328	728	4,460	405	1,257	34	9,362
Sep-13	5	15	133	2,076	637	4,191	470	1,232	27	8,766
Oct-13	31	8	134	2,159	658	3,347	442	1,256	20	8,015
Nov-13	20	18	142	2,236	701	3,699	461	1,307	25	8,572
Dec-13	11	18	155	2,377	729	3,625	480	1,336	28	8,731
			1,756	26,744	8,167	44,215	5,487	15,136	318	101,823

+ plus

Add: Monsanto Curtailment (ID) - Grossed up for Line Losses (No adjustment - Forecast Loads assumes no curta

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-13	10	8	-	-	-	-	-	-	-	-
Feb-13	5	8	-	-	-	-	-	-	-	-
Mar-13	7	8	-	-	-	-	-	-	-	-
Apr-13	3	8	-	-	-	-	-	-	-	-
May-13	14	14	-	-	-	-	-	-	-	-
Jun-13	20	15	-	-	-	-	-	-	-	-
Jul-13	15	15	-	-	-	-	-	-	-	-
Aug-13	22	15	-	-	-	-	-	-	-	-
Sep-13	5	15	-	-	-	-	-	-	-	-
Oct-13	31	8	-	-	-	-	-	-	-	-
Nov-13	20	18	-	-	-	-	-	-	-	-
Dec-13	11	18	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (CP)										
			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-13	10	8	166	2,626	829	3,123	450	1,274	23	8,491
Feb-13	5	8	155	2,455	681	3,204	429	1,260	26	8,210
Mar-13	7	8	152	2,271	660	3,090	410	1,259	21	7,863
Apr-13	3	8	139	2,166	572	3,044	408	1,218	20	7,567
May-13	14	14	125	1,805	560	3,981	484	1,193	26	8,175
Jun-13	20	15	146	1,981	673	4,042	514	1,247	24	8,628
Jul-13	15	15	157	2,262	739	4,410	535	1,298	43	9,444
Aug-13	22	15	151	2,328	728	4,460	405	1,257	34	9,362
Sep-13	5	15	133	2,076	637	4,191	470	1,232	27	8,766
Oct-13	31	8	134	2,159	658	3,347	442	1,256	20	8,015
Nov-13	20	18	142	2,236	701	3,699	461	1,307	25	8,572
Dec-13	11	18	155	2,377	729	3,625	480	1,336	28	8,731
			1,756	26,744	8,167	44,215	5,487	15,136	318	101,823

Pro Forma Factors December 31, 2013
Oregon General Rate Case - December 2013
ENERGY

FORECAST LOADS (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2013	Jan	86,680	1,384,670	434,800	2,126,550	297,890	871,500	18,569	5,220,659
2013	Feb	74,270	1,204,390	363,180	1,914,340	260,930	797,120	16,126	4,630,356
2013	Mar	77,100	1,263,770	364,890	2,042,880	289,760	875,530	17,764	4,931,694
2013	Apr	73,820	1,146,050	327,700	1,985,840	277,690	846,900	17,225	4,675,225
2013	May	77,250	1,142,140	329,500	2,137,430	331,750	858,940	17,028	4,894,038
2013	Jun	79,580	1,115,280	323,630	2,122,820	372,490	807,910	19,186	4,840,896
2013	Jul	86,260	1,252,410	384,240	2,512,930	420,470	871,550	23,190	5,551,050
2013	Aug	81,850	1,243,250	379,420	2,564,480	373,000	837,980	22,820	5,502,800
2013	Sep	70,600	1,116,360	342,460	2,176,090	289,080	819,230	18,895	4,832,715
2013	Oct	69,200	1,144,080	363,610	2,102,710	288,690	872,940	17,024	4,858,254
2013	Nov	74,120	1,222,130	380,710	2,058,160	275,800	875,630	17,253	4,903,803
2013	Dec	84,490	1,369,700	431,580	2,170,870	293,850	865,600	19,058	5,235,148
		935,220	14,604,230	4,425,720	25,915,100	3,771,400	10,200,830	224,137	60,076,637

- (less)

Subtract: MagCorp Buy-Throughs and Load No Longer Served (Reductions to Load)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2013	Jan				6,046		-		6,046
2013	Feb				-		-		-
2013	Mar				-		-		-
2013	Apr				-		-		-
2013	May				-		-		-
2013	Jun				4,051		-		4,051
2013	Jul				5,920		-		5,920
2013	Aug				5,944		-		5,944
2013	Sep				4,357		-		4,357
2013	Oct				-		-		-
2013	Nov				-		-		-
2013	Dec				6,566		-		6,566
		-	-	-	32,885	-	-	-	32,885

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2013	Jan	86,680	1,384,670	434,800	2,120,504	297,890	871,500	18,569	5,214,613
2013	Feb	74,270	1,204,390	363,180	1,914,340	260,930	797,120	16,126	4,630,356
2013	Mar	77,100	1,263,770	364,890	2,042,880	289,760	875,530	17,764	4,931,694
2013	Apr	73,820	1,146,050	327,700	1,985,840	277,690	846,900	17,225	4,675,225
2013	May	77,250	1,142,140	329,500	2,137,430	331,750	858,940	17,028	4,894,038
2013	Jun	79,580	1,115,280	323,630	2,118,769	372,490	807,910	19,186	4,836,845
2013	Jul	86,260	1,252,410	384,240	2,507,010	420,470	871,550	23,190	5,545,129
2013	Aug	81,850	1,243,250	379,420	2,558,536	373,000	837,980	22,820	5,496,855
2013	Sep	70,600	1,116,360	342,460	2,171,733	289,080	819,230	18,895	4,828,358
2013	Oct	69,200	1,144,080	363,610	2,102,710	288,690	872,940	17,024	4,858,254
2013	Nov	74,120	1,222,130	380,710	2,058,160	275,800	875,630	17,253	4,903,803
2013	Dec	84,490	1,369,700	431,580	2,164,304	293,850	865,600	19,058	5,228,582
		935,220	14,604,230	4,425,720	25,882,215	3,771,400	10,200,830	224,137	60,043,752

+ plus

Add: Monsanto Curtailment (ID), Nucor Curtailment (UT), Magcorp Curtailment (UT) - Grossed up for Line Losses

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2013	Jan				457	579	-		1,036
2013	Feb				446	398	-		843
2013	Mar				335	352	-		687
2013	Apr				297	387	-		683
2013	May				381	417	-		798
2013	Jun				424	1,001	-		1,425
2013	Jul				429	4,704	-		5,133
2013	Aug				424	4,471	-		4,894
2013	Sep				219	968	-		1,187
2013	Oct				395	779	-		1,174
2013	Nov				224	2,039	-		2,263
2013	Dec				297	2,123	-		2,420
		-	-	-	4,327	18,216	-	-	22,543

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2013	Jan	86,680	1,384,670	434,800	2,120,961	298,469	871,500	18,569	5,215,649
2013	Feb	74,270	1,204,390	363,180	1,914,786	261,328	797,120	16,126	4,631,199
2013	Mar	77,100	1,263,770	364,890	2,043,215	290,112	875,530	17,764	4,932,381
2013	Apr	73,820	1,146,050	327,700	1,986,137	278,077	846,900	17,225	4,675,908
2013	May	77,250	1,142,140	329,500	2,137,811	332,167	858,940	17,028	4,894,836
2013	Jun	79,580	1,115,280	323,630	2,119,193	373,491	807,910	19,186	4,838,270
2013	Jul	86,260	1,252,410	384,240	2,507,438	425,174	871,550	23,190	5,550,262
2013	Aug	81,850	1,243,250	379,420	2,558,959	377,471	837,980	22,820	5,501,749
2013	Sep	70,600	1,116,360	342,460	2,171,952	290,048	819,230	18,895	4,829,544
2013	Oct	69,200	1,144,080	363,610	2,103,105	289,469	872,940	17,024	4,859,428
2013	Nov	74,120	1,222,130	380,710	2,058,384	277,839	875,630	17,253	4,906,065
2013	Dec	84,490	1,369,700	431,580	2,164,601	295,973	865,600	19,058	5,231,003
		935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	60,066,295

Pro Forma Factors December 31, 2013
Oregon General Rate Case - December 2013

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	**60,066,295**	**Ref Page 11.16**
System Energy Factor	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%	100.00%	
Divisional Energy - Pacific	3.3508%	52.3252%	15.8568%	0.0000%	0.0000%	28.4672%	0.0000%	100.00%	
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	80.5036%	11.7852%	7.0142%	0.6970%	100.00%	
System Generation Factor	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%	100.00%	
Divisional Generation - Pacific	3.5470%	54.3287%	16.5606%	0.0000%	0.0000%	25.5638%	0.0000%	100.00%	
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	82.4723%	10.6915%	6.2132%	0.6230%	100.00%	
System Capacity (kw)									
Accord	1,756.4	26,743.9	8,166.8	44,215.4	5,486.9	15,136.0	317.8	**101,823**	**Ref Page 11.15**
Modified Accord	1,756.4	26,743.9	8,166.8	44,215.4	5,486.9	15,136.0	317.8	**101,823**	**Ref Page 11.15**
Rolled-In	1,756.4	26,743.9	8,166.8	44,215.4	5,486.9	15,136.0	317.8	**101,823**	**Ref Page 11.15**
Rolled-In with Hydro Adj.	1,756.4	26,743.9	8,166.8	44,215.4	5,486.9	15,136.0	317.8	**101,823**	**Ref Page 11.15**
Rolled-In with Off-Sys Adj.	1,756.4	26,743.9	8,166.8	44,215.4	5,486.9	15,136.0	317.8	**101,823**	**Ref Page 11.15**
System Capacity Factor									
Accord	1.7249%	26.2650%	8.0206%	43.4237%	5.3886%	14.8650%	0.3121%	100.00%	
Modified Accord	1.7249%	26.2650%	8.0206%	43.4237%	5.3886%	14.8650%	0.3121%	100.00%	
Rolled-In	1.7249%	26.2650%	8.0206%	43.4237%	5.3886%	14.8650%	0.3121%	100.00%	
Rolled-In with Hydro Adj.	1.7249%	26.2650%	8.0206%	43.4237%	5.3886%	14.8650%	0.3121%	100.00%	
Rolled-In with Off-Sys Adj.	1.7249%	26.2650%	8.0206%	43.4237%	5.3886%	14.8650%	0.3121%	100.00%	
System Energy (kwh)									
Accord	935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	60,066,295	
Modified Accord	935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	60,066,295	
Rolled-In	935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	60,066,295	
Rolled-In with Hydro Adj.	935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	60,066,295	
Rolled-In with Off-Sys Adj.	935,220	14,604,230	4,425,720	25,886,542	3,789,616	10,200,830	224,137	60,066,295	
System Energy Factor									
Accord	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%	100.00%	
Modified Accord	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%	100.00%	
Rolled-In	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%	100.00%	
Rolled-In with Hydro Adj.	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%	100.00%	
Rolled-In with Off-Sys Adj.	1.5570%	24.3135%	7.3681%	43.0966%	6.3091%	16.9826%	0.3731%	100.00%	
System Generation Factor									
Accord	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%	100.00%	
Modified Accord	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%	100.00%	
Rolled-In	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%	100.00%	
Rolled-In with Hydro Adj.	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%	100.00%	
Rolled-In with Off-Sys Adj.	1.6829%	25.7772%	7.8574%	43.3419%	5.6187%	15.3944%	0.3274%	100.00%	

Pro Forma Factors December 31, 2013
Oregon General Rate Case - December 2013

Oregon General Rate Case - December 2013
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE MID COLUMBIA CONTRACTS

Contract	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Wells	4,256	65,193	19,872	109,617	14,210	38,934	828	
Rocky Reach	-	-	-	-	-	-	-	
Wanapum		-	-			-		
Priority		-				-		
Displacement		-				-		
Surplus		75,982	12,063			-		
0		-				-		
Total	4,256	141,175	31,936	109,617	14,210	38,934	828	
MC Factor	1.2483%	41.4056%	9.3665%	32.1498%	4.1678%	11.4191%	0.2428%	100%

Oregon General Rate Case - December 2013
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF THE COMBUSTION TURBINES

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-13	18,944	8.52%	7,382	117,927	37,030	180,634	25,419	74,222	1,581	
Feb-13	16,497	7.42%	5,508	89,321	26,935	142,006	19,381	59,117	1,196	
Mar-13	18,944	8.52%	6,566	107,630	31,076	174,012	24,708	74,565	1,513	
Apr-13	18,333	8.24%	6,084	94,456	27,009	163,695	22,919	69,800	1,420	
May-13	18,944	8.52%	6,579	97,272	28,062	182,069	28,289	73,152	1,450	
Jun-13	18,333	8.24%	6,559	91,920	26,673	174,661	30,783	66,587	1,581	
Jul-13	18,944	8.52%	7,346	106,663	32,724	213,549	36,210	74,226	1,975	
Aug-13	18,944	8.52%	6,971	105,883	32,314	217,936	32,148	71,367	1,943	
Sep-13	18,333	8.24%	5,819	92,009	28,225	179,009	23,905	67,520	1,557	
Oct-13	18,944	8.52%	5,893	97,437	30,967	179,113	24,653	74,345	1,450	
Nov-13	18,333	8.24%	6,109	100,726	31,378	169,649	22,899	72,168	1,422	
Dec-13	18,944	8.52%	7,196	116,652	36,756	184,350	25,207	73,720	1,623	
	222,439	100.00%	78,013	1,217,895	369,149	2,160,685	316,521	850,791	18,712	
SSECT Factor			1.56%	24.30%	7.37%	43.11%	6.32%	16.98%	0.37%	100%

Oregon General Rate Case - December 2013
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF THE COMBUSTION TURBINES

MONTH	MWH	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-13	18,944	8.52%	14.1	223.7	70.6	266.0	38.3	108.5	2.0	
Feb-13	16,497	7.42%	11.5	182.1	50.5	237.6	31.8	93.4	2.0	
Mar-13	18,944	8.52%	12.9	193.4	56.2	263.1	34.9	107.3	1.8	
Apr-13	18,333	8.24%	11.5	178.5	47.1	250.9	33.6	100.4	1.7	
May-13	18,944	8.52%	10.7	153.8	47.7	339.1	41.2	101.6	2.2	
Jun-13	18,333	8.24%	12.1	163.3	55.5	333.2	42.4	102.7	2.0	
Jul-13	18,944	8.52%	13.4	192.6	63.0	375.5	45.6	110.6	3.6	
Aug-13	18,944	8.52%	12.8	198.3	62.0	379.8	34.5	107.0	2.9	
Sep-13	18,333	8.24%	10.9	171.1	52.5	345.4	38.7	101.6	2.2	
Oct-13	18,944	8.52%	11.4	183.9	56.0	285.0	37.6	106.9	1.7	
Nov-13	18,333	8.24%	11.7	184.3	57.7	304.9	38.0	107.7	2.1	
Dec-13	18,944	8.52%	13.2	202.4	62.1	308.8	40.9	113.8	2.4	
	222,439	100.00%	146	2,227	681	3,689	457	1,261	27	
SSCCT Factor			1.72%	26.24%	8.02%	43.46%	5.39%	14.86%	0.31%	100%
SSGCT Factor			1.68%	25.75%	7.86%	43.37%	5.62%	15.39%	0.33%	100%

Oregon General Rate Case - December 2013
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF CHOLLA IV/APS

MONTH	MWH Cholla IV	APS	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC
Jan-13	246,480	142,380	388,860	14.39%	12,474	199,270	62,573	305,230	42,953	125,419	2,672
Feb-13	216,687	68,775	285,462	10.56%	7,846	127,238	38,368	202,288	27,608	84,212	1,704
Mar-13	223,639	-	223,639	8.28%	6,381	104,597	30,200	169,108	24,011	72,464	1,470
Apr-13	119,258	-	119,258	4.41%	3,258	50,582	14,463	87,660	12,273	37,379	760
May-13	216,837	(78,030)	138,807	5.14%	3,968	58,672	16,927	109,820	17,064	44,124	875
Jun-13	203,519	(137,900)	65,619	2.43%	1,933	27,084	7,859	51,463	9,070	19,620	466
Jul-13	247,681	(142,570)	105,111	3.89%	3,356	48,719	14,947	97,539	16,539	33,903	902
Aug-13	255,501	(142,430)	113,071	4.18%	3,425	52,025	15,877	107,082	15,796	35,066	955
Sep-13	242,887	(68,660)	174,227	6.45%	4,552	71,981	22,081	140,045	18,702	52,823	1,218
Oct-13	249,509	78,180	327,689	12.13%	8,392	138,746	44,096	255,049	35,105	105,864	2,065
Nov-13	236,759	137,985	374,744	13.87%	10,279	169,494	52,800	285,471	38,533	121,439	2,393
Dec-13	243,095	142,500	385,595	14.27%	12,057	195,460	61,588	308,895	42,236	123,524	2,720
	2,701,853	230	2,702,082	100.00%	77,922	1,243,867	381,779	2,119,651	299,889	855,835	18,199
SSECH Factor					1.56%	24.89%	7.64%	42.42%	6.00%	17.13%	0.36%	100%

Oregon General Rate Case - December 2013
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF CHOLLA IV/APS

MONTH	MWH Cholla IV	APS	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-13	246,480	142,380	388,860	14.39%	23.9	377.9	119.3	449.4	64.7	183.3	3.3	
Feb-13	216,687	68,775	285,462	10.56%	16.3	259.4	71.9	338.5	45.3	133.1	2.8	
Mar-13	223,639	-	223,639	8.28%	12.6	188.0	54.7	255.7	33.9	104.2	1.7	
Apr-13	119,258	-	119,258	4.41%	6.1	95.6	25.2	134.3	18.0	53.8	0.9	
May-13	216,837	(78,030)	138,807	5.14%	6.4	92.7	28.8	204.5	24.9	61.3	1.3	
Jun-13	203,519	(137,900)	65,619	2.43%	3.6	48.1	16.3	98.2	12.5	30.3	0.6	
Jul-13	247,681	(142,570)	105,111	3.89%	6.1	88.0	28.8	171.5	20.8	50.5	1.7	
Aug-13	255,501	(142,430)	113,071	4.18%	6.3	97.4	30.5	186.6	16.9	52.6	1.4	
Sep-13	242,887	(68,660)	174,227	6.45%	8.6	133.9	41.1	270.2	30.3	79.4	1.8	
Oct-13	249,509	78,180	327,689	12.13%	16.3	261.8	79.8	405.9	53.5	152.3	2.4	
Nov-13	236,759	137,985	374,744	13.87%	19.8	310.1	97.2	513.1	63.9	181.3	3.5	
Dec-13	243,095	142,500	385,595	14.27%	22.2	339.2	104.0	517.4	68.6	190.6	4.0	
	2,701,853	230	2,702,082	100.00%	148	2,292	698	3,545	453	1,273	25	
SSCCH Factor					1.76%	27.18%	8.27%	42.03%	5.37%	15.09%	0.30%	100%
SSGCH Factor					1.71%	26.61%	8.11%	42.13%	5.53%	15.60%	0.32%	100%

Oregon General Rate Case - December 2013
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF SEASONAL PURCHASE CONTRACTS

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Apr-12	-	0%	-	-	-	-	-	-	-	
May-12	-	0%	-	-	-	-	-	-	-	
Jun-12	-	0%	-	-	-	-	-	-	-	
Jul-12	-	0%	-	-	-	-	-	-	-	
Aug-12	-	0%	-	-	-	-	-	-	-	
Sep-12	-	0%	-	-	-	-	-	-	-	
Oct-12	-	0%	-	-	-	-	-	-	-	
Nov-12	-	0%	-	-	-	-	-	-	-	
Dec-12	-	0%	-	-	-	-	-	-	-	
Jan-13	-	0%	-	-	-	-	-	-	-	
Feb-13	-	0%	-	-	-	-	-	-	-	
Mar-13	-	0%	-	-	-	-	-	-	-	
	-	0%	-	-	-	-	-	-	-	
SSEC Factor			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%

Oregon General Rate Case - December 2013

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF SEASONAL PURCHASE CONTRACTS

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Apr-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
May-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jun-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jul-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Aug-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sep-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oct-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Nov-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Dec-12	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jan-13	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Feb-13	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Mar-13	-	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%
SSGC Factor			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%

Oregon General Rate Case - December 2013
Twelve Months Ended December 31, 2013
ANNUAL EMBEDDED COSTS
Average Balance

Revised Protocol ECD

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
535 - 545	Hydro Operation & Maintenance Expense	40,995,385				Page 2.7, West only
403HP	Hydro Depreciation Expense	20,546,250				Page 2.15, West only
404IP / 404HP	Hydro Relicensing Amortization	11,029,282				Page 2.16, West only
	Total West Hydro Operating Expense	**72,570,917**				
330 - 336	Hydro Electric Plant in Service	750,568,730				Page 2.23, West only
302 & 182M	Hydro Relicensing	169,528,812				Page 2.29, West only
108HP	Hydro Accumulated Depreciation Reserve	(216,601,710)				Page 2.36, West only
111IP / 111HP	Hydro Relicensing Accumulated Reserve	(32,250,564)				Page 2.39, West only
154	Materials and Supplies	(1,860)				Page 2.32, West only
	West Hydro Net Rate Base	**671,243,408**				
	Pre-tax Return	11.23%				
	Rate Base Revenue Requirement	**75,349,079**				
	Annual Embedded Cost					
	West Hydro-Electric Resources	**147,919,995**	3,564,663	41.50	(22,719,268)	MWh from GRID

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Annual Mid-C Contracts Costs	5,598,611	340,956	16.42	(10,722,841)	GRID
	Grant Reasonable Portion	(5,988,942)			(5,988,942)	GRID
		(390,332)			(16,711,783)	

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Utah Annual Qualified Facilities Costs	28,174,764	407,995	69.06	8,644,172	
555	Oregon Annual Qualified Facilities Costs	12,095,063	82,994	145.73	8,122,154	
555	Idaho Annual Qualified Facilities Costs	1,325,441	76,732	17.27	(2,347,693)	
555	WYU Annual Qualified Facilities Costs	-	-	-	-	
555	WYP Annual Qualified Facilities Costs	776,687	11,390	68.19	231,432	
555	California Annual Qualified Facilities Costs	33,226	33,434	0.99	(1,567,258)	
555	Washington Annual Qualified Facilities Costs	-	-	-	-	
	Total Qualified Facilities Costs	42,405,181	612,546	69.23	13,082,809	GRID

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh	Reference
500 - 514	Steam Operation & Maintenance Expense	1,128,949,413			Page 2.5
535 - 545	East Hydro Operation & Maintenance Expense	9,403,702			Page 2.7, East only
546 - 554	Other Generation Operation & Maintenance Expense	422,560,223			Page 2.8
555	Other Purchased Power Contracts	640,746,249			GRID less QF and Mid-C
40910	Production Tax Credits	(104,937,023)			Page 2.20
4118	SO2 Emission Allowances	(1,235,033)			Page 2.4
	James River	(4,679,599)			James River Adj (Tab 5)
	REC Revenues	(9,806,620)			REC Revenues (Tab 3)
403SP	Steam Depreciation Expense	233,208,674			Page 2.15
403HP	East Hydro Depreciation Expense	5,547,316			Page 2.15, East only
403OP	Other Generation Depreciation Expense	107,343,785			Page 2.15
403MP	Mining Depreciation Expense	0			Page 2.15
404IP / 404 HP	East Hydro Relicensing Amortization	362,856			Page 2.16, East only
406	Amortization of Plant Acquisition Costs	5,193,044			Page 2.17
	Total All Other Operating Expenses	**2,432,656,987**			
310 - 316	Steam Electric Plant in Service	6,733,786,706			Page 2.21
330 - 336	East Hydro Electric Plant in Service	161,247,649			Page 2.23, East only
302 & 186M	East Hydro Relicensing	9,652,529			Page 2.29, East only
340 - 346	Other Electric Plant in Service	3,103,323,847			Page 2.24
399	Mining	488,304,005			Page 2.28
108SP	Steam Accumulated Depreciation Reserve	(2,754,653,837)			Page 2.36
108OP	Other Generation Accumulated Depreciation Reserve	(531,475,021)			Page 2.36
108MP	Other Accumulated Depreciation Reserve	(156,948,403)			Page 2.36, East only
108HP	East Hydro Accumulated Depreciation Reserve	(50,507,492)			Page 2.36, East only
111IP / 111HP	East Hydro Relicensing Accumulated Reserve	(4,728,500)			Page 2.39, East only
114	Electric Plant Acquisition Adjustment	159,175,508			Page 2.31
115	Accumulated Provision Acquisition Adjustment	(115,489,727)			Page 2.31
151	Fuel Stock	214,906,000			Page 2.32
253.16 - 253.19	Joint Owner WC Deposit	(6,313,631)			Page 2.32
253.98	SO2 Emission Allowances	(829,723)			Page 2.34
154	Materials & Supplies	87,220,162			Page 2.32
154	East Hydro Materials & Supplies	0			
	Total Net Rate Base	**7,336,670,073**			
	Pre-tax Return	11.23%			
	Rate Base Revenue Requirement	**823,563,143**			
	Annual Embedded Cost				
	All Other Generation Resources	**3,256,220,130**	68,022,612	47.87	MWh from GRID
	Total Annual Embedded Costs	**3,446,154,975**	**72,540,778**	**47.51**	

Oregon General Rate Case - December 2013
Twelve Months Ended December 31, 2013
ANNUAL EMBEDDED COSTS
Average Balance

2010 Protocol ECD

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
535 - 545	Hydro Operation & Maintenance Expense	40,995,385				Page 2.7, West only
403HP	Hydro Depreciation Expense	20,546,250				Page 2.15, West only
404IP / 404HP	Hydro Relicensing Amortization	11,029,282				Page 2.16, West only
	Total West Hydro Operating Expense	**72,570,917**				
330 - 336	Hydro Electric Plant in Service	750,568,730				Page 2.23, West only
302 & 182M	Hydro Relicensing	169,528,812				Page 2.29, West only
108HP	Hydro Accumulated Depreciation Reserve	(216,601,710)				Page 2.36, West only
111IP / 111HP	Hydro Relicensing Accumulated Reserve	(32,250,564)				Page 2.39, West only
154	Materials and Supplies	(1,860)				Page 2.32, West only
	West Hydro Net Rate Base	**671,243,408**				
	Pre-tax Return	11.23%				
	Rate Base Revenue Requirement	**75,349,079**				
	Annual Embedded Cost					
	West Hydro-Electric Resources	**147,919,995**	3,564,663	41.50	(10,473,926)	MWh from GRID

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Annual Mid-C Contracts Costs	5,598,611	340,956	16.42	(9,551,588)	GRID
	Grant Reasonable Portion	(5,988,942)			(5,988,942)	GRID
		(390,332)			(15,540,530)	

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Utah Annual Qualified Facilities Costs					
555	Oregon Annual Qualified Facilities Costs					
555	Idaho Annual Qualified Facilities Costs					
555	WYU Annual Qualified Facilities Costs					
555	WYP Annual Qualified Facilities Costs					
555	California Annual Qualified Facilities Costs					
555	Washington Annual Qualified Facilities Costs					
	Total Qualified Facilities Costs	-	-		-	GRID

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh	Reference
500 - 514	Steam Operation & Maintenance Expense	1,126,982,154			Page 2.5
535 - 545	East Hydro Operation & Maintenance Expense	9,403,702			Page 2.7, East only
546 - 554	Other Generation Operation & Maintenance Expense	92,404,783			Page 2.8
555	Other Purchased Power Contracts	113,425,620			GRID less QF and Mid-C
40910	Production Tax Credits	0			Page 2.20
4118	SO2 Emission Allowances	(1,235,033)			Page 2.4
	James River	(4,679,599)			James River Adj (Tab 5)
	REC Revenues	0			REC Revenues (Tab 3)
403SP	Steam Depreciation Expense	187,647,723			Page 2.15
403HP	East Hydro Depreciation Expense	5,547,316			Page 2.15, East only
403OP	Other Generation Depreciation Expense	8,635,361			Page 2.15
403MP	Mining Depreciation Expense	0			Page 2.15
404IP / 404 HP	East Hydro Relicensing Amortization	362,856			Page 2.16, East only
406	Amortization of Plant Acquisition Costs	5,193,044			Page 2.17
	Total All Other Operating Expenses	**1,543,687,928**			
310 - 316	Steam Electric Plant in Service	6,707,311,804			Page 2.21
330 - 336	East Hydro Electric Plant in Service	161,247,649			Page 2.23, East only
302 & 186M	East Hydro Relicensing	9,652,529			Page 2.29, East only
340 - 346	Other Electric Plant in Service	289,368,961			Page 2.24
399	Mining	488,304,005			Page 2.28
108SP	Steam Accumulated Depreciation Reserve	(2,635,921,853)			Page 2.36
108OP	Other Generation Accumulated Depreciation Reserve	(96,858,754)			Page 2.36
108MP	Other Accumulated Depreciation Reserve	(156,948,403)			Page 2.38, East only
108HP	East Hydro Accumulated Depreciation Reserve	(50,507,492)			Page 2.36, East only
111IP / 111HP	East Hydro Relicensing Accumulated Reserve	(4,728,500)			Page 2.39, East only
114	Electric Plant Acquisition Adjustment	159,175,508			Page 2.31
115	Accumulated Provision Acquisition Adjustment	(115,489,727)			Page 2.31
151	Fuel Stock	212,085,725			Page 2.32
253.16 - 253.19	Joint Owner WC Deposit	(6,313,631)			Page 2.32
253.98	SO2 Emission Allowances	(829,723)			Page 2.34
154	Materials & Supplies	87,220,162			Page 2.32
154	East Hydro Materials & Supplies	0			
	Total Net Rate Base	**5,046,768,261**			
	Pre-tax Return	11.23%			
	Rate Base Revenue Requirement	**566,514,821**			
	Annual Embedded Cost				
	All Other Generation Resources	**2,110,202,749**	47,490,221	44.43	MWh from GRID
	Total Annual Embedded Costs	**2,257,732,413**	**51,395,840**	**43.93**	

Table of Contents

Enclosed is a CD containing an electronic copy of the documents and exhibits in the file formats in which they were created.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Total Cash Working Capital

Oregon Jurisdiction

CASH WORKING CAPITAL	Amount	Reference
Revenue Lag Days	42.41	Page 2.1
Expense Lag Days	35.07	Page 2.1
Net Revenue Lag Days	7.34	Page 2.1
Daily Cost of Service (Total Expense Lag / 365)	1,641,448	Page 2.1
Total Cash Working Capital	**12,055,535**	**Page 2.1**

INTRODUCTION

PacifiCorp has adopted the definition of cash working capital proposed by FERC in its Notice of Proposed Rulemaking (NOPR) on "Calculation of Cash Working Capital Allowance for Electric Utilities," Docket No. RM84-9-000, issued April 5, 1984. In this NOPR, FERC indicates that cash working capital is the amount of cash needed on-hand by a public utility to pay its day-to-day operating expenses, for the time period during which the utility has provided electric service to its customers and has not yet received payment for that service. If, on average, the time difference between providing service and collecting the associated revenue exceeds the time difference between providing service and paying the associated expenses, the utility experiences a "net revenue receipt lag." This requires funding a working cash balance. On the other hand, if the lag in payment of expenses is longer than the lag in collection revenues the utility experiences a "net expense payment lag," meaning the collection of revenues occurs in advance of paying expenses. A utility experiencing a "net revenue receipt lag" requires working cash in its revenue requirement.

Cash working capital allowance describes the permissible net addition to rate base to reflect borrowed or investor-supplied working cash. With respect to the method of calculation of cash working capital, the FERC NOPR states that "a fully-developed and reliable lead/lag study is the most accurate method of determining the working cash needs of a particular utility." While the FERC NOPR was never fully adopted, it offered guidelines and is also consistent with Robert Hahne's text "Accounting for Public Utilities."

This report presents the results of the Company's recently completed lead/lag study based on 12-months ending December 2010 revenues and expenses. The revenues and expenses used in the study are consistent with the Company's December 2010 unadjusted results as published in the Results of Operations Report filed with the Commission (Oregon allocated results are derived using the 2010 Protocol/Rolled-In allocation methodology). This report summarizes the cash working capital requirement and describes the Company's method and calculations. The elements included in this study are consistent with those proposed in the FERC NOPR; namely, revenues, fuel costs, purchased power costs, labor, operation and maintenance expenses, income taxes, and property and other taxes. Separate lags were calculated for each major element in the study based on information developed from the Company's accounting and customer information systems. This report describes the calculation of each element and provides source documents. It is the Company's intention to clearly explain the assumptions and calculations included in this study, however, due to the voluminous nature of many of the revenue and expense transactions it is not feasible to detail every invoice and payment in this report. Full supporting detail is available for inspection on the Company's premises; additionally, the Company has provided a CD of the data files which are too lengthy to provide in print.

LEAD/LAG STUDY: SUMMARY

The lead/lag study described in this report incorporates data obtained directly from various business units throughout the Company. Results of the study are summarized by total company and jurisdiction on page 2.1. This summary sheet uses lag days calculated from the data received from the business units along with actual results from the December 2010 Results of Operations Report (Tab 5), based on the 2010 Protocol/Rolled-In allocation methodology. Net revenue lag days are shown as a result of net revenue lag less net expense lag, which represents the time between when the Company provides goods and services to when payment is received. The Company's required cash working capital balance is derived by multiplying the daily cost of service by the net revenue lag days.

Revenue and Expense Detail

The materials in Tabs 3 and 4 of this report describe the calculation of the revenue and expense lag days used to determine the cash working capital requirement. Calculation exhibits are provided beginning with summary level documentation, tracing calculations backward through successive levels of detail. The Company anticipates this informative approach will prove a useful method for identifying and explaining the vast array of source documents required to support the study.

December 2010 Actual Results

The pages provided under Tab 5 reflect the unadjusted results as reported in the Company's December 2010 Results of Operations Report, based on 2010 Protocol/Rolled-In allocation method[1], and are the basis for the calculations in this study.

Other Working Capital

This lead/lag study does not include other working capital. Other working capital is included in the miscellaneous rate base section of the Results of Operations Report. It is separate from cash working capital, and because the balances change continually, other working capital was excluded from the lead/lag study. The omission of other working capital does not impact the outcome of the lead/lag study with regard to cash working capital.

[1] The December 2010 Results of Operations was filed with the Oregon Commission prior to the Commission's approval of the 2010 Protocol. Consistent with the approved 2010 Protocol, Oregon results under the Rolled-In method are equivalent to the 2010 Protocol. For the lead/lag study, state taxes in the December 2010 results have been calculated using the blended statutory rate consistent with the 2010 Protocol, rather than the IBT factor.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Lead/Lag Study
December 2010

Oregon Jurisdiction

Line	Description	FERC Account(s)	2010 Unadjusted Results [1] Total Company	Oregon Allocated	Lag Days	Dollar Days	Lag Days Ref.
1	**REVENUE LAG:**						
2	General Business Revenues	440 - 448, 456 SBC [4]	3,474,487,964	925,369,330	43.92	40,644,719,222	Page 3.1
3	Other CSS Revenues	450-454	32,637,349	11,291,980	25.58	288,897,383	Page 3.1
4	Sales for Resale	447NPC	492,522,473	129,043,546	36.89	4,760,424,512	Page 3.4
5	Wheeling and Other Misc. Revenues	456/447	402,567,598	89,896,894	36.89	3,316,302,071	Page 3.4
6	**TOTAL REVENUE LAG**		**4,402,215,385**	**1,155,601,749**	**42.41**	**49,010,343,188**	
7							
8							
9	**EXPENSE LAG:**						
10	Operation & Maintenance:						
11	Coal	501NPC	618,412,475	155,317,996	29.58	4,594,757,244	Page 4.2
12	Natural Gas	501NPC / 547NPC	446,200,118	111,900,267	40.61	4,544,119,746	Page 4.3
13	Purchased Power	555NPC	416,825,351	109,812,334	38.47	4,224,886,112	Page 4.4
14	Wheeling Expense	565NPC	136,854,649	35,789,548	38.47	1,376,956,096	Page 4.4
15	Labor and Benefits	500-935	475,604,778	136,707,602	14.31	1,956,627,548	Page 4.5
16	Incentive	500-935	18,523,716	5,324,448	167.50	891,845,043	Page 4.5
17	Other Operations & Maintenance	500-935	617,082,337	165,180,219	33.54	5,539,884,747	Page 4.6
18	Operation & Maintenance Expense Lag		2,729,503,425	720,032,414	32.12	23,129,076,535	
19							
20	Embedded Cost Differential [2]	ECD	-	(8,556,793)			
21	BPA Credit [3]	555	(36,817,673)	(28,650,083)	50.14	(1,436,561,740)	Page 4.10
22							
23	O&M Expense From Results of Operations		2,692,685,751	682,825,538			
24							
25	Taxes Other Than Income:						
26	Property Taxes	408	100,361,440	27,801,379	140.77	3,913,706,057	Page 4.7
27	Other Taxes	408	36,151,288	25,768,360	36.12	930,876,053	Page 4.8
28	Total Taxes Other Than Income Lag		136,512,728	53,569,739	90.44	4,844,582,110	
29							
30	Income Taxes:						
31	Federal Income Taxes		(482,762,100)	(130,051,666)	37.87	(4,925,706,108)	Page 4.9
32	State Income Taxes		(58,348,093)	(15,771,919)	38.17	(601,962,162)	Page 4.9
33	Total Income Tax Lag		(541,110,193)	(145,823,585)	37.91	(5,527,668,270)	
34							
35	**TOTAL EXPENSE LAG**		**2,288,088,287**	**599,128,485**	**35.07**	**21,009,428,635**	
36							
37	**NET REVENUE LAG DAYS**				**7.34**		
38							
39	**Daily Cost of Service (Total Expense Lag Amount /365)**				**1,641,448**		
40							
41	**Cash Working Capital Balance (Net Revenue Lag Days x Daily Cost of Service)**				**12,055,535**		

Notes:
(1) The unadjusted results columns reflect actual results from the December 2010 Results of Operation Report based on 2010 Protocol/Rolled-In allocation method (see Tab 5). Current income taxes calculated using actuals from December 2010 Results and the blended statutory tax rate, consistent with 2010 Protocol, rather than allocated using the IBT factor.

(2) The Embedded Cost Differential is a non-cash expense item. As a result, it has been excluded from the lead/lag calculation.
(3) The BPA credit only applies to Oregon, Washington and Idaho.
(4) System Benefit Charges (Demand Side Management Revenues) in 456 are included with General Business Revenues since they're collected with customer bills.

REVENUE LAG

Lags were computed for general business revenues, other customer service system (CSS) revenues, sales for resale, and wheeling and other miscellaneous revenues. The following is an explanation of how each of the separate components of the revenue lag was developed:

General Business Revenue Lag

The general business revenue lag was computed by subdividing the lag into three components: service lag, billing lag and collection lag (see Page 3.1). General business revenue customers include the revenue categories of residential sales, commercial sales, industrial sales, public street and highway lighting, and other sales to public authorities. Collectively, these categories are referred to as sales to ultimate customers. Special contract revenues are incorporated into the general business revenue lag calculation because these contracts are captured in CSS.

Service Lag

The service lag is the time period between when the customer begins receiving service for a billing cycle and when the customer's meter is read. The service lag equals the total number of days in the year (365), divided by the number of billing periods per year (12), divided by two, to arrive at the midpoint for each service period. This calculation would not change if the meter reading date fluctuated from month-to-month, since any shortage of days from one month would be reflected as an increase in days for the following month. Using this calculation, the average service lag is 15.2 days for general business customers. This is the amount shown in the "Service Lag" column of page 3.1.

Billing Lag

The billing lag is the period beginning when the meter is read and ending when the invoice is processed in CSS. This lag was calculated using extracts obtained from CSS. Page 3.2 shows the calculation of the billing lag days.

Collection Lag

The collection lag is the time interval from the invoice date until the customer pays for the service. There is no automated reporting process within CSS to track payments against specific bills. The payment patterns of some customers when paying only partial bills, multiple bills or combining payments for multiple agreements renders a logical programming approach to tracking the collection lag on specific agreements extremely difficult, if not impossible.

Due to these complexities, the Company has developed another process for determining the collection lag. Collection lag is calculated by summing the daily accounts receivable balances for the year and dividing by the total revenues for the same period, yielding an average age of the revenues in customer accounts receivable. This is the same methodology used by the Company in the 2007 study.

The collection lag for general business revenues is shown on page 3.3, with pages 3.3.1 through 3.3.8 as backup. The general business revenue collection lag calculation also includes the revenue categories of forfeited discounts and interest, miscellaneous service revenues, and rent from electric property. These revenues are referred to as other CSS revenues in this study since they are captured in CSS along with the general business revenues.

Daily Accounts Receivable

Development of the collection lag begins with identifying the daily customer accounts receivable (A/R) balances for 2010 shown on page 3.3.1. Total company daily A/R balances are obtained by extracting the daily activity for each A/R general ledger account from SAP, the Company's accounting system. Each day's activity is added to the previous day's balance to arrive at a daily balance. Zero activity is input for those days with no activity due to holidays or weekends and the previous day's balance is carried forward to the next day.

Total company daily A/R balances from the SAP system have been allocated to the various states. This allocation was developed using the actual beginning and ending monthly A/R balances which are readily available by state from a monthly A/R aging report generated from CSS and included as page 3.3.2. The state to total company ratios of the beginning/ending average balances from page 3.3.2 are applied to the daily A/R balances from SAP. This procedure is shown on pages 3.3.3 and 3.3.4.

By following this process each month, page 3.3.5 was developed. This page shows the jurisdictional allocation of the sum of daily customer A/R balances. The total company amount shown on this page ties to the total company amount shown on page 3.3.1.

Revenues

Total electric revenues by state are obtained from SAP. The revenues used in the calculation of the general business collection lag are shown on page 3.3.6. These amounts tie to the totals included in the December 2010 Results of Operations Report (Tab 5).

Sales and Other Taxes

Page 3.3.7 shows the amount of pass-through taxes for states in which the Company bills customers directly. These amounts must be considered in the collection lag calculation because the daily A/R balances include amounts owed for these items. As a result, these taxes

are added to revenues as shown on page 3.3. to ensure that both the numerator (sum of daily A/R balances) and the denominator (total revenues) in the collection lag calculation are consistent.

Unbilled Revenues

The final adjustment needed for the general revenue collection lag calculation is the exclusion of the unbilled revenues. These amounts are included in electric revenues, but are not included in the CSS A/R balances. The 2010 amount of unbilled revenue by state is shown on page 3.3.8 and is also carried forward to page 3.3.

Sales for Resale, Wheeling, and Other Revenues

Sales for resale represent system revenues, so the lag days are identified at the total company level. The commercial and trading department calculated the lag days for these revenue categories. This calculation incorporates all energy transactions for the 12-months ending December 2010. Each payment received was analyzed through an automated process that tracks the average lag in payment received from the mid-point of the service period until the payment was received. The individual lags are then weighted to develop a weighted average revenue lag for these accounts as shown on page 3.4. This page reflects only a small subset of the transactions for the year. See the provided CD for a complete record of the transactions analyzed in this study. The weighted average shown on the bottom of page 3.4 is carried forward to page 3.1.

Other CSS Revenues

Typical charges in these accounts would include late payment fees, miscellaneous connection fees, temporary service loop rental, etc. Given the nature of these accounts, there is no service lag or billing lag associated with them, because they do not reflect metered usage. Therefore, there is no service period information in CSS to use in calculating either of these lags. What service or billing lag there might be on some items in these accounts would be immaterial to the overall revenue lag calculation. The collection lag for these accounts is included in the calculation of the collection lag for general business revenue customers, so the lag is the same as that calculated for those customers.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Revenue Lag Summary

Reference	California Jurisdiction			
	Note 1 Below	*Page 3.2*	*Pages 3.3 & 3.4*	*Page 2.1*
	Service Lag	**Billing Lag**	**Collection Lag**	**Total**
General Business Revenues	15.2	3.13	25.58	43.92
Other CSS Revenues			25.58	25.58
Sales for Resale			36.89	36.89
Wheeling and Other Misc. Revenues			36.89	36.89

Notes:

(1) Service lag is calculated by taking 365 days per year, divided by 12 billing periods, divided by 2 to get the average service lag.

(2) Service lag and billing lag is included in the collection lag column for the cateegories of other CSS revenues, sales for resale, wheeling revenues, and other misc. revenues.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Billing Lead/Lag Summary
12 Months Ending December 2010

OREGON JURISDICTION				
Year	**Month**	**Total Days**	**Count**	**Average Days**
2010	01	1,805,643	562,443	3.21
2010	02	1,785,667	566,012	3.15
2010	03	1,641,442	566,493	2.90
2010	04	1,586,488	567,172	2.80
2010	05	1,762,083	567,469	3.11
2010	06	1,762,291	569,339	3.10
2010	07	1,653,905	572,076	2.89
2010	08	1,809,420	572,515	3.16
2010	09	1,520,733	574,494	2.65
2010	10	3,095,449	574,694	5.39
2010	11	1,692,040	574,757	2.94
2010	12	1,302,347	575,043	2.26
Total Year		21,417,508	6,842,507	**3.13**

Ref. 3.1

Note: These days represent the amount of time from the billing cycle to when a bill is prepared.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Revenue Collection Lag

	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	Ref.
Revenues	3,689,452,249	89,169,927	213,012,473	967,307,033	1,613,299,599	266,236,367	540,426,696	3.3.6
Sales and Other Taxes	152,921,181	380,566	1,115,812	12,062,591	115,879,246	8,888,240	14,594,725	3.3.7
Total Revenue and Taxes	3,842,373,430	89,550,494	214,128,286	979,369,624	1,729,178,845	275,124,607	555,021,421	
Less:								
Unbilled Revenues	8,430,000	489,000	1,481,000	8,424,000	(324,000)	(780,000)	(860,000)	3.3.8
Subtotal	3,833,943,430	89,061,494	212,647,286	970,945,624	1,729,502,845	275,904,607	555,881,421	
Sum of Daily A/R	88,710,688,166	2,109,082,487	4,256,517,553	24,840,963,156	41,347,586,853	6,587,072,047	9,569,466,070	3.3.5
Collection Lag (Days)	**23.14**	**23.68**	**20.02**	**25.58**	**23.91**	**23.87**	**17.21**	3.1

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Daily Accounts Receivable Balances

Day	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Sum of CY 2010	
Beginning Balance	231,558,748	241,818,551	225,460,126	209,424,158	203,022,227	199,122,051	206,087,835	231,651,921	259,713,258	250,838,713	221,671,691	195,457,744		
1	*231,558,748*	231,934,017	215,934,285	218,687,642	*203,022,227*	195,909,601	219,838,645	*231,651,921*	277,568,271	257,767,767	223,038,522	199,638,485	2,706,550,130	
2	*231,558,748*	237,968,781	215,969,313	223,524,254	*203,022,227*	207,645,161	227,557,872	234,732,739	293,390,945	*257,767,767*	233,400,397	214,850,971	2,781,389,175	
3	*231,558,748*	239,949,653	222,266,362	*223,524,254*	204,956,847	214,708,778	*227,557,872*	253,419,661	294,578,460	*257,767,767*	239,372,454	221,553,599	2,831,214,455	
4	226,340,106	246,639,407	229,372,823	*223,524,254*	213,508,070	227,987,326	*227,557,872*	264,084,203	*294,578,460*	261,227,080	248,823,257	*221,553,599*	2,885,196,457	
5	237,531,405	256,235,649	235,878,826	216,112,644	219,541,076	*227,987,326*	*227,557,872*	280,541,511	*294,578,460*	272,008,005	249,566,018	*221,553,599*	2,939,092,391	
6	249,743,163	*256,235,649*	*235,878,826*	227,222,010	235,171,145	*227,987,326*	224,656,984	293,144,016	*294,578,460*	279,495,149	*249,566,018*	223,761,119	2,997,439,865	
7	260,613,400	*256,235,649*	*235,878,826*	239,135,983	242,383,203	229,927,821	237,369,625	*293,144,016*	292,868,652	283,755,688	*249,566,018*	237,965,939	3,058,844,820	
8	275,021,268	259,727,486	238,316,333	249,717,801	*242,383,203*	237,380,047	244,873,954	*293,144,016*	298,312,337	278,980,859	241,930,523	252,007,886	3,111,795,713	
9	*275,021,268*	264,978,011	247,294,236	248,105,871	*242,383,203*	239,036,499	253,216,812	287,936,516	299,210,459	*278,980,859*	248,200,416	259,291,072	3,143,655,223	
10	*275,021,268*	267,446,123	251,533,320	*248,105,871*	230,735,111	241,313,340	*253,216,812*	292,564,916	299,954,331	*278,980,859*	241,913,782	265,124,282	3,145,910,015	
11	271,529,141	271,484,182	253,757,271	*248,105,871*	232,227,994	239,802,476	*253,216,812*	296,316,313	*299,954,331*	274,386,781	*241,913,782*	*265,124,282*	3,147,819,236	
12	275,264,256	266,111,915	251,538,605	233,365,123	229,502,516	*239,802,476*	248,885,435	294,576,557	*299,954,331*	274,934,326	235,420,724	*265,124,282*	3,114,480,545	
13	273,797,127	*266,111,915*	*251,538,605*	238,621,939	229,729,906	*239,802,476*	248,857,121	296,433,858	281,742,954	273,125,012	*235,420,724*	253,474,453	3,088,656,090	
14	272,368,337	*266,111,915*	*251,538,605*	239,900,877	227,178,232	227,325,147	251,708,745	*296,433,858*	284,296,538	271,146,503	*235,420,724*	257,245,239	3,080,674,721	
15	273,908,871	255,854,886	235,342,622	239,374,527	*227,178,232*	229,285,683	251,758,147	*296,433,858*	282,300,083	266,512,397	224,535,243	260,194,079	3,042,678,628	
16	*273,908,871*	256,495,588	239,934,740	238,330,553	*227,178,232*	232,770,934	252,955,827	283,704,669	282,252,123	*266,512,397*	225,029,573	263,269,871	3,042,343,377	
17	*273,908,871*	259,388,251	240,500,126	*238,330,553*	216,887,880	231,965,667	*252,955,827*	289,726,100	281,363,426	*266,512,397*	223,241,844	265,679,637	3,040,460,579	
18	276,834,685	256,614,987	242,534,549	*238,330,553*	219,158,115	230,514,419	*252,955,827*	290,868,247	*281,363,426*	250,587,154	222,007,430	*265,679,637*	3,027,449,029	
19	267,600,131	250,738,112	240,386,003	222,181,853	217,730,933	*230,514,419*	242,085,174	288,004,821	*281,363,426*	245,738,375	221,578,381	*265,679,637*	2,973,601,265	
20	270,768,226	*250,738,112*	*240,386,003*	220,844,789	217,242,699	*230,514,419*	245,060,659	285,091,906	265,221,941	241,699,894	*221,578,381*	250,530,838	2,939,677,868	
21	268,632,366	*250,738,112*	*240,386,003*	220,259,443	216,279,386	216,330,167	246,512,220	*285,091,906*	260,546,560	238,740,107	*221,578,381*	248,044,930	2,913,139,581	
22	261,082,164	233,701,680	223,769,755	219,463,476	*216,279,386*	216,599,019	245,414,115	*285,091,906*	260,494,752	235,692,266	208,779,634	247,397,167	2,853,765,321	
23	*261,082,164*	234,165,335	226,276,622	214,355,581	*216,279,386*	213,887,020	*245,414,115*	263,875,158	256,986,612	*235,692,266*	206,156,936	247,537,517	2,821,708,713	
24	*261,082,164*	234,362,570	225,160,668	*214,355,581*	196,837,273	208,974,703	*245,414,115*	269,818,107	252,207,879	*235,692,266*	205,626,277	*247,537,517*	2,797,069,121	
25	241,329,390	230,533,237	224,469,167	*214,355,581*	195,233,787	203,880,332	*245,414,115*	266,267,547	*252,207,879*	217,374,282	*205,626,277*	*247,537,517*	2,744,229,112	
26	246,622,661	225,460,126	215,466,381	196,525,885	194,722,203	*203,880,332*	223,277,061	264,489,124	*252,207,879*	218,708,663	*205,626,277*	*247,537,517*	2,694,524,110	
27	239,951,732	*225,460,126*	*215,466,381*	199,160,898	195,955,088	*203,880,332*	218,294,369	262,035,697	236,997,225	219,665,154	*205,626,277*	231,469,911	2,653,963,190	
28	240,296,642	*225,460,126*	*215,466,381*	198,845,052	199,122,051	195,715,840	220,855,257	*262,035,697*	241,518,339	220,431,082	*205,626,277*	228,363,209	2,653,735,953	
29	241,818,551		203,266,271	201,367,527	*199,122,051*	204,055,190	228,918,013	*262,035,697*	245,501,103	221,671,691	188,570,970	233,090,012	2,429,417,076	
30	*241,818,551*		209,873,821	203,022,227	*199,122,051*	206,087,835	231,651,921	252,533,768	250,838,713	*221,671,691*	195,457,744	237,363,227	2,449,441,549	
31	*241,818,551*		209,424,158		*199,122,051*		*231,651,921*	259,713,258		*221,671,691*		*237,363,227*	1,600,764,856	
Sum of Daily Balances	7,969,391,575	6,976,881,599	7,184,805,890	6,756,758,473	6,709,195,765	6,655,472,113	7,426,661,115	8,574,941,566	8,288,938,356	7,824,898,196	6,760,199,263	7,582,544,255	**88,710,688,166**	Ref. 3.3.5
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31		
Daily Average	257,077,148	249,174,343	231,767,932	225,225,282	216,425,670	221,849,070	239,569,713	276,611,018	276,297,945	252,416,071	225,339,975	244,598,202		

Note: Numbers in Italics represent weekends or holidays. For these days, the prior business day balance is used.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Month-End Accounts Receivable Balances By State

Month	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	Ref.
Dec-09	231,558,748	5,881,383	8,143,384	68,496,433	103,738,368	18,342,691	26,956,489	3.3.3
Jan-10	241,818,551	6,535,139	11,530,026	72,228,968	103,487,315	21,404,713	26,632,391	3.3.3
Feb-10	225,460,126	5,693,546	6,820,506	65,246,971	100,970,910	19,755,283	26,972,911	3.3.3
Mar-10	209,424,158	5,615,276	6,202,382	65,368,080	89,425,245	17,243,652	25,569,523	3.3.3
Apr-10	203,022,227	5,407,758	5,870,267	65,833,044	85,695,701	16,970,948	23,244,509	3.3.3
May-10	199,122,051	5,155,688	6,941,399	62,021,518	87,275,456	15,504,345	22,223,645	3.3.3
Jun-10	206,087,835	4,759,149	9,655,816	60,285,502	94,814,857	14,760,837	21,811,672	3.3.3
Jul-10	231,651,921	5,016,303	15,675,234	59,433,553	114,109,229	15,350,188	22,067,414	3.3.4
Aug-10	259,713,258	5,400,449	17,295,910	63,900,588	134,231,820	15,923,315	22,961,176	3.3.4
Sep-10	250,838,713	5,098,166	18,589,624	59,334,981	128,732,058	15,369,280	23,714,604	3.3.4
Oct-10	221,671,691	4,415,828	13,691,018	54,465,885	110,154,945	14,071,656	24,872,358	3.3.4
Nov-10	195,457,744	4,773,708	7,782,384	53,635,251	92,701,922	14,363,170	22,201,308	3.3.4
Dec-10	237,363,227	5,865,968	8,297,179	69,045,616	108,441,295	18,723,459	26,989,708	3.3.4

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Sum of Daily Customer Accounts Receivable Balances by Month

Month/Description	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	Ref.
January 2010								
Beginning A/R Balance	231,558,748	5,881,383	8,143,384	68,496,433	103,738,368	18,342,691	26,956,489	3.3.2
Ending A/R Balance	241,818,551	6,535,139	11,530,026	72,228,968	103,487,315	21,404,713	26,632,391	
Average A/R Balance	236,688,650	6,208,261	9,836,705	70,362,701	103,612,841	19,873,702	26,794,440	
State Ratio	100.00%	2.62%	4.16%	29.73%	43.78%	8.40%	11.32%	
Calculated Daily A/R	257,077,148	6,743,044	10,684,044	76,423,785	112,538,112	21,585,634	29,102,528	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	7,969,391,575	209,034,370	331,205,375	2,369,137,324	3,488,681,470	669,154,655	902,178,380	
February 2010								
Beginning A/R Balance	241,818,551	6,535,139	11,530,026	72,228,968	103,487,315	21,404,713	26,632,391	3.3.2
Ending A/R Balance	225,460,126	5,693,546	6,820,506	65,246,971	100,970,910	19,755,283	26,972,911	
Average A/R Balance	233,639,339	6,114,342	9,175,266	68,737,970	102,229,113	20,579,998	26,802,651	
State Ratio	100.00%	2.62%	3.93%	29.42%	43.76%	8.81%	11.47%	
Calculated Daily A/R	249,174,343	6,520,893	9,785,342	73,308,453	109,026,468	21,948,391	28,584,796	
Days in Month	28	28	28	28	28	28	28	
Calc. Sum of Daily A/R	6,976,881,599	182,585,012	273,989,567	2,052,636,678	3,052,741,113	614,554,937	800,374,291	
March 2010								
Beginning A/R Balance	225,460,126	5,693,546	6,820,506	65,246,971	100,970,910	19,755,283	26,972,911	3.3.2
Ending A/R Balance	209,424,158	5,615,276	6,202,382	65,368,080	89,425,245	17,243,652	25,569,523	
Average A/R Balance	217,442,142	5,654,411	6,511,444	65,307,525	95,198,078	18,499,468	26,271,217	
State Ratio	100.00%	2.60%	2.99%	30.03%	43.78%	8.51%	12.08%	
Calculated Daily A/R	231,767,932	6,026,942	6,940,439	69,610,196	101,470,034	19,718,272	28,002,049	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	7,184,805,890	186,835,194	215,153,597	2,157,916,071	3,145,571,062	611,266,439	868,063,528	
April 2010								
Beginning A/R Balance	209,424,158	5,615,276	6,202,382	65,368,080	89,425,245	17,243,652	25,569,523	3.3.2
Ending A/R Balance	203,022,227	5,407,758	5,870,267	65,833,044	85,695,701	16,970,948	23,244,509	
Average A/R Balance	206,223,192	5,511,517	6,036,325	65,600,562	87,560,473	17,107,300	24,407,016	
State Ratio	100.00%	2.67%	2.93%	31.81%	42.46%	8.30%	11.84%	
Calculated Daily A/R	225,225,282	6,019,367	6,592,532	71,645,216	95,628,586	18,683,623	26,655,959	
Days in Month	30	30	30	30	30	30	30	
Calc. Sum of Daily A/R	6,756,758,473	180,581,000	197,775,949	2,149,356,469	2,868,857,579	560,508,694	799,678,782	
May 2010								
Beginning A/R Balance	203,022,227	5,407,758	5,870,267	65,833,044	85,695,701	16,970,948	23,244,509	3.3.2
Ending A/R Balance	199,122,051	5,155,688	6,941,399	62,021,518	87,275,456	15,504,345	22,223,645	
Average A/R Balance	201,072,139	5,281,723	6,405,833	63,927,281	86,485,578	16,237,646	22,734,077	
State Ratio	100.00%	2.63%	3.19%	31.79%	43.01%	8.08%	11.31%	
Calculated Daily A/R	216,425,670	5,685,026	6,894,972	68,808,661	93,089,472	17,477,526	24,470,013	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	6,709,195,765	176,235,818	213,744,131	2,133,068,486	2,885,773,623	541,803,302	758,570,405	
June 2010								
Beginning A/R Balance	199,122,051	5,155,688	6,941,399	62,021,518	87,275,456	15,504,345	22,223,645	3.3.2
Ending A/R Balance	206,087,835	4,759,149	9,655,816	60,285,502	94,814,857	14,760,837	21,811,672	
Average A/R Balance	202,604,943	4,957,419	8,298,608	61,153,510	91,045,157	15,132,591	22,017,659	
State Ratio	100.00%	2.45%	4.10%	30.18%	44.94%	7.47%	10.87%	
Calculated Daily A/R	221,849,070	5,428,291	9,086,839	66,962,085	99,692,944	16,569,938	24,108,973	
Days in Month	30	30	30	30	30	30	30	
Calc. Sum of Daily A/R	6,655,472,113	162,848,745	272,605,159	2,008,862,541	2,990,788,335	497,098,137	723,269,197	

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Sum of Daily Customer Accounts Receivable Balances by Month

Month/Description	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	Ref.
July 2010								
Beginning A/R Balance	206,087,835	4,759,149	9,655,816	60,285,502	94,814,857	14,760,837	21,811,672	3.3.2
Ending A/R Balance	231,651,921	5,016,303	15,675,234	59,433,553	114,109,229	15,350,188	22,067,414	
Average A/R Balance	218,869,878	4,887,726	12,665,525	59,859,528	104,462,043	15,055,513	21,939,543	
State Ratio	100.00%	2.23%	5.79%	27.35%	47.73%	6.88%	10.02%	
Calculated Daily A/R	239,569,713	5,349,988	13,863,380	65,520,802	114,341,645	16,479,403	24,014,497	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	7,426,661,115	165,849,614	429,764,768	2,031,144,862	3,544,590,982	510,861,483	744,449,407	
August 2010								
Beginning A/R Balance	231,651,921	5,016,303	15,675,234	59,433,553	114,109,229	15,350,188	22,067,414	3.3.2
Ending A/R Balance	259,713,258	5,400,449	17,295,910	63,900,588	134,231,820	15,923,315	22,961,176	
Average A/R Balance	245,682,589	5,208,376	16,485,572	61,667,071	124,170,524	15,636,752	22,514,295	
State Ratio	100.00%	2.12%	6.71%	25.10%	50.54%	6.36%	9.16%	
Calculated Daily A/R	276,611,018	5,864,046	18,560,903	69,430,200	139,802,073	17,605,227	25,348,569	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	8,574,941,566	181,785,438	575,388,006	2,152,336,191	4,333,864,255	545,762,044	785,805,632	
September 2010								
Beginning A/R Balance	259,713,258	5,400,449	17,295,910	63,900,588	134,231,820	15,923,315	22,961,176	3.3.2
Ending A/R Balance	250,838,713	5,098,166	18,589,624	59,334,981	128,732,058	15,369,280	23,714,604	
Average A/R Balance	255,275,986	5,249,307	17,942,767	61,617,784	131,481,939	15,646,298	23,337,890	
State Ratio	100.00%	2.06%	7.03%	24.14%	51.51%	6.13%	9.14%	
Calculated Daily A/R	276,297,945	5,681,587	19,420,353	66,692,005	142,309,467	16,934,769	25,259,764	
Days in Month	30	30	30	30	30	30	30	
Calc. Sum of Daily A/R	8,288,938,356	170,447,625	582,610,585	2,000,760,137	4,269,284,022	508,043,080	757,792,908	
October 2010								
Beginning A/R Balance	250,838,713	5,098,166	18,589,624	59,334,981	128,732,058	15,369,280	23,714,604	3.3.2
Ending A/R Balance	221,671,691	4,415,828	13,691,018	54,465,885	110,154,945	14,071,656	24,872,358	
Average A/R Balance	236,255,202	4,756,997	16,140,321	56,900,433	119,443,502	14,720,468	24,293,481	
State Ratio	100.00%	2.01%	6.83%	24.08%	50.56%	6.23%	10.28%	
Calculated Daily A/R	252,416,071	5,082,396	17,244,388	60,792,666	127,613,949	15,727,411	25,955,259	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	7,824,898,196	157,554,287	534,576,040	1,884,572,655	3,956,032,431	487,549,748	804,613,036	
November 2010								
Beginning A/R Balance	221,671,691	4,415,828	13,691,018	54,465,885	110,154,945	14,071,656	24,872,358	3.3.2
Ending A/R Balance	195,457,744	4,773,708	7,782,384	53,635,251	92,701,922	14,363,170	22,201,308	
Average A/R Balance	208,564,717	4,594,768	10,736,701	54,050,568	101,428,434	14,217,413	23,536,833	
State Ratio	100.00%	2.20%	5.15%	25.92%	48.63%	6.82%	11.29%	
Calculated Daily A/R	225,339,975	4,964,334	11,600,274	58,397,958	109,586,516	15,360,947	25,429,945	
Days in Month	30	30	30	30	30	30	30	
Calc. Sum of Daily A/R	6,760,199,263	148,930,029	348,008,232	1,751,938,753	3,287,595,485	460,828,405	762,898,359	
December 2010								
Beginning A/R Balance	195,457,744	4,773,708	7,782,384	53,635,251	92,701,922	14,363,170	22,201,308	3.3.2
Ending A/R Balance	237,363,227	5,865,968	8,297,179	69,045,616	108,441,295	18,723,459	26,989,708	
Average A/R Balance	216,410,485	5,319,838	8,039,782	61,340,434	100,571,609	16,543,315	24,595,508	
State Ratio	100.00%	2.46%	3.72%	28.34%	46.47%	7.64%	11.37%	
Calculated Daily A/R	244,598,202	6,012,753	9,086,972	69,330,096	113,671,177	18,698,101	27,799,101	
Days in Month	31	31	31	31	31	31	31	
Calc. Sum of Daily A/R	7,582,544,255	186,395,354	281,696,146	2,149,232,990	3,523,806,497	579,641,125	861,772,145	

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Sum of Daily Customer Accounts Receivable Balances by Month

Month	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	Ref.
Jan-10	7,969,391,575	209,034,370	331,205,375	2,369,137,324	3,488,681,470	669,154,655	902,178,380	3.3.3
Feb-10	6,976,881,599	182,585,012	273,989,567	2,052,636,678	3,052,741,113	614,554,937	800,374,291	3.3.3
Mar-10	7,184,805,890	186,835,194	215,153,597	2,157,916,071	3,145,571,062	611,266,439	868,063,528	3.3.3
Apr-10	6,756,758,473	180,581,000	197,775,949	2,149,356,469	2,868,857,579	560,508,694	799,678,782	3.3.3
May-10	6,709,195,765	176,235,818	213,744,131	2,133,068,486	2,885,773,623	541,803,302	758,570,405	3.3.3
Jun-10	6,655,472,113	162,848,745	272,605,159	2,008,862,541	2,990,788,335	497,098,137	723,269,197	3.3.3
Jul-10	7,426,661,115	165,849,614	429,764,768	2,031,144,862	3,544,590,982	510,861,483	744,449,407	3.3.4
Aug-10	8,574,941,566	181,785,438	575,388,006	2,152,336,191	4,333,864,255	545,762,044	785,805,632	3.3.4
Sep-10	8,288,938,356	170,447,625	582,610,585	2,000,760,137	4,269,284,022	508,043,080	757,792,908	3.3.4
Oct-10	7,824,898,196	157,554,287	534,576,040	1,884,572,655	3,956,032,431	487,549,748	804,613,036	3.3.4
Nov-10	6,760,199,263	148,930,029	348,008,232	1,751,938,753	3,287,595,485	460,828,405	762,898,359	3.3.4
Dec-10	7,582,544,255	186,395,354	281,696,146	2,149,232,990	3,523,806,497	579,641,125	861,772,145	3.3.4
Total	88,710,688,166	2,109,082,487	4,256,517,553	24,840,963,156	41,347,586,853	6,587,072,047	9,569,466,070	3.3

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Revenues Included in Customer Accounts Receivables Balances

FERC Account	Description	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	FERC	
440	RESIDENTIAL SALES	1,357,826,906	45,021,008	61,511,506	464,939,004	585,459,607	111,623,664	89,272,117	-	
442	COMMERCIAL/INDUSTRIAL SALES	2,176,375,421	42,588,522	144,577,729	473,504,235	926,732,212	143,778,553	445,194,169	-	
444	PUB ST/HWY LIGHT	20,610,361	366,334	470,881	5,688,658	10,911,823	1,237,336	1,935,329	-	
445	OTHER SALES PUBLIC	19,770,416	-	-	-	19,770,416	-	-	-	
Subtotal General Business Revenues		3,574,583,105	87,975,864	206,560,116	944,131,898	1,542,874,059	256,639,553	536,401,615	-	
450	FORFIETED DISCOUNTS	7,411,888	255,515	406,930	2,682,694	2,957,255	555,425	554,069	-	
451	MISC SERVICE REVENUES	5,919,272	71,591	104,200	1,129,792	3,710,917	154,412	748,204	155	
454	RENT FROM ELECTRIC PROPERTY	1,442,845	1,710	1,394	600,081	776,213	31,975	31,472	-	
456	MISC. REVENUES (System Benefit Charg	100,095,141	865,247	5,939,833	18,762,568	62,981,154	8,855,002	2,691,337		
Subtotal Other Revenues		114,869,145	1,194,063	6,452,357	23,175,135	70,425,540	9,596,814	4,025,082	155	
	A/R Balance Related Total	**3,689,452,249**	**89,169,927**	**213,012,473**	**967,307,033**	**1,613,299,599**	**266,236,367**	**540,426,696**	**155**	Ref. 3.3

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Pass-Through Taxes Included on Customer Billings

State Taxes

	CA	ID	OR	UT	WA	WY	Total
State Sales Taxes	-	-	-	51,726,389	-	11,090,464	62,816,853

Other Taxes and Fees

	CA	ID	OR	UT	WA	WY	Total	
Pass-through Franchise Taxes	-	1,115,812	12,062,591	63,788,733	8,888,240	3,504,261	89,359,637	
Pass-through PUC fee	198,923	-	-	-	-	-	198,923	
CA Electrical Energy Surcharge	181,643	-	-	-	-	-	181,643	
Navajo Sales Tax	-	-	-	364,124	-	-	364,124	
Totals	**380,566**	**1,115,812**	**12,062,591**	**115,879,246**	**8,888,240**	**14,594,725**	**152,921,181**	Ref. 3.3

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Unbilled Revenues

	Total Company	California	Idaho	Oregon	Utah	Washington	Wyoming	
CY 2010	8,430,000	489,000	1,481,000	8,424,000	(324,000)	(780,000)	(860,000)	Ref. 3.3

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead Lag Study
Wholesale Power Receivables

FERC	FERC sub	Operating Mo & Yr	End of Service Date	Payment date	Billing Lag	Product Lag	Total Lag	Amt of Invoice	DollarDays
142	41	Dec-09	12/31/09	01/01/10	15.2	1	16.2	45,108.00	730,749.60
142	41	Dec-09	12/31/09	01/13/10	15.2	13	28.2	3,446.24	97,183.97
142	41	Dec-09	12/31/09	01/15/10	15.2	15	30.2	335,185.92	10,122,614.78
142	41	Dec-09	12/31/09	01/15/10	15.2	15	30.2	300,740.22	9,082,354.64
142	41	Dec-09	12/31/09	01/15/10	15.2	15	30.2	108,086.00	3,264,197.20
142	41	Dec-09	12/31/09	01/15/10	15.2	15	30.2	64,130.00	1,936,726.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	3,744,712.50	131,813,880.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	12,465.00	438,768.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	639,126.00	22,497,235.20
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	2,282,026.52	80,327,333.50
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	1,658,269.00	58,371,068.80
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	2,681,556.25	94,390,780.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	357,438.60	12,581,838.72
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	51,430.00	1,810,336.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	2,439,030.00	85,853,856.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	2,103,235.96	74,033,905.79
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	7,138,248.76	251,266,356.35
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	129,800.00	4,568,960.00
142	41	Dec-09	12/31/09	01/20/10	15.2	20	35.2	4,675,199.50	164,567,022.40
									00

This data has been redacted due to its voluminous nature. Please see CD provided for complete record.

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142	41	Nov-10	11/30/10	12/20/10	15.2	20	35.2	370,895.00	13,055,504.00
142	41	Nov-10	11/30/10	12/20/10	15.2	20	35.2	138,503.00	4,875,305.60
142	41	Nov-10	11/30/10	12/21/10	15.2	21	36.2	2,419,971.00	87,602,950.20
142	41	Nov-10	11/30/10	12/23/10	15.2	23	38.2	33,170.00	1,267,094.00
142	41	Nov-10	11/30/10	12/24/10	15.2	24	39.2	114,000.00	4,468,800.00
142	41	Nov-10	11/30/10	12/24/10	15.2	24	39.2	71,000.00	2,783,200.00
142	41	Nov-10	11/30/10	12/27/10	15.2	27	42.2	86,200.00	3,637,640.00
142	41	Nov-10	11/30/10	12/27/10	15.2	27	42.2	11,015.50	464,854.10
142	41	Nov-10	11/30/10	12/27/10	15.2	27	42.2	72,620.05	3,064,566.11
142	41	Nov-10	11/30/10	12/27/10	15.2	27	42.2	85,144.97	3,593,117.73
142	41	Nov-10	11/30/10	12/27/10	15.2	27	42.2	117,041.77	4,939,162.69
142	41	Nov-10	11/30/10	12/27/10	15.2	27	42.2	1,757,371.37	74,161,071.81
142	41	Nov-10	11/30/10	12/30/10	15.2	30	45.2	18,614.60	841,379.92
142	41	Nov-10	11/30/10	12/30/10	15.2	30	45.2	349,526.00	15,798,575.20
							36.89	**632,707,267.98**	**23,340,610,919.34**

Ref. 3.1

EXPENSE LAG

This section of the report documents how the expense lag was developed. The lead/lag analysis identifies the expense lag as the elapsed time from the receipt of goods and services to the time the utility pays for the goods and services. In most cases, this study uses the invoice date to represent the date goods and services were received and the check date to represent the date payment occurred. The expense lag is comprised of the following elements: coal expense, natural gas purchases, purchased power, wheeling, labor and benefits, incentive, other operation and maintenance expenses, property taxes, other taxes, federal income taxes, and state income taxes. The calculation conforms to the method sponsored by the FERC in Docket No. RM84-9-000.

The following narrative explains the method and assumptions underlying the expense lag analysis. The explanation begins with the summarized expense lag and illustrates how the lag days were calculated. It then gives key assumptions and components specific to each element (or group) within expense (i.e. coal expense, natural gas purchases, etc.)

By accessing information from the accounts payable office, commercial and trading back office, fuels group, payroll department, tax department, and others, reports were used to calculate the elapsed time from the invoice date to the check date (payment lag) for transactions processed during the 12-months ended December 2010. A description of each section is provided below, and any assumptions made are explained. The expense lag summary can be found on page 4.1.

Coal Lag

The coal expense lag is calculated from multiple sources. Page 4.2 is the coal expense lag summary which consists of expenses for coal and transportation of coal (detailed in 4.2.1 - 4.2.2), steam purchases (also included in 4.2.1 - 4.2.2), Energy West payables (4.2.3), Bridger payables (4.2.4), Energy West management payroll (4.2.5), Bridger management payroll (4.2.6), Energy West workforce payroll (4.2.7), and Bridger workforce payroll (4.2.8). The total weighted lag days as calculated on page 4.2 are multiplied by the actual coal expense for the 12-months ended December 2010 (5.13) and summarized on page 2.1.

The coal and transportation lag analysis on page 4.2 includes the following groups of fuel expenses: coal purchases, captive coal operations, steam purchases for the Blundell plant and coal transportation.

This analysis is based on a number of assumptions, which include the following: First, the lag for coal expense can be approximated by the lag for delivered coal; Second, purchased coal lag should be divided into coal contracts and transportation contracts since the lags may be different depending on contract terms; Third, any non-cash costs that can be identified in the fuel should be excluded since there is no lag related to non-cash costs; Fourth, where possible,

delivered dollars should be adjusted to exclude any period-end estimates that are included in delivered fuel costs; Finally, for purchased coal, it is assumed that the product is received evenly over the invoice period.

Coal Lag: Energy West and Bridger Lag

In addition to the amounts in the coal and transportation summary worksheet, the coal expense lag incorporates accounts payable data from Energy West and Jim Bridger Mines. Because PacifiCorp funds the daily operations of the captive mines, an analysis of the various cash expenditures of the mines is necessary. This analysis incorporates the accounts payable lag and the payroll lag for each of the mines. It should be noted that only 66.67% of amounts relating to the Bridger mine are used as this is the portion PacifiCorp owns.

Coal Lag: Payroll Lag Days – Coal

The calculation of the payroll lag for each mining operation is shown on pages 4.2.5 through 4.2.8, and is carried forward to page 4.2. For Energy West and Bridger, union and management employees are on different payroll schedules, requiring separate calculations.

Natural Gas Purchases Lag

The natural gas purchases lag is displayed on page 4.3. This page shows a summary of the data prepared by the commercial and trading back office based on data from vendor invoices. It shows the total amount of purchases and the lag days associated with each transaction. Natural gas receivables have been included with the purchases as negative amounts. The total weighted lag days as calculated on page 4.3 are multiplied by the actual natural gas expense for the 12-months ended December 2010 (5.13) and summarized on page 2.1.

Purchased Power Lag

Page 4.4 shows the calculation of the purchased power lag. This page provides the information on the net payment by PacifiCorp to counter parties for purchased power for the 12-months ended December 2010.

Wholesale power transactions are typically delivered throughout the month and invoiced after month end. The lag was calculated as the difference between the payment date and the end of service date, effectively combining the billing lag and payment lag. An additional 15.2 day product lag is added to the lag calculated above, to account for the receipt of energy that was assumed to occurred evenly throughout the invoice month. The total weighted lag days as calculated on page 4.4 are multiplied by the actual purchased power expense for the 12-months ended December 2010 (5.13) and summarized on page 2.1.

Wheeling Expense Lag

The wheeling expense lag used in this study is the same as the purchased power lag described above. When the Company enters into a contract to purchase power, the associated wheeling expense is included in the contract.

Labor and Benefits Lag

The labor and benefit lag is calculated on page 4.5, which shows the lag between the midpoint of each pay period and the pay date. On page 2.1 these lag days are multiplied by the actual labor and overhead expenses for the 12-months ended December 2010 (4.5.1 – 4.5.3).

Incentive Lag

The incentive lag is also calculated on page 4.5. This lag was developed by determining the days between the midpoint of the year and the incentive pay date, December 17, 2010. On page 2.1, these lag days are multiplied by the actual incentive expense incurred for the 12-months December 2010 (4.5.1 – 4.5.3).

Other Operation and Maintenance (O&M) Expense Lag

The other O&M expense lag is used for expenses not included in other sections of the study. Page 4.6 shows the calculated lag which was developed using monthly reports from the central accounts payable office. The invoices from each month of payables were pulled into reports which excluded all documents pertaining to the other expense lag categories accounted for separately in this study. See page 4.6.1 for a data sample of invoices for January 2010.

Invoices with payment terms of RECUR and R999 were removed from the data. RECUR are associated with recurring payments that have the potential of being set up in SAP as a parked document since 1999 and would skew the study. The payment terms of R999 are the retention holdouts on invoice payments that are typically not due and payable until the end of a project. These types of payments are generally associated with capital projects. The Company could hold these invoices for up to three years or longer, depending on the project.

The database is only for company code 1000, which includes only the regulated electric operations portion of the business. Similar to the other expense sections, the invoice date, payment date and amount of each invoice were used to calculate the lag days, effectively weighted by invoice amount. These lag days are multiplied by the remaining O&M expenses not accounted for elsewhere in the study as shown on page 2.1.

Property Taxes Lag

The property tax lag relates specifically to each individual state's property taxes. Because every state has different schedules for paying property taxes, the lags vary significantly by state. The total company property tax lag is the weighted average of the state lags and is shown on page 4.7.

Other Taxes Lag

The other taxes lag is the composite lag of various taxes included in FERC account 408 excluding property taxes. The lag days for this category vary by jurisdiction, caused by state specific fees and taxes. These lags were calculated from the midpoint of the tax period to the payment date from schedules obtained from the tax department for taxes paid for the 12-months ended December 2010 and are summarized on pages 4.8 and 4.8.2.

Income Tax Lag

Federal and state income tax lags were developed based on data provided by the tax department and shown on page 4.9. Federal income tax lag days were calculated as the number of days between the midpoint of each quarter and the quarterly tax payment date. The lags associated with each quarter were then weighted to arrive at a total federal tax lag. These lag days were multiplied by the total federal taxes as reported in the Results of Operations Report, shown on page 2.1.

The state income tax lag follows the same procedure as the federal tax lag described above; however each state's percentage of total state taxes paid is multiplied by the individual state lag days to arrive at a weighted number of lag days. The sum of the individual state weighted lag days yields the average state income tax lag, which is then multiplied by the total state income taxes as reported in the Results of Operations Report, shown on page 2.1.

BPA Credit

Exhibit 4.4 captures most of the purchased power transactions; however, the Bonneville Power Administration (BPA) Regional Credit is not reflected in this report. Idaho, Washington, and Oregon received credits during the December 2010 test period. Exhibit 4.10 calculates the BPA Credit lag days for Idaho, Washington and Oregon. Supplementing purchased power lag data with the BPA Credit lag days correctly mirrors customer accounts receivable information, which is net of the BPA Credit.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Expense Lag Study

Expense Lag Component	Oregon	Reference
Coal	29.58	Page 4.2
Natural Gas	40.61	Page 4.3
Purchased Power	38.47	Page 4.4
Wheeling Expenses	38.47	Page 4.4
Labor and Benefits	14.31	Page 4.5
Incentive	167.50	Page 4.5
Other Operations and Maintenance	33.54	Page 4.6
Property Taxes	140.77	Page 4.7
Other Taxes	36.12	Page 4.8
Federal Income Taxes	37.87	Page 4.9
State Income Taxes	38.17	Page 4.9
BPA Credit	50.14	Page 4.10

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Coal Expense Lag Summary

Description	Amount	Lag Days	Dollar Days	Reference
Expense				
Coal & Transportation	509,588,563	29.58	15,075,109,116	4.2.1 - 4.2.2
Total Coal Lag	**509,588,563**	**29.58**	**15,075,109,116**	
		Ref. 4.1		

Calculation of Energy West Lag	Amount	Lag Days	Dollar Days	Reference
Energy West Payables	48,121,265	34.30	1,650,420,198	4.2.3
Energy West Payroll - Management	7,870,775	14.31	112,629,741	4.2.5
Energy West Payroll - Union	17,027,804	17.00	289,472,673	4.2.7
Total Energy West	**73,019,844**	**28.11**	**2,052,522,612**	

Calculation of Bridger Lag	Amount	Lag Days	Dollar Days	Reference
Bridger Payables	60,044,985	71.42	4,288,435,220	4.2.4
Bridger Payroll - Management	7,101,333	14.33	101,783,355	4.2.6
Bridger Payroll - Union	18,471,029	17.00	314,007,498	4.2.8
Total Bridger	**85,617,347**	**54.94**	**4,704,226,072**	

Note: The Energy West and Bridger lags are taken into consideration on pages 4.2.1 through 4.2.2

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Fuel (excluding gas)

A	B	C	D	E	F	G	H	I	J	K	L
Plant	Supplier	Type	Total $000 per Acctg	Total $000 per FMS	Adjusted Amount	Invoice Frequency	Product Lag Days	Billing Lag Days	Payment Lag Days	Total Avg Lag Days	Dollar Days
Bridger	Black Butte	Coal	45,805	45,410	45,410	Monthly	15.00	5.36	10.04	30.40	1,380,510
Bridger	UPRR	Transportation	7,311	7,260	7,260	By Shipment	-	9.22	10.92	20.14	146,241
Bridger	Bridger Mine	Coal	54,419	54,748	54,748					54.94	3,008,117
Bridger	Bridger Mine	Fuel credit	(15,041)	(15,041)	(15,041)					54.94	(826,443)
Carbon	Deer Creek / Huntington	Coal	859		859					28.11	24,146
Carbon	Deer Creek / Swap	Coal	4,258		4,258					28.11	119,689
Carbon	Trimac	Transportation	568	601	601	Monthly	14.54	1.00	29.27	44.80	26,919
Carbon	Dugout	Coal	2,645	2,716	2,716	Semi-Monthly	6.53	2.83	14.98	24.34	66,093
Carbon	Savage	Transportation	246	253	253	Monthly	13.59	4.51	15.00	33.11	8,383
Carbon	Arch / Skyline	Coal	7,444	7,496	7,496	Monthly	6.60	2.63	14.85	24.08	180,528
Carbon	Trimac	Transportation	896	905	905	Monthly	14.70	1.32	27.27	43.29	39,164
Carbon	America West / Horizon	Coal	1,741	1,717	1,717	Semi-Monthly	6.96	1.26	9.67	17.89	30,710
Cholla	Lee Ranch / APS	Coal	3,206	3,089	3,089	Monthly	14.28	7.52	5.42	27.22	84,100
Cholla	APS	Transportation	1,210	1,513	1,513	2 times per month	0.14	8.41	8.55	17.10	25,874
Cholla	El Segundo / APS	Coal	28,400	28,286	28,286	Monthly	14.42	8.38	4.39	27.19	769,208
Cholla	APS	Transportation	10,828	11,406	11,406	2 times per month	1.60	7.38	8.14	17.12	195,295
Colstrip	WECO	Coal	10,653	11,109	11,109	Monthly	16.18	14.09	15.00	45.26	502,830
Craig	Trapper	Coal	12,392	12,736	12,736	Monthly	15.24	7.88	15.81	38.93	495,890
	Trapper	Fuel credit	(446)		(446)		15.24	7.88	15.81	38.93	(17,365)
Craig	ColoWyo	Coal	6,226	6,155	6,155	Semimonthly	7.11	1.85	10.00	18.96	116,718
Craig	ColoWyo	Transportation	538	512	512	Monthly	14.71	(13.76)	14.13	15.09	7,728
Craig	Twenty Mile	Coal	503	503	503	Semimonthly	7.16	4.00	12.37	23.53	11,842
Craig	Twenty Mile	Transportation	95	97	97	Monthly	15.00	(12.42)	11.06	13.64	1,328
Hayden	Twenty Mile	Coal	10,674	10,518	10,518	2 times per month	7.24	6.75	7.65	21.65	227,719
Hunter	Prep Plant (Captive)	Coal	7,688		7,688					28.11	216,103
Hunter	Prep Plant (Purchased)	Coal	56,282		56,282	Semi-Monthly	5.32	5.28	15.32	25.92	1,458,729
Hunter	Deer Creek	Coal	10,070		10,070					28.11	283,059
Hunter	Trimac	Transportation	1,011		1,011	Monthly	14.68	1.13	28.67	44.49	44,977
Hunter	Trail Mtn	Misc	29		29					28.11	815
Hunter	Sufco	Coal	29,878		29,878	Semi-Monthly	5.32	5.28	15.32	25.92	774,384
Hunter	Sufco	Transportation	8,753		8,753	Semi-Monthly	4.47	6.15	14.65	25.27	221,207
Hunter	Westridge	Coal	778		778	Semi-Monthly	7.19	12.13	9.96	29.28	22,780
Hunter	Savage / Attco	Transportation	180		180	Monthly	14.04	8.82	16.25	39.12	7,041
Hunter	Dugout	Coal	4,627		4,627	Semi-Monthly	7.46	4.78	16.54	28.77	133,135
Hunter	Savage	Transportation	870		870	Monthly	13.72	4.91	14.95	33.58	29,216
Huntington	Deer Creek	Coal	47,041		47,041					28.11	1,322,281
Huntington	Rock Garden	Coal	1,758		1,758					28.11	49,416

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Fuel (excluding gas)

A	B	C	D	E	F	G	H	I	J	K	L
Plant	**Supplier**	**Type**	**Total $000 per Acctg**	**Total $000 per FMS**	**Adjusted Amount**	**Invoice Frequency**	**Product Lag Days**	**Billing Lag Days**	**Payment Lag Days**	**Total Avg Lag Days**	**Dollar Days**
Huntington	Rock Garden	Transportation	52		52	Monthly	14.47	1.04	27.60	43.12	2,242
Huntington	Deer Creek	Tsfr to Carbon	(857)		(857)					28.11	(24,090)
Huntington	Deer Creek	Tsfr to Hunter	(9,649)		(9,649)					28.11	(271,225)
Huntington	Deer Creek	Tsfr to Prep Plant	(5,961)		(5,961)					28.11	(167,558)
Huntington	Deer Creek	Tsfr to Rock Garden	(5,511)		(5,511)					28.11	(154,909)
Huntington	Deer Creek	Coal Sales	(980)		(980)					28.11	(27,547)
Huntington	Sufco	Coal	6,707		6,707	Semi-Monthly	4.37	6.11	14.71	25.18	168,909
Huntington	Sufco	Transportation	2,565		2,565	Semi-Monthly	4.47	6.15	14.65	25.27	64,823
Huntington	Dugout	Coal	4,932		4,932	Semi-Monthly	8.70	4.29	17.46	30.45	150,185
Huntington	Savage	Transportation	774		774	Monthly	13.72	4.02	15.00	32.73	25,336
D. Johnston	Dry Fork	Coal	14,020	13,867	13,867	Semi-monthly	7.16	4.72	7.46	19.34	268,223
D. Johnston	BNRR	Transportation	8,553	8,447	8,447	Each Shipment	0.04	4.12	12.85	17.00	143,585
D. Johnston	Rawhide	Coal	3,081	2,923	2,923	Semi-monthly	7.05	4.03	9.09	20.17	58,947
D. Johnston	BNRR	Transportation	1,493	1,265	1,265	Each Shipment	-	3.06	13.24	16.30	20,628
D. Johnston	Wyodak (Clovis)	Coal	10,152	10,055	10,055	Monthly	14.66	7.94	11.89	34.50	346,857
D. Johnston	BNRR	Transportation	7,074	6,967	6,967	Each Shipment	0.00	5.27	13.07	18.34	127,772
Naughton	P&M High	Coal	44,412	43,619	43,619	Monthly	14.73	9.08	7.51	31.33	1,366,411
Naughton	P&M Low	Coal	45,784	45,515	45,515	Monthly	14.67	8.63	7.80	31.10	1,415,696
Wyodak	Wyodak	Coal	17,895	18,047	18,047	Monthly	23.03	(20.46)	16.32	18.89	340,990
Blundell	Various	Steam	1,183		1,183					26.60	31,467
Total			**510,114**		**509,589**					**29.58**	**15,075,109**
					Ref. 4.2					Ref. 4.2	Ref. 4.2

Column D - Ties to total dollars delivered to fuel inventory for the 12 months ended December 31, 2010
Column E - Where possible, excludes any month end estimates and true-up in the subsequent month
Column F - The value from Column E where available, otherwise Column D
Column H - The average period of time over which the Company receives the product billed on a given invoice
Column I - The average delay between last day of product delivery and the invoice date
Column J - The average length of time between invoice receipt and invoice payment
Column K - The total of Columns H through J
Column L - Column F * Column K

Energy West Lag	28.11
Bridger Coal Lag	54.94

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Energy West Mining (Accounts Payable)

Invoice Date	Check Date	Invoice Amount	Lag Days	Dollar Days
10/29/2009	12/29/2009	$ 2,567.40	70.47	$ 180,924.68
11/5/2009	12/29/2009	$ 525.64	63.47	$ 33,362.37
11/12/2009	12/29/2009	$ (1,078.42)	56.47	$ (60,898.38)
11/13/2009	12/29/2009	$ 138.08	55.47	$ 7,659.30
11/17/2009	12/29/2009	$ 978.44	51.47	$ 50,360.31
11/20/2009	12/29/2009	$ 391.85	48.47	$ 18,992.97
12/2/2009	12/29/2009	$ 82,932.95	36.47	$ 3,024,564.69
12/2/2009	12/29/2009	$ 33,290.19	36.47	$ 1,214,093.23
12/2/2009	12/29/2009	$ 8,884.44	36.47	$ 324,015.53
12/2/2009	12/29/2009	$ 3,041.19	36.47	$ 110,912.20
12/2/2009	12/29/2009	$ 2,641.74	36.47	$ 96,344.26
12/2/2009	12/29/2009	$ 1,970.67	36.47	$ 71,870.33
[illegible]	[illegible]	$ [illegible]	[illegible]	$ [illegible]6.74
[illegible]	[illegible]	$ [illegible]	[illegible]	[illegible]8.45
[illegible]	[illegible]	$ [illegible]	[illegible]	[illegible]8.96
[illegible]	[illegible]	$ [illegible]	[illegible]	[illegible]3.55
[illegible]	[illegible]	$ [illegible]	[illegible]	[illegible]0.96
[illegible]	[illegible]	$ [illegible]	[illegible]	[illegible]2.70
[illegible]	[illegible]	$ [illegible]	[illegible]	[illegible]5.74
[illegible]	[illegible]	$ [illegible]	[illegible]	$ [illegible]6.64
12/17/2010	12/21/2010	$ 126.13	13.47	$ 1,698.97
12/17/2010	12/21/2010	$ 86.26	13.47	$ 1,161.92
12/17/2010	12/21/2010	$ 26.80	13.47	$ 361.00
12/17/2010	12/21/2010	$ 12.84	13.47	$ 172.95
12/17/2010	12/21/2010	$ 9.47	13.47	$ 127.56
12/20/2010	12/21/2010	$ 3,709.00	10.47	$ 38,833.23
12/21/2010	12/21/2010	$ 370.00	9.47	$ 3,503.90
11/30/2010	12/31/2010	$ 159,584.98	46	$ 7,340,909.04
12/31/2010	1/28/2011	$ 62,686.54	73	$ 4,576,117.42
12/31/2010	1/31/2011	$ 908,685.29	46	$ 41,799,523.12
		$ 48,121,265	**34.30**	**$ 1,650,420,198**

Ref. 4.2

This data has been redacted due to its voluminous nature. Please see CD provided for full record of invoices.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Bridger (Accounts Payable)

Invoice Date	Check Date	Invoice Amount	Invoice #	Lag Days	Dollar Days
12/18/09	1/4/10	$ 94,652	BCC9002	25.65	$ 2,427,824
11/17/09	1/4/10	$ 44,902	269813	56.65	$ 2,543,698
12/28/09	1/4/10	$ 37,004	59697	15.65	$ 579,113
12/28/09	1/4/10	$ 31,307	59698	15.65	$ 489,955
11/20/09	1/4/10	$ 30,961	000030840-Y	53.65	$ 1,661,046
12/22/09	1/4/10	$ 29,705	510830	21.65	$ 643,113
12/23/09	1/4/10	$ 29,705	510827	20.65	$ 613,408
10/15/09	1/4/10	$ 29,420	318471	89.65	$ 2,637,496
12/15/09	1/4/10	$ 26,915	0070425-IN	28.65	$ 771,114
12/7/09	1/4/10	$ 23,971	0069386-IN	36.65	$ 878,555
12/8/09	1/4/10	$ 23,853	0069479-IN	35.65	$ 850,365
12/9/09	1/4/10	$ 23,744	0069625-IN	34.65	$ 822,715
11/20/09	1/4/10	$ 23,740	18468	53.65	$ 1,273,655
12/10/09	1/4/10	$ 23,311	0069788-IN	33.65	$ 784,415
12/14/09	1/4/10	$ 23,051	0070176-IN	29.65	$ 683,476
12/16/09	1/4/10	$ 22,828	0070264-IN	27.65	$ 631,187
11/6/09	1/4/10	$ 21,388	0025733-IN	67.65	$ 1,446,898
11/6/09	1/4/10	$ 21,388	0025734-IN	67.65	$ 1,446,898
11/25/09	1/4/10	$ 14,468	WT006286	48.65	$ 703,890
11/14					75,450
11/25					16,723
12/7					1,497
12/4					1,577
12/4					1,543
12/6					1,267
12/2					1,421
12/6/10	12/30/10	$ 35	S4153681.001	32.65	$ 1,134
12/4/10	12/30/10	$ 31	2331612	34.65	$ 1,086
12/1/10	12/30/10	$ 31	N987215	37.65	$ 1,169
12/7/10	12/30/10	$ 29	U86089	31.65	$ 914
12/7/10	12/30/10	$ 26	I841488	31.65	$ 835
12/7/10	12/30/10	$ 24	9403338805	31.65	$ 775
12/7/10	12/30/10	$ 24	I639361	31.65	$ 754
12/7/10	12/30/10	$ 23	104738001	31.65	$ 721
12/1/10	12/30/10	$ 22	N987248	37.65	$ 844
12/6/10	12/30/10	$ 19	S41535269.001	32.65	$ 629
12/3/10	12/30/10	$ 19	PO 2390924	35.65	$ 678
12/2/10	12/30/10	$ 18	104731847	36.65	$ 665
12/1/10	12/30/10	$ 16	N987316	37.65	$ 586
12/3/10	12/30/10	$ 14	PO 2390925	35.65	$ 515
12/1/10	12/30/10	$ 11	9403332756	37.65	$ 422
12/21/10	12/30/10	$ 8	ARV/13808596	17.65	$ 142
12/15/10	12/30/10	$ 4	ARV/13765623	23.65	$ 103
11/16/10	12/30/10	$ (525)	27315	52.65	$ (27,640)
Total		$ 90,067,477		71.42	$ 6,432,652,829
PacifiCorp Share @ 66.67%		**$ 60,044,985**		**71.42**	**$ 4,288,435,220**

This data has been redacted due to its voluminous nature. Please see CD provided for full record of invoices.

Ref. 4.2

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Energy West Mining Payroll - Management

Beg Date Pay Period	End Date Pay Period	Pay Period Days	Pay date	Check Lag	Total Lag	Energy West	Energy West Dollar Days	
12/26/2009	1/10/2010	16	01/15/10	5	13	330,227	4,292,957	
1/11/2010	1/25/2010	15	02/02/10	8	16	304,437	4,718,769	
1/26/2010	2/10/2010	16	02/17/10	7	15	306,193	4,592,895	
2/11/2010	2/25/2010	15	03/02/10	5	13	303,695	3,796,181	
2/26/2010	3/10/2010	13	03/17/10	7	14	314,841	4,250,349	
3/11/2010	3/25/2010	15	04/02/10	8	16	298,526	4,627,155	
3/26/2010	4/10/2010	16	04/16/10	6	14	300,979	4,213,709	
4/11/2010	4/25/2010	15	04/30/10	5	13	299,163	3,739,541	
4/26/2010	5/10/2010	15	05/17/10	7	15	298,134	4,322,945	
5/11/2010	5/25/2010	15	06/02/10	8	16	300,096	4,651,482	
5/26/2010	6/10/2010	16	06/17/10	7	15	300,335	4,505,031	
6/11/2010	6/25/2010	15	07/02/10	7	15	300,420	4,356,086	
6/26/2010	7/10/2010	15	07/16/10	6	14	320,588	4,327,932	
7/11/2010	7/25/2010	15	08/02/10	8	16	304,991	4,727,356	
7/26/2010	8/10/2010	16	08/17/10	7	15	300,607	4,509,101	
8/11/2010	8/25/2010	15	09/02/10	8	16	289,600	4,488,797	
8/26/2010	9/10/2010	16	09/17/10	7	15	304,232	4,563,485	
9/11/2010	9/25/2010	15	10/01/10	6	14	283,830	3,831,705	
9/26/2010	10/10/2010	15	10/15/10	5	13	284,639	3,557,984	
10/11/2010	10/25/2010	15	11/02/10	8	16	286,365	4,438,662	
10/26/2010	11/10/2010	16	11/17/10	7	15	286,350	4,295,246	
11/11/2010	11/25/2010	15	12/02/10	7	15	286,686	4,156,940	
11/26/2010	12/10/2010	15	12/17/10	7	15	921,202	13,357,427	
12/11/2010	12/25/2010	15	12/30/10	5	13	344,640	4,308,005	
					14.31	**7,870,775**	**112,629,741**	**Ref 4.2**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Bridger Mining Payroll - Management

Beg Date Pay Period	End Date Pay Period	Pay Period Days	Pay date	Check Lag	Total Lag	Bridger	Bridger Dollar Days	
12/26/2009	1/10/2010	16	01/15/10	5	13	279,144	3,628,874	
1/11/2010	1/25/2010	15	02/02/10	8	16	270,534	4,193,282	
1/26/2010	2/10/2010	16	02/17/10	7	15	291,061	4,365,908	
2/11/2010	2/25/2010	15	03/02/10	5	13	265,310	3,316,372	
2/26/2010	3/10/2010	13	03/17/10	7	14	270,592	3,652,992	
3/11/2010	3/25/2010	15	04/02/10	8	16	296,726	4,599,250	
3/26/2010	4/10/2010	16	04/16/10	6	14	279,402	3,911,631	
4/11/2010	4/25/2010	15	04/30/10	5	13	265,011	3,312,635	
4/26/2010	5/10/2010	15	05/17/10	7	15	260,715	3,780,364	
5/11/2010	5/25/2010	15	06/02/10	8	16	262,320	4,065,954	
5/26/2010	6/10/2010	16	06/17/10	7	15	275,118	4,126,775	
6/11/2010	6/25/2010	15	07/02/10	7	15	250,976	3,639,154	
6/26/2010	7/10/2010	15	07/16/10	6	14	269,110	3,632,988	
7/11/2010	7/25/2010	15	08/02/10	8	16	265,513	4,115,449	
7/26/2010	8/10/2010	16	08/17/10	7	15	265,884	3,988,267	
8/11/2010	8/25/2010	15	09/02/10	8	16	261,768	4,057,400	
8/26/2010	9/10/2010	16	09/17/10	7	15	277,539	4,163,082	
9/11/2010	9/25/2010	15	10/01/10	6	14	272,322	3,676,349	
9/26/2010	10/10/2010	15	10/15/10	5	13	269,806	3,372,574	
10/11/2010	10/25/2010	15	11/02/10	8	16	269,980	4,184,692	
10/26/2010	11/10/2010	16	11/17/10	7	15	272,339	4,085,079	
11/11/2010	11/25/2010	15	12/02/10	7	15	278,222	4,034,222	
11/26/2010	12/10/2010	15	12/17/10	7	15	865,396	12,548,243	
12/11/2010	12/25/2010	15	12/30/10	5	13	266,545	3,331,818	
					14.33	**7,101,333**	**101,783,355**	**Ref 4.2**

Note: Only PacifiCorp ownership share is reflected in this worksheet (66.667%)

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Energy West Mining Payroll - Union

Beginning Date Pay Period	Ending Date Pay Period	Pay Period Days	Pay date	Check Lag	Total Lag	Energy West	Energy West Dollar Days	
12/13/09	12/26/09	14	1/5/10	10	17	685,235	11,648,998	
12/27/09	1/9/10	14	1/19/10	10	17	672,501	11,432,511	
1/10/10	1/23/10	14	2/2/10	10	17	617,445	10,496,563	
1/24/10	2/6/10	14	2/16/10	10	17	723,614	12,301,445	
2/7/10	2/20/10	14	3/2/10	10	17	603,342	10,256,809	
2/21/10	3/6/10	14	3/16/10	10	17	624,032	10,608,547	
3/7/10	3/20/10	14	3/30/10	10	17	608,991	10,352,843	
3/21/10	4/3/10	14	4/13/10	10	17	635,376	10,801,389	
4/4/10	4/17/10	14	4/27/10	10	17	606,859	10,316,599	
4/18/10	5/1/10	14	5/11/10	10	17	659,259	11,207,401	
5/2/10	5/15/10	14	5/25/10	10	17	613,141	10,423,401	
5/16/10	5/29/10	14	6/8/10	10	17	614,468	10,445,963	
5/30/10	6/12/10	14	6/22/10	10	17	622,003	10,574,053	
6/13/10	6/26/10	14	7/6/10	10	17	598,640	10,176,873	
6/27/10	7/10/10	14	7/20/10	10	17	1,161,281	19,741,775	
7/11/10	7/24/10	14	8/3/10	10	17	586,181	9,965,080	
7/25/10	8/7/10	14	8/17/10	10	17	169,924	2,888,709	
8/8/10	8/21/10	14	8/31/10	10	17	606,819	10,315,915	
8/22/10	9/4/10	14	9/14/10	10	17	622,174	10,576,961	
9/5/10	9/18/10	14	9/28/10	10	17	682,545	11,603,264	
9/19/10	10/2/10	14	10/12/10	10	17	650,871	11,064,807	
10/3/10	10/16/10	14	10/26/10	10	17	657,125	11,171,133	
10/17/10	10/30/10	14	11/9/10	10	17	635,389	10,801,615	
10/31/10	11/13/10	14	11/23/10	10	17	670,117	11,391,992	
11/14/10	11/27/10	14	12/7/10	10	17	735,715	12,507,155	
11/28/10	12/11/10	14	12/21/10	10	17	964,757	16,400,875	
					17	**17,027,804**	**289,472,673**	**Ref 4.2**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Bridger Mining Payroll - Union

Beginning Date Pay Period	Ending Date Pay Period	Pay Period Days	Pay date	Check Lag	Total Lag	Bridger	Bridger Dollar Days	
12/13/09	12/26/09	14	1/5/10	10	17	813,427	13,828,251	
12/27/09	1/9/10	14	1/19/10	10	17	778,486	13,234,254	
1/10/10	1/23/10	14	2/2/10	10	17	735,697	12,506,857	
1/24/10	2/6/10	14	2/16/10	10	17	761,302	12,942,139	
2/7/10	2/20/10	14	3/2/10	10	17	759,595	12,913,110	
2/21/10	3/6/10	14	3/16/10	10	17	709,003	12,053,043	
3/7/10	3/20/10	14	3/30/10	10	17	642,808	10,927,731	
3/21/10	4/3/10	14	4/13/10	10	17	669,140	11,375,384	
4/4/10	4/17/10	14	4/27/10	10	17	651,005	11,067,081	
4/18/10	5/1/10	14	5/11/10	10	17	692,318	11,769,413	
5/2/10	5/15/10	14	5/25/10	10	17	662,069	11,255,180	
5/16/10	5/29/10	14	6/8/10	10	17	678,175	11,528,970	
5/30/10	6/12/10	14	6/22/10	10	17	721,456	12,264,755	
6/13/10	6/26/10	14	7/6/10	10	17	693,779	11,794,247	
6/27/10	7/10/10	14	7/20/10	10	17	715,437	12,162,425	
7/11/10	7/24/10	14	8/3/10	10	17	694,905	11,813,380	
7/25/10	8/7/10	14	8/17/10	10	17	674,667	11,469,333	
8/8/10	8/21/10	14	8/31/10	10	17	710,574	12,079,754	
8/22/10	9/4/10	14	9/14/10	10	17	678,296	11,531,029	
9/5/10	9/18/10	14	9/28/10	10	17	712,543	12,113,227	
9/19/10	10/2/10	14	10/12/10	10	17	650,207	11,053,524	
10/3/10	10/16/10	14	10/26/10	10	17	644,381	10,954,470	
10/17/10	10/30/10	14	11/9/10	10	17	696,123	11,834,088	
10/31/10	11/13/10	14	11/23/10	10	17	723,794	12,304,501	
11/14/10	11/27/10	14	12/7/10	10	17	680,062	11,561,059	
11/28/10	12/11/10	14	12/21/10	10	17	921,782	15,670,290	
					17	**18,471,029**	**314,007,498**	**Ref 4.2**

Note: Only PacifiCorp ownership share is reflected in this worksheet (66.667%)

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Physical Natural Gas Payables

FERC	FERC sub	Operating Mo	End of Service	Payment Date	Billing Lag	Product Lag	Total Lag	Amt of Invoice	DollarDays
501	1902394200	Dec-09	12/31/09	1/15/2010	15.2	15.0	30.2	118,355	3,574,319
501	1902396270	Dec-09	12/31/09	1/21/2010	15.2	21.0	36.2	52,437	1,898,203
501	1902396270	Dec-09	12/31/09	1/21/2010	15.2	21.0	36.2	98,336	3,559,749
501	1902396270	Dec-09	12/31/09	1/21/2010	15.2	21.0	36.2	477,675	17,291,827
501	1902396270	Dec-09	12/31/09	1/21/2010	15.2	21.0	36.2	157,065	5,685,769
501	1902396270	Dec-09	12/31/09	1/21/2010	15.2	21.0	36.2	868	31,405
501	1902396271	Dec-09	12/31/09	1/21/2010	15.2	21.0	36.2	39	1,396
501	1902396819	Dec-09	12/31/09	1/22/2010	15.2	22.0	37.2	285,894	10,635,241
501	1902396785	Dec-09	12/31/09	1/25/2010	15.2	25.0	40.2	1,002,950	40,318,590
501	1902396803	Dec-09	12/31/09	1/25/2010	15.2	25.0	40.2	3,851,039	154,811,774
501	1902396812	Dec-09	12/31/09	1/25/2010	15.2	25.0	40.2	6,567,786	264,025,013
501	1902396816	Dec-09	12/31/09	1/25/2010	15.2	25.0	40.2	1,149,346	46,203,690
501	1902396817	Dec-09	12/31/09	1/25/2010	15.2	25.0	40.2	495,034	19,900,366
									510
									140
									849
									946
									839
									120
501	1902624700	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	689,075	29,078,965
501	1902624885	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	110,251	4,652,575
501	1902625220	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	51,688	2,181,249
501	1902625220	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	35,123	1,482,180
501	1902625220	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	120,274	5,075,552
501	1902625225	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	120,615	5,089,953
501	1902625228	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	3,999,000	168,757,800
501	1902625286	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	2,539,075	107,148,965
501	1902625289	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	278,850	11,767,470
501	1902625298	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	3,549,903	149,805,886
501	1902624698	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	2,504,010	105,669,226
501	1902625227	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	1,224,932	51,692,114
501	1902625288	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	2,609,441	110,118,426
501	1902625299	Nov-10	11/30/10	12/27/2010	15.2	27.0	42.2	1,262,662	53,284,326
142	1800064604	Jan-10	1/15/10	2/25/2010	15.2	41.0	56.2	77,100	4,333,020
142	1800065703	May-10	5/15/10	6/25/2010	15.2	41.0	56.2	101,883	5,725,797
142	1800065412	Apr-10	4/15/10	6/25/2010	15.2	71.0	86.2	184,850	15,934,070
142	1800066300	Jun-10	6/15/10	7/30/2010	15.2	45.0	60.2	378,925	22,811,285
Natural Gas Payables Lag						**Ref. 4.1**	**40.61**	**319,499,930**	**12,974,463,633**

This data has been redacted due to its voluminous nature. Please see CD provided for complete record.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Purchased Power

Check No	Inv Date	DocumentNo	End of Service	Payment Date	Billing Lag	Product Lag	Total Lag	Amount	Dollar Days
	1/4/2010	1902382289	10/31/2009	1/4/2010	65	15.2	80	1,446,412	116,002,242
	1/4/2010	1902382282	11/30/2009	1/4/2010	35	15.2	50	27,878	1,399,457
	1/4/2010	1902382295	11/30/2009	1/4/2010	35	15.2	50	44,584	2,238,119
	1/4/2010	1902382285	11/30/2009	1/4/2010	35	15.2	50	69,930	3,510,466
2329270	10/30/2009	1902381924	11/30/2009	1/5/2010	36	15.2	51	4,875	249,600
	1/5/2010	1902383774	11/30/2009	1/5/2010	36	15.2	51	73,681	3,772,492
	1/6/2010	1902387015	11/30/2009	1/6/2010	37	15.2	52	174,288	9,097,809
	1/6/2010	1902386990	11/30/2009	1/6/2010	37	15.2	52	68,617	3,581,817
	1/6/2010	1902386990	11/30/2009	1/6/2010	37	15.2	52	66	3,465
	1/8/2010	1902387163	11/30/2009	1/8/2010	39	15.2	54	3,488	189,062
	1/8/2010	1902390371	11/30/2009	1/8/2010	39	15.2	54	17,205	932,511
	1/8/2010	1902387167	1/31/2010	1/8/2010	-23	15.2	-8	1,694,395	(13,216,284)
2330738	11/30/2009	1902387482	11/30/2009	1/11/2010	42	15.2	57	83	4,748
2330738	11/30/2009	1902387483	11/30/2009	1/11/2010	42	15.2	57	80	4,602
2330635	12/7/2009	1902387107	12/7/2009	1/11/2010	35	15.2	50	404	20,281
2330739	1/3/2010	1902387486	12/14/2009	1/11/2010	28	15.2	43	446	19,278
2330631	12/28/2009	1902387105	12/15/2009	1/11/2010	27	15.2	42	630	26,566
2330739	12/27/2009	1902387484	12/15/2009	1/11/2010	27	15.2	42	540	22,805
2330739	12/27/2009	1902387485	12/15/2009	1/11/2010	27	15.2	42	302	12,725

This data has been redacted due to its voluminous nature. Please see CD provided for full record of invoices.

2331271	12/16/2009	1902387056	11/30/2009	1/12/2010	43	15.2	58	44,717	2,602,531
2331293	12/17/2009	1902387618	12/17/2009	1/12/2010	26	15.2	41	158	6,503
	12/30/2010	1902625310	11/30/2010	12/30/2010	30	15.2	45	285,220	12,891,965
	12/30/2010	1902625300	11/30/2010	12/30/2010	30	15.2	45	31,386	1,418,631
	12/30/2010	1902625300	11/30/2010	12/30/2010	30	15.2	45	707	31,973
	12/30/2010	1902625316	11/30/2010	12/30/2010	30	15.2	45	3,564	161,089
	12/30/2010	1902625313	11/30/2010	12/30/2010	30	15.2	45	1,720	77,737
	12/30/2010	1902625301	11/30/2010	12/30/2010	30	15.2	45	2,419,971	109,382,689
2443928	11/30/2010	1902625294	11/30/2010	12/30/2010	30	15.2	45	1,457	65,853
2444372	9/30/2010	1902621534	9/30/2010	12/31/2010	92	15.2	107	21,433	2,297,649
	12/31/2010	1902625788	10/31/2010	12/31/2010	61	15.2	76	3,170,244	241,572,593
	12/31/2010	1902625787	11/30/2010	12/31/2010	31	15.2	46	3,950,476	182,512,000
	12/31/2010	1902625786	11/30/2010	12/31/2010	31	15.2	46	2,003,939	92,581,961
	12/31/2010	1902622337	11/30/2010	12/31/2010	31	15.2	46	821,102	37,934,926
	12/31/2010	1902622337	11/30/2010	12/31/2010	31	15.2	46	(85,337)	(3,942,562)
	Purchased Power Lag Days					**Ref. 4.1**	**38.47**	**638,897,680**	**24,580,753,640**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study

Labor and Overhead Calculation					
Beginning Date Pay Period	**Ending Date Pay Period**	**Pay Period Days**	**Pay date**	**Check Lag**	**Total Lag**
12/26/2009	1/10/2010	16.00	01/15/10	5	13.00
1/11/2010	1/25/2010	15.00	02/02/10	8	15.50
1/26/2010	2/10/2010	16.00	02/17/10	7	15.00
2/11/2010	2/25/2010	15.00	03/02/10	5	12.50
2/26/2010	3/10/2010	13.00	03/17/10	7	13.50
3/11/2010	3/25/2010	15.00	04/02/10	8	15.50
3/26/2010	4/10/2010	16.00	04/16/10	6	14.00
4/11/2010	4/25/2010	15.00	04/30/10	5	12.50
4/26/2010	5/10/2010	15.00	05/17/10	7	14.50
5/11/2010	5/25/2010	15.00	06/02/10	8	15.50
5/26/2010	6/10/2010	16.00	06/17/10	7	15.00
6/11/2010	6/25/2010	15.00	07/02/10	7	14.50
6/26/2010	7/10/2010	15.00	07/16/10	6	13.50
7/11/2010	7/25/2010	15.00	08/02/10	8	15.50
7/26/2010	8/10/2010	16.00	08/17/10	7	15.00
8/11/2010	8/25/2010	15.00	09/02/10	8	15.50
8/26/2010	9/10/2010	16.00	09/17/10	7	15.00
9/11/2010	9/25/2010	15.00	10/01/10	6	13.50
9/26/2010	10/10/2010	15.00	10/15/10	5	12.50
10/11/2010	10/25/2010	15.00	11/02/10	8	15.50
10/26/2010	11/10/2010	16.00	11/17/10	7	15.00
11/11/2010	11/25/2010	15.00	12/02/10	7	14.50
11/26/2010	12/10/2010	15.00	12/17/10	7	14.50
12/11/2010	12/25/2010	15.00	12/30/10	5	12.50
			AVERAGE		**14.31**

Ref. 4.1

Incentive Lag Calculation	
Begininning of Year	January 1, 2010
End of Year	December 31, 2010
2010 Midpoint	July 2, 2010
Incentive Payment Date	December 17, 2010
Incentive Lag	**167.50**

Ref. 4.1

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Actual Labor, Overhead and Incentive Expenses

			December 2010 Actuals					
			Total Company			Oregon Allocated		
FERC Account	2010 Protocol Factor	Indicator	Labor & Overhead	Incentive	Total Labor, Overheads, and Incentive	Labor & Overheads	Incentive	Total Labor, Overheads, and Incentive
500	SG	500SG	14,856,883	578,642	15,435,524	3,892,890	151,619	4,044,509
501	SE	501SE	(164,716)	(6,416)	(171,132)	(41,308)	(1,609)	(42,917)
502	SG	502SG	16,593,595	646,283	17,239,877	4,347,953	169,343	4,517,296
505	SG	505SG	1,741,614	67,832	1,809,446	456,348	17,774	474,122
506	SG	506SG	38,990,811	1,518,603	40,509,413	10,216,606	397,913	10,614,520
510	SG	510SG	2,774,500	108,060	2,882,561	726,991	28,315	755,306
511	SG	511SG	6,595,007	256,860	6,851,867	1,728,063	67,304	1,795,367
512	SG	512SG	24,965,292	972,341	25,937,633	6,541,556	254,779	6,796,334
513	SG	513SG	10,614,127	413,396	11,027,523	2,781,177	108,320	2,889,498
514	SG	514SG	2,508,029	97,682	2,605,711	657,169	25,595	682,764
535	SG-P	535SG	2,282,458	88,897	2,371,355	598,063	23,293	621,357
535	SG-U	535SG	1,599,252	62,287	1,661,539	419,046	16,321	435,366
536	SG-P	536SG	77,062	3,001	80,063	20,192	786	20,979
537	SG-P	537SG	359,729	14,011	373,739	94,258	3,671	97,929
537	SG-U	537SG	56,141	2,187	58,328	14,710	573	15,283
539	SG-P	539SG	5,652,399	220,148	5,872,547	1,481,076	57,685	1,538,760
539	SG-U	539SG	4,410,548	171,781	4,582,329	1,155,678	45,011	1,200,689
540	SG-P	540SG	(148,196)	(5,772)	(153,968)	(38,831)	(1,512)	(40,343)
540	SG-U	540SG	8	0	8	2	0	2
541	SG-P	541SG	232	9	241	61	2	63
542	SG-P	542SG	409,024	15,931	424,955	107,175	4,174	111,349
542	SG-U	542SG	75,310	2,933	78,243	19,733	769	20,502
543	SG-P	543SG	314,350	12,243	326,593	82,368	3,208	85,576
543	SG-U	543SG	443,838	17,286	461,125	116,297	4,530	120,827
544	SG-P	544SG	704,863	27,453	732,316	184,692	7,193	191,886
544	SG-U	544SG	258,063	10,051	268,113	67,619	2,634	70,253
545	SG-P	545SG	680,724	26,513	707,237	178,367	6,947	185,314
545	SG-U	545SG	278,823	10,860	289,682	73,059	2,845	75,904
546	SG	546SG	1,649	64	1,713	432	17	449
548	SG	548SG	5,148,230	200,512	5,348,742	1,348,970	52,539	1,401,509
549	SG	549SG	2,495,668	97,201	2,592,869	653,930	25,469	679,399
552	SG	552SG	165,102	6,430	171,532	43,261	1,685	44,946
553	SG	553SG	1,994,290	77,673	2,071,963	522,556	20,352	542,908
554	SG	554SG	121,910	4,748	126,658	31,943	1,244	33,188
556	SG	556SG	397,042	15,464	412,506	104,035	4,052	108,087
557	SG	557SG	31,133,250	1,212,569	32,345,818	8,157,721	317,725	8,475,446
560	SG	560SG	3,766,701	146,704	3,913,406	986,974	38,440	1,025,414
561	SG	561SG	8,334,622	324,614	8,659,236	2,183,888	85,057	2,268,945
562	SG	562SG	1,071,595	41,736	1,113,332	280,786	10,936	291,722
563	SG	563SG	67,489	2,629	70,117	17,684	689	18,373
566	SG	566SG	307,352	11,971	319,322	80,534	3,137	83,671
567	SG	567SG	152,623	5,944	158,567	39,991	1,558	41,549
568	SG	568SG	993,381	38,690	1,032,071	260,292	10,138	270,429
569	SG	569SG	2,442,985	95,149	2,538,134	640,126	24,931	665,057
570	SG	570SG	5,981,845	232,979	6,214,824	1,567,399	61,047	1,628,445
571	SG	571SG	(2,333,633)	(90,890)	(2,424,522)	(611,472)	(23,815)	(635,288)
572	SG	572SG	13,460	524	13,984	3,527	137	3,664
573	SG	573SG	6,344	247	6,591	1,662	65	1,727
580	SNPD	580SNPD	14,655,203	570,787	15,225,990	4,123,598	160,605	4,284,203
581	SNPD	581SNPD	12,737,900	496,112	13,234,012	3,584,118	139,593	3,723,711
582	CA	582CA	72,939	2,841	75,780	-	-	-
582	ID	582ID	117,569	4,579	122,148	-	-	-
582	OR	582OR	464,543	18,093	482,635	464,543	18,093	482,635
582	SNPD	582SNPD	18,723	729	19,452	5,268	205	5,473
582	UT	582UT	740,397	28,837	769,234	-	-	-
582	WA	582WA	138,639	5,400	144,038	-	-	-
582	WYP	582WYP	304,141	11,846	315,987	-	-	-
583	CA	583CA	291,844	11,367	303,211	-	-	-
583	ID	583ID	161,176	6,277	167,453	-	-	-
583	OR	583OR	2,358,416	91,855	2,450,270	2,358,416	91,855	2,450,270
583	SNPD	583SNPD	18,865	735	19,599	5,308	207	5,515
583	UT	583UT	1,220,224	47,525	1,267,749	-	-	-
583	WA	583WA	274,095	10,675	284,771	-	-	-
583	WYP	583WYP	237,226	9,239	246,466	-	-	-
583	WYU	583WYU	71,779	2,796	74,574	-	-	-
585	SNPD	585SNPD	201,051	7,830	208,882	56,571	2,203	58,774
586	CA	586CA	172,055	6,701	178,756	-	-	-
586	ID	586ID	224,126	8,729	232,855	-	-	-
586	OR	586OR	2,053,443	79,977	2,133,419	2,053,443	79,977	2,133,419
586	SNPD	586SNPD	911,490	35,500	946,990	256,470	9,989	266,459
586	UT	586UT	1,124,460	43,795	1,168,255	-	-	-
586	WA	586WA	279,967	10,904	290,871	-	-	-
586	WYP	586WYP	442,717	17,243	459,960	-	-	-
586	WYU	586WYU	50,757	1,977	52,733	-	-	-
587	CA	587CA	496,651	19,343	515,995	-	-	-
587	ID	587ID	321,623	12,526	334,150	-	-	-
587	OR	587OR	3,646,867	142,037	3,788,904	3,646,867	142,037	3,788,904

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Actual Labor, Overhead and Incentive Expenses

			December 2010 Actuals					
			Total Company			Oregon Allocated		
FERC Account	2010 Protocol Factor	Indicator	Labor & Overhead	Incentive	Total Labor, Overheads, and Incentive	Labor & Overheads	Incentive	Total Labor, Overheads, and Incentive
587	UT	587UT	4,108,882	160,032	4,268,914	-	-	-
587	WA	587WA	785,910	30,609	816,519	-	-	-
587	WYP	587WYP	761,129	29,644	790,773	-	-	-
587	WYU	587WYU	50,585	1,970	52,555	-	-	-
588	CA	588CA	(39,905)	(1,554)	(41,459)	-	-	-
588	ID	588ID	(51,070)	(1,989)	(53,059)	-	-	-
588	OR	588OR	(441,944)	(17,213)	(459,157)	(441,944)	(17,213)	(459,157)
588	SNPD	588SNPD	197,923	7,709	205,631	55,690	2,169	57,859
588	UT	588UT	10,100	393	10,494	-	-	-
588	WA	588WA	(49,385)	(1,923)	(51,309)	-	-	-
588	WYP	588WYP	(78,263)	(3,048)	(81,311)	-	-	-
588	WYU	588WYU	(39,108)	(1,523)	(40,631)	-	-	-
589	CA	589CA	10,190	397	10,587	-	-	-
589	ID	589ID	719	28	747	-	-	-
589	OR	589OR	79,478	3,096	82,574	79,478	3,096	82,574
589	UT	589UT	14,173	552	14,725	-	-	-
589	WA	589WA	8,769	342	9,111	-	-	-
589	WYP	589WYP	8,589	335	8,923	-	-	-
589	WYU	589WYU	(124)	(5)	(129)	-	-	-
590	CA	590CA	14,938	582	15,519	-	-	-
590	ID	590ID	41,106	1,601	42,707	-	-	-
590	OR	590OR	223,015	8,686	231,701	223,015	8,686	231,701
590	SNPD	590SNPD	4,396,895	171,249	4,568,144	1,237,173	48,185	1,285,358
590	UT	590UT	277,012	10,789	287,801	-	-	-
590	WA	590WA	9,497	370	9,867	-	-	-
590	WYP	590WYP	76,106	2,964	79,070	-	-	-
592	CA	592CA	394,779	15,376	410,155	-	-	-
592	ID	592ID	479,444	18,673	498,117	-	-	-
592	OR	592OR	2,223,709	86,608	2,310,317	2,223,709	86,608	2,310,317
592	SNPD	592SNPD	1,319,064	51,375	1,370,439	371,151	14,455	385,606
592	UT	592UT	2,521,601	98,211	2,619,811	-	-	-
592	WA	592WA	441,131	17,181	458,313	-	-	-
592	WYP	592WYP	673,876	26,246	700,122	-	-	-
592	WYU	592WYU	512	20	532	-	-	-
593	CA	593CA	3,348,951	130,434	3,479,385	-	-	-
593	ID	593ID	2,137,832	83,264	2,221,096	-	-	-
593	OR	593OR	7,035,893	274,032	7,309,925	7,035,893	274,032	7,309,925
593	SNPD	593SNPD	(544,255)	(21,197)	(565,452)	(153,139)	(5,964)	(159,104)
593	UT	593UT	7,498,559	292,052	7,790,611	-	-	-
593	WA	593WA	410,503	15,988	426,491	-	-	-
593	WYP	593WYP	1,312,315	51,112	1,363,427	-	-	-
593	WYU	593WYU	394,541	15,366	409,907	-	-	-
594	CA	594CA	345,410	13,453	358,863	-	-	-
594	ID	594ID	382,155	14,884	397,039	-	-	-
594	OR	594OR	3,579,115	139,398	3,718,513	3,579,115	139,398	3,718,513
594	UT	594UT	6,986,672	272,115	7,258,787	-	-	-
594	WA	594WA	700,789	27,294	728,084	-	-	-
594	WYP	594WYP	866,594	33,752	900,346	-	-	-
594	WYU	594WYU	109,487	4,264	113,751	-	-	-
595	SNPD	595SNPD	691,741	26,942	718,683	194,638	7,581	202,219
596	CA	596CA	104,090	4,054	108,144	-	-	-
596	ID	596ID	120,201	4,682	124,883	-	-	-
596	OR	596OR	805,027	31,354	836,381	805,027	31,354	836,381
596	UT	596UT	325,215	12,666	337,882	-	-	-
596	WA	596WA	130,000	5,063	135,063	-	-	-
596	WYP	596WYP	276,313	10,762	287,075	-	-	-
596	WYU	596WYU	36,526	1,423	37,949	-	-	-
597	CA	597CA	47,929	1,867	49,796	-	-	-
597	ID	597ID	246,711	9,609	256,319	-	-	-
597	OR	597OR	854,872	33,295	888,167	854,872	33,295	888,167
597	SNPD	597SNPD	708,403	27,591	735,993	199,326	7,763	207,090
597	UT	597UT	1,716,086	66,838	1,782,924	-	-	-
597	WA	597WA	357,846	13,937	371,784	-	-	-
597	WYP	597WYP	450,708	17,554	468,262	-	-	-
597	WYU	597WYU	79,058	3,079	82,138	-	-	-
598	CA	598CA	14,380	560	14,940	-	-	-
598	OR	598OR	62,857	2,448	65,306	62,857	2,448	65,306
598	SNPD	598SNPD	1,033,363	40,247	1,073,610	290,762	11,325	302,086
598	UT	598UT	5,941	231	6,172	-	-	-
598	WA	598WA	28,915	1,126	30,041	-	-	-
598	WYU	598WYU	161	6	167	-	-	-
901	CN	901CN	1,899,933	73,998	1,973,931	584,612	22,769	607,382
901	OR	901OR	1,120	44	1,164	1,120	44	1,164
901	WYP	901WYP	67	3	70	-	-	-
902	CA	902CA	715,837	27,880	743,717	-	-	-
902	CN	902CN	1,425,630	55,525	1,481,155	438,668	17,085	455,754
902	ID	902ID	1,322,078	51,492	1,373,570	-	-	-

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Actual Labor, Overhead and Incentive Expenses

			December 2010 Actuals					
			Total Company			Oregon Allocated		
FERC Account	2010 Protocol Factor	Indicator	Labor & Overhead	Incentive	Total Labor, Overheads, and Incentive	Labor & Overheads	Incentive	Total Labor, Overheads, and Incentive
902	OR	902OR	7,702,921	300,011	8,002,932	7,702,921	300,011	8,002,932
902	UT	902UT	3,688,167	143,646	3,831,813	-	-	-
902	WA	902WA	1,865,266	72,648	1,937,914	-	-	-
902	WYP	902WYP	1,295,982	50,476	1,346,458	-	-	-
902	WYU	902WYU	214,844	8,368	223,212	-	-	-
903	CA	903CA	158,106	6,158	164,263	-	-	-
903	CN	903CN	31,393,334	1,222,698	32,616,032	9,659,778	376,226	10,036,005
903	ID	903ID	278,785	10,858	289,643	-	-	-
903	OR	903OR	1,426,261	55,550	1,481,811	1,426,261	55,550	1,481,811
903	UT	903UT	2,478,915	96,548	2,575,463	-	-	-
903	WA	903WA	433,508	16,884	450,392	-	-	-
903	WYP	903WYP	246,997	9,620	256,617	-	-	-
903	WYU	903WYU	68,609	2,672	71,281	-	-	-
905	CN	905CN	107,513	4,187	111,700	33,082	1,288	34,370
907	CN	907CN	233,643	9,100	242,742	71,892	2,800	74,692
908	CA	908CA	1,136	44	1,180	-	-	-
908	CN	908CN	2,432,862	94,754	2,527,617	748,596	29,156	777,752
908	ID	908ID	416,485	16,221	432,706	-	-	-
908	OR	908OR	1,155,246	44,994	1,200,240	1,155,246	44,994	1,200,240
908	OTHER	908OTHER	36,302	1,414	37,716	-	-	-
908	UT	908UT	2,028,092	78,990	2,107,082	-	-	-
908	WYP	908WYP	814,734	31,732	846,466	-	-	-
909	CA	909CA	84	3	87	-	-	-
909	CN	909CN	445,886	17,366	463,253	137,200	5,344	142,544
910	CN	910CN	1,299	51	1,350	400	16	415
920	SO	920SO	75,535,895	2,941,950	78,477,845	20,924,391	814,957	21,739,348
921	SO	921SO	(241,929)	(9,423)	(251,351)	(67,017)	(2,610)	(69,627)
921	WA	921WA	21	1	22	-	-	-
922	SO	922SO	27,518,812	1,071,795	28,590,607	7,623,057	296,901	7,919,957
928	CA	928CA	196,452	7,651	204,104	-	-	-
928	ID	928ID	581,757	22,658	604,415	-	-	-
928	OR	928OR	424,405	16,530	440,935	424,405	16,530	440,935
928	SO	928SO	183,256	7,137	190,393	50,764	1,977	52,741
928	UT	928UT	641,690	24,992	666,682	-	-	-
928	WA	928WA	400,604	15,603	416,207	-	-	-
928	WYP	928WYP	491,481	19,142	510,623	-	-	-
929	SO	929SO	(900,482)	(35,072)	(935,554)	(249,445)	(9,715)	(259,160)
935	OR	935OR	16,660	649	17,309	16,660	649	17,309
935	SO	935SO	2,373,666	92,449	2,466,115	657,535	25,609	683,145
935	WA	935WA	2,050	80	2,130	-	-	-
Utility Labor			**475,604,778**	**18,523,716**	**494,128,494**	**136,707,602**	**5,324,448**	**142,032,049**
					Lag Days	**14.31**	**167.50**	**Ref. 4.5**
					Dollar Days	**2,032,833,707**	**23,790,369,098**	**Ref. 4.1**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Other O&M Calculation

Month	Amount	Lag Days	Dollar Days
1	182,289,449	27.53	5,017,820,263
2	150,334,584	32.72	4,918,337,263
3	161,914,863	30.63	4,960,102,079
4	185,188,906	44.21	8,187,273,430
5	168,397,380	31.01	5,222,784,857
6	151,737,324	33.34	5,059,461,702
7	156,988,998	33.27	5,222,823,722
8	162,575,074	32.91	5,349,770,811
9	159,269,376	36.36	5,791,277,937
10	164,543,375	31.92	5,251,822,164
11	162,555,769	35.68	5,799,655,199
12	166,874,339	32.23	5,379,100,680
	1,972,669,436	**33.54**	**66,160,230,107**

Ref. 4.1

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Other O&M - January

DocumentNo	Type	PayT	Invoice Date	Cash Date	Amount	Lag Days	Dollar Days
1902380909	KR	DUE	12/24/2009	1/1/2010	$2,000	8	$16,000
1902381171	KR	DUE	12/9/2009	1/1/2010	$20	23	$460
5601516916	RE	NT30	11/25/2009	1/1/2010	$301	37	$11,124
1902380799	KR	DUE	12/11/2009	1/1/2010	$54	21	$1,129
1902381176	KR	DUE	12/11/2009	1/1/2010	$47	21	$984
1902380790	KR	DUE	12/28/2009	1/1/2010	$82	4	$330
1902381071	KR	DUE	12/10/2009	1/1/2010	$9	22	$191
1902381157	KR	DUE	12/24/2009	1/1/2010	$44	8	$350
1902381190	KR	DUE	12/10/2009	1/1/2010	$28	22	$605
1902380844	KR	DUE	12/9/2009	1/1/2010	$24	23	$541
1902380837	KR	DUE	12/10/2009	1/1/2010	$72	22	$1,584
5601516682	RE	NT30	12/4/2009	1/1/2010	$36,837	28	$1,031,447
1902380910	KR	DUE	11/10/2009	1/1/2010	$1,500	52	$78,000
1902380911	KR	DUE	12/28/2009	1/1/2010	$5,000	4	$20,000
1902378265	KR	DUE	12/1/2009	1/1/2010	$440	31	$13,640
1902378266	KR	DUE	12/14/2009	1/1/2010	$3,797	18	$68,346
1902381081	KR	DUE	12/11/2009	1/1/2010	$160	21	$3,360
1902381098	KR	DUE	12/9/2009	1/1/2010	$32	23	$728
1902380833	KR	DUE	12/11/2009	1/1/2010	$413	21	$8,665
1902372956	KR	NT30	12/6/2009	1/1/2010	$216	26	$5,617
1902381080	KR	DUE	12/11/2009	1/1/2010	$64	21	$1,353
1902381101	KR	DUE	12/11/2009	1/1/2010	$45	21	$945
190							$36,788
190							$5,842,841
190							$6,525,000
560							$129,456
5601533202	RE	NT30	12/30/2009	1/31/2010	$3,100	32	$99,200
5601533203	RE	NT30	12/31/2009	1/31/2010	$7,021	31	$217,640
5601533231	RE	NT30	12/31/2009	1/31/2010	$6,734	31	$208,768
5601533242	RE	NT30	12/31/2009	1/31/2010	$753	31	$23,343
5601533332	RE	NT30	11/17/2009	1/31/2010	$15,744	75	$1,180,800
5601533339	RE	NT30	11/9/2009	1/31/2010	$82,270	83	$6,828,410
5601534006	RE	NT30	12/31/2009	1/31/2010	$9,103	31	$282,189
5601533367	RE	NT02	1/21/2010	1/31/2010	$61,941	10	$619,412
5601534004	RE	NT30	12/31/2009	1/31/2010	$10	31	$310
5601533384	RE	NT30	1/6/2010	1/31/2010	($1,854)	25	($46,350)
5601533475	RE	NT15	1/12/2010	1/31/2010	$8,696	19	$165,215
5601533476	RE	NT30	12/11/2009	1/31/2010	$411,356	51	$20,979,150
5601533617	RE	NT30	11/3/2009	1/31/2010	$38,682	89	$3,442,698
5601533626	RE	NT30	12/31/2009	1/31/2010	$6,525	31	$202,275
5601533631	RE	NT30	11/3/2009	1/31/2010	$38,797	89	$3,452,933
5601533682	RE	NT30	12/30/2009	1/31/2010	$16,431	32	$525,801
5601533992	RE	2%10	1/19/2010	1/31/2010	$48	12	$573
5601534002	RE	NT30	12/31/2009	1/31/2010	$7,016	31	$217,485
1902396647	KR	NT30	12/25/2009	1/31/2010	$363	37	$13,419
5601533340	RE	NT30	11/17/2009	1/31/2010	$82,270	75	$6,170,250
					$182,289,449	**27.53**	**$5,017,820,263**

This data has been redacted due to its voluminous nature. Please see CD provided for complete record.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Cash Payments for Property Taxes

January 1, 2010 to December 31, 2010

State	CY 2010 Amount	Est. / Statutory Date Paid	Mid-Point of Tax Period	Lag Days	Dollar Days
Arizona	960,566	5/1/2010	6/30/2009	305	292,972,728
	1,181,569	11/1/2010	6/30/2010	124	146,514,536
	2,142,135				439,487,264
California	1,163,181	4/10/2010	12/31/2009	100	116,318,105
	1,125,932	12/10/2010	12/31/2010	(21)	(23,644,564)
	2,289,113				92,673,541
Colorado	1,820,136	4/30/2010	6/30/2009	304	553,321,344
	(40,402)	4/30/2010	6/30/2009	304	(12,282,208)
	1,779,734				541,039,136
Idaho	788,788	6/20/2010	6/30/2009	355	280,019,868
	1,150,396	12/15/2010	6/30/2010	168	193,266,572
	632,878	1/31/2010	6/30/2009	215	136,068,875
	2,572,063				609,355,315
Montana	1,407,124	5/31/2010	6/30/2009	335	471,386,540
	1,635,650	11/30/2010	6/30/2010	153	250,254,450
	3,042,774				721,640,990
New Mexico	8,398	12/10/2010	6/30/2010	163	1,368,874
Oregon	21,486,739	11/15/2010	12/31/2010	(46)	(988,389,990)
	(449,521)	11/15/2010	12/31/2010	(46)	20,677,966
	21,037,218				(967,712,024)
Utah (note 1)	52,144,875	11/30/2010	6/30/2010	153	7,978,165,809
	(5,208,543)	11/30/2010	6/30/2010	153	(796,907,079)
	398,349	1/31/2010	6/30/2010	(150)	(59,752,397)
	47,334,681				7,121,506,334
Washington	3,564,976	4/30/2010	6/30/2009	304	1,083,752,788
	3,561,865	10/31/2010	6/30/2009	488	1,738,190,014
	7,126,841				2,821,942,802
Wyoming	5,855,494	5/10/2010	6/30/2009	314	1,838,625,220
	7,000,665	11/10/2010	6/30/2010	133	931,088,402
	12,856,159				2,769,713,622
Subtotal Property Taxes	100,189,116				14,151,015,854
Ute	27,349	5/14/2010	6/30/2010	(47)	(1,285,403)
Shoshone Bannock	151,097	4/15/2010	6/30/2010	(76)	(11,483,372)
Goshute	15,079	5/7/2010	6/30/2010	(54)	(814,283)
Crow	63,720	9/20/2010	6/30/2010	82	5,225,040
Umatilla	32,144	6/15/2010	6/30/2010	(15)	(482,164)
	32,144	11/15/2010	6/30/2010	138	4,435,907
	64,289				3,953,743
Navajo	18,002	5/1/2010	6/30/2009	305	5,490,695
	17,939	11/1/2010	6/30/2010	124	2,224,385
	35,941				7,715,081
Subtotal Possessory Interest Taxes	357,475				3,310,805
Total Taxes based on Property	100,546,591			**140.77**	14,154,326,659
				Ref. 4.1	

Notes:
Only Centrally Assessed Property
Taxes paid on 2010 assessment year
(1) Amount paid after pumping exemption

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Other Taxes (FERC Account 408)

2010 AMOUNTS		PacifiCorp								
State	**Factor**	**TOTAL**	**OR**	**WA**	**WY**	**UT**	**ID**	**CA**	**FERC**	**Ref**
Oregon Franchise Tax	OR	22,389,970	22,389,970	-	-	-	-	-	-	4.8.1
Washington Business & Occupation Tax	WA	45,946	-	45,946	-	-	-	-	-	4.8.1
Washington Public Utility Tax	SO	9,741,196	2,722,558	760,564	26,170	4,068,941	540,418	227,697	-	4.8.1
Idaho Kilowatt Hour Tax	SE	14,436	3,620	1,114	51	5,952	915	237	-	4.8.2
California Franchise Tax	CA	1,112,815	-	-	-	-	-	1,112,815	-	4.8.2
Wyoming Franchise Tax	WYP	1,559,177	-	-	1,559,177	-	-	-	-	4.8.2
Montana Wholesale Energy Transaction Tax	SE	174,547	43,774	13,467	619	71,964	11,068	2,862	-	4.8.2
Montana Energy License Tax	SE	244,969	61,434	18,901	869	100,998	15,534	4,017	-	4.8.2
TOTAL		35,283,056	25,221,357	839,991	1,586,887	4,247,854	567,935	1,347,628	-	
		-								

2010 DOLLARDAYS		PacifiCorp								
State	**Factor**	**TOTAL**	**OR**	**WA**	**WY**	**UT**	**ID**	**CA**	**FERC**	**Ref**
Oregon Franchise Tax	OR	792,943,144	792,943,144	-	-	-	-	-	-	4.8.1
Washington Business & Occupation Tax	WA	1,859,926	-	1,859,926	-	-	-	-	-	4.8.1
Washington Public Utility Tax	SO	393,687,422	110,031,339	30,737,963	1,057,649	164,444,976	21,840,822	9,202,306	-	4.8.1
Idaho Kilowatt Hour Tax	SE	585,827	146,917	45,200	2,079	241,530	37,147	9,607	-	4.8.2
California Franchise Tax	CA	287,106,270	-	-	-	-	-	287,106,270	-	4.8.2
Wyoming Franchise Tax	WYP	55,240,419	-	-	55,240,419	-	-	-	-	4.8.2
Montana Wholesale Energy Transaction Tax	SE	13,263,054	3,326,174	1,023,313	47,066	5,468,213	841,013	217,498	-	4.8.2
Montana Energy License Tax	SE	18,614,081	4,668,131	1,436,172	66,055	7,674,383	1,180,323	305,249	-	4.8.2
AMOUNT		1,563,300,144	911,115,705	35,102,572	56,413,268	177,829,102	23,899,306	296,840,930	-	
		-								
LAG DAYS		**44.31**	**36.12**	**41.79**	**35.55**	**41.86**	**42.08**	**220.27**	**-**	**4.1**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Cash Payments for Other Taxes

Category	Payment Period	2010 Payment Amt.	Payment date	Midpoint of Tax Period	Lag Days	Dollardays	Ref.
Oregon Franchise Tax	Jan-10	2,954,927	02/20/10	01/16/10	35	103,422,445	
	Feb-10	1,583,508	03/20/10	02/14/10	34	53,839,279	
	Mar-10	1,476,279	04/20/10	03/15/10	36	53,146,044	
	Apr-10	2,737,222	05/20/10	04/15/10	35	95,802,770	
	May-10	1,347,846	06/20/10	05/15/10	36	48,522,456	
	Jun-10	1,301,029	07/20/10	06/15/10	35	45,536,015	
	Jul-10	2,506,108	08/20/10	07/15/10	36	90,219,888	
	Aug-10	1,324,661	09/20/10	08/15/10	36	47,687,796	
	Sep-10	1,520,446	10/20/10	09/15/10	35	53,215,610	
	Oct-10	2,355,678	11/20/10	10/15/10	36	84,804,408	
	Nov-10	1,415,147	12/20/10	11/15/10	35	49,530,145	
	Dec-10	1,867,119	01/20/11	12/15/10	36	67,216,287	
		22,389,970			35	792,943,144	4.8
Washington Business & Occupation Tax	Jan-10	3,247	2/25/2010	01/16/10	40	129,878	
	Feb-10	3,141	3/25/2010	02/14/10	39	122,518	
	Mar-10	3,950	4/25/2010	03/15/10	41	161,930	
	Apr-10	4,218	5/25/2010	04/15/10	40	168,714	
	May-10	3,885	6/25/2010	05/15/10	41	159,275	
	Jun-10	3,615	7/25/2010	06/15/10	40	144,611	
	Jul-10	3,841	8/25/2010	07/15/10	41	157,481	
	Aug-10	6,102	9/25/2010	08/15/10	41	250,173	
	Sep-10	3,253	10/25/2010	09/15/10	40	130,138	
	Oct-10	3,609	11/25/2010	10/15/10	41	147,976	
	Nov-10	3,231	12/25/2010	11/15/10	40	129,242	
	Dec-10	3,853	1/25/2011	12/15/10	41	157,988	
		45,946			40	1,859,926	4.8
Washington Public Utility Tax	Jan-10	1,008,503	2/25/2010	01/16/10	40	40,340,136	
	Feb-10	775,639	3/25/2010	02/14/10	39	30,249,929	
	Mar-10	789,545	4/25/2010	03/15/10	41	32,371,350	
	Apr-10	773,904	5/25/2010	04/15/10	40	30,956,174	
	May-10	577,525	6/25/2010	05/15/10	41	23,678,528	
	Jun-10	748,893	7/25/2010	06/15/10	40	29,955,734	
	Jul-10	834,678	8/25/2010	07/15/10	41	34,221,798	
	Aug-10	850,757	9/25/2010	08/15/10	41	34,881,028	
	Sep-10	683,030	10/25/2010	09/15/10	40	27,321,205	
	Oct-10	821,801	11/25/2010	10/15/10	41	33,693,859	
	Nov-10	936,006	12/25/2010	11/15/10	40	37,440,226	
	Dec-10	940,914	1/25/2011	12/15/10	41	38,577,455	
		9,741,196			40	393,687,422	4.8

Idaho Kilowatt Hour Tax		Jan-10	397	2/25/2010	01/16/10	40	15,896	
		Feb-10	408	3/25/2010	02/14/10	39	15,921	
		Mar-10	920	4/25/2010	03/15/10	41	37,711	
		Apr-10	1,584	5/25/2010	04/15/10	40	63,353	
		May-10	1,065	6/25/2010	05/15/10	41	43,645	
		Jun-10	2,081	7/25/2010	06/15/10	40	83,223	
		Jul-10	4,676	8/25/2010	07/15/10	41	191,700	
		Aug-10	865	9/25/2010	08/15/10	41	35,457	
		Sep-10	360	10/25/2010	09/15/10	40	14,400	
		Oct-10	186	11/25/2010	10/15/10	41	7,637	
		Nov-10	808	12/25/2010	11/15/10	40	32,313	
		Dec-10	1,087	1/25/2011	12/15/10	41	44,572	
			14,436			41	585,827	4.8
California Franchise Tax Paid annually in March for prior calendar year		2010	1,112,815	3/15/2010	06/30/09	258	287,106,270	4.8
Wyoming Franchise Tax		Jan-10	121,339	02/20/10	01/16/10	35	4,246,849	
		Feb-10	111,995	03/20/10	02/14/10	34	3,807,835	
		Mar-10	193,078	04/20/10	03/15/10	36	6,950,808	
		Apr-10	101,596	05/20/10	04/15/10	35	3,555,860	
		May-10	91,070	06/20/10	05/15/10	36	3,278,520	
		Jun-10	167,099	07/20/10	06/15/10	35	5,848,465	
		Jul-10	98,663	08/20/10	07/15/10	36	3,551,868	
		Aug-10	107,654	09/20/10	08/15/10	36	3,875,544	
		Sep-10	175,364	10/20/10	09/15/10	35	6,137,740	
		Oct-10	93,631	11/20/10	10/15/10	36	3,370,724	
		Nov-10	100,568	12/20/10	11/15/10	35	3,519,880	
		Dec-10	197,120	01/20/11	12/15/10	36	7,096,325	
			1,559,177			35	55,240,419	4.8
Montana Wholesale Energy Transaction Tax	Jan 1 to Mar 31		44,839	4/30/2010	02/14/10	75	3,362,929	
	Apr 1 to Jun 30		41,876	7/31/2010	05/16/10	76	3,182,590	
	Jul 1 to Sep 30		45,509	10/31/2010	08/16/10	76	3,458,648	
	Oct 1 to Dec 31		42,323	1/31/2011	11/15/10	77	3,258,887	
			174,547			76	13,263,054	4.8
Montana Energy License Tax	Jan 1 to Mar 31		62,930	4/30/2010	02/14/10	75	4,719,720	
	Apr 1 to Jun 30		58,772	7/31/2010	05/16/10	76	4,466,657	
	Jul 1 to Sep 30		63,870	10/31/2010	08/16/10	76	4,854,105	
	Oct 1 to Dec 31		59,397	1/31/2011	11/15/10	77	4,573,600	
			244,969			76	18,614,081	4.8
	TOTAL		**35,283,056**			**44.31**	**1,563,300,144**	4.8

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Income Tax Lag

		Q1	Q2	Q3	Q4			
Federal Income Taxes								
	Start of Quarter	1/1/2010	4/1/2010	7/1/2010	10/1/2010			
	End of Quarter	3/31/2010	6/30/2010	9/30/2010	12/31/2010			
	Days in Quarter	90.00	91.00	92.00	92.00			
	Midpoint of Quarter	2/15/2010	5/16/2010	8/16/2010	11/16/2010			
	Quarterly Payment Date	4/15/2010	6/15/2010	9/15/2010	12/15/2010			
	Lag	60	30	31	30			
	Weight	25%	25%	25%	25%			
	Weighted Total	**15.00**	**7.62**	**7.75**	**7.50**	**Total Federal Tax Lag Days**		**37.87**
								Ref. 4.1
State Income Taxes								
						Total Lag Days	**% of Total State Taxes Paid**	**Allocated Lag Days**
California	Start of Quarter	1/1/2010	4/1/2010	7/1/2010	10/1/2010			
	End of Quarter	3/31/2010	6/30/2010	9/30/2010	12/31/2010			
	Days in Quarter	90.00	91.00	92.00	92.00			
	Midpoint of Quarter	2/15/2010	5/16/2010	8/16/2010	11/16/2010			
	Quarterly Payment Date	4/15/2010	6/15/2010	9/15/2010	1/15/2011			
	Lag	60	30	31	61			
	Weight	30%	40%	0%	30%			
	Weighted Total	**18.00**	**12.20**	**-**	**18.30**	48.50	2.75%	**1.33**
Idaho	Start of Quarter	1/1/2010	4/1/2010	7/1/2010	10/1/2010			
	End of Quarter	3/31/2010	6/30/2010	9/30/2010	12/31/2010			
	Days in Quarter	90.00	91.00	92.00	92.00			
	Midpoint of Quarter	2/15/2010	5/16/2010	8/16/2010	11/16/2010			
	Quarterly Payment Date	4/15/2010	6/15/2010	9/15/2010	12/15/2010			
	Lag	60	30	31	30			
	Weight	25%	25%	25%	25%			
	Weighted Total	**15.00**	**7.62**	**7.75**	**7.50**	37.87	6.76%	**2.56**
Oregon	Start of Quarter	1/1/2010	4/1/2010	7/1/2010	10/1/2010			
	End of Quarter	3/31/2010	6/30/2010	9/30/2010	12/31/2010			
	Days in Quarter	90.00	91.00	92.00	92.00			
	Midpoint of Quarter	2/15/2010	5/16/2010	8/16/2010	11/16/2010			
	Quarterly Payment Date	4/15/2010	6/15/2010	9/15/2010	12/15/2010			
	Lag	60	30	31	30			
	Weight	25%	25%	25%	25%			
	Weighted Total	**15.00**	**7.62**	**7.75**	**7.50**	37.87	47.10%	**17.84**
Utah	Start of Quarter	1/1/2010	4/1/2010	7/1/2010	10/1/2010			
	End of Quarter	3/31/2010	6/30/2010	9/30/2010	12/31/2010			
	Days in Quarter	90.00	91.00	92.00	92.00			
	Midpoint of Quarter	2/15/2010	5/16/2010	8/16/2010	11/16/2010			
	Quarterly Payment Date	4/15/2010	6/15/2010	9/15/2010	12/15/2010			
	Lag	60	30	31	30			
	Weight	25.0%	25.0%	25.0%	25.0%			
	Weighted Total	**15.00**	**7.62**	**7.75**	**7.50**	37.87	43.40%	**16.44**
						Average Total State Tax Lag Days		**38.17**
								Ref. 4.1

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
BPA Credit - Payments Received from BPA

Service Month	Payment Amount	Payment Clearing Date	Midpoint of Service Month	Lag Days	Dollar Days
Jan-10	(4,413,344)	3/10/2010	1/16/2010	53	(233,907,232)
Feb-10	(3,245,272)	4/2/2010	2/14/2010	47	(152,527,784)
Mar-10	(2,960,626)	5/3/2010	3/16/2010	48	(142,110,048)
Apr-10	(3,055,992)	6/2/2010	4/15/2010	48	(146,687,616)
May-10	(2,555,581)	7/1/2010	5/16/2010	46	(117,556,726)
Jun-10	(2,092,038)	7/30/2010	6/16/2010	44	(92,049,672)
Jul-10	(2,867,868)	9/1/2010	7/16/2010	47	(134,789,816)
Aug-10	(3,496,665)	10/1/2010	8/16/2010	46	(160,846,571)
Sep-10	(2,733,295)	11/12/2010	9/15/2010	58	(158,531,113)
Oct-10	(2,308,764)	12/17/2010	10/16/2010	62	(143,143,360)
Nov-10	(2,291,356)	1/3/2011	11/15/2010	49	(112,276,438)
Dec-10	(3,900,345)	2/7/2011	12/16/2010	53	(206,718,301)
	(35,921,146)			**50.14**	(1,801,144,677)
				Ref 4.1	

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study

RESULTS OF OPERATIONS SUMMARY

2010 PROTOCOL
Beginning/Ending

	Description of Account Summary:	UNADJUSTED RESULTS TOTAL	OTHER	OREGON	Ref.
1	Operating Revenues				
2	General Business Revenues	3,574,583,105	2,630,451,207	944,131,898	
3	Interdepartmental	0	0	0	
4	Special Sales	501,563,210	371,494,915	130,068,295	
5	Other Operating Revenues	326,069,070	244,667,514	81,401,557	
6	Total Operating Revenues	4,402,215,385	3,246,613,636	1,155,601,749	2.1
7					
8	Operating Expenses:				
9	Steam Production	957,497,818	713,690,054	243,807,764	
10	Nuclear Production	0	0	0	
11	Hydro Production	40,481,667	29,874,417	10,607,249	
12	Other Power Supply	922,755,661	712,803,752	209,951,909	
13	Transmission	195,628,269	144,438,504	51,189,765	
14	Distribution	208,550,302	140,458,235	68,092,067	
15	Customer Accounting	92,750,645	60,569,609	32,181,036	
16	Customer Service & Infor	128,944,905	106,541,644	22,403,261	
17	Sales	0	0	0	
18	Administrative & General	146,076,485	101,483,999	44,592,486	
19					
20	Total O & M Expenses	2,692,685,751	2,009,860,214	682,825,538	2.1
21					
22	Depreciation	491,643,870	351,175,658	140,468,212	
23	Amortization	44,975,946	32,465,708	12,510,239	
24	Taxes Other Than Income	136,512,728	82,942,990	53,569,739	
25	Income Taxes - Federal	(482,762,100)	(352,710,434)	(130,051,666)	2.1
26	Income Taxes - State	(58,348,093)	(42,576,174)	(15,771,919)	2.1
27	Income Taxes - Def Net	761,444,172	559,352,716	202,091,457	
28	Investment Tax Credit Adj.	(1,874,204)	(1,874,204)	0	
29	Misc Revenue & Expense	(5,388,606)	(4,664,058)	(724,548)	
30					
31	Total Operating Expenses	3,578,889,466	2,633,972,415	944,917,051	
32					
33	Operating Revenue for Return	823,325,919	612,641,221	210,684,698	
34					
35	Rate Base:				
36	Electric Plant in Service	20,347,033,834	14,710,649,998	5,636,383,837	
37	Plant Held for Future Use	15,175,403	10,068,007	5,107,396	
38	Misc Deferred Debits	164,786,435	144,926,143	19,860,292	
39	Elec Plant Acq Adj	59,786,774	44,121,084	15,665,690	
40	Nuclear Fuel	0	0	0	
41	Prepayments	36,569,894	26,568,702	10,001,193	
42	Fuel Stock	179,989,733	134,851,020	45,138,713	
43	Material & Supplies	182,198,510	129,325,442	52,873,068	
44	Working Capital	64,539,304	47,001,190	17,538,114	
45	Weatherization Loans	18,524,395	18,525,629	(1,234)	
46	Miscellaneous Rate Base	972,508	707,002	265,506	
47					
48	Total Electric Plant	21,069,576,791	15,266,744,217	5,802,832,574	
49					
50	Rate Base Deductions:				
51	Accum Prov For Depr	(6,753,405,676)	(4,775,578,999)	(1,977,826,677)	
52	Accum Prov For Amort	(441,232,410)	(314,686,644)	(126,545,767)	
53	Accum Def Income Taxes	(2,482,347,796)	(1,795,938,049)	(686,409,746)	
54	Unamortized ITC	(6,606,954)	(2,350,986)	(4,255,967)	
55	Customer Adv for Const	(22,100,039)	(17,165,458)	(4,934,581)	
56	Customer Service Deposits	0	0	0	
57	Misc. Rate Base Deductions	(65,686,584)	(51,032,953)	(14,653,631)	
58					
59	Total Rate Base Deductions	(9,771,379,459)	(6,956,753,089)	(2,814,626,370)	
60					
61	Total Rate Base	11,298,197,332	8,309,991,128	2,988,206,204	
62					
63	Return on Rate Base	7.287%		7.051%	
64					
65	Return on Equity	8.592%		8.137%	
66	Net Power Costs	1,125,770,120		283,776,600	
67	100 Basis Points in Equity:				
68	Revenue Requirement Impact	94,684,243		25,042,583	
69	Rate Base Decrease	(752,515,381)		(205,251,812)	

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	UNADJUSTED RESULTS TOTAL	OTHER	OREGON	
524	2010 Protocol Stipulated Embedded Cost Differential							
525		Company Owned Hydro		DGP	(41,510,730)	(19,367,541)	(22,143,189)	
526		Company Owned Hydro		SG	41,510,730	30,633,839	10,876,891	
527		Mid-C Contract		MC	(30,896,884)	(14,193,449)	(16,703,435)	
528		Mid-C Contract		SG	30,896,884	22,801,097	8,095,787	
529		Klamath Dam Removal Surcharge Re-alloc.		SG	0	(11,317,153)	11,317,153	
					0	8,556,793	(8,556,793)	2.1

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Results of Operations for Revenues

			Total Company				Oregon				
Account	RP Factor	Amount	General Business Revenues	Other CSS Revenues	Sales For Resale	Wheeling & Other Misc Revenues	General Business Revenues	Other CSS Revenues	Sales For Resale	Wheeling & Other Misc Revenues	
440	CA	45,021,008	45,021,008			-	-	-	-	-	
440	ID	61,511,506	61,511,506			-	-	-	-	-	
440	OR	464,939,004	464,939,004			-	464,939,004	-	-	-	
440	UT	585,459,607	585,459,607			-	-	-	-	-	
440	WA	111,623,664	111,623,664			-	-	-	-	-	
440	WYP	78,141,249	78,141,249			-	-	-	-	-	
440	WYU	11,130,868	11,130,868			-	-	-	-	-	
442	CA	42,588,522	42,588,522			-	-	-	-	-	
442	ID	144,577,729	144,577,729			-	-	-	-	-	
442	OR	473,504,235	473,504,235			-	473,504,235	-	-	-	
442	UT	926,732,212	926,732,212			-	-	-	-	-	
442	WA	143,778,553	143,778,553			-	-	-	-	-	
442	WYP	364,105,963	364,105,963			-	-	-	-	-	
442	WYU	81,088,205	81,088,205			-	-	-	-	-	
444	CA	366,334	366,334			-	-	-	-	-	
444	ID	470,881	470,881			-	-	-	-	-	
444	OR	5,688,658	5,688,658			-	5,688,658	-	-	-	
444	UT	10,911,823	10,911,823			-	-	-	-	-	
444	WA	1,237,336	1,237,336			-	-	-	-	-	
444	WYP	1,580,752	1,580,752			-	-	-	-	-	
444	WYU	354,577	354,577			-	-	-	-	-	
445	UT	19,770,416	19,770,416			-	-	-	-	-	
447	FERC	7,981,896				7,981,896	-	-	-	-	
447NPC	SE	903,103			903,103	-	-	-	226,485	-	
447NPC	SG	491,619,370			491,619,370	-	-	-	128,817,061	-	
447	OR	1,024,749				1,024,749	-	-	-	1,024,749	
447	SG	-				-	-	-	-	-	
447	WYP	34,091				34,091	-	-	-	-	
450	CA	255,515				255,515	-	-	-	-	
450	ID	406,930		406,930		-	-	-	-	-	
450	OR	2,682,694		2,682,694		-	-	2,682,694	-	-	
450	UT	2,957,255		2,957,255		-	-	-	-	-	
450	WA	555,425		555,425		-	-	-	-	-	
450	WYP	483,145		483,145		-	-	-	-	-	
450	WYU	70,924		70,924		-	-	-	-	-	
451	CA	70,245		70,245		-	-	-	-	-	
451	ID	101,005		101,005		-	-	-	-	-	
451	OR	1,113,696		1,113,696		-	-	1,113,696	-	-	
451	SO	57,591		57,591		-	-	15,954	-	-	
451	UT	3,686,861		3,686,861		-	-	-	-	-	
451	WA	149,915		149,915		-	-	-	-	-	
451	WYP	492,940		492,940		-	-	-	-	-	
451	WYU	247,018		247,018		-	-	-	-	-	
453	SG	2,609		2,609		-	-	684	-	-	
454	CA	532,583		532,583		-	-	-	-	-	
454	ID	208,736		208,736		-	-	-	-	-	
454	OR	5,093,973		5,093,973		-	-	5,093,973	-	-	
454	SG	5,417,250		5,417,250		-	-	1,419,460	-	-	
454	SO	3,485,471		3,485,471		-	-	965,519	-	-	
454	UT	3,410,084		3,410,084		-	-	-	-	-	
454	WA	1,031,803		1,031,803		-	-	-	-	-	
454	WYP	347,072		347,072		-	-	-	-	-	
454	WYU	32,125		32,125		-	-	-	-	-	
456	CA	865,247	865,247			-	-	-	-	-	
456	ID	5,939,873	5,939,833			39	-	-	-	-	
456	OR	18,762,486	18,762,568			(81)	18,762,568	-	-	(81)	
456	OTHER	(2,971,704)				(2,971,704)	-	-	-	-	
456	SE	8,162,720				8,162,720	-	-	-	2,047,087	
456	SG	187,647,753				187,647,753	-	-	-	49,168,592	
456	SO	474,389				474,389	-	-	-	131,412	
456	UT	62,561,630	62,981,154			(419,524)	-	-	-	-	
456	WA	8,802,937	8,855,002			(52,065)	-	-	-	-	
456	WYP	2,282,598	2,043,069			239,529	-	-	-	-	
456	WYU	648,277	648,268			9	-	-	-	-	
Total		**4,402,215,385**	**3,674,678,245**	**32,637,349**	**492,522,473**	**202,377,317**	**962,894,465**	**11,291,980**	**129,043,546**	**52,371,759**	**Ref. 2.1**
					Total Revenues	**4,402,215,385**			**Total Revenues**	**1,155,601,749**	**Ref. 2.1**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Results of Operations for O&M Expenses

				Total Company								
FERC Account	2010 Protocol Factor	Indicator	Amount	Coal	Natural Gas	Purchased Power	ECD	BPA Credit	Wheeling Expense	Labor & Benefits	Incentive	Other O&M
500	SG	500SG	20,107,030	-	-	-	-	-	-	14,856,883	578,642	4,671,506
501	SE	501SE	18,393,613	-	-	-	-	-	-	(164,716)	(6,416)	18,564,745
501NPC	ID	501NPCID	(249,096)	(249,096)	-	-	-	-	-	-	-	-
501NPC	SE	501NPCSE	629,251,120	615,671,735	13,579,385	-	-	-	-	-	-	0
501NPC	WYP	501NPCWYP	(665,891)	(665,891)	-	-	-	-	-	-	-	-
502	SG	502SG	38,472,021	-	-	-	-	-	-	16,593,595	646,283	21,232,143
503NPC	SE	503NPCSE	3,655,727	3,655,727	-	-	-	-	-	-	-	-
505	SG	505SG	4,285,137	-	-	-	-	-	-	1,741,614	67,832	2,475,691
506	SG	506SG	48,042,874	-	-	-	-	-	-	38,990,811	1,518,603	7,533,460
507	SG	507SG	338,685	-	-	-	-	-	-	-	-	338,685
510	SG	510SG	6,462,259	-	-	-	-	-	-	2,774,500	108,060	3,579,698
511	SG	511SG	25,480,955	-	-	-	-	-	-	6,595,007	256,860	18,629,088
512	SG	512SG	112,922,881	-	-	-	-	-	-	24,965,292	972,341	86,985,248
513	SG	513SG	38,934,338	-	-	-	-	-	-	10,614,127	413,396	27,906,815
514	SG	514SG	12,066,167	-	-	-	-	-	-	2,508,029	97,682	9,460,456
535	SG	535SG	3,825,666	-	-	-	-	-	-	3,881,710	151,184	(207,229)
536	SG	536SG	212,409	-	-	-	-	-	-	77,062	3,001	132,346
537	SG	537SG	3,449,509	-	-	-	-	-	-	415,870	16,197	3,017,441
539	SG	539SG	25,196,163	-	-	-	-	-	-	10,062,947	391,929	14,741,287
540	SG	540SG	117,398	-	-	-	-	-	-	(148,188)	(5,772)	271,357
541	SG	541SG	469	-	-	-	-	-	-	232	9	228
542	SG	542SG	1,430,392	-	-	-	-	-	-	484,334	18,864	927,195
543	SG	543SG	1,959,700	-	-	-	-	-	-	758,188	29,530	1,171,982
544	SG	544SG	1,635,171	-	-	-	-	-	-	962,926	37,504	634,741
545	SG	545SG	2,654,790	-	-	-	-	-	-	959,547	37,372	1,657,871
546	SG	546SG	358,628	-	-	-	-	-	-	1,649	64	356,915
547NPC	SE	547NPCSE	432,620,733	-	432,620,733	-	-	-	-	-	-	(0)
548	SG	548SG	14,638,534	-	-	-	-	-	-	5,148,230	200,512	9,289,792
549	SG	549SG	18,701,556	-	-	-	-	-	-	2,495,668	97,201	16,108,687
550	SG	550SG	3,558,679	-	-	-	-	-	-	-	-	3,558,679
552	SG	552SG	1,240,594	-	-	-	-	-	-	165,102	6,430	1,069,062
553	SG	553SG	8,996,404	-	-	-	-	-	-	1,994,290	77,673	6,924,442
554	SG	554SG	2,196,166	-	-	-	-	-	-	121,910	4,748	2,069,508
555	ID	555ID	606,635	-	-	-	-	606,635	-	-	-	-
555	OR	555OR	(28,650,083)	-	-	-	-	(28,650,083)	-	-	-	-
555	WA	555WA	(8,774,226)	-	-	-	-	(8,774,226)	-	-	-	-
555NPC	SE	555NPCSE	(52,775,347)	-	-	(52,775,347)	-	-	-	-	-	0
555NPC	SG	555NPCSG	469,600,699	-	-	469,600,699	-	-	-	-	-	(0)
556	SG	556SG	877,454	-	-	-	-	-	-	397,042	15,464	464,949
557	ID	557ID	(32,973)	-	-	-	-	-	-	-	-	(32,973)
557	OR	557OR	(53,813)	-	-	-	-	-	-	-	-	(53,813)
557	SG	557SG	58,620,601	-	-	-	-	-	-	31,133,250	1,212,569	26,274,783
557	SGCT	557SGCT	1,122,425	-	-	-	-	-	-	-	-	1,122,425
557	WA	557WA	(97,006)	-	-	-	-	-	-	-	-	(97,006)
560	SG	560SG	5,041,115	-	-	-	-	-	-	3,766,701	146,704	1,127,710
561	SG	561SG	10,336,896	-	-	-	-	-	-	8,334,622	324,614	1,677,660
562	SG	562SG	2,124,825	-	-	-	-	-	-	1,071,595	41,736	1,011,493
563	SG	563SG	120,209	-	-	-	-	-	-	67,489	2,629	50,092
565NPC	SE	565NPCSE	6,220,893	-	-	-	-	-	6,220,893	-	-	-
565NPC	SG	565NPCSG	130,633,756	-	-	-	-	-	130,633,756	-	-	-
566	SG	566SG	4,257,862	-	-	-	-	-	-	307,352	11,971	3,938,539
567	SG	567SG	1,312,382	-	-	-	-	-	-	152,623	5,944	1,153,814
568	SG	568SG	1,334,303	-	-	-	-	-	-	993,381	38,690	302,233
569	SG	569SG	4,669,784	-	-	-	-	-	-	2,442,985	95,149	2,131,650
570	SG	570SG	10,092,385	-	-	-	-	-	-	5,981,845	232,979	3,877,561
571	SG	571SG	19,173,510	-	-	-	-	-	-	(2,333,633)	(90,890)	21,598,033
572	SG	572SG	36,881	-	-	-	-	-	-	13,460	524	22,897
573	SG	573SG	273,467	-	-	-	-	-	-	6,344	247	266,876
580	CA	580CA	34,542	-	-	-	-	-	-	-	-	34,542

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580	ID	580ID	(35,716)	-	-	-	-	-	-	-	-	(35,716)
580	SNPD	580SNPD	15,572,431	-	-	-	-	-	-	14,655,203	570,787	346,441
580	UT	580UT	35,859	-	-	-	-	-	-	-	-	35,859
580	WA	580WA	18,008	-	-	-	-	-	-	-	-	18,008
580	WYP	580WYP	327	-	-	-	-	-	-	-	-	327
580	WYU	580WYU	-	-	-	-	-	-	-	-	-	-
581	SNPD	581SNPD	13,735,481	-	-	-	-	-	-	12,737,900	496,112	501,469
582	CA	582CA	133,451	-	-	-	-	-	-	72,939	2,841	57,671
582	ID	582ID	239,621	-	-	-	-	-	-	117,569	4,579	117,473
582	OR	582OR	916,683	-	-	-	-	-	-	464,543	18,093	434,048
582	SNPD	582SNPD	23,895	-	-	-	-	-	-	18,723	729	4,443
582	UT	582UT	1,726,434	-	-	-	-	-	-	740,397	28,837	957,200
582	WA	582WA	265,878	-	-	-	-	-	-	138,639	5,400	121,839
582	WYP	582WYP	506,871	-	-	-	-	-	-	304,141	11,846	190,884
583	CA	583CA	344,720	-	-	-	-	-	-	291,844	11,367	41,508
583	ID	583ID	193,198	-	-	-	-	-	-	161,176	6,277	25,745
583	OR	583OR	2,864,283	-	-	-	-	-	-	2,358,416	91,855	414,012
583	SNPD	583SNPD	36,344	-	-	-	-	-	-	18,865	735	16,744
583	UT	583UT	1,558,309	-	-	-	-	-	-	1,220,224	47,525	290,560
583	WA	583WA	340,279	-	-	-	-	-	-	274,095	10,675	55,509
583	WYP	583WYP	327,419	-	-	-	-	-	-	237,226	9,239	80,953
583	WYU	583WYU	97,602	-	-	-	-	-	-	71,779	2,796	23,028
584	ID	584ID	23	-	-	-	-	-	-	-	-	23
584	SNPD	584SNPD	-	-	-	-	-	-	-	-	-	-
584	UT	584UT	264	-	-	-	-	-	-	-	-	264
585	SNPD	585SNPD	209,265	-	-	-	-	-	-	201,051	7,830	383
586	CA	586CA	212,176	-	-	-	-	-	-	172,055	6,701	33,420
586	ID	586ID	275,498	-	-	-	-	-	-	224,126	8,729	42,643
586	OR	586OR	2,539,527	-	-	-	-	-	-	2,053,443	79,977	406,108
586	SNPD	586SNPD	1,186,441	-	-	-	-	-	-	911,490	35,500	239,451
586	UT	586UT	1,393,923	-	-	-	-	-	-	1,124,460	43,795	225,667
586	WA	586WA	348,794	-	-	-	-	-	-	279,967	10,904	57,923
586	WYP	586WYP	545,967	-	-	-	-	-	-	442,717	17,243	86,007
586	WYU	586WYU	62,035	-	-	-	-	-	-	50,757	1,977	9,301
587	CA	587CA	606,703	-	-	-	-	-	-	496,651	19,343	90,708
587	ID	587ID	399,341	-	-	-	-	-	-	321,623	12,526	65,191
587	OR	587OR	4,466,370	-	-	-	-	-	-	3,646,867	142,037	677,465
587	UT	587UT	5,167,135	-	-	-	-	-	-	4,108,882	160,032	898,221
587	WA	587WA	973,411	-	-	-	-	-	-	785,910	30,609	156,892
587	WYP	587WYP	960,141	-	-	-	-	-	-	761,129	29,644	169,368
587	WYU	587WYU	61,749	-	-	-	-	-	-	50,585	1,970	9,193
588	CA	588CA	22,144	-	-	-	-	-	-	(39,905)	(1,554)	63,604
588	ID	588ID	2,311	-	-	-	-	-	-	(51,070)	(1,989)	55,371
588	OR	588OR	411,285	-	-	-	-	-	-	(441,944)	(17,213)	870,442
588	SNPD	588SNPD	4,576,455	-	-	-	-	-	-	197,923	7,709	4,370,823
588	UT	588UT	807,700	-	-	-	-	-	-	10,100	393	797,207
588	WA	588WA	92,677	-	-	-	-	-	-	(49,385)	(1,923)	143,985
588	WYP	588WYP	(6,067)	-	-	-	-	-	-	(78,263)	(3,048)	75,244
588	WYU	588WYU	(19,242)	-	-	-	-	-	-	(39,108)	(1,523)	21,389
589	CA	589CA	88,561	-	-	-	-	-	-	10,190	397	77,974
589	ID	589ID	12,850	-	-	-	-	-	-	719	28	12,102
589	OR	589OR	1,883,954	-	-	-	-	-	-	79,478	3,096	1,801,380
589	SNPD	589SNPD	65,814	-	-	-	-	-	-	-	-	65,814
589	UT	589UT	517,694	-	-	-	-	-	-	14,173	552	502,970
589	WA	589WA	87,812	-	-	-	-	-	-	8,769	342	78,701
589	WYP	589WYP	579,787	-	-	-	-	-	-	8,589	335	570,864
589	WYU	589WYU	17,200	-	-	-	-	-	-	(124)	(5)	17,329
590	CA	590CA	19,678	-	-	-	-	-	-	14,938	582	4,159
590	ID	590ID	53,068	-	-	-	-	-	-	41,106	1,601	10,360

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590	OR	590OR	289,363	-	-	-	-	-	-	223,015	8,686	57,662
590	SNPD	590SNPD	4,676,484	-	-	-	-	-	-	4,396,895	171,249	108,341
590	UT	590UT	341,472	-	-	-	-	-	-	277,012	10,789	53,671
590	WA	590WA	13,492	-	-	-	-	-	-	9,497	370	3,625
590	WYP	590WYP	99,673	-	-	-	-	-	-	76,106	2,964	20,603
591	CA	591CA	34,917	-	-	-	-	-	-	-	-	34,917
591	ID	591ID	154,460	-	-	-	-	-	-	-	-	154,460
591	OR	591OR	511,889	-	-	-	-	-	-	-	-	511,889
591	SNPD	591SNPD	79,605	-	-	-	-	-	-	-	-	79,605
591	UT	591UT	682,305	-	-	-	-	-	-	-	-	682,305
591	WA	591WA	101,035	-	-	-	-	-	-	-	-	101,035
591	WYP	591WYP	215,238	-	-	-	-	-	-	-	-	215,238
591	WYU	591WYU	49,420	-	-	-	-	-	-	-	-	49,420
592	CA	592CA	602,587	-	-	-	-	-	-	394,779	15,376	192,432
592	ID	592ID	734,232	-	-	-	-	-	-	479,444	18,673	236,115
592	OR	592OR	3,738,693	-	-	-	-	-	-	2,223,709	86,608	1,428,375
592	SNPD	592SNPD	1,476,908	-	-	-	-	-	-	1,319,064	51,375	106,470
592	UT	592UT	4,065,883	-	-	-	-	-	-	2,521,601	98,211	1,446,072
592	WA	592WA	681,092	-	-	-	-	-	-	441,131	17,181	222,779
592	WYP	592WYP	1,321,760	-	-	-	-	-	-	673,876	26,246	621,638
592	WYU	592WYU	916	-	-	-	-	-	-	512	20	384
593	CA	593CA	5,372,165	-	-	-	-	-	-	3,348,951	130,434	1,892,780
593	ID	593ID	5,104,158	-	-	-	-	-	-	2,137,832	83,264	2,883,062
593	MT	593MT	-	-	-	-	-	-	-	-	-	-
593	OR	593OR	29,338,958	-	-	-	-	-	-	7,035,893	274,032	22,029,034
593	SNPD	593SNPD	1,056,813	-	-	-	-	-	-	(544,255)	(21,197)	1,622,266
593	UT	593UT	33,126,353	-	-	-	-	-	-	7,498,559	292,052	25,335,743
593	WA	593WA	4,367,920	-	-	-	-	-	-	410,503	15,988	3,941,428
593	WYP	593WYP	4,891,397	-	-	-	-	-	-	1,312,315	51,112	3,527,971
593	WYU	593WYU	1,472,630	-	-	-	-	-	-	394,541	15,366	1,062,723
594	CA	594CA	465,094	-	-	-	-	-	-	345,410	13,453	106,231
594	ID	594ID	687,240	-	-	-	-	-	-	382,155	14,884	290,201
594	OR	594OR	5,755,946	-	-	-	-	-	-	3,579,115	139,398	2,037,433
594	SNPD	594SNPD	-	-	-	-	-	-	-	-	-	-
594	UT	594UT	12,375,764	-	-	-	-	-	-	6,986,672	272,115	5,116,977
594	WA	594WA	1,079,850	-	-	-	-	-	-	700,789	27,294	351,767
594	WYP	594WYP	2,135,613	-	-	-	-	-	-	866,594	33,752	1,235,267
594	WYU	594WYU	286,909	-	-	-	-	-	-	109,487	4,264	173,158
595	SNPD	595SNPD	883,285	-	-	-	-	-	-	691,741	26,942	164,602
595	UT	595UT	-	-	-	-	-	-	-	-	-	-
596	CA	596CA	129,901	-	-	-	-	-	-	104,090	4,054	21,756
596	ID	596ID	156,790	-	-	-	-	-	-	120,201	4,682	31,907
596	OR	596OR	1,065,645	-	-	-	-	-	-	805,027	31,354	229,264
596	UT	596UT	2,021,111	-	-	-	-	-	-	325,215	12,666	1,683,229
596	WA	596WA	168,275	-	-	-	-	-	-	130,000	5,063	33,212
596	WYP	596WYP	451,954	-	-	-	-	-	-	276,313	10,762	164,880
596	WYU	596WYU	90,884	-	-	-	-	-	-	36,526	1,423	52,935
597	CA	597CA	62,766	-	-	-	-	-	-	47,929	1,867	12,970
597	ID	597ID	302,207	-	-	-	-	-	-	246,711	9,609	45,888
597	OR	597OR	1,054,691	-	-	-	-	-	-	854,872	33,295	166,524
597	SNPD	597SNPD	1,088,248	-	-	-	-	-	-	708,403	27,591	352,255
597	UT	597UT	2,267,135	-	-	-	-	-	-	1,716,086	66,838	484,211
597	WA	597WA	468,153	-	-	-	-	-	-	357,846	13,937	96,370
597	WYP	597WYP	550,845	-	-	-	-	-	-	450,708	17,554	82,583
597	WYU	597WYU	96,599	-	-	-	-	-	-	79,058	3,079	14,462
598	CA	598CA	92,218	-	-	-	-	-	-	14,380	560	77,277
598	ID	598ID	44,807	-	-	-	-	-	-	-	-	44,807
598	OR	598OR	492,635	-	-	-	-	-	-	62,857	2,448	427,330
598	SNPD	598SNPD	689,001	-	-	-	-	-	-	1,033,363	40,247	(384,610)

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598	UT	598UT	1,111,290	-	-	-	-	-	-	5,941	231	1,105,118
598	WA	598WA	6,250	-	-	-	-	-	-	28,915	1,126	(23,791)
598	WYP	598WYP	307,579	-	-	-	-	-	-	-	-	307,579
598	WYU	598WYU	1,441	-	-	-	-	-	-	161	6	1,274
901	CN	901CN	2,495,978	-	-	-	-	-	-	1,899,933	73,998	522,047
901	OR	901OR	1,375	-	-	-	-	-	-	1,120	44	211
901	WYP	901WYP	328	-	-	-	-	-	-	67	3	259
902	CA	902CA	875,698	-	-	-	-	-	-	715,837	27,880	131,981
902	CN	902CN	1,919,847	-	-	-	-	-	-	1,425,630	55,525	438,693
902	ID	902ID	1,684,580	-	-	-	-	-	-	1,322,078	51,492	311,009
902	OR	902OR	9,283,571	-	-	-	-	-	-	7,702,921	300,011	1,280,639
902	UT	902UT	4,547,623	-	-	-	-	-	-	3,688,167	143,646	715,810
902	WA	902WA	2,218,397	-	-	-	-	-	-	1,865,266	72,648	280,483
902	WYP	902WYP	1,746,927	-	-	-	-	-	-	1,295,982	50,476	400,469
902	WYU	902WYU	276,845	-	-	-	-	-	-	214,844	8,368	53,634
903	CA	903CA	213,153	-	-	-	-	-	-	158,106	6,158	48,890
903	CN	903CN	47,482,101	-	-	-	-	-	-	31,393,334	1,222,698	14,866,069
903	ID	903ID	391,315	-	-	-	-	-	-	278,785	10,858	101,672
903	OR	903OR	2,079,360	-	-	-	-	-	-	1,426,261	55,550	597,548
903	UT	903UT	3,663,328	-	-	-	-	-	-	2,478,915	96,548	1,087,865
903	WA	903WA	643,197	-	-	-	-	-	-	433,508	16,884	192,805
903	WYP	903WYP	381,706	-	-	-	-	-	-	246,997	9,620	125,089
903	WYU	903WYU	84,733	-	-	-	-	-	-	68,609	2,672	13,452
904	CA	904CA	566,220	-	-	-	-	-	-	-	-	566,220
904	CN	904CN	95,649	-	-	-	-	-	-	-	-	95,649
904	ID	904ID	678,156	-	-	-	-	-	-	-	-	678,156
904	OR	904OR	4,762,466	-	-	-	-	-	-	-	-	4,762,466
904	UT	904UT	4,011,727	-	-	-	-	-	-	-	-	4,011,727
904	WA	904WA	1,561,038	-	-	-	-	-	-	-	-	1,561,038
904	WYP	904WYP	915,400	-	-	-	-	-	-	-	-	915,400
904	WYU	904WYU	-	-	-	-	-	-	-	-	-	-
905	CN	905CN	164,911	-	-	-	-	-	-	107,513	4,187	53,211
905	OR	905OR	5,016	-	-	-	-	-	-	-	-	5,016
907	CN	907CN	263,903	-	-	-	-	-	-	233,643	9,100	21,161
908	CA	908CA	1,128,030	-	-	-	-	-	-	1,136	44	1,126,850
908	CN	908CN	2,794,497	-	-	-	-	-	-	2,432,862	94,754	266,880
908	ID	908ID	6,803,334	-	-	-	-	-	-	416,485	16,221	6,370,628
908	OR	908OR	20,004,876	-	-	-	-	-	-	1,155,246	44,994	18,804,636
908	OTHER	908OTHER	4,235,143	-	-	-	-	-	-	36,302	1,414	4,197,427
908	UT	908UT	76,607,673	-	-	-	-	-	-	2,028,092	78,990	74,500,592
908	WA	908WA	8,925,882	-	-	-	-	-	-	-	-	8,925,882
908	WYP	908WYP	3,656,365	-	-	-	-	-	-	814,734	31,732	2,809,899
909	CA	909CA	52,116	-	-	-	-	-	-	84	3	52,028
909	CN	909CN	3,789,781	-	-	-	-	-	-	445,886	17,366	3,326,529
909	ID	909ID	60,122	-	-	-	-	-	-	-	-	60,122
909	OR	909OR	263,443	-	-	-	-	-	-	-	-	263,443
909	UT	909UT	86,979	-	-	-	-	-	-	-	-	86,979
909	WA	909WA	26,010	-	-	-	-	-	-	-	-	26,010
909	WYP	909WYP	135,715	-	-	-	-	-	-	-	-	135,715
909	WYU	909WYU	20,866	-	-	-	-	-	-	-	-	20,866
910	CN	910CN	90,169	-	-	-	-	-	-	1,299	51	88,819
920	CA	920CA	(72,947)	-	-	-	-	-	-	-	-	(72,947)
920	ID	920ID	493,730	-	-	-	-	-	-	-	-	493,730
920	OR	920OR	677,723	-	-	-	-	-	-	-	-	677,723
920	SO	920SO	71,688,978	-	-	-	-	-	-	75,535,895	2,941,950	(6,788,868)
920	UT	920UT	(5,352,652)	-	-	-	-	-	-	-	-	(5,352,652)
920	WA	920WA	(695,192)	-	-	-	-	-	-	-	-	(695,192)
920	WYP	920WYP	(280,815)	-	-	-	-	-	-	-	-	(280,815)
921	CA	921CA	18,914	-	-	-	-	-	-	-	-	18,914

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				Total Company								
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921	ID	921ID	49,229	-	-	-	-	-	-	-	-	49,229
921	OR	921OR	277,438	-	-	-	-	-	-	-	-	277,438
921	SO	921SO	9,237,574	-	-	-	-	-	-	(241,929)	(9,423)	9,488,925
921	UT	921UT	204,211	-	-	-	-	-	-	-	-	204,211
921	WA	921WA	52,177	-	-	-	-	-	-	21	1	52,155
921	WYP	921WYP	118,187	-	-	-	-	-	-	-	-	118,187
921	WYU	921WYU	16,154	-	-	-	-	-	-	-	-	16,154
922	SO	922SO	(28,375,128)	-	-	-	-	-	-	27,518,812	1,071,795	(56,965,735)
923	CA	923CA	-	-	-	-	-	-	-	-	-	-
923	OR	923OR	8,195	-	-	-	-	-	-	-	-	8,195
923	SO	923SO	9,396,107	-	-	-	-	-	-	-	-	9,396,107
923	UT	923UT	-	-	-	-	-	-	-	-	-	-
924	SO	924SO	23,341,430	-	-	-	-	-	-	-	-	23,341,430
925	SO	925SO	8,492,514	-	-	-	-	-	-	-	-	8,492,514
928	CA	928CA	725,998	-	-	-	-	-	-	196,452	7,651	521,894
928	ID	928ID	1,199,068	-	-	-	-	-	-	581,757	22,658	594,653
928	OR	928OR	3,489,938	-	-	-	-	-	-	424,405	16,530	3,049,004
928	SG	928SG	2,513,914	-	-	-	-	-	-	-	-	2,513,914
928	SO	928SO	1,538,229	-	-	-	-	-	-	183,256	7,137	1,347,836
928	UT	928UT	4,996,941	-	-	-	-	-	-	641,690	24,992	4,330,259
928	WA	928WA	1,222,850	-	-	-	-	-	-	400,604	15,603	806,643
928	WYP	928WYP	2,239,902	-	-	-	-	-	-	491,481	19,142	1,729,280
929	SO	929SO	(6,130,868)	-	-	-	-	-	-	(900,482)	(35,072)	(5,195,314)
930	CA	930CA	(2,123)	-	-	-	-	-	-	-	-	(2,123)
930	CN	930CN	1,601	-	-	-	-	-	-	-	-	1,601
930	ID	930ID	12,950	-	-	-	-	-	-	-	-	12,950
930	OR	930OR	2,335,084	-	-	-	-	-	-	-	-	2,335,084
930	SO	930SO	13,592,405	-	-	-	-	-	-	-	-	13,592,405
930	UT	930UT	298,972	-	-	-	-	-	-	-	-	298,972
930	WA	930WA	9,267	-	-	-	-	-	-	-	-	9,267
930	WYP	930WYP	63,877	-	-	-	-	-	-	-	-	63,877
931	ID	931ID	-	-	-	-	-	-	-	-	-	-
931	OR	931OR	991,618	-	-	-	-	-	-	-	-	991,618
931	SO	931SO	5,344,545	-	-	-	-	-	-	-	-	5,344,545
931	UT	931UT	1,541	-	-	-	-	-	-	-	-	1,541
935	OR	935OR	20,356	-	-	-	-	-	-	16,660	649	3,048
935	SO	935SO	22,312,089	-	-	-	-	-	-	2,373,666	92,449	19,845,974
935	UT	935UT	-	-	-	-	-	-	-	-	-	-
935	WA	935WA	2,504	-	-	-	-	-	-	2,050	80	375
ECD	DGP	ECDDGP	(41,510,730)	-	-	-	(41,510,730)	-	-	-	-	-
ECD	MC	ECDMC	(30,896,884)	-	-	-	(30,896,884)	-	-	-	-	-
ECD	SG	ECDSG	72,407,614	-	-	-	72,407,614	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
Total O&M			**2,692,685,751**	**618,412,475**	**446,200,118**	**416,825,351**	**-**	**(36,817,673)**	**136,854,649**	**475,604,778**	**18,523,716**	**617,082,337**
											Total O&M Expense	**2,692,685,751**

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500	SG	500SG	20,107,030	-	-	-	-	-	-	3,892,890	151,619	1,224,056	
501	SE	501SE	18,393,613	-	-	-	-	-	-	(41,308)	(1,609)	4,655,758	
501NPC	ID	501NPCID	(249,096)	-	-	-	-	-	-	-	-	-	
501NPC	SE	501NPCSE	629,251,120	154,401,195	3,405,505	-	-	-	-	-	-	0	
501NPC	WYP	501NPCWYP	(665,891)	-	-	-	-	-	-	-	-	-	
502	SG	502SG	38,472,021	-	-	-	-	-	-	4,347,953	169,343	5,563,374	
503NPC	SE	503NPCSE	3,655,727	916,801	-	-	-	-	-	-	-	-	
505	SG	505SG	4,285,137	-	-	-	-	-	-	456,348	17,774	648,695	
506	SG	506SG	48,042,874	-	-	-	-	-	-	10,216,606	397,913	1,973,963	
507	SG	507SG	338,685	-	-	-	-	-	-	-	-	88,744	
510	SG	510SG	6,462,259	-	-	-	-	-	-	726,991	28,315	937,974	
511	SG	511SG	25,480,955	-	-	-	-	-	-	1,728,063	67,304	4,881,306	
512	SG	512SG	112,922,881	-	-	-	-	-	-	6,541,556	254,779	22,792,397	
513	SG	513SG	38,934,338	-	-	-	-	-	-	2,781,177	108,320	7,312,311	
514	SG	514SG	12,066,167	-	-	-	-	-	-	657,169	25,595	2,478,886	
535	SG	535SG	3,825,666	-	-	-	-	-	-	1,017,109	39,614	(54,299)	
536	SG	536SG	212,409	-	-	-	-	-	-	20,192	786	34,678	
537	SG	537SG	3,449,509	-	-	-	-	-	-	108,969	4,244	790,648	
539	SG	539SG	25,196,163	-	-	-	-	-	-	2,636,754	102,696	3,862,601	
540	SG	540SG	117,398	-	-	-	-	-	-	(38,829)	(1,512)	71,103	
541	SG	541SG	469	-	-	-	-	-	-	61	2	60	
542	SG	542SG	1,430,392	-	-	-	-	-	-	126,908	4,943	242,949	
543	SG	543SG	1,959,700	-	-	-	-	-	-	198,665	7,738	307,090	
544	SG	544SG	1,635,171	-	-	-	-	-	-	252,312	9,827	166,319	
545	SG	545SG	2,654,790	-	-	-	-	-	-	251,426	9,792	434,405	
546	SG	546SG	358,628	-	-	-	-	-	-	432	17	93,521	
547NPC	SE	547NPCSE	432,620,733	-	108,494,762	-	-	-	-	-	-	(0)	
548	SG	548SG	14,638,534	-	-	-	-	-	-	1,348,970	52,539	2,434,167	
549	SG	549SG	18,701,556	-	-	-	-	-	-	653,930	25,469	4,220,895	
550	SG	550SG	3,558,679	-	-	-	-	-	-	-	-	932,466	
552	SG	552SG	1,240,594	-	-	-	-	-	-	43,261	1,685	280,122	
553	SG	553SG	8,996,404	-	-	-	-	-	-	522,556	20,352	1,814,384	
554	SG	554SG	2,196,166	-	-	-	-	-	-	31,943	1,244	542,265	
555	ID	555ID	606,635	-	-	-	-	-	-	-	-	-	
555	OR	555OR	(28,650,083)	-	-	-	-	(28,650,083)	-	-	-	-	
555	WA	555WA	(8,774,226)	-	-	-	-	-	-	-	-	-	
555NPC	SE	555NPCSE	(52,775,347)	-	-	(13,235,262)	-	-	-	-	-	0	
555NPC	SG	555NPCSG	469,600,699	-	-	123,047,596	-	-	-	-	-	(0)	
556	SG	556SG	877,454	-	-	-	-	-	-	104,035	4,052	121,829	
557	ID	557ID	(32,973)	-	-	-	-	-	-	-	-	-	
557	OR	557OR	(53,813)	-	-	-	-	-	-	-	-	(53,813)	
557	SG	557SG	58,620,601	-	-	-	-	-	-	8,157,721	317,725	6,884,677	
557	SGCT	557SGCT	1,122,425	-	-	-	-	-	-	-	-	295,245	
557	WA	557WA	(97,006)	-	-	-	-	-	-	-	-	-	
560	SG	560SG	5,041,115	-	-	-	-	-	-	986,974	38,440	295,489	
561	SG	561SG	10,336,896	-	-	-	-	-	-	2,183,888	85,057	439,590	
562	SG	562SG	2,124,825	-	-	-	-	-	-	280,786	10,936	265,038	
563	SG	563SG	120,209	-	-	-	-	-	-	17,684	689	13,125	
565NPC	SE	565NPCSE	6,220,893	-	-	-	-	-	1,560,106	-	-	-	
565NPC	SG	565NPCSG	130,633,756	-	-	-	-	-	34,229,441	-	-	-	
566	SG	566SG	4,257,862	-	-	-	-	-	-	80,534	3,137	1,032,000	
567	SG	567SG	1,312,382	-	-	-	-	-	-	39,991	1,558	302,329	
568	SG	568SG	1,334,303	-	-	-	-	-	-	260,292	10,138	79,193	
569	SG	569SG	4,669,784	-	-	-	-	-	-	640,126	24,931	558,548	
570	SG	570SG	10,092,385	-	-	-	-	-	-	1,567,399	61,047	1,016,022	
571	SG	571SG	19,173,510	-	-	-	-	-	-	(611,472)	(23,815)	5,659,246	
572	SG	572SG	36,881	-	-	-	-	-	-	3,527	137	6,000	
573	SG	573SG	273,467	-	-	-	-	-	-	1,662	65	69,929	
580	CA	580CA	34,542	-	-	-	-	-	-	-	-	-	

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580	ID	580ID	(35,716)	-	-	-	-	-	-	-	-	-	
580	SNPD	580SNPD	15,572,431	-	-	-	-	-	-	4,123,598	160,605	97,480	
580	UT	580UT	35,859	-	-	-	-	-	-	-	-	-	
580	WA	580WA	18,008	-	-	-	-	-	-	-	-	-	
580	WYP	580WYP	327	-	-	-	-	-	-	-	-	-	
580	WYU	580WYU	-	-	-	-	-	-	-	-	-	-	
581	SNPD	581SNPD	13,735,481	-	-	-	-	-	-	3,584,118	139,593	141,101	
582	CA	582CA	133,451	-	-	-	-	-	-	-	-	-	
582	ID	582ID	239,621	-	-	-	-	-	-	-	-	-	
582	OR	582OR	916,683	-	-	-	-	-	-	464,543	18,093	434,048	
582	SNPD	582SNPD	23,895	-	-	-	-	-	-	5,268	205	1,250	
582	UT	582UT	1,726,434	-	-	-	-	-	-	-	-	-	
582	WA	582WA	265,878	-	-	-	-	-	-	-	-	-	
582	WYP	582WYP	506,871	-	-	-	-	-	-	-	-	-	
583	CA	583CA	344,720	-	-	-	-	-	-	-	-	-	
583	ID	583ID	193,198	-	-	-	-	-	-	-	-	-	
583	OR	583OR	2,864,283	-	-	-	-	-	-	2,358,416	91,855	414,012	
583	SNPD	583SNPD	36,344	-	-	-	-	-	-	5,308	207	4,711	
583	UT	583UT	1,558,309	-	-	-	-	-	-	-	-	-	
583	WA	583WA	340,279	-	-	-	-	-	-	-	-	-	
583	WYP	583WYP	327,419	-	-	-	-	-	-	-	-	-	
583	WYU	583WYU	97,602	-	-	-	-	-	-	-	-	-	
584	ID	584ID	23	-	-	-	-	-	-	-	-	-	
584	SNPD	584SNPD	-	-	-	-	-	-	-	-	-	-	
584	UT	584UT	264	-	-	-	-	-	-	-	-	-	
585	SNPD	585SNPD	209,265	-	-	-	-	-	-	56,571	2,203	108	
586	CA	586CA	212,176	-	-	-	-	-	-	-	-	-	
586	ID	586ID	275,498	-	-	-	-	-	-	-	-	-	
586	OR	586OR	2,539,527	-	-	-	-	-	-	2,053,443	79,977	406,108	
586	SNPD	586SNPD	1,186,441	-	-	-	-	-	-	256,470	9,989	67,375	
586	UT	586UT	1,393,923	-	-	-	-	-	-	-	-	-	
586	WA	586WA	348,794	-	-	-	-	-	-	-	-	-	
586	WYP	586WYP	545,967	-	-	-	-	-	-	-	-	-	
586	WYU	586WYU	62,035	-	-	-	-	-	-	-	-	-	
587	CA	587CA	606,703	-	-	-	-	-	-	-	-	-	
587	ID	587ID	399,341	-	-	-	-	-	-	-	-	-	
587	OR	587OR	4,466,370	-	-	-	-	-	-	3,646,867	142,037	677,465	
587	UT	587UT	5,167,135	-	-	-	-	-	-	-	-	-	
587	WA	587WA	973,411	-	-	-	-	-	-	-	-	-	
587	WYP	587WYP	960,141	-	-	-	-	-	-	-	-	-	
587	WYU	587WYU	61,749	-	-	-	-	-	-	-	-	-	
588	CA	588CA	22,144	-	-	-	-	-	-	-	-	-	
588	ID	588ID	2,311	-	-	-	-	-	-	-	-	-	
588	OR	588OR	411,285	-	-	-	-	-	-	(441,944)	(17,213)	870,442	
588	SNPD	588SNPD	4,576,455	-	-	-	-	-	-	55,690	2,169	1,229,837	
588	UT	588UT	807,700	-	-	-	-	-	-	-	-	-	
588	WA	588WA	92,677	-	-	-	-	-	-	-	-	-	
588	WYP	588WYP	(6,067)	-	-	-	-	-	-	-	-	-	
588	WYU	588WYU	(19,242)	-	-	-	-	-	-	-	-	-	
589	CA	589CA	88,561	-	-	-	-	-	-	-	-	-	
589	ID	589ID	12,850	-	-	-	-	-	-	-	-	-	
589	OR	589OR	1,883,954	-	-	-	-	-	-	79,478	3,096	1,801,380	
589	SNPD	589SNPD	65,814	-	-	-	-	-	-	-	-	18,518	
589	UT	589UT	517,694	-	-	-	-	-	-	-	-	-	
589	WA	589WA	87,812	-	-	-	-	-	-	-	-	-	
589	WYP	589WYP	579,787	-	-	-	-	-	-	-	-	-	
589	WYU	589WYU	17,200	-	-	-	-	-	-	-	-	-	
590	CA	590CA	19,678	-	-	-	-	-	-	-	-	-	
590	ID	590ID	53,068	-	-	-	-	-	-	-	-	-	

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590	OR	590OR	289,363	-	-	-	-	-	-	223,015	8,686	57,662	
590	SNPD	590SNPD	4,676,484	-	-	-	-	-	-	1,237,173	48,185	30,484	
590	UT	590UT	341,472	-	-	-	-	-	-	-	-	-	
590	WA	590WA	13,492	-	-	-	-	-	-	-	-	-	
590	WYP	590WYP	99,673	-	-	-	-	-	-	-	-	-	
591	CA	591CA	34,917	-	-	-	-	-	-	-	-	-	
591	ID	591ID	154,460	-	-	-	-	-	-	-	-	-	
591	OR	591OR	511,889	-	-	-	-	-	-	-	-	511,889	
591	SNPD	591SNPD	79,605	-	-	-	-	-	-	-	-	22,399	
591	UT	591UT	682,305	-	-	-	-	-	-	-	-	-	
591	WA	591WA	101,035	-	-	-	-	-	-	-	-	-	
591	WYP	591WYP	215,238	-	-	-	-	-	-	-	-	-	
591	WYU	591WYU	49,420	-	-	-	-	-	-	-	-	-	
592	CA	592CA	602,587	-	-	-	-	-	-	-	-	-	
592	ID	592ID	734,232	-	-	-	-	-	-	-	-	-	
592	OR	592OR	3,738,693	-	-	-	-	-	-	2,223,709	86,608	1,428,375	
592	SNPD	592SNPD	1,476,908	-	-	-	-	-	-	371,151	14,455	29,958	
592	UT	592UT	4,065,883	-	-	-	-	-	-	-	-	-	
592	WA	592WA	681,092	-	-	-	-	-	-	-	-	-	
592	WYP	592WYP	1,321,760	-	-	-	-	-	-	-	-	-	
592	WYU	592WYU	916	-	-	-	-	-	-	-	-	-	
593	CA	593CA	5,372,165	-	-	-	-	-	-	-	-	-	
593	ID	593ID	5,104,158	-	-	-	-	-	-	-	-	-	
593	MT	593MT	-	-	-	-	-	-	-	-	-	-	
593	OR	593OR	29,338,958	-	-	-	-	-	-	7,035,893	274,032	22,029,034	
593	SNPD	593SNPD	1,056,813	-	-	-	-	-	-	(153,139)	(5,964)	456,464	
593	UT	593UT	33,126,353	-	-	-	-	-	-	-	-	-	
593	WA	593WA	4,367,920	-	-	-	-	-	-	-	-	-	
593	WYP	593WYP	4,891,397	-	-	-	-	-	-	-	-	-	
593	WYU	593WYU	1,472,630	-	-	-	-	-	-	-	-	-	
594	CA	594CA	465,094	-	-	-	-	-	-	-	-	-	
594	ID	594ID	687,240	-	-	-	-	-	-	-	-	-	
594	OR	594OR	5,755,946	-	-	-	-	-	-	3,579,115	139,398	2,037,433	
594	SNPD	594SNPD	-	-	-	-	-	-	-	-	-	-	
594	UT	594UT	12,375,764	-	-	-	-	-	-	-	-	-	
594	WA	594WA	1,079,850	-	-	-	-	-	-	-	-	-	
594	WYP	594WYP	2,135,613	-	-	-	-	-	-	-	-	-	
594	WYU	594WYU	286,909	-	-	-	-	-	-	-	-	-	
595	SNPD	595SNPD	883,285	-	-	-	-	-	-	194,638	7,581	46,315	
595	UT	595UT	-	-	-	-	-	-	-	-	-	-	
596	CA	596CA	129,901	-	-	-	-	-	-	-	-	-	
596	ID	596ID	156,790	-	-	-	-	-	-	-	-	-	
596	OR	596OR	1,065,645	-	-	-	-	-	-	805,027	31,354	229,264	
596	UT	596UT	2,021,111	-	-	-	-	-	-	-	-	-	
596	WA	596WA	168,275	-	-	-	-	-	-	-	-	-	
596	WYP	596WYP	451,954	-	-	-	-	-	-	-	-	-	
596	WYU	596WYU	90,884	-	-	-	-	-	-	-	-	-	
597	CA	597CA	62,766	-	-	-	-	-	-	-	-	-	
597	ID	597ID	302,207	-	-	-	-	-	-	-	-	-	
597	OR	597OR	1,054,691	-	-	-	-	-	-	854,872	33,295	166,524	
597	SNPD	597SNPD	1,088,248	-	-	-	-	-	-	199,326	7,763	99,115	
597	UT	597UT	2,267,135	-	-	-	-	-	-	-	-	-	
597	WA	597WA	468,153	-	-	-	-	-	-	-	-	-	
597	WYP	597WYP	550,845	-	-	-	-	-	-	-	-	-	
597	WYU	597WYU	96,599	-	-	-	-	-	-	-	-	-	
598	CA	598CA	92,218	-	-	-	-	-	-	-	-	-	
598	ID	598ID	44,807	-	-	-	-	-	-	-	-	-	
598	OR	598OR	492,635	-	-	-	-	-	-	62,857	2,448	427,330	
598	SNPD	598SNPD	689,001	-	-	-	-	-	-	290,762	11,325	(108,219)	

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December 2010 Lead/Lag Study
Results of Operations for O&M Expenses

FERC Account	2010 Protocol Factor	Indicator	Amount	Oregon									Ref.
				Coal	Natural Gas	Purchased Power	ECD	BPA Credit	Wheeling Expense	Labor & Benefits	Incentive	Other O&M	
598	UT	598UT	1,111,290	-	-	-	-	-	-	-	-	-	
598	WA	598WA	6,250	-	-	-	-	-	-	-	-	-	
598	WYP	598WYP	307,579	-	-	-	-	-	-	-	-	-	
598	WYU	598WYU	1,441	-	-	-	-	-	-	-	-	-	
901	CN	901CN	2,495,978	-	-	-	-	-	-	584,612	22,769	160,635	
901	OR	901OR	1,375	-	-	-	-	-	-	1,120	44	211	
901	WYP	901WYP	328	-	-	-	-	-	-	-	-	-	
902	CA	902CA	875,698	-	-	-	-	-	-	-	-	-	
902	CN	902CN	1,919,847	-	-	-	-	-	-	438,668	17,085	134,986	
902	ID	902ID	1,684,580	-	-	-	-	-	-	-	-	-	
902	OR	902OR	9,283,571	-	-	-	-	-	-	7,702,921	300,011	1,280,639	
902	UT	902UT	4,547,623	-	-	-	-	-	-	-	-	-	
902	WA	902WA	2,218,397	-	-	-	-	-	-	-	-	-	
902	WYP	902WYP	1,746,927	-	-	-	-	-	-	-	-	-	
902	WYU	902WYU	276,845	-	-	-	-	-	-	-	-	-	
903	CA	903CA	213,153	-	-	-	-	-	-	-	-	-	
903	CN	903CN	47,482,101	-	-	-	-	-	-	9,659,778	376,226	4,574,313	
903	ID	903ID	391,315	-	-	-	-	-	-	-	-	-	
903	OR	903OR	2,079,360	-	-	-	-	-	-	1,426,261	55,550	597,548	
903	UT	903UT	3,663,328	-	-	-	-	-	-	-	-	-	
903	WA	903WA	643,197	-	-	-	-	-	-	-	-	-	
903	WYP	903WYP	381,706	-	-	-	-	-	-	-	-	-	
903	WYU	903WYU	84,733	-	-	-	-	-	-	-	-	-	
904	CA	904CA	566,220	-	-	-	-	-	-	-	-	-	
904	CN	904CN	95,649	-	-	-	-	-	-	-	-	29,431	
904	ID	904ID	678,156	-	-	-	-	-	-	-	-	-	
904	OR	904OR	4,762,466	-	-	-	-	-	-	-	-	4,762,466	
904	UT	904UT	4,011,727	-	-	-	-	-	-	-	-	-	
904	WA	904WA	1,561,038	-	-	-	-	-	-	-	-	-	
904	WYP	904WYP	915,400	-	-	-	-	-	-	-	-	-	
904	WYU	904WYU	-	-	-	-	-	-	-	-	-	-	
905	CN	905CN	164,911	-	-	-	-	-	-	33,082	1,288	16,373	
905	OR	905OR	5,016	-	-	-	-	-	-	-	-	5,016	
907	CN	907CN	263,903	-	-	-	-	-	-	71,892	2,800	6,511	
908	CA	908CA	1,128,030	-	-	-	-	-	-	-	-	-	
908	CN	908CN	2,794,497	-	-	-	-	-	-	748,596	29,156	82,119	
908	ID	908ID	6,803,334	-	-	-	-	-	-	-	-	-	
908	OR	908OR	20,004,876	-	-	-	-	-	-	1,155,246	44,994	18,804,636	
908	OTHER	908OTHER	4,235,143	-	-	-	-	-	-	-	-	-	
908	UT	908UT	76,607,673	-	-	-	-	-	-	-	-	-	
908	WA	908WA	8,925,882	-	-	-	-	-	-	-	-	-	
908	WYP	908WYP	3,656,365	-	-	-	-	-	-	-	-	-	
909	CA	909CA	52,116	-	-	-	-	-	-	-	-	-	
909	CN	909CN	3,789,781	-	-	-	-	-	-	137,200	5,344	1,023,578	
909	ID	909ID	60,122	-	-	-	-	-	-	-	-	-	
909	OR	909OR	263,443	-	-	-	-	-	-	-	-	263,443	
909	UT	909UT	86,979	-	-	-	-	-	-	-	-	-	
909	WA	909WA	26,010	-	-	-	-	-	-	-	-	-	
909	WYP	909WYP	135,715	-	-	-	-	-	-	-	-	-	
909	WYU	909WYU	20,866	-	-	-	-	-	-	-	-	-	
910	CN	910CN	90,169	-	-	-	-	-	-	400	16	27,330	
920	CA	920CA	(72,947)	-	-	-	-	-	-	-	-	-	
920	ID	920ID	493,730	-	-	-	-	-	-	-	-	-	
920	OR	920OR	677,723	-	-	-	-	-	-	-	-	677,723	
920	SO	920SO	71,688,978	-	-	-	-	-	-	20,924,391	814,957	(1,880,602)	
920	UT	920UT	(5,352,652)	-	-	-	-	-	-	-	-	-	
920	WA	920WA	(695,192)	-	-	-	-	-	-	-	-	-	
920	WYP	920WYP	(280,815)	-	-	-	-	-	-	-	-	-	
921	CA	921CA	18,914	-	-	-	-	-	-	-	-	-	

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December 2010 Lead/Lag Study
Results of Operations for O&M Expenses

FERC Account	2010 Protocol Factor	Indicator	Amount	Oregon									Ref.
				Coal	Natural Gas	Purchased Power	ECD	BPA Credit	Wheeling Expense	Labor & Benefits	Incentive	Other O&M	
921	ID	921ID	49,229	-	-	-	-	-	-	-	-	-	
921	OR	921OR	277,438	-	-	-	-	-	-	-	-	277,438	
921	SO	921SO	9,237,574	-	-	-	-	-	-	(67,017)	(2,610)	2,628,551	
921	UT	921UT	204,211	-	-	-	-	-	-	-	-	-	
921	WA	921WA	52,177	-	-	-	-	-	-	-	-	-	
921	WYP	921WYP	118,187	-	-	-	-	-	-	-	-	-	
921	WYU	921WYU	16,154	-	-	-	-	-	-	-	-	-	
922	SO	922SO	(28,375,128)	-	-	-	-	-	-	7,623,057	296,901	(15,780,224)	
923	CA	923CA	-	-	-	-	-	-	-	-	-	-	
923	OR	923OR	8,195	-	-	-	-	-	-	-	-	8,195	
923	SO	923SO	9,396,107	-	-	-	-	-	-	-	-	2,602,840	
923	UT	923UT	-	-	-	-	-	-	-	-	-	-	
924	SO	924SO	23,341,430	-	-	-	-	-	-	-	-	6,465,869	
925	SO	925SO	8,492,514	-	-	-	-	-	-	-	-	2,352,533	
928	CA	928CA	725,998	-	-	-	-	-	-	-	-	-	
928	ID	928ID	1,199,068	-	-	-	-	-	-	-	-	-	
928	OR	928OR	3,489,938	-	-	-	-	-	-	424,405	16,530	3,049,004	
928	SG	928SG	2,513,914	-	-	-	-	-	-	-	-	658,711	
928	SO	928SO	1,538,229	-	-	-	-	-	-	50,764	1,977	373,368	
928	UT	928UT	4,996,941	-	-	-	-	-	-	-	-	-	
928	WA	928WA	1,222,850	-	-	-	-	-	-	-	-	-	
928	WYP	928WYP	2,239,902	-	-	-	-	-	-	-	-	-	
929	SO	929SO	(6,130,868)	-	-	-	-	-	-	(249,445)	(9,715)	(1,439,167)	
930	CA	930CA	(2,123)	-	-	-	-	-	-	-	-	-	
930	CN	930CN	1,601	-	-	-	-	-	-	-	-	493	
930	ID	930ID	12,950	-	-	-	-	-	-	-	-	-	
930	OR	930OR	2,335,084	-	-	-	-	-	-	-	-	2,335,084	
930	SO	930SO	13,592,405	-	-	-	-	-	-	-	-	3,765,267	
930	UT	930UT	298,972	-	-	-	-	-	-	-	-	-	
930	WA	930WA	9,267	-	-	-	-	-	-	-	-	-	
930	WYP	930WYP	63,877	-	-	-	-	-	-	-	-	-	
931	ID	931ID	-	-	-	-	-	-	-	-	-	-	
931	OR	931OR	991,618	-	-	-	-	-	-	-	-	991,618	
931	SO	931SO	5,344,545	-	-	-	-	-	-	-	-	1,480,506	
931	UT	931UT	1,541	-	-	-	-	-	-	-	-	-	
935	OR	935OR	20,356	-	-	-	-	-	-	16,660	649	3,048	
935	SO	935SO	22,312,089	-	-	-	-	-	-	657,535	25,609	5,497,584	
935	UT	935UT	-	-	-	-	-	-	-	-	-	-	
935	WA	935WA	2,504	-	-	-	-	-	-	-	-	-	
ECD	DGP	ECDDGP	(41,510,730)	-	-	-	(22,143,189)	-	-	-	-	-	
ECD	MC	ECDMC	(30,896,884)	-	-	-	(16,703,435)	-	-	-	-	-	
ECD	SG	ECDSG	72,407,614	-	-	-	30,289,831	-	-	-	-	-	
				-	-	-	-	-	-	-	-	-	
Total O&M			**2,692,685,751**	**155,317,996**	**111,900,267**	**109,812,334**	**(8,556,793)**	**(28,650,083)**	**35,789,548**	**136,707,602**	**5,324,448**	**165,180,219**	
											Total O&M Expense	**682,825,538**	**Ref. 2.1**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Results of Operations for Taxes Other Than Income

				Total Company		Oregon		
Account	2010 Protocol Factor	Indicator	Amount	Property Taxes	Taxes Other Than Income	Property Taxes	Taxes Other Than Income	
408	CA	408CA	1,150,174		1,150,174	-	-	
408	GPS	408GPS	100,361,440	100,361,440	-	27,801,379	-	
408	OR	408OR	22,932,597		22,932,597	-	22,932,597	
408	SE	408SE	879,415		879,415	-	220,544	
408	SO	408SO	9,440,796		9,440,796	-	2,615,219	
408	UT	408UT	1,452		1,452	-	-	
408	WA	408WA	122,591		122,591	-	-	
408	WYP	408WYP	1,624,264		1,624,264	-	-	
			136,512,728	**100,361,440**	**36,151,288**	**27,801,379**	**25,768,360**	**Ref. 2.1**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

December 2010 Lead/Lag Study
Net Power Costs

Description	Account	Unadjusted NPC Costs	Factor	Lead/Lag Section	Oregon	
Sales for Resale (Account 447)						
Existing Firm Sales PPL	447.12	-	SG	Sales for Resale	-	
Existing Firm Sales UPL	447.122	-	SG	Sales for Resale	-	
Post-merger Firm Sales	447.13, 447.14, 447.2, 447.61, 447.62	491,619,370	SG	Sales for Resale	128,817,061	
Non-firm Sales	447.5	903,103	SE	Sales for Resale	226,485	
Transmission Services	447.9	-	S	Sales for Resale	-	
On-system Wholesale Sales	447.1	-	S	Sales for Resale	-	
Total Revenue Adjustments		492,522,473			129,043,546	
Purchased Power (Account 555)						
Existing Firm Demand PPL	555.66	-	SG	Purchased Power	-	
Existing Firm Demand UPL	555.68	-	SG	Purchased Power	-	
Existing Firm Energy	555.65, 555.69	469,600,699	SG	Purchased Power	123,047,596	
Post-merger Firm	555, 555.55,555.61,555.62, 555.67	(52,775,347)	SE	Purchased Power	(13,235,262)	
Secondary Purchases	555.7, 555.25	-	SE	Purchased Power	-	
Total Purchased Power Adjustment		416,825,351			109,812,334	
Wheeling (Account 565)						
Existing Firm PPL	565.26	-	SG	Wheeling Expense	-	
Existing Firm UPL	565.27	-	SG	Wheeling Expense	-	
Post-merger Firm	565.0, 565.46, 565.1	130,633,756	SG	Wheeling Expense	34,229,441	
Non-firm	565.25	6,220,893	SE	Wheeling Expense	1,560,106	
Total Wheeling Expense Adj		136,854,649			35,789,548	
Fuel Expense (Accounts 501, 503 and 547)						
Fuel - Overburden Amortization - Idaho	501.12	(249,096)	ID	Coal	-	
Fuel - Overburden Amortization - Wyoming	501.12	(665,891)	WYP	Coal	-	
Fuel Consumed - Coal	501.1, 501.11	567,561,611	SE	Coal	142,335,901	
Fuel Consumed - Gas	501.35	13,579,385	SE	Natural Gas	3,405,505	
Steam From Other Sources	503	3,655,727	SE	Coal	916,801	
Natural Gas Consumed	547	411,275,695	SE	Natural Gas	103,141,748	
Simple Cycle Combustion Turbines	547	21,345,038	SE	Natural Gas	5,353,014	
Cholla/APS Exchange	501,501.1,501.2,501.45	48,110,124	SE	Coal	12,065,294	
Miscellaneous Fuel Costs	501,501.15,501.2,501.3, 501.4, 501.45,	-	SE		-	
Total Fuel Expense		1,064,612,593			267,218,263	
Net Power Cost		**1,125,770,120**			**283,776,600**	**Ref. 5.0**

B1. REVENUE

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4118000	GAINS-DISP OF ALLOW	ALOW	Sales of S02 Allowances	SE	-$560	-$9	-$136	-$41	-$74	-$95	-$241	-$35	-$21	-$2	$	$
4118000 Total					**-$560**	**-$9**	**-$136**	**-$41**	**-$74**	**-$95**	**-$241**	**-$35**	**-$21**	**-$2**	**$**	**$**
4211000	GAIN DISPOS PROP	DISP	Sale of Utility Plant	CA	-$50	-$50	$	$	$	$	$	$	$	$	$	$
4211000	GAIN DISPOS PROP	DISP	Sale of Utility Plant	OR	$278	$	$278	$	$	$	$	$	$	$	$	$
4211000	GAIN DISPOS PROP	DISP	Sale of Utility Plant	SG	-$984	-$17	-$254	-$77	-$119	-$151	-$426	-$55	-$32	-$3	$	$
4211000	GAIN DISPOS PROP	DISP	Sale of Utility Plant	SO	-$436	-$10	-$118	-$33	-$49	-$61	-$187	-$24	-$12	-$1	$	$
4211000 Total					**-$1,192**	**-$77**	**-$94**	**-$111**	**-$169**	**-$213**	**-$614**	**-$79**	**-$44**	**-$4**	**$**	**$**
4212000	LOSS DISPOS PROP	DISP	Sale of Utility Plant	CN	$1	$	$	$	$	$	$	$	$	$	$	$
4212000	LOSS DISPOS PROP	DISP	Sale of Utility Plant	OR	-$2	$	-$2	$	$	$	$	$	$	$	$	$
4212000	LOSS DISPOS PROP	DISP	Sale of Utility Plant	SG	$	$	$	$	$	$	$	$	$	$	$	$
4212000	LOSS DISPOS PROP	DISP	Sale of Utility Plant	SO	$55	$1	$15	$4	$6	$8	$24	$3	$2	$	$	$
4212000	LOSS DISPOS PROP	DISP	Sale of Utility Plant	WA	$8	$	$	$8	$	$	$	$	$	$	$	$
4212000	LOSS DISPOS PROP	DISP	Sale of Utility Plant	WYP	$	$	$	$	$	$	$	$	$	$	$	$
4212000 Total					**$62**	**$1**	**$13**	**$12**	**$7**	**$8**	**$24**	**$3**	**$2**	**$**	**$**	**$**
4401000	RESIDENTIAL SALES	RETL	Retail Sales	CA	$49,498	$49,498	$	$	$	$	$	$	$	$	$	$
4401000	RESIDENTIAL SALES	RETL	Retail Sales	IDU	$63,994	$	$	$	$	$	$	$63,994	$	$	$	$
4401000	RESIDENTIAL SALES	RETL	Retail Sales	OR	$545,966	$	$545,966	$	$	$	$	$	$	$	$	$
4401000	RESIDENTIAL SALES	RETL	Retail Sales	UT	$590,286	$	$	$	$	$	$590,286	$	$	$	$	$
4401000	RESIDENTIAL SALES	RETL	Retail Sales	WA	$121,982	$	$	$121,982	$	$	$	$	$	$	$	$
4401000	RESIDENTIAL SALES	RETL	Retail Sales	WYP	$81,169	$	$	$	$81,169	$81,169	$	$	$	$	$	$
4401000	RESIDENTIAL SALES	RETL	Retail Sales	WYU	$11,662	$	$	$	$	$11,662	$	$	$11,662	$	$	$
4401000 Total					**$1,464,557**	**$49,498**	**$545,966**	**$121,982**	**$81,169**	**$92,832**	**$590,286**	**$63,994**	**$11,662**	**$**	**$**	**$**
4403000	BPA REG BAL-RES	RETL	Retail Sales	IDU	$1,188	$	$	$	$	$	$	$1,188	$	$	$	$
4403000	BPA REG BAL-RES	RETL	Retail Sales	OR	-$20,668	$	-$20,668	$	$	$	$	$	$	$	$	$
4403000	BPA REG BAL-RES	RETL	Retail Sales	WA	-$7,594	$	$	-$7,594	$	$	$	$	$	$	$	$
4403000 Total					**-$27,074**	**$**	**-$20,668**	**-$7,594**	**$**	**$**	**$**	**$1,188**	**$**	**$**	**$**	**$**
4421000	COMMERCIAL SALES	RETL	Retail Sales	CA	$31,543	$31,543	$	$	$	$	$	$	$	$	$	$
4421000	COMMERCIAL SALES	RETL	Retail Sales	IDU	$32,460	$	$	$	$	$	$	$32,460	$	$	$	$
4421000	COMMERCIAL SALES	RETL	Retail Sales	OR	$380,621	$	$380,621	$	$	$	$	$	$	$	$	$
4421000	COMMERCIAL SALES	RETL	Retail Sales	UT	$556,744	$	$	$	$	$	$556,744	$	$	$	$	$
4421000	COMMERCIAL SALES	RETL	Retail Sales	WA	$96,838	$	$	$96,838	$	$	$	$	$	$	$	$
4421000	COMMERCIAL SALES	RETL	Retail Sales	WYP	$100,141	$	$	$	$100,141	$100,141	$	$	$	$	$	$
4421000	COMMERCIAL SALES	RETL	Retail Sales	WYU	$11,802	$	$	$	$	$11,802	$	$	$11,802	$	$	$
4421000 Total					**$1,210,149**	**$31,543**	**$380,621**	**$96,838**	**$100,141**	**$111,943**	**$556,744**	**$32,460**	**$11,802**	**$**	**$**	**$**
4421200	BPA REG BAL-INDUST	RETL	Retail Sales	IDU	$11	$	$	$	$	$	$	$11	$	$	$	$
4421200	BPA REG BAL-INDUST	RETL	Retail Sales	OR	-$3	$	-$3	$	$	$	$	$	$	$	$	$
4421200	BPA REG BAL-INDUST	RETL	Retail Sales	WA	-$28	$	$	-$28	$	$	$	$	$	$	$	$
4421200 Total					**-$20**	**$**	**-$3**	**-$28**	**$**	**$**	**$**	**$11**	**$**	**$**	**$**	**$**
4421400	BPA REG BAL-IRRIG	RETL	Retail Sales	IDU	-$1,191	$	$	$	$	$	$	-$1,191	$	$	$	$
4421400	BPA REG BAL-IRRIG	RETL	Retail Sales	OR	-$687	$	-$687	$	$	$	$	$	$	$	$	$
4421400	BPA REG BAL-IRRIG	RETL	Retail Sales	WA	-$526	$	$	-$526	$	$	$	$	$	$	$	$
4421400 Total					**-$2,404**	**$**	**-$687**	**-$526**	**$**	**$**	**$**	**-$1,191**	**$**	**$**	**$**	**$**
4421500	BPA REG BAL-COMMRC	RETL	Retail Sales	IDU	$76	$	$	$	$	$	$	$76	$	$	$	$
4421500	BPA REG BAL-COMMRC	RETL	Retail Sales	OR	-$997	$	-$997	$	$	$	$	$	$	$	$	$
4421500	BPA REG BAL-COMMRC	RETL	Retail Sales	WA	-$567	$	$	-$567	$	$	$	$	$	$	$	$
4421500 Total					**-$1,488**	**$**	**-$997**	**-$567**	**$**	**$**	**$**	**$76**	**$**	**$**	**$**	**$**
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	CA	$4,326	$4,326	$	$	$	$	$	$	$	$	$	$
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	IDU	$78,938	$	$	$	$	$	$	$78,938	$	$	$	$
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	OR	$133,357	$	$133,357	$	$	$	$	$	$	$	$	$
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	UT	$385,141	$	$	$	$	$	$385,141	$	$	$	$	$
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	WA	$42,668	$	$	$42,668	$	$	$	$	$	$	$	$
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	WYP	$275,776	$	$	$	$275,776	$275,776	$	$	$	$	$	$
4422000	IND SLS/EXCL IRRIG	RETL	Retail Sales	WYU	$73,312	$	$	$	$	$73,312	$	$	$73,312	$	$	$
4422000 Total					**$993,518**	**$4,326**	**$133,357**	**$42,668**	**$275,776**	**$349,088**	**$385,141**	**$78,938**	**$73,312**	**$**	**$**	**$**
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	CA	$9,219	$9,219	$	$	$	$	$	$	$	$	$	$
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	IDU	$38,000	$	$	$	$	$	$	$38,000	$	$	$	$
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	OR	$14,123	$	$14,123	$	$	$	$	$	$	$	$	$
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	UT	$11,547	$	$	$	$	$	$11,547	$	$	$	$	$
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	WA	$10,098	$	$	$10,098	$	$	$	$	$	$	$	$
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	WYP	$1,368	$	$	$	$1,368	$1,368	$	$	$	$	$	$
4423000	INDUST SALES-IRRIG	RETL	Retail Sales	WYU	$248	$	$	$	$	$248	$	$	$248	$	$	$
4423000 Total					**$84,603**	**$9,219**	**$14,123**	**$10,098**	**$1,368**	**$1,616**	**$11,547**	**$38,000**	**$248**	**$**	**$**	**$**
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	CA	$397	$397	$	$	$	$	$	$	$	$	$	$
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	IDU	$482	$	$	$	$	$	$	$482	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	OR	$5,732	$	$5,732	$	$	$	$	$	$	$	$	$
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	UT	$10,749	$	$	$	$	$	$10,749	$	$	$	$	$
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	WA	$1,190	$	$	$1,190	$	$	$	$	$	$	$	$
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	WYP	$1,604	$	$	$	$1,604	$1,604	$	$	$	$	$	$
4441000	PUB ST/HWY LIGHT	RETL	Retail Sales	WYU	$461	$	$	$	$	$461	$	$	$461	$	$	$
4441000 Total					**$20,615**	**$397**	**$5,732**	**$1,190**	**$1,604**	**$2,065**	**$10,749**	**$482**	**$461**	**$**	**$**	**$**
4451000	OTHER SALES PUBLIC	RETL	Retail Sales	UT	$19,771	$	$	$	$	$	$19,771	$	$	$	$	$
4451000 Total					**$19,771**	**$**	**$**	**$**	**$**	**$**	**$19,771**	**$**	**$**	**$**	**$**	**$**
4471000	ON-SYS WHOLE-FIRM	OSSR	On-System Sales for Resale	FERC	$6,686	$	$	$	$	$	$	$	$	$6,686	$	$
4471000	ON-SYS WHOLE-FIRM	OSSR	On-System Sales for Resale	OR	$1,019	$	$1,019	$	$	$	$	$	$	$	$	$
4471000	ON-SYS WHOLE-FIRM	OSSR	On-System Sales for Resale	WYP	$25	$	$	$	$25	$25	$	$	$	$	$	$
4471000 Total					**$7,729**	**$**	**$1,019**	**$**	**$25**	**$25**	**$**	**$**	**$**	**$6,686**	**$**	**$**
4471300	POST MERGER FIRM	RSLE	Sales for Resale	SG	$99,753	$1,679	$25,714	$7,838	$12,099	$15,356	$43,235	$5,605	$3,257	$327	$	$
4471300 Total					**$99,753**	**$1,679**	**$25,714**	**$7,838**	**$12,099**	**$15,356**	**$43,235**	**$5,605**	**$3,257**	**$327**	**$**	**$**
4471400	S/T FIRM WHOLESALE	RSLE	Sales for Resale	SG	$266,574	$4,486	$68,715	$20,946	$32,333	$41,038	$115,539	$14,978	$8,704	$873	$	$
4471400 Total					**$266,574**	**$4,486**	**$68,715**	**$20,946**	**$32,333**	**$41,038**	**$115,539**	**$14,978**	**$8,704**	**$873**	**$**	**$**
4472000	SLS FOR RESL-SURP	RSLE	Sales for Resale	SG	-$6,921	-$116	-$1,784	-$544	-$840	-$1,066	-$3,000	-$389	-$226	-$23	$	$
4472000 Total					**-$6,921**	**-$116**	**-$1,784**	**-$544**	**-$840**	**-$1,066**	**-$3,000**	**-$389**	**-$226**	**-$23**	**$**	**$**
4475000	OFF-SYS - NON FIRM	RSLE	Sales for Resale	SE	$975	$15	$237	$72	$129	$166	$420	$62	$37	$4	$	$
4475000 Total					**$975**	**$15**	**$237**	**$72**	**$129**	**$166**	**$420**	**$62**	**$37**	**$4**	**$**	**$**
4476100	BOOKOUTS NETTED-GAIN	RSLE	Sales for Resale	SG	$8,734	$147	$2,251	$686	$1,059	$1,345	$3,786	$491	$285	$29	$	$
4476100 Total					**$8,734**	**$147**	**$2,251**	**$686**	**$1,059**	**$1,345**	**$3,786**	**$491**	**$285**	**$29**	**$**	**$**
4476200	TRADING NETTED-GAINS	RSLE	Sales for Resale	SG	$905	$15	$233	$71	$110	$139	$392	$51	$30	$3	$	$
4476200 Total					**$905**	**$15**	**$233**	**$71**	**$110**	**$139**	**$392**	**$51**	**$30**	**$3**	**$**	**$**
4479000	TRANS SRVC	RSLE	Sales for Resale	FERC	$1,424	$	$	$	$	$	$	$	$	$1,424	$	$
4479000	TRANS SRVC	RSLE	Sales for Resale	WYP	$6	$	$	$	$6	$6	$	$	$	$	$	$
4479000 Total					**$1,430**	**$**	**$**	**$**	**$6**	**$6**	**$**	**$**	**$**	**$1,424**	**$**	**$**
4501000	FORF DISC/INT-RES	OREV	Other Revenue	CA	$187	$187	$	$	$	$	$	$	$	$	$	$
4501000	FORF DISC/INT-RES	OREV	Other Revenue	IDU	$194	$	$	$	$	$	$	$194	$	$	$	$
4501000	FORF DISC/INT-RES	OREV	Other Revenue	OR	$2,520	$	$2,520	$	$	$	$	$	$	$	$	$
4501000	FORF DISC/INT-RES	OREV	Other Revenue	UT	$2,097	$	$	$	$	$	$2,097	$	$	$	$	$
4501000	FORF DISC/INT-RES	OREV	Other Revenue	WA	$466	$	$	$466	$	$	$	$	$	$	$	$
4501000	FORF DISC/INT-RES	OREV	Other Revenue	WYP	$347	$	$	$	$347	$347	$	$	$	$	$	$
4501000	FORF DISC/INT-RES	OREV	Other Revenue	WYU	$45	$	$	$	$	$45	$	$	$45	$	$	$
4501000 Total					**$5,856**	**$187**	**$2,520**	**$466**	**$347**	**$392**	**$2,097**	**$194**	**$45**	**$**	**$**	**$**
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	CA	$70	$70	$	$	$	$	$	$	$	$	$	$
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	IDU	$30	$	$	$	$	$	$	$30	$	$	$	$
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	OR	$515	$	$515	$	$	$	$	$	$	$	$	$
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	UT	$612	$	$	$	$	$	$612	$	$	$	$	$
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	WA	$103	$	$	$103	$	$	$	$	$	$	$	$
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	WYP	$91	$	$	$	$91	$91	$	$	$	$	$	$
4502000	FORF DISC/INT-COMM	OREV	Other Revenue	WYU	$16	$	$	$	$	$16	$	$	$16	$	$	$
4502000 Total					**$1,437**	**$70**	**$515**	**$103**	**$91**	**$108**	**$612**	**$30**	**$16**	**$**	**$**	**$**
4503000	FORF DISC/INT-IND	OREV	Other Revenue	CA	$20	$20	$	$	$	$	$	$	$	$	$	$
4503000	FORF DISC/INT-IND	OREV	Other Revenue	IDU	$232	$	$	$	$	$	$	$232	$	$	$	$
4503000	FORF DISC/INT-IND	OREV	Other Revenue	OR	$104	$	$104	$	$	$	$	$	$	$	$	$
4503000	FORF DISC/INT-IND	OREV	Other Revenue	UT	$206	$	$	$	$	$	$206	$	$	$	$	$
4503000	FORF DISC/INT-IND	OREV	Other Revenue	WA	$28	$	$	$28	$	$	$	$	$	$	$	$
4503000	FORF DISC/INT-IND	OREV	Other Revenue	WYP	$33	$	$	$	$33	$33	$	$	$	$	$	$
4503000	FORF DISC/INT-IND	OREV	Other Revenue	WYU	$30	$	$	$	$	$30	$	$	$30	$	$	$
4503000 Total					**$654**	**$20**	**$104**	**$28**	**$33**	**$63**	**$206**	**$232**	**$30**	**$**	**$**	**$**
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	CA	$2	$2	$	$	$	$	$	$	$	$	$	$
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	IDU	$	$	$	$	$	$	$	$	$	$	$	$
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	OR	$10	$	$10	$	$	$	$	$	$	$	$	$
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	UT	$89	$	$	$	$	$	$89	$	$	$	$	$
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	WA	$11	$	$	$11	$	$	$	$	$	$	$	$
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	WYP	$5	$	$	$	$5	$5	$	$	$	$	$	$
4504000	GOVT MUNI/ALL OTH	OREV	Other Revenue	WYU	$	$	$	$	$	$	$	$	$	$	$	$
4504000 Total					**$117**	**$2**	**$10**	**$11**	**$5**	**$5**	**$89**	**$**	**$**	**$**	**$**	**$**
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	CA	$42	$42	$	$	$	$	$	$	$	$	$	$
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	IDU	$103	$	$	$	$	$	$	$103	$	$	$	$
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	OR	$695	$	$695	$	$	$	$	$	$	$	$	$
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	UT	$2,841	$	$	$	$	$	$2,841	$	$	$	$	$
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	WA	$152	$	$	$152	$	$	$	$	$	$	$	$

PACIFICORP
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Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	WYP	$158	$	$	$	$158	$158	$	$	$	$	$	$
4511000	ACCOUNT SERV CHG	OREV	Other Revenue	WYU	$27	$	$	$	$	$27	$	$	$27	$	$	$
4511000 Total					**$4,019**	**$42**	**$695**	**$152**	**$158**	**$185**	**$2,841**	**$103**	**$27**	**$**	**$**	**$**
4512000	TAMPER/RECONNECT	OREV	Other Revenue	CA	$1	$1	$	$	$	$	$	$	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	IDU	$1	$	$	$	$	$	$	$1	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	OR	$24	$	$24	$	$	$	$	$	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	SO	$	$	$	$	$	$	$	$	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	UT	$22	$	$	$	$	$	$22	$	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	WA	$5	$	$	$5	$	$	$	$	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	WYP	$2	$	$	$	$2	$2	$	$	$	$	$	$
4512000	TAMPER/RECONNECT	OREV	Other Revenue	WYU	$	$	$	$	$	$	$	$	$	$	$	$
4512000 Total					**$55**	**$1**	**$24**	**$5**	**$2**	**$2**	**$22**	**$1**	**$**	**$**	**$**	**$**
4513000	OTHER	OREV	Other Revenue	CA	$36	$36	$	$	$	$	$	$	$	$	$	$
4513000	OTHER	OREV	Other Revenue	IDU	$3	$	$	$	$	$	$	$3	$	$	$	$
4513000	OTHER	OREV	Other Revenue	OR	$422	$	$422	$	$	$	$	$	$	$	$	$
4513000	OTHER	OREV	Other Revenue	SO	$1	$	$	$	$	$	$	$	$	$	$	$
4513000	OTHER	OREV	Other Revenue	UT	$1,006	$	$	$	$	$	$1,006	$	$	$	$	$
4513000	OTHER	OREV	Other Revenue	WA	$13	$	$	$13	$	$	$	$	$	$	$	$
4513000	OTHER	OREV	Other Revenue	WYP	$128	$	$	$	$128	$128	$	$	$	$	$	$
4513000	OTHER	OREV	Other Revenue	WYU	$235	$	$	$	$	$235	$	$	$235	$	$	$
4513000 Total					**$1,845**	**$36**	**$422**	**$13**	**$128**	**$364**	**$1,007**	**$3**	**$235**	**$**	**$**	**$**
4513500	WEATHERIZ 12% 12MO	OREV	Other Revenue	IDU	$	$	$	$	$	$	$	$	$	$	$	$
4513500 Total					**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
4514100	ENERGY FINANSWER	OREV	Other Revenue	UT	$17	$	$	$	$	$	$17	$	$	$	$	$
4514100	ENERGY FINANSWER	OREV	Other Revenue	WA	$2	$	$	$2	$	$	$	$	$	$	$	$
4514100 Total					**$19**	**$**	**$**	**$2**	**$**	**$**	**$17**	**$**	**$**	**$**	**$**	**$**
4514400	ENGY FINANSWER LGHT	OREV	Other Revenue	CA	$1	$1	$	$	$	$	$	$	$	$	$	$
4514400	ENGY FINANSWER LGHT	OREV	Other Revenue	WA	$3	$	$	$3	$	$	$	$	$	$	$	$
4514400 Total					**$4**	**$1**	**$**	**$3**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
4514900	ENGY FINNSWR 12000	OREV	Other Revenue	WYU	$	$	$	$	$	$	$	$	$	$	$	$
4514900 Total					**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
4530000	SLS WATER & W PWR	OREV	Other Revenue	SG	$86	$1	$22	$7	$10	$13	$37	$5	$3	$	$	$
4530000 Total					**$86**	**$1**	**$22**	**$7**	**$10**	**$13**	**$37**	**$5**	**$3**	**$**	**$**	**$**
4541000	RENTS - COMMON	OREV	Other Revenue	CA	$502	$502	$	$	$	$	$	$	$	$	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	IDU	$190	$	$	$	$	$	$	$190	$	$	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	OR	$5,103	$	$5,103	$	$	$	$	$	$	$	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	SG	$2,346	$39	$605	$184	$285	$361	$1,017	$132	$77	$8	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	SO	$3,505	$81	$952	$268	$396	$495	$1,507	$193	$99	$8	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	UT	$3,430	$	$	$	$	$	$3,430	$	$	$	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	WA	$1,031	$	$	$1,031	$	$	$	$	$	$	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	WYP	$351	$	$	$	$351	$351	$	$	$	$	$	$
4541000	RENTS - COMMON	OREV	Other Revenue	WYU	$18	$	$	$	$	$18	$	$	$18	$	$	$
4541000 Total					**$16,477**	**$622**	**$6,660**	**$1,484**	**$1,032**	**$1,226**	**$5,954**	**$516**	**$194**	**$16**	**$**	**$**
4542000	RENTS - NON COMMON	OREV	Other Revenue	SG	$	$	$	$	$	$	$	$	$	$	$	$
4542000	RENTS - NON COMMON	OREV	Other Revenue	SO	-$4	$	-$1	$	$	-$1	-$2	$	$	$	$	$
4542000	RENTS - NON COMMON	OREV	Other Revenue	UT	$4	$	$	$	$	$	$4	$	$	$	$	$
4542000 Total					**$**	**$**	**-$1**	**$**	**$**	**-$1**	**$2**	**$**	**$**	**$**	**$**	**$**
4543000	MCI FOGWIRE REVENUES	OREV	Other Revenue	SG	$3,351	$56	$864	$263	$406	$516	$1,453	$188	$109	$11	$	$
4543000 Total					**$3,351**	**$56**	**$864**	**$263**	**$406**	**$516**	**$1,453**	**$188**	**$109**	**$11**	**$**	**$**
4561100	Other Wheeling Rev	OREV	Other Revenue	SG	$27,687	$466	$7,137	$2,176	$3,358	$4,262	$12,000	$1,556	$904	$91	$	$
4561100 Total					**$27,687**	**$466**	**$7,137**	**$2,176**	**$3,358**	**$4,262**	**$12,000**	**$1,556**	**$904**	**$91**	**$**	**$**
4561910	S/T FIRM WHEEL REV	OREV	Other Revenue	SG	$1,361	$23	$351	$107	$165	$209	$590	$76	$44	$4	$	$
4561910 Total					**$1,361**	**$23**	**$351**	**$107**	**$165**	**$209**	**$590**	**$76**	**$44**	**$4**	**$**	**$**
4561920	L/T FIRM WHEEL REV	OREV	Other Revenue	SG	$32,252	$543	$8,314	$2,534	$3,912	$4,965	$13,979	$1,812	$1,053	$106	$	$
4561920 Total					**$32,252**	**$543**	**$8,314**	**$2,534**	**$3,912**	**$4,965**	**$13,979**	**$1,812**	**$1,053**	**$106**	**$**	**$**
4561930	NON-FIRM WHEEL REV	OREV	Other Revenue	SE	$10,745	$167	$2,613	$792	$1,421	$1,825	$4,631	$678	$403	$40	$	$
4561930 Total					**$10,745**	**$167**	**$2,613**	**$792**	**$1,421**	**$1,825**	**$4,631**	**$678**	**$403**	**$40**	**$**	**$**
4562100	USE OF FACIL REV	OREV	Other Revenue	SG	$24	$	$6	$2	$3	$4	$11	$1	$1	$	$	$
4562100 Total					**$24**	**$**	**$6**	**$2**	**$3**	**$4**	**$11**	**$1**	**$1**	**$**	**$**	**$**
4562200	DSM REVENUES	OREV	Other Revenue	CA	$1,086	$1,086	$	$	$	$	$	$	$	$	$	$
4562200	DSM REVENUES	OREV	Other Revenue	IDU	$6,003	$	$	$	$	$	$	$6,003	$	$	$	$
4562200	DSM REVENUES	OREV	Other Revenue	OR	$21,405	$	$21,405	$	$	$	$	$	$	$	$	$
4562200	DSM REVENUES	OREV	Other Revenue	OTHER	$201	$	$	$	$	$	$	$	$	$	$201	$
4562200	DSM REVENUES	OREV	Other Revenue	UT	$53,697	$	$	$	$	$	$53,697	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4562200	DSM REVENUES	OREV	Other Revenue	WA	$8,763	$	$	$8,763	$	$	$	$	$	$	$	$
4562200	DSM REVENUES	OREV	Other Revenue	WYP	$3,013	$	$	$	$3,013	$3,013	$	$	$	$	$	$
4562200	DSM REVENUES	OREV	Other Revenue	WYU	$328	$	$	$	$	$328	$	$	$328	$	$	$
4562200 Total					**$94,497**	**$1,086**	**$21,405**	**$8,763**	**$3,013**	**$3,341**	**$53,697**	**$6,003**	**$328**	**$**	**$201**	**$**
4562300	MISC OTHER REV	OREV	Other Revenue	IDU	$	$	$	$	$	$	$	$	$	$	$	$
4562300	MISC OTHER REV	OREV	Other Revenue	OR	$	$	$	$	$	$	$	$	$	$	$	$
4562300	MISC OTHER REV	OREV	Other Revenue	SG	$27,392	$461	$7,061	$2,152	$3,322	$4,217	$11,872	$1,539	$894	$90	$	$
4562300	MISC OTHER REV	OREV	Other Revenue	UT	$11	$	$	$	$	$	$11	$	$	$	$	$
4562300	MISC OTHER REV	OREV	Other Revenue	WA	-$52	$	$	-$52	$	$	$	$	$	$	$	$
4562300	MISC OTHER REV	OREV	Other Revenue	WYP	$232	$	$	$	$232	$232	$	$	$	$	$	$
4562300	MISC OTHER REV	OREV	Other Revenue	WYU	$	$	$	$	$	$	$	$	$	$	$	$
4562300 Total					**$27,582**	**$461**	**$7,061**	**$2,100**	**$3,554**	**$4,449**	**$11,883**	**$1,539**	**$894**	**$90**	**$**	**$**
4562400	M&S INVENTORY SALES	OREV	Other Revenue	IDU	$	$	$	$	$	$	$	$	$	$	$	$
4562400	M&S INVENTORY SALES	OREV	Other Revenue	SO	$286	$7	$78	$22	$32	$40	$123	$16	$8	$1	$	$
4562400	M&S INVENTORY SALES	OREV	Other Revenue	UT	$6	$	$	$	$	$	$6	$	$	$	$	$
4562400	M&S INVENTORY SALES	OREV	Other Revenue	WYP	$1	$	$	$	$1	$1	$	$	$	$	$	$
4562400 Total					**$293**	**$7**	**$78**	**$22**	**$33**	**$41**	**$129**	**$16**	**$8**	**$1**	**$**	**$**
4562500	M&S INV COST OF SALE	OREV	Other Revenue	UT	-$274	$	$	$	$	$	-$274	$	$	$	$	$
4562500 Total					**-$274**	**$**	**$**	**$**	**$**	**$**	**-$274**	**$**	**$**	**$**	**$**	**$**
4562700	RNW ENRGY CRDT SALES	OREV	Other Revenue	OTHER	-$1,024	$	$	$	$	$	$	$	$	$	-$1,024	$
4562700	RNW ENRGY CRDT SALES	OREV	Other Revenue	SG	$91,247	$1,536	$23,521	$7,170	$11,068	$14,047	$39,548	$5,127	$2,979	$299	$	$
4562700 Total					**$90,223**	**$1,536**	**$23,521**	**$7,170**	**$11,068**	**$14,047**	**$39,548**	**$5,127**	**$2,979**	**$299**	**-$1,024**	**$**
4569500	BLUE SKY REVENUE	OREV	Other Revenue	OTHER	$4,920	$	$	$	$	$	$	$	$	$	$4,920	$
4569500 Total					**$4,920**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$4,920**	**$**
Grand Total					**$4,462,948**	**$106,452**	**$1,235,930**	**$319,192**	**$533,483**	**$650,268**	**$1,884,312**	**$252,724**	**$116,785**	**$9,973**	**$4,097**	**$**

B2. O&M EXPENSE

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	$18,861	$317	$4,862	$1,482	$2,288	$2,903	$8,175	$1,060	$616	$62	$	$
5000000 Total					$18,861	$317	$4,862	$1,482	$2,288	$2,903	$8,175	$1,060	$616	$62	$	$
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	$792	$13	$204	$62	$96	$122	$343	$44	$26	$3	$	$
5001000 Total					$792	$13	$204	$62	$96	$122	$343	$44	$26	$3	$	$
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	$137	$2	$33	$10	$18	$23	$59	$9	$5	$1	$	$
5010000 Total					$137	$2	$33	$10	$18	$23	$59	$9	$5	$1	$	$
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	$650,098	$10,122	$158,062	$47,900	$85,993	$110,404	$280,170	$41,015	$24,411	$2,426	$	$
5011000 Total					$650,098	$10,122	$158,062	$47,900	$85,993	$110,404	$280,170	$41,015	$24,411	$2,426	$	$
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	-$103	$	$	$	$	$	$	-$103	$	$	$	$
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	-$306	$	$	$	-$306	-$306	$	$	$	$	$	$
5011200 Total					-$409	$	$	$	-$306	-$306	$	-$103	$	$	$	$
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	$9,515	$148	$2,313	$701	$1,259	$1,616	$4,100	$600	$357	$36	$	$
5012000 Total					$9,515	$148	$2,313	$701	$1,259	$1,616	$4,100	$600	$357	$36	$	$
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	$388	$6	$94	$29	$51	$66	$167	$24	$15	$1	$	$
5013000 Total					$388	$6	$94	$29	$51	$66	$167	$24	$15	$1	$	$
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	$13,695	$213	$3,330	$1,009	$1,812	$2,326	$5,902	$864	$514	$51	$	$
5013500 Total					$13,695	$213	$3,330	$1,009	$1,812	$2,326	$5,902	$864	$514	$51	$	$
5014000	FUEL CONSUMED-DIESEL	NPCX	Net Power Cost Expense	SE	$48	$1	$12	$4	$6	$8	$20	$3	$2	$	$	$
5014000 Total					$48	$1	$12	$4	$6	$8	$20	$3	$2	$	$	$
5014500	START UP FUEL-DIESEL	NPCX	Net Power Cost Expense	SE	$10,610	$165	$2,580	$782	$1,403	$1,802	$4,572	$669	$398	$40	$	$
5014500 Total					$10,610	$165	$2,580	$782	$1,403	$1,802	$4,572	$669	$398	$40	$	$
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	$557	$9	$135	$41	$74	$95	$240	$35	$21	$2	$	$
5015000 Total					$557	$9	$135	$41	$74	$95	$240	$35	$21	$2	$	$
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	$	$	$	$	$	$	$	$	$	$	$	$
5015100 Total					$	$	$	$	$	$	$	$	$	$	$	$
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	$21,537	$362	$5,552	$1,692	$2,612	$3,316	$9,335	$1,210	$703	$71	$	$
5020000 Total					$21,537	$362	$5,552	$1,692	$2,612	$3,316	$9,335	$1,210	$703	$71	$	$
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	$1,146	$19	$296	$90	$139	$176	$497	$64	$37	$4	$	$
5022000 Total					$1,146	$19	$296	$90	$139	$176	$497	$64	$37	$4	$	$
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	$2,834	$48	$730	$223	$344	$436	$1,228	$159	$93	$9	$	$
5024000 Total					$2,834	$48	$730	$223	$344	$436	$1,228	$159	$93	$9	$	$
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	$13,766	$232	$3,548	$1,082	$1,670	$2,119	$5,966	$773	$449	$45	$	$
5029000 Total					$13,766	$232	$3,548	$1,082	$1,670	$2,119	$5,966	$773	$449	$45	$	$
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	$3,322	$52	$808	$245	$439	$564	$1,432	$210	$125	$12	$	$
5030000 Total					$3,322	$52	$808	$245	$439	$564	$1,432	$210	$125	$12	$	$
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	$4,199	$71	$1,082	$330	$509	$646	$1,820	$236	$137	$14	$	$
5050000 Total					$4,199	$71	$1,082	$330	$509	$646	$1,820	$236	$137	$14	$	$
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	$46	$1	$12	$4	$6	$7	$20	$3	$2	$	$	$
5051000 Total					$46	$1	$12	$4	$6	$7	$20	$3	$2	$	$	$
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	$75,380	$1,269	$19,431	$5,923	$9,143	$11,604	$32,671	$4,235	$2,461	$247	$	$
5060000 Total					$75,380	$1,269	$19,431	$5,923	$9,143	$11,604	$32,671	$4,235	$2,461	$247	$	$
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	$1,294	$22	$333	$102	$157	$199	$561	$73	$42	$4	$	$
5061000 Total					$1,294	$22	$333	$102	$157	$199	$561	$73	$42	$4	$	$
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	$1,099	$18	$283	$86	$133	$169	$476	$62	$36	$4	$	$
5061100 Total					$1,099	$18	$283	$86	$133	$169	$476	$62	$36	$4	$	$
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	$922	$16	$238	$72	$112	$142	$400	$52	$30	$3	$	$
5061300 Total					$922	$16	$238	$72	$112	$142	$400	$52	$30	$3	$	$
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	$1,322	$22	$341	$104	$160	$203	$573	$74	$43	$4	$	$
5061400 Total					$1,322	$22	$341	$104	$160	$203	$573	$74	$43	$4	$	$
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	$257	$4	$66	$20	$31	$40	$111	$14	$8	$1	$	$
5061500 Total					$257	$4	$66	$20	$31	$40	$111	$14	$8	$1	$	$
5061600	MISC STM EXP FIRE	STEX	Steam O&M Expense	SG	$21	$	$5	$2	$3	$3	$9	$1	$1	$	$	$
5061600 Total					$21	$	$5	$2	$3	$3	$9	$1	$1	$	$	$
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	$1,480	$25	$381	$116	$179	$228	$641	$83	$48	$5	$	$
5062000 Total					$1,480	$25	$381	$116	$179	$228	$641	$83	$48	$5	$	$
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	-$37,792	-$636	-$9,742	-$2,969	-$4,584	-$5,818	-$16,380	-$2,123	-$1,234	-$124	$	$
5063000 Total					-$37,792	-$636	-$9,742	-$2,969	-$4,584	-$5,818	-$16,380	-$2,123	-$1,234	-$124	$	$
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	$8	$	$2	$1	$1	$1	$4	$	$	$	$	$
5064000 Total					$8	$	$2	$1	$1	$1	$4	$	$	$	$	$
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	$550	$9	$142	$43	$67	$85	$238	$31	$18	$2	$	$
5065000 Total					$550	$9	$142	$43	$67	$85	$238	$31	$18	$2	$	$
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	$1,060	$18	$273	$83	$129	$163	$460	$60	$35	$3	$	$
5066000 Total					$1,060	$18	$273	$83	$129	$163	$460	$60	$35	$3	$	$
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	$1,843	$31	$475	$145	$224	$284	$799	$104	$60	$6	$	$
5067000 Total					$1,843	$31	$475	$145	$224	$284	$799	$104	$60	$6	$	$
5068000	MISC STM EXP TRAVL	STEX	Steam O&M Expense	SG	$23	$	$6	$2	$3	$4	$10	$1	$1	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5068000 Total					$23	$	$6	$2	$3	$4	$10	$1	$1	$	$	$
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	$161	$3	$42	$13	$20	$25	$70	$9	$5	$1	$	$
5069000 Total					$161	$3	$42	$13	$20	$25	$70	$9	$5	$1	$	$
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	$3,079	$52	$794	$242	$373	$474	$1,335	$173	$101	$10	$	$
5069900 Total					$3,079	$52	$794	$242	$373	$474	$1,335	$173	$101	$10	$	$
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	$287	$5	$74	$23	$35	$44	$124	$16	$9	$1	$	$
5070000 Total					$287	$5	$74	$23	$35	$44	$124	$16	$9	$1	$	$
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	$3,763	$63	$970	$296	$456	$579	$1,631	$211	$123	$12	$	$
5100000 Total					$3,763	$63	$970	$296	$456	$579	$1,631	$211	$123	$12	$	$
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	$2,830	$48	$730	$222	$343	$436	$1,227	$159	$92	$9	$	$
5101000 Total					$2,830	$48	$730	$222	$343	$436	$1,227	$159	$92	$9	$	$
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	$2,876	$48	$741	$226	$349	$443	$1,247	$162	$94	$9	$	$
5110000 Total					$2,876	$48	$741	$226	$349	$443	$1,247	$162	$94	$9	$	$
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	$6,175	$104	$1,592	$485	$749	$951	$2,676	$347	$202	$20	$	$
5111000 Total					$6,175	$104	$1,592	$485	$749	$951	$2,676	$347	$202	$20	$	$
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	$1,401	$24	$361	$110	$170	$216	$607	$79	$46	$5	$	$
5111100 Total					$1,401	$24	$361	$110	$170	$216	$607	$79	$46	$5	$	$
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	$1,161	$20	$299	$91	$141	$179	$503	$65	$38	$4	$	$
5111200 Total					$1,161	$20	$299	$91	$141	$179	$503	$65	$38	$4	$	$
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	$7,920	$133	$2,042	$622	$961	$1,219	$3,433	$445	$259	$26	$	$
5112000 Total					$7,920	$133	$2,042	$622	$961	$1,219	$3,433	$445	$259	$26	$	$
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	$10	$	$3	$1	$1	$2	$4	$1	$	$	$	$
5114000 Total					$10	$	$3	$1	$1	$2	$4	$1	$	$	$	$
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	$445	$7	$115	$35	$54	$69	$193	$25	$15	$1	$	$
5116000 Total					$445	$7	$115	$35	$54	$69	$193	$25	$15	$1	$	$
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	$1,288	$22	$332	$101	$156	$198	$558	$72	$42	$4	$	$
5117000 Total					$1,288	$22	$332	$101	$156	$198	$558	$72	$42	$4	$	$
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	$1,162	$20	$300	$91	$141	$179	$504	$65	$38	$4	$	$
5118000 Total					$1,162	$20	$300	$91	$141	$179	$504	$65	$38	$4	$	$
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	$1,597	$27	$412	$126	$194	$246	$692	$90	$52	$5	$	$
5119000 Total					$1,597	$27	$412	$126	$194	$246	$692	$90	$52	$5	$	$
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	$110	$2	$28	$9	$13	$17	$48	$6	$4	$	$	$
5119900 Total					$110	$2	$28	$9	$13	$17	$48	$6	$4	$	$	$
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	$16,523	$278	$4,259	$1,298	$2,004	$2,544	$7,161	$928	$540	$54	$	$
5120000 Total					$16,523	$278	$4,259	$1,298	$2,004	$2,544	$7,161	$928	$540	$54	$	$
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	$17,396	$293	$4,484	$1,367	$2,110	$2,678	$7,540	$977	$568	$57	$	$
5121000 Total					$17,396	$293	$4,484	$1,367	$2,110	$2,678	$7,540	$977	$568	$57	$	$
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	$161	$3	$42	$13	$20	$25	$70	$9	$5	$1	$	$
5121100 Total					$161	$3	$42	$13	$20	$25	$70	$9	$5	$1	$	$
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	$6,586	$111	$1,698	$517	$799	$1,014	$2,854	$370	$215	$22	$	$
5121200 Total					$6,586	$111	$1,698	$517	$799	$1,014	$2,854	$370	$215	$22	$	$
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	$608	$10	$157	$48	$74	$94	$263	$34	$20	$2	$	$
5121400 Total					$608	$10	$157	$48	$74	$94	$263	$34	$20	$2	$	$
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	$620	$10	$160	$49	$75	$95	$269	$35	$20	$2	$	$
5121500 Total					$620	$10	$160	$49	$75	$95	$269	$35	$20	$2	$	$
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	$2,514	$42	$648	$198	$305	$387	$1,090	$141	$82	$8	$	$
5121600 Total					$2,514	$42	$648	$198	$305	$387	$1,090	$141	$82	$8	$	$
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	$446	$8	$115	$35	$54	$69	$193	$25	$15	$1	$	$
5121700 Total					$446	$8	$115	$35	$54	$69	$193	$25	$15	$1	$	$
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	$5,097	$86	$1,314	$400	$618	$785	$2,209	$286	$166	$17	$	$
5121800 Total					$5,097	$86	$1,314	$400	$618	$785	$2,209	$286	$166	$17	$	$
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	$77	$1	$20	$6	$9	$12	$34	$4	$3	$	$	$
5121900 Total					$77	$1	$20	$6	$9	$12	$34	$4	$3	$	$	$
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	$1,113	$19	$287	$87	$135	$171	$482	$63	$36	$4	$	$
5122000 Total					$1,113	$19	$287	$87	$135	$171	$482	$63	$36	$4	$	$
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	$1,404	$24	$362	$110	$170	$216	$608	$79	$46	$5	$	$
5122100 Total					$1,404	$24	$362	$110	$170	$216	$608	$79	$46	$5	$	$
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	$9,821	$165	$2,532	$772	$1,191	$1,512	$4,257	$552	$321	$32	$	$
5122200 Total					$9,821	$165	$2,532	$772	$1,191	$1,512	$4,257	$552	$321	$32	$	$
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	$2,966	$50	$765	$233	$360	$457	$1,286	$167	$97	$10	$	$
5122300 Total					$2,966	$50	$765	$233	$360	$457	$1,286	$167	$97	$10	$	$
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	$839	$14	$216	$66	$102	$129	$364	$47	$27	$3	$	$
5122400 Total					$839	$14	$216	$66	$102	$129	$364	$47	$27	$3	$	$
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	$268	$5	$69	$21	$33	$41	$116	$15	$9	$1	$	$
5122500 Total					$268	$5	$69	$21	$33	$41	$116	$15	$9	$1	$	$
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	$721	$12	$186	$57	$87	$111	$313	$41	$24	$2	$	$

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5122600 Total					$721	$12	$186	$57	$87	$111	$313	$41	$24	$2	$	$
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	$2,543	$43	$656	$200	$308	$392	$1,102	$143	$83	$8	$	$
5122800 Total					$2,543	$43	$656	$200	$308	$392	$1,102	$143	$83	$8	$	$
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	$11,331	$191	$2,921	$890	$1,374	$1,744	$4,911	$637	$370	$37	$	$
5122900 Total					$11,331	$191	$2,921	$890	$1,374	$1,744	$4,911	$637	$370	$37	$	$
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	$6,611	$111	$1,704	$519	$802	$1,018	$2,865	$371	$216	$22	$	$
5123000 Total					$6,611	$111	$1,704	$519	$802	$1,018	$2,865	$371	$216	$22	$	$
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	$658	$11	$170	$52	$80	$101	$285	$37	$21	$2	$	$
5123100 Total					$658	$11	$170	$52	$80	$101	$285	$37	$21	$2	$	$
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	$1,067	$18	$275	$84	$129	$164	$462	$60	$35	$3	$	$
5123200 Total					$1,067	$18	$275	$84	$129	$164	$462	$60	$35	$3	$	$
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	$90	$2	$23	$7	$11	$14	$39	$5	$3	$	$	$
5123300 Total					$90	$2	$23	$7	$11	$14	$39	$5	$3	$	$	$
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	$2,017	$34	$520	$159	$245	$311	$874	$113	$66	$7	$	$
5123400 Total					$2,017	$34	$520	$159	$245	$311	$874	$113	$66	$7	$	$
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	$897	$15	$231	$70	$109	$138	$389	$50	$29	$3	$	$
5124000 Total					$897	$15	$231	$70	$109	$138	$389	$50	$29	$3	$	$
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	$4,393	$74	$1,132	$345	$533	$676	$1,904	$247	$143	$14	$	$
5125000 Total					$4,393	$74	$1,132	$345	$533	$676	$1,904	$247	$143	$14	$	$
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	$1,198	$20	$309	$94	$145	$184	$519	$67	$39	$4	$	$
5126000 Total					$1,198	$20	$309	$94	$145	$184	$519	$67	$39	$4	$	$
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	$229	$4	$59	$18	$28	$35	$99	$13	$7	$1	$	$
5127000 Total					$229	$4	$59	$18	$28	$35	$99	$13	$7	$1	$	$
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	$6,115	$103	$1,576	$481	$742	$941	$2,650	$344	$200	$20	$	$
5128000 Total					$6,115	$103	$1,576	$481	$742	$941	$2,650	$344	$200	$20	$	$
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	$820	$14	$211	$64	$100	$126	$356	$46	$27	$3	$	$
5129000 Total					$820	$14	$211	$64	$100	$126	$356	$46	$27	$3	$	$
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	$1,379	$23	$355	$108	$167	$212	$598	$77	$45	$5	$	$
5129900 Total					$1,379	$23	$355	$108	$167	$212	$598	$77	$45	$5	$	$
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	$3,597	$61	$927	$283	$436	$554	$1,559	$202	$117	$12	$	$
5130000 Total					$3,597	$61	$927	$283	$436	$554	$1,559	$202	$117	$12	$	$
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	$21,123	$355	$5,445	$1,660	$2,562	$3,252	$9,155	$1,187	$690	$69	$	$
5131000 Total					$21,123	$355	$5,445	$1,660	$2,562	$3,252	$9,155	$1,187	$690	$69	$	$
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	$779	$13	$201	$61	$95	$120	$338	$44	$25	$3	$	$
5131100 Total					$779	$13	$201	$61	$95	$120	$338	$44	$25	$3	$	$
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	$12	$	$3	$1	$1	$2	$5	$1	$	$	$	$
5131300 Total					$12	$	$3	$1	$1	$2	$5	$1	$	$	$	$
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	$5,374	$90	$1,385	$422	$652	$827	$2,329	$302	$175	$18	$	$
5131400 Total					$5,374	$90	$1,385	$422	$652	$827	$2,329	$302	$175	$18	$	$
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	$1,536	$26	$396	$121	$186	$236	$666	$86	$50	$5	$	$
5132000 Total					$1,536	$26	$396	$121	$186	$236	$666	$86	$50	$5	$	$
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	$423	$7	$109	$33	$51	$65	$183	$24	$14	$1	$	$
5133000 Total					$423	$7	$109	$33	$51	$65	$183	$24	$14	$1	$	$
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	$202	$3	$52	$16	$25	$31	$88	$11	$7	$1	$	$
5134000 Total					$202	$3	$52	$16	$25	$31	$88	$11	$7	$1	$	$
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	$1,247	$21	$321	$98	$151	$192	$540	$70	$41	$4	$	$
5135000 Total					$1,247	$21	$321	$98	$151	$192	$540	$70	$41	$4	$	$
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	$2,050	$34	$528	$161	$249	$316	$888	$115	$67	$7	$	$
5137000 Total					$2,050	$34	$528	$161	$249	$316	$888	$115	$67	$7	$	$
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	$2,891	$49	$745	$227	$351	$445	$1,253	$162	$94	$9	$	$
5138000 Total					$2,891	$49	$745	$227	$351	$445	$1,253	$162	$94	$9	$	$
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	$273	$5	$70	$21	$33	$42	$118	$15	$9	$1	$	$
5139000 Total					$273	$5	$70	$21	$33	$42	$118	$15	$9	$1	$	$
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	$12	$	$3	$1	$1	$2	$5	$1	$	$	$	$
5139900 Total					$12	$	$3	$1	$1	$2	$5	$1	$	$	$	$
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	$4,669	$79	$1,203	$367	$566	$719	$2,024	$262	$152	$15	$	$
5140000 Total					$4,669	$79	$1,203	$367	$566	$719	$2,024	$262	$152	$15	$	$
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	$2,609	$44	$673	$205	$316	$402	$1,131	$147	$85	$9	$	$
5141000 Total					$2,609	$44	$673	$205	$316	$402	$1,131	$147	$85	$9	$	$
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	$3	$	$1	$	$	$	$1	$	$	$	$	$
5142000 Total					$3	$	$1	$	$	$	$1	$	$	$	$	$
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	$358	$6	$92	$28	$43	$55	$155	$20	$12	$1	$	$
5144000 Total					$358	$6	$92	$28	$43	$55	$155	$20	$12	$1	$	$
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	$352	$6	$91	$28	$43	$54	$153	$20	$11	$1	$	$
5145000 Total					$352	$6	$91	$28	$43	$54	$153	$20	$11	$1	$	$
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	$229	$4	$59	$18	$28	$35	$99	$13	$7	$1	$	$

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5146000 Total					$229	$4	$59	$18	$28	$35	$99	$13	$7	$1	$	$
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	$2,667	$45	$688	$210	$324	$411	$1,156	$150	$87	$9	$	$
5147000 Total					$2,667	$45	$688	$210	$324	$411	$1,156	$150	$87	$9	$	$
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	$1,057	$18	$273	$83	$128	$163	$458	$59	$35	$3	$	$
5148000 Total					$1,057	$18	$273	$83	$128	$163	$458	$59	$35	$3	$	$
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	$158	$3	$41	$12	$19	$24	$69	$9	$5	$1	$	$
5149000 Total					$158	$3	$41	$12	$19	$24	$69	$9	$5	$1	$	$
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	$5,437	$92	$1,402	$427	$659	$837	$2,357	$305	$178	$18	$	$
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	-$924	-$16	-$238	-$73	-$112	-$142	-$401	-$52	-$30	-$3	$	$
5350000 Total					$4,513	$76	$1,163	$355	$547	$695	$1,956	$254	$147	$15	$	$
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	$200	$3	$52	$16	$24	$31	$87	$11	$7	$1	$	$
5360000 Total					$200	$3	$52	$16	$24	$31	$87	$11	$7	$1	$	$
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	$2,217	$37	$571	$174	$269	$341	$961	$125	$72	$7	$	$
5370000 Total					$2,217	$37	$571	$174	$269	$341	$961	$125	$72	$7	$	$
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	$50	$1	$13	$4	$6	$8	$21	$3	$2	$	$	$
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	$114	$2	$29	$9	$14	$17	$49	$6	$4	$	$	$
5371000 Total					$163	$3	$42	$13	$20	$25	$71	$9	$5	$1	$	$
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	-$7	$	-$2	-$1	-$1	-$1	-$3	$	$	$	$	$
5372000 Total					-$7	$	-$2	-$1	-$1	-$1	-$3	$	$	$	$	$
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	$287	$5	$74	$23	$35	$44	$125	$16	$9	$1	$	$
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	$36	$1	$9	$3	$4	$5	$15	$2	$1	$	$	$
5374000 Total					$323	$5	$83	$25	$39	$50	$140	$18	$11	$1	$	$
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	$831	$14	$214	$65	$101	$128	$360	$47	$27	$3	$	$
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	$111	$2	$29	$9	$13	$17	$48	$6	$4	$	$	$
5379000 Total					$941	$16	$243	$74	$114	$145	$408	$53	$31	$3	$	$
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	$19,787	$333	$5,101	$1,555	$2,400	$3,046	$8,576	$1,112	$646	$65	$	$
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	$7,389	$124	$1,905	$581	$896	$1,137	$3,202	$415	$241	$24	$	$
5390000 Total					$27,176	$457	$7,005	$2,135	$3,296	$4,184	$11,779	$1,527	$887	$89	$	$
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	$159	$3	$41	$12	$19	$24	$69	$9	$5	$1	$	$
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	$1	$	$	$	$	$	$	$	$	$	$	$
5400000 Total					$160	$3	$41	$13	$19	$25	$69	$9	$5	$1	$	$
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	$2	$	$	$	$	$	$1	$	$	$	$	$
5410000 Total					$2	$	$	$	$	$	$1	$	$	$	$	$
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	$1,029	$17	$265	$81	$125	$158	$446	$58	$34	$3	$	$
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	$22	$	$6	$2	$3	$3	$10	$1	$1	$	$	$
5420000 Total					$1,051	$18	$271	$83	$128	$162	$456	$59	$34	$3	$	$
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	$1,391	$23	$359	$109	$169	$214	$603	$78	$45	$5	$	$
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	$637	$11	$164	$50	$77	$98	$276	$36	$21	$2	$	$
5430000 Total					$2,028	$34	$523	$159	$246	$312	$879	$114	$66	$7	$	$
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	$176	$3	$45	$14	$21	$27	$76	$10	$6	$1	$	$
5440000 Total					$176	$3	$45	$14	$21	$27	$76	$10	$6	$1	$	$
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	$764	$13	$197	$60	$93	$118	$331	$43	$25	$3	$	$
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	$102	$2	$26	$8	$12	$16	$44	$6	$3	$	$	$
5441000 Total					$866	$15	$223	$68	$105	$133	$375	$49	$28	$3	$	$
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	$516	$9	$133	$41	$63	$79	$224	$29	$17	$2	$	$
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	$84	$1	$22	$7	$10	$13	$37	$5	$3	$	$	$
5442000 Total					$600	$10	$155	$47	$73	$92	$260	$34	$20	$2	$	$
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	$117	$2	$30	$9	$14	$18	$51	$7	$4	$	$	$
5450000 Total					$117	$2	$30	$9	$14	$18	$51	$7	$4	$	$	$
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	$199	$3	$51	$16	$24	$31	$86	$11	$6	$1	$	$
5451000 Total					$199	$3	$51	$16	$24	$31	$86	$11	$6	$1	$	$
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	$16	$	$4	$1	$2	$3	$7	$1	$1	$	$	$
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	$	$	$	$	$	$	$	$	$	$	$	$
5454000 Total					$16	$	$4	$1	$2	$3	$7	$1	$1	$	$	$
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-P	$548	$9	$141	$43	$66	$84	$238	$31	$18	$2	$	$
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	$448	$8	$115	$35	$54	$69	$194	$25	$15	$1	$	$
5455000 Total					$996	$17	$257	$78	$121	$153	$432	$56	$33	$3	$	$
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	$1,097	$18	$283	$86	$133	$169	$476	$62	$36	$4	$	$
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	$416	$7	$107	$33	$50	$64	$180	$23	$14	$1	$	$
5459000 Total					$1,513	$25	$390	$119	$184	$233	$656	$85	$49	$5	$	$
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	$398	$7	$103	$31	$48	$61	$173	$22	$13	$1	$	$
5460000 Total					$398	$7	$103	$31	$48	$61	$173	$22	$13	$1	$	$
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	$381,797	$5,944	$92,828	$28,131	$50,503	$64,839	$164,542	$24,088	$14,336	$1,425	$	$
5471000 Total					$381,797	$5,944	$92,828	$28,131	$50,503	$64,839	$164,542	$24,088	$14,336	$1,425	$	$
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	$13,903	$234	$3,584	$1,092	$1,686	$2,140	$6,026	$781	$454	$46	$	$
5480000 Total					$13,903	$234	$3,584	$1,092	$1,686	$2,140	$6,026	$781	$454	$46	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	$21,482	$362	$5,537	$1,688	$2,606	$3,307	$9,311	$1,207	$701	$70	$	$
5490000 Total					$21,482	$362	$5,537	$1,688	$2,606	$3,307	$9,311	$1,207	$701	$70	$	$
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	$3,847	$65	$992	$302	$467	$592	$1,667	$216	$126	$13	$	$
5500000 Total					$3,847	$65	$992	$302	$467	$592	$1,667	$216	$126	$13	$	$
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	$2,681	$45	$691	$211	$325	$413	$1,162	$151	$88	$9	$	$
5520000 Total					$2,681	$45	$691	$211	$325	$413	$1,162	$151	$88	$9	$	$
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	$10,023	$169	$2,584	$788	$1,216	$1,543	$4,344	$563	$327	$33	$	$
5530000 Total					$10,023	$169	$2,584	$788	$1,216	$1,543	$4,344	$563	$327	$33	$	$
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	$2,714	$46	$699	$213	$329	$418	$1,176	$152	$89	$9	$	$
5540000 Total					$2,714	$46	$699	$213	$329	$418	$1,176	$152	$89	$9	$	$
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	$3	$	$1	$	$	$1	$1	$	$	$	$	$
5546000 Total					$3	$	$1	$	$	$1	$1	$	$	$	$	$
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	-$244,994	-$4,123	-$63,153	-$19,250	-$29,716	-$37,715	-$106,185	-$13,766	-$8,000	-$802	$	$
5550000 Total					-$244,994	-$4,123	-$63,153	-$19,250	-$29,716	-$37,715	-$106,185	-$13,766	-$8,000	-$802	$	$
5551100	REG BILL OR-(PACF)	PSEX	Power Supply Expense	OR	-$22,356	$	-$22,356	$	$	$	$	$	$	$	$	$
5551100 Total					-$22,356	$	-$22,356	$	$	$	$	$	$	$	$	$
5551200	REG BILL-WA (PACF)	PSEX	Power Supply Expense	WA	-$8,715	$	$	-$8,715	$	$	$	$	$	$	$	$
5551200 Total					-$8,715	$	$	-$8,715	$	$	$	$	$	$	$	$
5551330	REG BILL-ID (UTAH)	PSEX	Power Supply Expense	IDU	$84	$	$	$	$	$	$	$84	$	$	$	$
5551330 Total					$84	$	$	$	$	$	$	$84	$	$	$	$
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	$23,645	$368	$5,749	$1,742	$3,128	$4,016	$10,190	$1,492	$888	$88	$	$
5552500 Total					$23,645	$368	$5,749	$1,742	$3,128	$4,016	$10,190	$1,492	$888	$88	$	$
5555500	IPP ENERGY PURCH	NPCX	Net Power Cost Expense	SG	$28,142	$474	$7,254	$2,211	$3,413	$4,332	$12,197	$1,581	$919	$92	$	$
5555500 Total					$28,142	$474	$7,254	$2,211	$3,413	$4,332	$12,197	$1,581	$919	$92	$	$
5556100	BOOKOUTS NETTED-LOSS	NPCX	Net Power Cost Expense	SG	$10,464	$176	$2,697	$822	$1,269	$1,611	$4,535	$588	$342	$34	$	$
5556100 Total					$10,464	$176	$2,697	$822	$1,269	$1,611	$4,535	$588	$342	$34	$	$
5556200	TRADING NETTED-LOSS	NPCX	Net Power Cost Expense	SG	$16	$	$4	$1	$2	$2	$7	$1	$1	$	$	$
5556200 Total					$16	$	$4	$1	$2	$2	$7	$1	$1	$	$	$
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	$634,819	$10,684	$163,638	$49,881	$76,998	$97,727	$275,143	$35,669	$20,728	$2,078	$	$
5556300 Total					$634,819	$10,684	$163,638	$49,881	$76,998	$97,727	$275,143	$35,669	$20,728	$2,078	$	$
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	$136,870	$2,303	$35,281	$10,754	$16,601	$21,070	$59,322	$7,690	$4,469	$448	$	$
5556400 Total					$136,870	$2,303	$35,281	$10,754	$16,601	$21,070	$59,322	$7,690	$4,469	$448	$	$
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	-$162,540	-$2,735	-$41,898	-$12,771	-$19,715	-$25,022	-$70,448	-$9,133	-$5,307	-$532	$	$
5556700 Total					-$162,540	-$2,735	-$41,898	-$12,771	-$19,715	-$25,022	-$70,448	-$9,133	-$5,307	-$532	$	$
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	$1,200	$20	$309	$94	$146	$185	$520	$67	$39	$4	$	$
5560000 Total					$1,200	$20	$309	$94	$146	$185	$520	$67	$39	$4	$	$
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	$4,303	$67	$1,046	$317	$569	$731	$1,854	$271	$162	$16	$	$
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	$62,079	$1,045	$16,002	$4,878	$7,530	$9,557	$26,906	$3,488	$2,027	$203	$	$
5570000 Total					$66,382	$1,112	$17,048	$5,195	$8,099	$10,287	$28,761	$3,760	$2,189	$219	$	$
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	IDU	-$33	$	$	$	$	$	$	-$33	$	$	$	$
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	OR	-$54	$	-$54	$	$	$	$	$	$	$	$	$
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	SGCT	$1,122	$19	$290	$88	$137	$173	$488	$63	$37	$	$	$
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	WA	-$97	$	$	-$97	$	$	$	$	$	$	$	$
5578000 Total					$939	$19	$236	-$9	$137	$173	$488	$30	$37	$	$	$
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	$6,080	$102	$1,567	$478	$737	$936	$2,635	$342	$199	$20	$	$
5600000 Total					$6,080	$102	$1,567	$478	$737	$936	$2,635	$342	$199	$20	$	$
5610000	LOAD DISPATCHING	TNEX	Transmission O&M Expense	SG	$650	$11	$168	$51	$79	$100	$282	$37	$21	$2	$	$
5610000 Total					$650	$11	$168	$51	$79	$100	$282	$37	$21	$2	$	$
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	$7,760	$131	$2,000	$610	$941	$1,195	$3,363	$436	$253	$25	$	$
5612000 Total					$7,760	$131	$2,000	$610	$941	$1,195	$3,363	$436	$253	$25	$	$
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	$1,363	$23	$351	$107	$165	$210	$591	$77	$45	$4	$	$
5615000 Total					$1,363	$23	$351	$107	$165	$210	$591	$77	$45	$4	$	$
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	$134	$2	$35	$11	$16	$21	$58	$8	$4	$	$	$
5616000 Total					$134	$2	$35	$11	$16	$21	$58	$8	$4	$	$	$
5617000	GEN INTERCNCT STUD	TNEX	Transmission O&M Expense	SG	$902	$15	$233	$71	$109	$139	$391	$51	$29	$3	$	$
5617000 Total					$902	$15	$233	$71	$109	$139	$391	$51	$29	$3	$	$
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	$2,821	$47	$727	$222	$342	$434	$1,223	$159	$92	$9	$	$
5620000 Total					$2,821	$47	$727	$222	$342	$434	$1,223	$159	$92	$9	$	$
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	$117	$2	$30	$9	$14	$18	$51	$7	$4	$	$	$
5630000 Total					$117	$2	$30	$9	$14	$18	$51	$7	$4	$	$	$
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	$2,405	$40	$620	$189	$292	$370	$1,042	$135	$79	$8	$	$
5650000 Total					$2,405	$40	$620	$189	$292	$370	$1,042	$135	$79	$8	$	$
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	$2,221	$37	$572	$174	$269	$342	$962	$125	$73	$7	$	$
5651000 Total					$2,221	$37	$572	$174	$269	$342	$962	$125	$73	$7	$	$
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	$6,292	$98	$1,530	$464	$832	$1,069	$2,712	$397	$236	$23	$	$
5652500 Total					$6,292	$98	$1,530	$464	$832	$1,069	$2,712	$397	$236	$23	$	$

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	$126,983	$2,137	$32,733	$9,978	$15,402	$19,548	$55,037	$7,135	$4,146	$416	$	$
5654600 Total					$126,983	$2,137	$32,733	$9,978	$15,402	$19,548	$55,037	$7,135	$4,146	$416	$	$
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	$4,257	$72	$1,097	$334	$516	$655	$1,845	$239	$139	$14	$	$
5660000 Total					$4,257	$72	$1,097	$334	$516	$655	$1,845	$239	$139	$14	$	$
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	$1,837	$31	$474	$144	$223	$283	$796	$103	$60	$6	$	$
5670000 Total					$1,837	$31	$474	$144	$223	$283	$796	$103	$60	$6	$	$
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	$2,287	$38	$589	$180	$277	$352	$991	$128	$75	$7	$	$
5680000 Total					$2,287	$38	$589	$180	$277	$352	$991	$128	$75	$7	$	$
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	$	$	$	$	$	$	$	$	$	$	$	$
5690000 Total					$	$	$	$	$	$	$	$	$	$	$	$
5691000	MAINT-COMP HW TRANS	TNEX	Transmission O&M Expense	SG	$65	$1	$17	$5	$8	$10	$28	$4	$2	$	$	$
5691000 Total					$65	$1	$17	$5	$8	$10	$28	$4	$2	$	$	$
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	$1,165	$20	$300	$92	$141	$179	$505	$65	$38	$4	$	$
5692000 Total					$1,165	$20	$300	$92	$141	$179	$505	$65	$38	$4	$	$
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	$3,576	$60	$922	$281	$434	$551	$1,550	$201	$117	$12	$	$
5693000 Total					$3,576	$60	$922	$281	$434	$551	$1,550	$201	$117	$12	$	$
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	$11,188	$188	$2,884	$879	$1,357	$1,722	$4,849	$629	$365	$37	$	$
5700000 Total					$11,188	$188	$2,884	$879	$1,357	$1,722	$4,849	$629	$365	$37	$	$
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	$20,882	$351	$5,383	$1,641	$2,533	$3,215	$9,051	$1,173	$682	$68	$	$
5710000 Total					$20,882	$351	$5,383	$1,641	$2,533	$3,215	$9,051	$1,173	$682	$68	$	$
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	$141	$2	$36	$11	$17	$22	$61	$8	$5	$	$	$
5720000 Total					$141	$2	$36	$11	$17	$22	$61	$8	$5	$	$	$
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	$269	$5	$69	$21	$33	$41	$117	$15	$9	$1	$	$
5730000 Total					$269	$5	$69	$21	$33	$41	$117	$15	$9	$1	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	$30	$30	$	$	$	$	$	$	$	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	-$33	$	$	$	$	$	$	-$33	$	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	$	$	$	$	$	$	$	$	$	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	$13,877	$494	$3,734	$878	$1,198	$1,433	$6,675	$664	$234	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	$45	$	$	$	$	$	$45	$	$	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	$14	$	$	$14	$	$	$	$	$	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	-$15	$	$	$	-$15	-$15	$	$	$	$	$	$
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYU	$	$	$	$	$	$	$	$	$	$	$	$
5800000 Total					$13,919	$525	$3,734	$892	$1,183	$1,418	$6,720	$631	$234	$	$	$
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	$13,794	$491	$3,712	$872	$1,191	$1,424	$6,635	$660	$233	$	$	$
5810000 Total					$13,794	$491	$3,712	$872	$1,191	$1,424	$6,635	$660	$233	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	$118	$118	$	$	$	$	$	$	$	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	$266	$	$	$	$	$	$	$266	$	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	$1,102	$	$1,102	$	$	$	$	$	$	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	$34	$1	$9	$2	$3	$3	$16	$2	$1	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	$1,638	$	$	$	$	$	$1,638	$	$	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	$295	$	$	$295	$	$	$	$	$	$	$	$
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	$621	$	$	$	$621	$621	$	$	$	$	$	$
5820000 Total					$4,073	$119	$1,111	$297	$624	$625	$1,654	$267	$1	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	$360	$360	$	$	$	$	$	$	$	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	$210	$	$	$	$	$	$	$210	$	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	$2,969	$	$2,969	$	$	$	$	$	$	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	$30	$1	$8	$2	$3	$3	$15	$1	$1	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	$1,628	$	$	$	$	$	$1,628	$	$	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	$343	$	$	$343	$	$	$	$	$	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	$294	$	$	$	$294	$294	$	$	$	$	$	$
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	$178	$	$	$	$	$178	$	$	$178	$	$	$
5830000 Total					$6,012	$361	$2,977	$345	$297	$476	$1,642	$211	$179	$	$	$
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	IDU	$	$	$	$	$	$	$	$	$	$	$	$
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	SNPD	$	$	$	$	$	$	$	$	$	$	$	$
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	$	$	$	$	$	$	$	$	$	$	$	$
5840000 Total					$	$	$	$	$	$	$	$	$	$	$	$
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	$221	$8	$60	$14	$19	$23	$107	$11	$4	$	$	$
5850000 Total					$221	$8	$60	$14	$19	$23	$107	$11	$4	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	$223	$223	$	$	$	$	$	$	$	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	$312	$	$	$	$	$	$	$312	$	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	$2,841	$	$2,841	$	$	$	$	$	$	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	$1,338	$48	$360	$85	$116	$138	$644	$64	$23	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	$1,392	$	$	$	$	$	$1,392	$	$	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	$431	$	$	$431	$	$	$	$	$	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	$492	$	$	$	$492	$492	$	$	$	$	$	$
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	$56	$	$	$	$	$56	$	$	$56	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5860000 Total					$7,086	$271	$3,202	$516	$608	$686	$2,035	$376	$79	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	$597	$597	$	$	$	$	$	$	$	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	$378	$	$	$	$	$	$	$378	$	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	$4,336	$	$4,336	$	$	$	$	$	$	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	$5,412	$	$	$	$	$	$5,412	$	$	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	$1,023	$	$	$1,023	$	$	$	$	$	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	$899	$	$	$	$899	$899	$	$	$	$	$	$
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	$61	$	$	$	$	$61	$	$	$61	$	$	$
5870000 Total					$12,707	$597	$4,336	$1,023	$899	$960	$5,412	$378	$61	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	$40	$40	$	$	$	$	$	$	$	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	-$16	$	$	$	$	$	$	-$16	$	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	$271	$	$271	$	$	$	$	$	$	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	$4,035	$144	$1,086	$255	$348	$417	$1,941	$193	$68	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	$840	$	$	$	$	$	$840	$	$	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	$52	$	$	$52	$	$	$	$	$	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	$21	$	$	$	$21	$21	$	$	$	$	$	$
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-$45	$	$	$	$	-$45	$	$	-$45	$	$	$
5880000 Total					$5,198	$184	$1,357	$307	$369	$392	$2,781	$177	$23	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	$82	$82	$	$	$	$	$	$	$	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	$15	$	$	$	$	$	$	$15	$	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	$1,726	$	$1,726	$	$	$	$	$	$	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	$64	$2	$17	$4	$6	$7	$31	$3	$1	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	$588	$	$	$	$	$	$588	$	$	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	$123	$	$	$123	$	$	$	$	$	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	$521	$	$	$	$521	$521	$	$	$	$	$	$
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	$50	$	$	$	$	$50	$	$	$50	$	$	$
5890000 Total					$3,170	$85	$1,743	$127	$527	$578	$619	$19	$51	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	$21	$21	$	$	$	$	$	$	$	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	$46	$	$	$	$	$	$	$46	$	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	$319	$	$319	$	$	$	$	$	$	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	$3,963	$141	$1,066	$251	$342	$409	$1,906	$190	$67	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	$323	$	$	$	$	$	$323	$	$	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	$14	$	$	$14	$	$	$	$	$	$	$	$
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	$100	$	$	$	$100	$100	$	$	$	$	$	$
5900000 Total					$4,786	$162	$1,385	$265	$443	$510	$2,230	$235	$67	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	$25	$25	$	$	$	$	$	$	$	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	$129	$	$	$	$	$	$	$129	$	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	$483	$	$483	$	$	$	$	$	$	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	$82	$3	$22	$5	$7	$8	$39	$4	$1	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	$693	$	$	$	$	$	$693	$	$	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	$90	$	$	$90	$	$	$	$	$	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	$192	$	$	$	$192	$192	$	$	$	$	$	$
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	$82	$	$	$	$	$82	$	$	$82	$	$	$
5910000 Total					$1,775	$28	$505	$95	$199	$282	$732	$133	$83	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	$553	$553	$	$	$	$	$	$	$	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	$790	$	$	$	$	$	$	$790	$	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	$4,794	$	$4,794	$	$	$	$	$	$	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	$1,454	$52	$391	$92	$126	$150	$699	$70	$25	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	$4,715	$	$	$	$	$	$4,715	$	$	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	$911	$	$	$911	$	$	$	$	$	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	$1,559	$	$	$	$1,559	$1,559	$	$	$	$	$	$
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	$	$	$	$	$	$	$	$	$	$	$	$
5920000 Total					$14,775	$604	$5,185	$1,003	$1,684	$1,709	$5,415	$859	$24	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	$5,899	$5,899	$	$	$	$	$	$	$	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	$4,923	$	$	$	$	$	$	$4,923	$	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	$28,695	$	$28,695	$	$	$	$	$	$	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	$935	$33	$252	$59	$81	$97	$450	$45	$16	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	$34,920	$	$	$	$	$	$34,920	$	$	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	$4,446	$	$	$4,446	$	$	$	$	$	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	$5,673	$	$	$	$5,673	$5,673	$	$	$	$	$	$
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	$1,303	$	$	$	$	$1,303	$	$	$1,303	$	$	$
5930000 Total					**$86,794**	**$5,933**	**$28,947**	**$4,505**	**$5,754**	**$7,072**	**$35,370**	**$4,968**	**$1,319**	**$**	**$**	**$**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	$24	$24	$	$	$	$	$	$	$	$	$	$
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	$275	$	$	$	$	$	$	$275	$	$	$	$
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	$127	$	$127	$	$	$	$	$	$	$	$	$
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	$1,427	$	$	$	$	$	$1,427	$	$	$	$	$

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	-$75	$	$	-$75	$	$	$	$	$	$	$	$
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	-$69	$	$	$	-$69	-$69	$	$	$	$	$	$
5931000 Total					**$1,709**	**$24**	**$127**	**-$75**	**-$69**	**-$69**	**$1,427**	**$275**	**$**	**$**	**$**	**$**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	$474	$474	$	$	$	$	$	$	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	$731	$	$	$	$	$	$	$731	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	$5,828	$	$5,828	$	$	$	$	$	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	$	$	$	$	$	$	$	$	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	$12,774	$	$	$	$	$	$12,774	$	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	$1,112	$	$	$1,112	$	$	$	$	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	$2,186	$	$	$	$2,186	$2,186	$	$	$	$	$	$
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	$262	$	$	$	$	$262	$	$	$262	$	$	$
5940000 Total					**$23,367**	**$474**	**$5,828**	**$1,112**	**$2,186**	**$2,448**	**$12,774**	**$731**	**$262**	**$**	**$**	**$**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	$864	$31	$232	$55	$75	$89	$416	$41	$15	$	$	$
5950000 Total					**$864**	**$31**	**$232**	**$55**	**$75**	**$89**	**$416**	**$41**	**$15**	**$**	**$**	**$**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	$130	$130	$	$	$	$	$	$	$	$	$	$
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	$160	$	$	$	$	$	$	$160	$	$	$	$
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	$1,173	$	$1,173	$	$	$	$	$	$	$	$	$
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	$1,957	$	$	$	$	$	$1,957	$	$	$	$	$
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	$172	$	$	$172	$	$	$	$	$	$	$	$
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	$382	$	$	$	$382	$382	$	$	$	$	$	$
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	$109	$	$	$	$	$109	$	$	$109	$	$	$
5960000 Total					**$4,084**	**$130**	**$1,173**	**$172**	**$382**	**$491**	**$1,957**	**$160**	**$109**	**$**	**$**	**$**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	$65	$65	$	$	$	$	$	$	$	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	$311	$	$	$	$	$	$	$311	$	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	$1,020	$	$1,020	$	$	$	$	$	$	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	$1,014	$36	$273	$64	$88	$105	$488	$48	$17	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	$2,269	$	$	$	$	$	$2,269	$	$	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	$468	$	$	$468	$	$	$	$	$	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	$527	$	$	$	$527	$527	$	$	$	$	$	$
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	$97	$	$	$	$	$97	$	$	$97	$	$	$
5970000 Total					**$5,771**	**$101**	**$1,293**	**$532**	**$615**	**$729**	**$2,757**	**$359**	**$114**	**$**	**$**	**$**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	$181	$181	$	$	$	$	$	$	$	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	$43	$	$	$	$	$	$	$43	$	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	$450	$	$450	$	$	$	$	$	$	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	-$292	-$10	-$79	-$18	-$25	-$30	-$141	-$14	-$5	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	$1,096	$	$	$	$	$	$1,096	$	$	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	-$37	$	$	-$37	$	$	$	$	$	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	$351	$	$	$	$351	$351	$	$	$	$	$	$
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYU	$2	$	$	$	$	$2	$	$	$2	$	$	$
5980000 Total					**$1,793**	**$171**	**$371**	**-$56**	**$325**	**$322**	**$955**	**$29**	**-$3**	**$**	**$**	**$**
7071000	LBR CLR - RMP	UNAS	Unassigned	OTHER	$	$	$	$	$	$	$	$	$	$	$	$
7071000 Total					**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
7072000	LBR CLR - PACPWR	UNAS	Unassigned	OTHER	$	$	$	$	$	$	$	$	$	$	$	$
7072000 Total					**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	$2,625	$63	$771	$176	$170	$192	$1,325	$99	$22	$	$	$
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	OR	$1	$	$1	$	$	$	$	$	$	$	$	$
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	WYP	$2	$	$	$	$2	$2	$	$	$	$	$	$
9010000 Total					**$2,627**	**$63**	**$772**	**$176**	**$171**	**$193**	**$1,325**	**$99**	**$22**	**$**	**$**	**$**
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	$868	$868	$	$	$	$	$	$	$	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	$2,206	$53	$648	$148	$143	$161	$1,113	$83	$18	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	$1,637	$	$	$	$	$	$	$1,637	$	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	$9,821	$	$9,821	$	$	$	$	$	$	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	$4,701	$	$	$	$	$	$4,701	$	$	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	$1,547	$	$	$1,547	$	$	$	$	$	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	$1,781	$	$	$	$1,781	$1,781	$	$	$	$	$	$
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	$322	$	$	$	$	$322	$	$	$322	$	$	$
9020000 Total					**$22,883**	**$921**	**$10,469**	**$1,695**	**$1,924**	**$2,264**	**$5,814**	**$1,720**	**$340**	**$**	**$**	**$**
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	$876	$21	$257	$59	$57	$64	$442	$33	$7	$	$	$
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	UT	$4	$	$	$	$	$	$4	$	$	$	$	$
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	WA	$	$	$	$	$	$	$	$	$	$	$	$
9030000 Total					**$880**	**$21**	**$257**	**$59**	**$57**	**$64**	**$446**	**$33**	**$7**	**$**	**$**	**$**
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	$4,037	$97	$1,185	$271	$261	$295	$2,037	$152	$34	$	$	$
9031000 Total					**$4,037**	**$97**	**$1,185**	**$271**	**$261**	**$295**	**$2,037**	**$152**	**$34**	**$**	**$**	**$**
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	$12,026	$289	$3,531	$807	$777	$878	$6,069	$452	$101	$	$	$
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	IDU	$1	$	$	$	$	$	$	$1	$	$	$	$

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	OR	$1	$	$1	$	$	$	$	$	$	$	$	$
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	UT	-$4	$	$	$	$	$	-$4	$	$	$	$	$
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	WYP	$1	$	$	$	$1	$1	$	$	$	$	$	$
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	WYU	$	$	$	$	$	$	$	$	$	$	$	$
9032000 Total					**$12,024**	**$289**	**$3,532**	**$807**	**$779**	**$879**	**$6,064**	**$453**	**$101**	**$**	**$**	**$**
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	$218	$218	$	$	$	$	$	$	$	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	$10,901	$262	$3,201	$731	$705	$796	$5,501	$410	$91	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	$366	$	$	$	$	$	$	$366	$	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	$2,032	$	$2,032	$	$	$	$	$	$	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	$3,646	$	$	$	$	$	$3,646	$	$	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	$688	$	$	$688	$	$	$	$	$	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	$478	$	$	$	$478	$478	$	$	$	$	$	$
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	$84	$	$	$	$	$84	$	$	$84	$	$	$
9033000 Total					**$18,415**	**$480**	**$5,233**	**$1,419**	**$1,183**	**$1,358**	**$9,148**	**$777**	**$175**	**$**	**$**	**$**
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	$	$	$	$	$	$	$	$	$	$	$	$
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	$53	$	$	$	$	$	$	$53	$	$	$	$
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	$35	$	$35	$	$	$	$	$	$	$	$	$
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	$71	$	$	$	$	$	$71	$	$	$	$	$
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	$3	$	$	$	$3	$3	$	$	$	$	$	$
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	$3	$	$	$	$	$3	$	$	$3	$	$	$
9035000 Total					**$165**	**$**	**$35**	**$**	**$3**	**$6**	**$71**	**$53**	**$3**	**$**	**$**	**$**
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	$20,835	$501	$6,118	$1,397	$1,347	$1,521	$10,514	$784	$174	$	$	$
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	$157	$	$157	$	$	$	$	$	$	$	$	$
9036000 Total					**$20,993**	**$501**	**$6,275**	**$1,397**	**$1,347**	**$1,521**	**$10,514**	**$784**	**$174**	**$**	**$**	**$**
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	$464	$464	$	$	$	$	$	$	$	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	$391	$9	$115	$26	$25	$29	$197	$15	$3	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	$419	$	$	$	$	$	$	$419	$	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	$5,854	$	$5,854	$	$	$	$	$	$	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	$3,350	$	$	$	$	$	$3,350	$	$	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	$1,632	$	$	$1,632	$	$	$	$	$	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	$643	$	$	$	$643	$643	$	$	$	$	$	$
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYU	$	$	$	$	$	$	$	$	$	$	$	$
9040000 Total					**$12,754**	**$473**	**$5,969**	**$1,658**	**$669**	**$672**	**$3,547**	**$434**	**$3**	**$**	**$**	**$**
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	$46	$46	$	$	$	$	$	$	$	$	$	$
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	$	$	$	$	$	$	$	$	$	$	$	$
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	$142	$	$142	$	$	$	$	$	$	$	$	$
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	$21	$	$	$	$	$	$21	$	$	$	$	$
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	$36	$	$	$36	$	$	$	$	$	$	$	$
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	-$10	$	$	$	-$10	-$10	$	$	$	$	$	$
9042000 Total					**$235**	**$46**	**$142**	**$36**	**-$10**	**-$10**	**$21**	**$**	**$**	**$**	**$**	**$**
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	$177	$4	$52	$12	$11	$13	$89	$7	$1	$	$	$
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	OR	$10	$	$10	$	$	$	$	$	$	$	$	$
9050000 Total					**$187**	**$4**	**$62**	**$12**	**$11**	**$13**	**$89**	**$7**	**$1**	**$**	**$**	**$**
9051000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	$10	$	$3	$1	$1	$1	$5	$	$	$	$	$
9051000 Total					**$10**	**$**	**$3**	**$1**	**$1**	**$1**	**$5**	**$**	**$**	**$**	**$**	**$**
9070000	SUPRV (CUST SERV)	CSEX	Customer Service Expense	CN	$280	$7	$82	$19	$18	$20	$141	$11	$2	$	$	$
9070000 Total					**$280**	**$7**	**$82**	**$19**	**$18**	**$20**	**$141**	**$11**	**$2**	**$**	**$**	**$**
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CA	$47	$47	$	$	$	$	$	$	$	$	$	$
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	$1,404	$34	$412	$94	$91	$103	$709	$53	$12	$	$	$
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	IDU	$12	$	$	$	$	$	$	$12	$	$	$	$
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	$428	$	$428	$	$	$	$	$	$	$	$	$
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	$59	$	$	$	$	$	$59	$	$	$	$	$
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WA	$142	$	$	$142	$	$	$	$	$	$	$	$
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WYP	$27	$	$	$	$27	$27	$	$	$	$	$	$
9080000 Total					**$2,118**	**$81**	**$840**	**$236**	**$117**	**$129**	**$768**	**$64**	**$12**	**$**	**$**	**$**
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	$29	$1	$8	$2	$2	$2	$15	$1	$	$	$	$
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	UT	$227	$	$	$	$	$	$227	$	$	$	$	$
9081000 Total					**$256**	**$1**	**$8**	**$2**	**$2**	**$2**	**$242**	**$1**	**$**	**$**	**$**	**$**
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	$50	$50	$	$	$	$	$	$	$	$	$	$
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	$471	$11	$138	$32	$30	$34	$237	$18	$4	$	$	$
9084000	DSM DIRECT	CSEX	Customer Service Expense	IDU	$102	$	$	$	$	$	$	$102	$	$	$	$
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	$69	$	$	$	$	$	$	$	$	$	$69	$
9084000	DSM DIRECT	CSEX	Customer Service Expense	UT	$154	$	$	$	$	$	$154	$	$	$	$	$
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	$67	$	$	$67	$	$	$	$	$	$	$	$
9084000	DSM DIRECT	CSEX	Customer Service Expense	WYP	$61	$	$	$	$61	$61	$	$	$	$	$	$

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
9084000 Total					**$974**	**$61**	**$138**	**$98**	**$92**	**$96**	**$391**	**$120**	**$4**	**$**	**$69**	**$**
9085000	DSM AMORT	CSEX	Customer Service Expense	IDU	$333	$	$	$	$	$	$	$333	$	$	$	$
9085000	DSM AMORT	CSEX	Customer Service Expense	UT	$157	$	$	$	$	$	$157	$	$	$	$	$
9085000	DSM AMORT	CSEX	Customer Service Expense	WYP	$47	$	$	$	$47	$47	$	$	$	$	$	$
9085000 Total					**$537**	**$**	**$**	**$**	**$47**	**$47**	**$157**	**$333**	**$**	**$**	**$**	**$**
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	CA	$1,086	$1,086	$	$	$	$	$	$	$	$	$	$
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	IDU	$6,003	$	$	$	$	$	$	$6,003	$	$	$	$
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OR	$21,405	$	$21,405	$	$	$	$	$	$	$	$	$
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	UT	$53,697	$	$	$	$	$	$53,697	$	$	$	$	$
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	WA	$8,763	$	$	$8,763	$	$	$	$	$	$	$	$
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	WYP	$3,341	$	$	$	$3,341	$3,341	$	$	$	$	$	$
9085100 Total					**$94,296**	**$1,086**	**$21,405**	**$8,763**	**$3,341**	**$3,341**	**$53,697**	**$6,003**	**$**	**$**	**$**	**$**
9086000	CUST SERV	CSEX	Customer Service Expense	CA	$163	$163	$	$	$	$	$	$	$	$	$	$
9086000	CUST SERV	CSEX	Customer Service Expense	CN	$597	$14	$175	$40	$39	$44	$301	$22	$5	$	$	$
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	$422	$	$	$	$	$	$	$422	$	$	$	$
9086000	CUST SERV	CSEX	Customer Service Expense	OR	$1,152	$	$1,152	$	$	$	$	$	$	$	$	$
9086000	CUST SERV	CSEX	Customer Service Expense	UT	$2,306	$	$	$	$	$	$2,306	$	$	$	$	$
9086000	CUST SERV	CSEX	Customer Service Expense	WA	$74	$	$	$74	$	$	$	$	$	$	$	$
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	$939	$	$	$	$939	$939	$	$	$	$	$	$
9086000 Total					**$5,653**	**$177**	**$1,327**	**$114**	**$978**	**$983**	**$2,607**	**$445**	**$5**	**$**	**$**	**$**
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	$4,920	$	$	$	$	$	$	$	$	$	$4,920	$
9089500 Total					**$4,920**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$4,920**	**$**
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	$32	$32	$	$	$	$	$	$	$	$	$	$
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	$4,159	$100	$1,221	$279	$269	$304	$2,099	$156	$35	$	$	$
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	$54	$	$	$	$	$	$	$54	$	$	$	$
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	$215	$	$215	$	$	$	$	$	$	$	$	$
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	$71	$	$	$	$	$	$71	$	$	$	$	$
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	$18	$	$	$18	$	$	$	$	$	$	$	$
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	$155	$	$	$	$155	$155	$	$	$	$	$	$
9090000 Total					**$4,705**	**$132**	**$1,436**	**$297**	**$424**	**$459**	**$2,170**	**$211**	**$35**	**$**	**$**	**$**
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	$89	$2	$26	$6	$6	$6	$45	$3	$1	$	$	$
9100000 Total					**$89**	**$2**	**$26**	**$6**	**$6**	**$6**	**$45**	**$3**	**$1**	**$**	**$**	**$**
9101000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	$144	$3	$42	$10	$9	$11	$73	$5	$1	$	$	$
9101000 Total					**$144**	**$3**	**$42**	**$10**	**$9**	**$11**	**$73**	**$5**	**$1**	**$**	**$**	**$**
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	CA	$16	$16	$	$	$	$	$	$	$	$	$	$
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	IDU	$305	$	$	$	$	$	$	$305	$	$	$	$
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	$1,274	$	$1,274	$	$	$	$	$	$	$	$	$
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	$76,070	$1,758	$20,664	$5,827	$8,592	$10,741	$32,701	$4,199	$2,150	$179	$	$
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	UT	-$5,389	$	$	$	$	$	-$5,389	$	$	$	$	$
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WA	-$1,018	$	$	-$1,018	$	$	$	$	$	$	$	$
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WYP	-$1,090	$	$	$	-$1,090	-$1,090	$	$	$	$	$	$
9200000 Total					**$70,168**	**$1,773**	**$21,939**	**$4,809**	**$7,502**	**$9,652**	**$27,311**	**$4,505**	**$2,150**	**$179**	**$**	**$**
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	$21	$21	$	$	$	$	$	$	$	$	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	$53	$	$	$	$	$	$	$53	$	$	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	$302	$	$302	$	$	$	$	$	$	$	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	$8,822	$204	$2,397	$676	$996	$1,246	$3,793	$487	$249	$21	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	$241	$	$	$	$	$	$241	$	$	$	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	$57	$	$	$57	$	$	$	$	$	$	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	$127	$	$	$	$127	$127	$	$	$	$	$	$
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	$17	$	$	$	$	$17	$	$	$17	$	$	$
9210000 Total					**$9,641**	**$225**	**$2,699**	**$733**	**$1,123**	**$1,390**	**$4,034**	**$540**	**$267**	**$21**	**$**	**$**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	-$31,727	-$733	-$8,619	-$2,430	-$3,583	-$4,480	-$13,639	-$1,751	-$897	-$75	$	$
9220000 Total					**-$31,727**	**-$733**	**-$8,619**	**-$2,430**	**-$3,583**	**-$4,480**	**-$13,639**	**-$1,751**	**-$897**	**-$75**	**$**	**$**
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	$2	$2	$	$	$	$	$	$	$	$	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	$	$	$	$	$	$	$	$	$	$	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	$13	$	$13	$	$	$	$	$	$	$	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	$14,126	$326	$3,637	$1,082	$1,595	$1,995	$6,073	$780	$399	$33	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	$2	$	$	$	$	$	$2	$	$	$	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	$	$	$	$	$	$	$	$	$	$	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	$2	$	$	$	$2	$2	$	$	$	$	$	$
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	$1	$	$	$	$	$1	$	$	$1	$	$	$
9230000 Total					**$14,146**	**$328**	**$3,850**	**$1,083**	**$1,598**	**$1,997**	**$6,075**	**$780**	**$400**	**$33**	**$**	**$**
9240000	PROP INSURANCE - SYS	AGEX	Administrative & General Expense	SO	$22,520	$520	$6,117	$1,725	$2,543	$3,180	$9,681	$1,243	$636	$53	$	$
9240000 Total					**$22,520**	**$520**	**$6,117**	**$1,725**	**$2,543**	**$3,180**	**$9,681**	**$1,243**	**$636**	**$53**	**$**	**$**
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	IDU	$36	$	$	$	$	$	$	$36	$	$	$	$

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(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	$1,319	$	$1,319	$	$	$	$	$	$	$	$	$
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	SO	$	$	$	$	$	$	$	$	$	$	$	$
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	$596	$	$	$	$	$	$596	$	$	$	$	$
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	$97	$	$	$	$97	$97	$	$	$	$	$	$
9241000 Total					**$2,048**	**$**	**$1,319**	**$**	**$97**	**$97**	**$596**	**$36**	**$**	**$**	**$**	**$**
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	-$12	$	-$12	$	$	$	$	$	$	$	$	$
9242000 Total					**-$12**	**$**	**-$12**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	$829	$19	$225	$64	$94	$117	$356	$46	$23	$2	$	$
9243000 Total					**$829**	**$19**	**$225**	**$64**	**$94**	**$117**	**$356**	**$46**	**$23**	**$2**	**$**	**$**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	$8,315	$192	$2,259	$637	$939	$1,174	$3,574	$459	$235	$20	$	$
9250000 Total					**$8,315**	**$192**	**$2,259**	**$637**	**$939**	**$1,174**	**$3,574**	**$459**	**$235**	**$20**	**$**	**$**
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	$585	$585	$	$	$	$	$	$	$	$	$	$
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	IDU	$1,298	$	$	$	$	$	$	$1,298	$	$	$	$
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	$967	$	$967	$	$	$	$	$	$	$	$	$
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	$1,800	$42	$489	$138	$203	$254	$774	$99	$51	$4	$	$
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	$1,948	$	$	$	$	$	$1,948	$	$	$	$	$
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	$1,148	$	$	$1,148	$	$	$	$	$	$	$	$
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	$1,381	$	$	$	$1,381	$1,381	$	$	$	$	$	$
9280000 Total					**$9,126**	**$627**	**$1,456**	**$1,286**	**$1,584**	**$1,635**	**$2,722**	**$1,397**	**$51**	**$4**	**$**	**$**
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	$190	$190	$	$	$	$	$	$	$	$	$	$
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	$403	$	$	$	$	$	$	$403	$	$	$	$
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	$2,080	$	$2,080	$	$	$	$	$	$	$	$	$
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	$3,360	$	$	$	$	$	$3,360	$	$	$	$	$
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	$513	$	$	$513	$	$	$	$	$	$	$	$
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	$1,087	$	$	$	$1,087	$1,087	$	$	$	$	$	$
9282000 Total					**$7,633**	**$190**	**$2,080**	**$513**	**$1,087**	**$1,087**	**$3,360**	**$403**	**$**	**$**	**$**	**$**
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	$1,657	$28	$427	$130	$201	$255	$718	$93	$54	$5	$	$
9283000 Total					**$1,657**	**$28**	**$427**	**$130**	**$201**	**$255**	**$718**	**$93**	**$54**	**$5**	**$**	**$**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	-$6,812	-$157	-$1,850	-$522	-$769	-$962	-$2,928	-$376	-$193	-$16	$	$
9290000 Total					**-$6,812**	**-$157**	**-$1,850**	**-$522**	**-$769**	**-$962**	**-$2,928**	**-$376**	**-$193**	**-$16**	**$**	**$**
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	$20	$	$5	$2	$2	$3	$9	$1	$1	$	$	$
9301000 Total					**$20**	**$**	**$5**	**$2**	**$2**	**$3**	**$9**	**$1**	**$1**	**$**	**$**	**$**
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	CA	-$1	-$1	$	$	$	$	$	$	$	$	$	$
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	IDU	$6	$	$	$	$	$	$	$6	$	$	$	$
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	$1,359	$	$1,359	$	$	$	$	$	$	$	$	$
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	$14,532	$336	$3,948	$1,113	$1,641	$2,052	$6,247	$802	$411	$34	$	$
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	UT	$213	$	$	$	$	$	$213	$	$	$	$	$
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WA	$5	$	$	$5	$	$	$	$	$	$	$	$
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	$71	$	$	$	$71	$71	$	$	$	$	$	$
9302000 Total					**$16,186**	**$335**	**$5,307**	**$1,118**	**$1,712**	**$2,123**	**$6,460**	**$808**	**$411**	**$34**	**$**	**$**
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	$2	$2	$	$	$	$	$	$	$	$	$	$
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	IDU	$	$	$	$	$	$	$	$	$	$	$	$
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	$1,056	$	$1,056	$	$	$	$	$	$	$	$	$
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	$5,322	$123	$1,446	$408	$601	$752	$2,288	$294	$150	$13	$	$
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	$4	$	$	$	$	$	$4	$	$	$	$	$
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	$5	$	$	$5	$	$	$	$	$	$	$	$
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	$18	$	$	$	$18	$18	$	$	$	$	$	$
9310000 Total					**$6,408**	**$125**	**$2,502**	**$413**	**$619**	**$770**	**$2,292**	**$294**	**$150**	**$13**	**$**	**$**
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	$4	$4	$	$	$	$	$	$	$	$	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	$19	$	$	$	$	$	$	$19	$	$	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	$90	$	$90	$	$	$	$	$	$	$	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	$23,579	$545	$6,405	$1,806	$2,663	$3,329	$10,136	$1,302	$666	$56	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	$64	$	$	$	$	$	$64	$	$	$	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	$16	$	$	$16	$	$	$	$	$	$	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	$28	$	$	$	$28	$28	$	$	$	$	$	$
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	$13	$	$	$	$	$13	$	$	$13	$	$	$
9350000 Total					**$23,814**	**$549**	**$6,495**	**$1,823**	**$2,691**	**$3,371**	**$10,200**	**$1,320**	**$680**	**$56**	**$**	**$**
Grand Total					**$2,713,492**	**$53,895**	**$693,517**	**$196,750**	**$321,211**	**$405,221**	**$1,189,657**	**$161,526**	**$84,010**	**$7,936**	**$4,989**	**$**

B3. DEPRECIATION EXPENSE

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Depreciation Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
4030000	DEPN EXPENSE-ELECT	3102000	LAND RIGHTS	SG	$860	$14	$222	$68	$104	$132	$373	$48	$28	$3
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	$17,060	$287	$4,398	$1,340	$2,069	$2,626	$7,394	$959	$557	$56
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	$78,894	$1,328	$20,337	$6,199	$9,569	$12,145	$34,194	$4,433	$2,576	$258
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	$21,605	$364	$5,569	$1,698	$2,621	$3,326	$9,364	$1,214	$705	$71
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	$6,948	$117	$1,791	$546	$843	$1,070	$3,011	$390	$227	$23
4030000	DEPN EXPENSE-ELECT	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	$1	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	$927	$16	$239	$73	$112	$143	$402	$52	$30	$3
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-P	$89	$2	$23	$7	$11	$14	$39	$5	$3	$
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-U	$1	$	$	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-U	$2	$	$	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-P	$3	$	$1	$	$	$1	$2	$	$	$
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-U	$2	$	$1	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	$3	$	$1	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-P	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-U	$183	$3	$47	$14	$22	$28	$79	$10	$6	$1
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	$1,131	$19	$292	$89	$137	$174	$490	$64	$37	$4
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	$93	$2	$24	$7	$11	$14	$40	$5	$3	$
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	$591	$10	$152	$46	$72	$91	$256	$33	$19	$2
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	$10	$	$3	$1	$1	$2	$5	$1	$	$
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	$239	$4	$62	$19	$29	$37	$104	$13	$8	$1
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	$68	$1	$18	$5	$8	$10	$29	$4	$2	$
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	$73	$1	$19	$6	$9	$11	$32	$4	$2	$
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	$552	$9	$142	$43	$67	$85	$239	$31	$18	$2
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	$4,872	$82	$1,256	$383	$591	$750	$2,112	$274	$159	$16
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	$1,001	$17	$258	$79	$121	$154	$434	$56	$33	$3
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	$302	$5	$78	$24	$37	$46	$131	$17	$10	$1
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	$15	$	$4	$1	$2	$2	$7	$1	$	$
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	$2	$	$1	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	$2	$	$	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	$1,901	$32	$490	$149	$231	$293	$824	$107	$62	$6
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	$1,039	$17	$268	$82	$126	$160	$450	$58	$34	$3
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	$1,625	$27	$419	$128	$197	$250	$704	$91	$53	$5
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	$328	$6	$85	$26	$40	$50	$142	$18	$11	$1
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	$119	$2	$31	$9	$14	$18	$52	$7	$4	$
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	$1	$	$	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3350000	MISC POWER PLANT EQUIP	SG-U	$5	$	$1	$	$1	$1	$2	$	$	$
4030000	DEPN EXPENSE-ELECT	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	$44	$1	$11	$3	$5	$7	$19	$2	$1	$
4030000	DEPN EXPENSE-ELECT	3352000	MISC POWER PLANT EQUIP - FISH & WILDLIFE	SG-P	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3353000	MISC POWER PLANT EQUIP - RECREATION	SG-P	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	$354	$6	$91	$28	$43	$54	$153	$20	$12	$1
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	$44	$1	$11	$3	$5	$7	$19	$2	$1	$
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	SG	$4,814	$81	$1,241	$378	$584	$741	$2,087	$270	$157	$16
4030000	DEPN EXPENSE-ELECT	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	$304	$5	$78	$24	$37	$47	$132	$17	$10	$1
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	$89,266	$1,502	$23,010	$7,014	$10,827	$13,742	$38,690	$5,016	$2,915	$292
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	$10,226	$172	$2,636	$803	$1,240	$1,574	$4,432	$575	$334	$33
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	$7,678	$129	$1,979	$603	$931	$1,182	$3,328	$431	$251	$25
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	$350	$6	$90	$28	$42	$54	$152	$20	$11	$1
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	$1,587	$27	$409	$125	$193	$244	$688	$89	$52	$5
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	$1,524	$26	$393	$120	$185	$235	$660	$86	$50	$5
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	$23,452	$395	$6,045	$1,843	$2,844	$3,610	$10,164	$1,318	$766	$77
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	$2,161	$36	$557	$170	$262	$333	$937	$121	$71	$7
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	$1,068	$18	$275	$84	$130	$164	$463	$60	$35	$3
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	$11,583	$195	$2,986	$910	$1,405	$1,783	$5,020	$651	$378	$38
4030000	DEPN EXPENSE-ELECT	3550000	POLES AND FIXTURES	SG	$15,743	$265	$4,058	$1,237	$1,910	$2,424	$6,823	$885	$514	$52
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	$18,276	$308	$4,711	$1,436	$2,217	$2,813	$7,921	$1,027	$597	$60
4030000	DEPN EXPENSE-ELECT	3562000	CLEARING AND GRADING	SG	$33	$1	$9	$3	$4	$5	$14	$2	$1	$
4030000	DEPN EXPENSE-ELECT	3570000	UNDERGROUND CONDUIT	SG	$54	$1	$14	$4	$6	$8	$23	$3	$2	$
4030000	DEPN EXPENSE-ELECT	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	$123	$2	$32	$10	$15	$19	$53	$7	$4	$
4030000	DEPN EXPENSE-ELECT	3590000	ROADS AND TRAILS	SG	$161	$3	$41	$13	$20	$25	$70	$9	$5	$1
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	CA	$22	$22	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	IDU	$18	$	$	$	$	$	$	$18	$	$
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	OR	$68	$	$68	$	$	$	$	$	$	$

PACIFICORP
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Depreciation Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	UT	$134	$	$	$	$	$	$134	$	$	$
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WA	$5	$	$	$5	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYP	$35	$	$	$	$35	$35	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYU	$33	$	$	$	$	$33	$	$	$33	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	CA	$73	$73	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	IDU	$24	$	$	$	$	$	$	$24	$	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	OR	$290	$	$290	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	UT	$638	$	$	$	$	$	$638	$	$	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WA	$39	$	$	$39	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYP	$157	$	$	$	$157	$157	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYU	$3	$	$	$	$	$3	$	$	$3	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	CA	$510	$510	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	IDU	$611	$	$	$	$	$	$	$611	$	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	OR	$4,073	$	$4,073	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	UT	$8,908	$	$	$	$	$	$8,908	$	$	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WA	$942	$	$	$942	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYP	$2,191	$	$	$	$2,191	$2,191	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYU	$201	$	$	$	$	$201	$	$	$201	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	$15	$15	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	$11	$	$	$	$	$	$	$11	$	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	$121	$	$121	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	$317	$	$	$	$	$	$317	$	$	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	$37	$	$	$37	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	$77	$	$	$	$77	$77	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	$2	$	$	$	$	$2	$	$	$2	$
4030000	DEPN EXPENSE-ELECT	3637000	STORAGE BATTERY EQUIPMENT - SUPRVISORY &	UT	$2	$	$	$	$	$	$2	$	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	CA	$2,184	$2,184	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	IDU	$2,193	$	$	$	$	$	$	$2,193	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	OR	$12,562	$	$12,562	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	UT	$10,648	$	$	$	$	$	$10,648	$	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WA	$3,695	$	$	$3,695	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYP	$3,068	$	$	$	$3,068	$3,068	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYU	$619	$	$	$	$	$619	$	$	$619	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	$1,004	$1,004	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	$977	$	$	$	$	$	$	$977	$	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	$6,904	$	$6,904	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	$6,394	$	$	$	$	$	$6,394	$	$	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	$1,687	$	$	$1,687	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	$2,187	$	$	$	$2,187	$2,187	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	$291	$	$	$	$	$291	$	$	$291	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	CA	$491	$491	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	IDU	$165	$	$	$	$	$	$	$165	$	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	OR	$2,154	$	$2,154	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	UT	$3,738	$	$	$	$	$	$3,738	$	$	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WA	$690	$	$	$690	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYP	$499	$	$	$	$499	$499	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYU	$145	$	$	$	$	$145	$	$	$145	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	$677	$677	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	$487	$	$	$	$	$	$	$487	$	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	$3,737	$	$3,737	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	$10,691	$	$	$	$	$	$10,691	$	$	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	$627	$	$	$627	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	$1,063	$	$	$	$1,063	$1,063	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	$565	$	$	$	$	$565	$	$	$565	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	CA	$1,327	$1,327	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	IDU	$1,485	$	$	$	$	$	$	$1,485	$	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	OR	$11,077	$	$11,077	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	UT	$8,613	$	$	$	$	$	$8,613	$	$	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WA	$2,772	$	$	$2,772	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYP	$2,352	$	$	$	$2,352	$2,352	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYU	$377	$	$	$	$	$377	$	$	$377	$
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	CA	$248	$248	$	$	$	$	$	$	$	$

PACIFICORP
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Depreciation Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	IDU	$124	$	$	$	$	$	$	$124	$	$
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	OR	$1,354	$	$1,354	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	UT	$1,262	$	$	$	$	$	$1,262	$	$	$
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WA	$400	$	$	$400	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYP	$247	$	$	$	$247	$247	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYU	$39	$	$	$	$	$39	$	$	$39	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	CA	$375	$375	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	IDU	$429	$	$	$	$	$	$	$429	$	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	OR	$3,141	$	$3,141	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	UT	$2,668	$	$	$	$	$	$2,668	$	$	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WA	$823	$	$	$823	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYP	$701	$	$	$	$701	$701	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYU	$218	$	$	$	$	$218	$	$	$218	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	CA	$179	$179	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	IDU	$449	$	$	$	$	$	$	$449	$	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	OR	$2,176	$	$2,176	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	UT	$2,478	$	$	$	$	$	$2,478	$	$	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WA	$533	$	$	$533	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYP	$448	$	$	$	$448	$448	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYU	$93	$	$	$	$	$93	$	$	$93	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	CA	$18	$18	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	$8	$	$	$	$	$	$	$8	$	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	OR	$118	$	$118	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	UT	$271	$	$	$	$	$	$271	$	$	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WA	$19	$	$	$19	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	$46	$	$	$	$46	$46	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	$9	$	$	$	$	$9	$	$	$9	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	$29	$29	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	$30	$	$	$	$	$	$	$30	$	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	$667	$	$667	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	$1,032	$	$	$	$	$	$1,032	$	$	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	$125	$	$	$125	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	$212	$	$	$	$212	$212	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	$62	$	$	$	$	$62	$	$	$62	$
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	IDU	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SG	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	UT	$1	$	$	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYP	$1	$	$	$	$1	$1	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYU	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CA	$36	$36	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CN	$174	$4	$51	$12	$11	$13	$88	$7	$1	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	IDU	$209	$	$	$	$	$	$	$209	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	OR	$560	$	$560	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SG	$147	$2	$38	$12	$18	$23	$64	$8	$5	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	$1,687	$39	$458	$129	$191	$238	$725	$93	$48	$4
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	UT	$808	$	$	$	$	$	$808	$	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WA	$415	$	$	$415	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYP	$84	$	$	$	$84	$84	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYU	$88	$	$	$	$	$88	$	$	$88	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CA	$6	$6	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CN	$59	$1	$17	$4	$4	$4	$30	$2	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	IDU	$2	$	$	$	$	$	$	$2	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	OR	$28	$	$28	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SG	$5	$	$1	$	$1	$1	$2	$	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SO	$766	$18	$208	$59	$87	$108	$329	$42	$22	$2
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	UT	$12	$	$	$	$	$	$12	$	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WA	$1	$	$	$1	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYP	$13	$	$	$	$13	$13	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYU	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CA	$2	$2	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CN	$101	$2	$30	$7	$7	$7	$51	$4	$1	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	IDU	$7	$	$	$	$	$	$	$7	$	$

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Depreciation Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	OR	$119	$	$119	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SG	$157	$3	$40	$12	$19	$24	$68	$9	$5	$1
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SO	$728	$17	$198	$56	$82	$103	$313	$40	$21	$2
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	UT	$40	$	$	$	$	$	$40	$	$	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WA	$39	$	$	$39	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYP	$31	$	$	$	$31	$31	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYU	$3	$	$	$	$	$3	$	$	$3	$
4030000	DEPN EXPENSE-ELECT	3911000	COMPUTER EQUIPMENT - MAINFRAME	SO	$156	$4	$42	$12	$18	$22	$67	$9	$4	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	$31	$31	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	$1,238	$30	$364	$83	$80	$90	$625	$47	$10	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	$123	$	$	$	$	$	$	$123	$	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	$284	$	$284	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	$15	$	$4	$1	$2	$3	$6	$1	$1	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	$288	$5	$74	$23	$35	$44	$125	$16	$9	$1
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	$8,451	$195	$2,296	$647	$954	$1,193	$3,633	$467	$239	$20
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	$364	$	$	$	$	$	$364	$	$	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	$152	$	$	$152	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	$448	$	$	$	$448	$448	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	$11	$	$	$	$	$11	$	$	$11	$
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	CN	$1	$	$	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	OR	$3	$	$3	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SG	$68	$1	$18	$5	$8	$10	$29	$4	$2	$
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SO	$19	$	$5	$1	$2	$3	$8	$1	$1	$
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	UT	$3	$	$	$	$	$	$3	$	$	$
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYP	$2	$	$	$	$2	$2	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	CA	$6	$6	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	IDU	$20	$	$	$	$	$	$	$20	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	OR	$129	$	$129	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SG	$204	$3	$53	$16	$25	$31	$88	$11	$7	$1
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SO	$15	$	$4	$1	$2	$2	$7	$1	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	UT	$156	$	$	$	$	$	$156	$	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WA	$24	$	$	$24	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYP	$51	$	$	$	$51	$51	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYU	$7	$	$	$	$	$7	$	$	$7	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	$22	$22	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	$80	$	$	$	$	$	$	$80	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	$460	$	$460	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	$1,234	$21	$318	$97	$150	$190	$535	$69	$40	$4
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	$189	$4	$51	$14	$21	$27	$81	$10	$5	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	$556	$	$	$	$	$	$556	$	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	$94	$	$	$94	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	$183	$	$	$	$183	$183	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	$24	$	$	$	$	$24	$	$	$24	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	CA	$15	$15	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	IDU	$69	$	$	$	$	$	$	$69	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	OR	$605	$	$605	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SE	$1	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	$358	$6	$92	$28	$43	$55	$155	$20	$12	$1
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SO	$305	$7	$83	$23	$34	$43	$131	$17	$9	$1
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	UT	$387	$	$	$	$	$	$387	$	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WA	$93	$	$	$93	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYP	$165	$	$	$	$165	$165	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYU	$39	$	$	$	$	$39	$	$	$39	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CA	$115	$115	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CN	$119	$3	$35	$8	$8	$9	$60	$4	$1	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	IDU	$236	$	$	$	$	$	$	$236	$	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	OR	$1,473	$	$1,473	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SE	$5	$	$1	$	$1	$1	$2	$	$	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SG	$4,323	$73	$1,114	$340	$524	$665	$1,874	$243	$141	$14
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	$2,192	$51	$595	$168	$248	$310	$942	$121	$62	$5
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	UT	$1,358	$	$	$	$	$	$1,358	$	$	$

PACIFICORP
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Depreciation Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WA	$468	$	$	$468	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYP	$876	$	$	$	$876	$876	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYU	$185	$	$	$	$	$185	$	$	$185	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CA	$3	$3	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CN	$2	$	$1	$	$	$	$1	$	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	IDU	$9	$	$	$	$	$	$	$9	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	OR	$44	$	$44	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SG	$40	$1	$10	$3	$5	$6	$18	$2	$1	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	$15	$	$4	$1	$2	$2	$6	$1	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	UT	$115	$	$	$	$	$	$115	$	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WA	$25	$	$	$25	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYP	$36	$	$	$	$36	$36	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYU	$3	$	$	$	$	$3	$	$	$3	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CA	$2	$2	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CN	$11	$	$3	$1	$1	$1	$6	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	IDU	$3	$	$	$	$	$	$	$3	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	OR	$36	$	$36	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SE	$	$	$	$	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SG	$99	$2	$25	$8	$12	$15	$43	$6	$3	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	$110	$3	$30	$8	$12	$16	$47	$6	$3	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	UT	$21	$	$	$	$	$	$21	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WA	$7	$	$	$7	$	$	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYP	$8	$	$	$	$8	$8	$	$	$	$
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYU	$1	$	$	$	$	$1	$	$	$1	$
4030000 Total					**$513,548**	**$13,431**	**$143,356**	**$41,374**	**$57,740**	**$72,170**	**$214,541**	**$27,541**	**$14,430**	**$1,136**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	$63	$1	$16	$5	$8	$10	$27	$4	$2	$
4032000 Total					**$63**	**$1**	**$16**	**$5**	**$8**	**$10**	**$27**	**$4**	**$2**	**$**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG	$	$	$	$	$	$	$	$	$	$
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	$2,225	$37	$574	$175	$270	$343	$965	$125	$73	$7
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	$1,352	$23	$348	$106	$164	$208	$586	$76	$44	$4
4033000 Total					**$3,577**	**$60**	**$922**	**$281**	**$434**	**$551**	**$1,550**	**$201**	**$117**	**$12**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	$4	$	$1	$	$	$1	$2	$	$	$
4034000 Total					**$4**	**$**	**$1**	**$**	**$**	**$1**	**$2**	**$**	**$**	**$**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	$3,765	$63	$970	$296	$457	$580	$1,632	$212	$123	$12
4035000 Total					**$3,765**	**$63**	**$970**	**$296**	**$457**	**$580**	**$1,632**	**$212**	**$123**	**$12**
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	-$6,008	-$6,008	$	$	$	$	$	$	$	$
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	$34	$	$	$	$	$	$	$34	$	$
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	$139	$	$139	$	$	$	$	$	$	$
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	$214	$	$	$	$	$	$214	$	$	$
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	$100	$	$	$100	$	$	$	$	$	$
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	$97	$	$	$	$97	$97	$	$	$	$
4036000 Total					**-$5,425**	**-$6,008**	**$139**	**$100**	**$97**	**$97**	**$214**	**$34**	**$**	**$**
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	$32	$1	$8	$3	$4	$5	$14	$2	$1	$
4037000 Total					**$32**	**$1**	**$8**	**$3**	**$4**	**$5**	**$14**	**$2**	**$1**	**$**
Grand Total					**$515,564**	**$7,547**	**$145,413**	**$42,058**	**$58,740**	**$73,413**	**$217,980**	**$27,993**	**$14,673**	**$1,160**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	IDU	$20	$	$	$	$	$	$	$20	$	$	$	$
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	$526	$9	$135	$41	$64	$81	$228	$30	$17	$2	$	$
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	$6,752	$114	$1,740	$531	$819	$1,039	$2,926	$379	$220	$22	$	$
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	$324	$5	$83	$25	$39	$50	$140	$18	$11	$1	$	$
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	$12	$	$12	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	$386	$7	$100	$30	$47	$59	$167	$22	$13	$1	$	$
4040000	AMOR LTD TRM PLNT	3031050	RWT - RCMS WORK TRACKING	SO	$188	$4	$51	$14	$21	$27	$81	$10	$5	$	$	$
4040000	AMOR LTD TRM PLNT	3031080	FMS - FUEL MANAGEMENT SYSTEM	SO	$10	$	$3	$1	$1	$1	$4	$1	$	$	$	$
4040000	AMOR LTD TRM PLNT	3031680	DISTRIBUTION AUTOMATION PILOT	SO	$435	$10	$118	$33	$49	$61	$187	$24	$12	$1	$	$
4040000	AMOR LTD TRM PLNT	3031760	RECORD CENTER MGMT SOFTWARE	SO	$12	$	$3	$1	$1	$2	$5	$1	$	$	$	$
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	$4,383	$105	$1,287	$294	$283	$320	$2,212	$165	$37	$	$	$
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	$5,239	$121	$1,423	$401	$592	$740	$2,252	$289	$148	$12	$	$
4040000	AMOR LTD TRM PLNT	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	$23	$1	$6	$2	$3	$3	$10	$1	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3032270	ENTERPRISE DATA WAREHOUSE	SO	$317	$7	$86	$24	$36	$45	$136	$18	$9	$1	$	$
4040000	AMOR LTD TRM PLNT	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	$73	$2	$20	$6	$8	$10	$31	$4	$2	$	$	$
4040000	AMOR LTD TRM PLNT	3032360	2002 GRID NET POWER COST MODELING	SO	$144	$3	$39	$11	$16	$20	$62	$8	$4	$	$	$
4040000	AMOR LTD TRM PLNT	3032510	OPERATIONS MAPPING SYSTEM	SO	$24	$1	$7	$2	$3	$3	$10	$1	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	$56	$1	$15	$4	$6	$8	$24	$3	$2	$	$	$
4040000	AMOR LTD TRM PLNT	3032600	SINGLE PERSON SCHEDULING	SO	$324	$7	$88	$25	$37	$46	$139	$18	$9	$1	$	$
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	$66	$2	$18	$5	$7	$9	$28	$4	$2	$	$	$
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	$6	$	$2	$	$1	$1	$3	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3032730	IMPROVEMENTS TO PLANT OWNED BY JAMES RIV	SG	$707	$12	$182	$56	$86	$109	$306	$40	$23	$2	$	$
4040000	AMOR LTD TRM PLNT	3032740	GADSBY INTANGIBLE ASSETS	SG	$227	$4	$58	$18	$28	$35	$98	$13	$7	$1	$	$
4040000	AMOR LTD TRM PLNT	3032750	EAGLE POINT HYDRO ASSETS	SG	$44	$1	$11	$3	$5	$7	$19	$2	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	$432	$7	$111	$34	$52	$66	$187	$24	$14	$1	$	$
4040000	AMOR LTD TRM PLNT	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	$15	$	$4	$1	$2	$2	$6	$1	$	$	$	$
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	$6	$	$1	$	$1	$1	$2	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	$1	$	$	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3032860	WEB SOFTWARE	SO	$468	$11	$127	$36	$53	$66	$201	$26	$13	$1	$	$
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	$160	$3	$41	$13	$19	$25	$69	$9	$5	$1	$	$
4040000	AMOR LTD TRM PLNT	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	$576	$13	$156	$44	$65	$81	$248	$32	$16	$1	$	$
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	$1,373	$23	$354	$108	$167	$211	$595	$77	$45	$4	$	$
4040000	AMOR LTD TRM PLNT	3033120	RANGER EMS/SCADA SYSTEM	SG	$22	$	$6	$2	$3	$3	$9	$1	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3033120	RANGER EMS/SCADA SYSTEM	SO	$3,886	$90	$1,056	$298	$439	$549	$1,671	$215	$110	$9	$	$
4040000	AMOR LTD TRM PLNT	3033120	RANGER EMS/SCADA SYSTEM	WYP	$71	$	$	$	$71	$71	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3033170	GTX VERSION 7 SOFTWARE	CN	$517	$12	$152	$35	$33	$38	$261	$19	$4	$	$	$
4040000	AMOR LTD TRM PLNT	3033180	HPOV - HP Openview Software	SO	$424	$10	$115	$32	$48	$60	$182	$23	$12	$1	$	$
4040000	AMOR LTD TRM PLNT	3033190	ITRON METER READING SOFTWARE	CN	$577	$14	$169	$39	$37	$42	$291	$22	$5	$	$	$
4040000	AMOR LTD TRM PLNT	3033300	SECID - CUST SECURE WEB LOGIN	CN	$218	$5	$64	$15	$14	$16	$110	$8	$2	$	$	$
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	$1,252	$29	$340	$96	$141	$177	$538	$69	$35	$3	$	$
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	$885	$20	$240	$68	$100	$125	$380	$49	$25	$2	$	$
4040000	AMOR LTD TRM PLNT	3033360	DSM REPORTING & TRACKING SOFTWARE	SO	$241	$6	$65	$18	$27	$34	$104	$13	$7	$1	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CN	$2	$	$1	$	$	$	$1	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	IDU	$	$	$	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	$3	$	$3	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SE	$14	$	$3	$1	$2	$2	$6	$1	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG	$5,427	$91	$1,399	$426	$658	$835	$2,352	$305	$177	$18	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG-P	$1	$	$	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	$432	$10	$117	$33	$49	$61	$186	$24	$12	$1	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	$13	$	$	$	$	$	$13	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	$	$	$	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	$76	$	$	$	$76	$76	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	$168	$3	$43	$13	$20	$26	$73	$9	$5	$1	$	$
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-U	$18	$	$5	$1	$2	$3	$8	$1	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3326000	RESERVOIR, DAMS, WATERWAYS, LEASE HOLDS	SG-U	$28	$	$7	$2	$3	$4	$12	$2	$1	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	$236	$236	$	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CN	$270	$6	$79	$18	$17	$20	$136	$10	$2	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	$778	$	$778	$	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	$1,266	$29	$344	$97	$143	$179	$544	$70	$36	$3	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	$1	$	$	$	$	$	$1	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	$111	$	$	$111	$	$	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	$542	$	$	$	$542	$542	$	$	$	$	$	$
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYU	$5	$	$	$	$	$5	$	$	$5	$	$	$
4040000 Total					**$40,811**	**$1,037**	**$11,271**	**$3,071**	**$4,938**	**$5,998**	**$17,260**	**$2,082**	**$1,060**	**$93**	**$**	**$**

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4049000	AMR LTD TRM PLNT-OTH	566200	AMORTIZATION OTHER INTANGIBLE	SG	-$227	-$4	-$58	-$18	-$28	-$35	-$98	-$13	-$7	-$1	$	$
4049000 Total					**-$227**	**-$4**	**-$58**	**-$18**	**-$28**	**-$35**	**-$98**	**-$13**	**-$7**	**-$1**	**$**	**$**
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	$5,524	$93	$1,424	$434	$670	$850	$2,394	$310	$180	$18	$	$
4061000 Total					**$5,524**	**$93**	**$1,424**	**$434**	**$670**	**$850**	**$2,394**	**$310**	**$180**	**$18**	**$**	**$**
4070000	AMRT PRP LOSS/RGST	566930	AMORTIZATION OF UNREC PLNT-POWERDALE	SG-P	$1,327	$22	$342	$104	$161	$204	$575	$75	$43	$4	$	$
4070000 Total					**$1,327**	**$22**	**$342**	**$104**	**$161**	**$204**	**$575**	**$75**	**$43**	**$4**	**$**	**$**
4071500	AMOR UNRECOV-TROJN	566941	AMORT OF UNREC PLANT - TROJAN	OR	-$40	$	-$40	$	$	$	$	$	$	$	$	$
4071500	AMOR UNRECOV-TROJN	566941	AMORT OF UNREC PLANT - TROJAN	TROJP	$1,164	$19	$297	$91	$143	$182	$504	$67	$39	$4	$	$
4071500	AMOR UNRECOV-TROJN	566941	AMORT OF UNREC PLANT - TROJAN	WA	-$161	$	$	-$161	$	$	$	$	$	$	$	$
4071500 Total					**$963**	**$19**	**$258**	**-$70**	**$143**	**$182**	**$504**	**$67**	**$39**	**$4**	**$**	**$**
Grand Total					**$48,399**	**$1,168**	**$13,237**	**$3,521**	**$5,885**	**$7,200**	**$20,635**	**$2,521**	**$1,315**	**$119**	**$**	**$**

B5. TAXES OTHER THAN INCOME

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Taxes Other Than Income (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Id-PPL	Mont	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4081000	TAX OTH INC-U OP I	583451	Extraction Tax - Mines	SO	$593	$14	$161	$45	$	$	$67	$84	$255	$33	$17	$1	$	$
4081000	TAX OTH INC-U OP I	583501	Federal Reclamation Tax - Mines	SO	$71	$2	$19	$5	$	$	$8	$10	$30	$4	$2	$	$	$
4081000	TAX OTH INC-U OP I	584101	Government Royalties - Mines	SO	$1,735	$40	$471	$133	$	$	$196	$245	$746	$96	$49	$4	$	$
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	-$2,918	-$67	-$793	-$224	$	$	-$330	-$412	-$1,254	-$161	-$82	-$7	$	$
4081000 Total					**-$519**	**-$12**	**-$141**	**-$40**	**$**	**$**	**-$59**	**-$73**	**-$223**	**-$29**	**-$15**	**-$1**	**$**	**$**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	$108,847	$2,515	$29,568	$8,338	$	$	$12,293	$15,370	$46,791	$6,009	$3,076	$257	$	$
4081500 Total					**$108,847**	**$2,515**	**$29,568**	**$8,338**	**$**	**$**	**$12,293**	**$15,370**	**$46,791**	**$6,009**	**$3,076**	**$257**	**$**	**$**
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	$1,138	$1,138	$	$	$	$	$	$	$	$	$	$	$	$
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	$23,898	$	$23,898	$	$	$	$	$	$	$	$	$	$	$
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WA	$91	$	$	$91	$	$	$	$	$	$	$	$	$	$
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	$1,599	$	$	$	$	$	$1,599	$1,599	$	$	$	$	$	$
4081800 Total					**$26,726**	**$1,138**	**$23,898**	**$91**	**$**	**$**	**$1,599**	**$1,599**	**$**	**$**	**$**	**$**	**$**	**$**
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	$10,142	$234	$2,755	$777	$	$	$1,145	$1,432	$4,360	$560	$287	$24	$	$
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	$730	$	$730	$	$	$	$	$	$	$	$	$	$	$
4081990	MISC TAXES - OTHER	583262	NAVAJO BUSINESS ACTIVITY TAX	UT	-$2	$	$	$	$	$	$	$	-$2	$	$	$	$	$
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	$234	$4	$57	$17	$	$	$31	$40	$101	$15	$9	$1	$	$
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICES	WA	$34	$	$	$34	$	$	$	$	$	$	$	$	$	$
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	$36	$1	$9	$3	$	$	$5	$6	$15	$2	$1	$	$	$
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	$56	$	$	$	$	$	$56	$56	$	$	$	$	$	$
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	$167	$3	$41	$12	$	$	$22	$28	$72	$11	$6	$1	$	$
4081990	MISC TAXES - OTHER	583272	Salt Lake Valley Law Enforcement Levy	UT	$1	$	$	$	$	$	$	$	$1	$	$	$	$	$
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	$391	$6	$95	$29	$	$	$52	$66	$168	$25	$15	$1	$	$
4081990 Total					**$11,789**	**$247**	**$3,687**	**$872**	**$**	**$**	**$1,311**	**$1,629**	**$4,715**	**$612**	**$318**	**$27**	**$**	**$**
Grand Total					**$146,843**	**$3,888**	**$57,012**	**$9,261**	**$**	**$**	**$15,145**	**$18,524**	**$51,283**	**$6,592**	**$3,379**	**$282**	**$**	**$**

B6. FEDERAL INCOME TAXES

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Schedule M (Actuals)
Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
SCHMAP	105105	30% Capitalized labor costs for PowerTax	SO	$450	$10	$122	$34	$51	$63	$193	$25	$13	$1	$	$
SCHMAP	105127	Book Depr Allocated to Medicare and M&E	SCHMDEXP	-$536	-$13	-$147	-$43	-$62	-$77	-$226	-$29	-$15	-$1	$	$
SCHMAP	130100	Non - Deductible Expenses	SO	$1,002	$23	$272	$77	$113	$142	$431	$55	$26	$2	$	$
SCHMAP	130400	PMINondeductible Exp	SE	$10	$	$2	$1	$1	$2	$4	$1	$	$	$	$
SCHMAP	130550	MEHC Insurance Services-Premium	SO	$4,222	$98	$1,147	$323	$477	$596	$1,815	$233	$119	$10	$	$
SCHMAP	130700	Mining Rescue Training Credit Addback	SE	$64	$1	$16	$5	$9	$11	$28	$4	$2	$	$	$
SCHMAP	610106	PMIFuel Tax Cr	SE	$16	$	$4	$1	$2	$3	$7	$1	$1	$	$	$
SCHMAP	610107	PMI Dividend Gross Up for Foreign Tax Cr	OTHER	$29	$	$	$	$	$	$	$	$	$	$29	$
SCHMAP	7201051	Contra Medicare Subsidy	SO	$8,533	$197	$2,318	$654	$964	$1,205	$3,668	$471	$241	$20	$	$
SCHMAP	920145	PMI Mining Rescue Training Credit Addbac	SE	$40	$1	$10	$3	$5	$7	$17	$3	$1	$	$	$
SCHMAP Total				**$13,830**	**$318**	**$3,743**	**$1,055**	**$1,560**	**$1,951**	**$5,938**	**$763**	**$391**	**$33**	**$29**	**$**
SCHMAT	105100	Capitalized Labor Costs	SO	$12,443	$287	$3,380	$953	$1,405	$1,757	$5,349	$687	$352	$29	$	$
SCHMAT	105120	Book Depreciation	SCHMDEXP	$568,694	$13,341	$156,467	$45,479	$65,594	$81,801	$239,322	$30,926	$16,207	$1,358	$	$
SCHMAT	105121	PMIBook Depreciation	SE	$17,815	$277	$4,331	$1,313	$2,356	$3,025	$7,678	$1,124	$669	$66	$	$
SCHMAT	105123	Sec. 481a Adj - Repair Deduction	SG	$15,479	$260	$3,990	$1,216	$1,877	$2,383	$6,709	$870	$505	$51	$	$
SCHMAT	105130	CIAC	CIAC	$27,829	$991	$7,488	$1,760	$2,403	$2,873	$13,386	$1,331	$470	$	$	$
SCHMAT	105140	Highway relocation	SNPD	$6,695	$238	$1,801	$423	$578	$691	$3,220	$320	$113	$	$	$
SCHMAT	105142	Avoided Costs	SNP	$48,346	$1,041	$12,665	$3,616	$5,470	$6,858	$21,400	$2,649	$1,388	$118	$	$
SCHMAT	105146	Capitalization of Test Energy	SG	$556	$9	$143	$44	$67	$86	$241	$31	$18	$2	$	$
SCHMAT	110100	Book Cost Depletion	SE	$2,153	$34	$523	$159	$285	$366	$928	$136	$81	$8	$	$
SCHMAT	145030	Distribution O&M Amort of Writeoff	SNPD	$2,872	$102	$773	$182	$248	$297	$1,382	$137	$49	$	$	$
SCHMAT	205025	PMI - Fuel Cost Adjustment	SE	$3,007	$47	$731	$222	$398	$511	$1,296	$190	$113	$11	$	$
SCHMAT	205100	Coal Pile Inventory Adjustment	SE	$3,742	$58	$910	$276	$495	$635	$1,612	$236	$140	$14	$	$
SCHMAT	205411	PMI Sec 263A Adjustment	SE	$122	$2	$30	$9	$16	$21	$52	$8	$5	$	$	$
SCHMAT	210100	Prepaid Taxes-OR PUC	OR	$355	$	$355	$	$	$	$	$	$	$	$	$
SCHMAT	210120	Prepaid Taxes-UT PUC	UT	$288	$	$	$	$	$	$288	$	$	$	$	$
SCHMAT	210180	Other Prepaids	SO	$1,097	$25	$298	$84	$124	$155	$471	$61	$31	$3	$	$
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	$1,315	$53	$614	$173	$67	$67	$364	$44	$	$	$	$
SCHMAT	320140	May 2000 Transition Plan Costs-OR	OR	$2,270	$	$2,270	$	$	$	$	$	$	$	$	$
SCHMAT	320220	Glenrock Excluding Reclamation-UT rate o	UT	$112	$	$	$	$	$	$112	$	$	$	$	$
SCHMAT	415110	Def Reg Asset-Transmission Srvc Deposit	SG	$419	$7	$108	$33	$51	$65	$182	$24	$14	$1	$	$
SCHMAT	415301	Environmental Costs WA	WA	$58	$	$	$58	$	$	$	$	$	$	$	$
SCHMAT	415500	Cholla Plt Transact Costs-APS Amort	SGCT	$1,122	$19	$290	$86	$137	$173	$488	$63	$37	$	$	$
SCHMAT	415510	WA Disallowed Colstrip #3 Write-off	WA	$52	$	$	$52	$	$	$	$	$	$	$	$
SCHMAT	415700	Reg Liability BPA balancing accounts-OR	OTHER	$756	$	$	$	$	$	$	$	$	$	$756	$
SCHMAT	415702	Reg Asset - Lake Side Liq	WYP	$28	$	$	$	$28	$28	$	$	$	$	$	$
SCHMAT	415703	Goodnoe Hills Liquidation Damages - WY	WYP	$21	$	$	$	$21	$21	$	$	$	$	$	$
SCHMAT	415704	Reg Liability - Tax Revenue Adjustment -	UT	$49	$	$	$	$	$	$49	$	$	$	$	$
SCHMAT	415803	WA RTO Grid West N/R w/o	WA	$47	$	$	$47	$	$	$	$	$	$	$	$
SCHMAT	415804	RTO Grid West Notes Receivable-OR	OR	$296	$	$296	$	$	$	$	$	$	$	$	$
SCHMAT	415805	RTO Grid West Notes Receivable-WY	WYP	$92	$	$	$	$92	$92	$	$	$	$	$	$
SCHMAT	415806	ID RTO Grid West N/R	IDU	$27	$	$	$	$	$	$	$27	$	$	$	$
SCHMAT	415822	Reg Asset _ Pension MMT -UT	UT	$283	$	$	$	$	$	$283	$	$	$	$	$
SCHMAT	415828	Regulatory Asset - Post -Ret MMT -WY	WYP	$309	$	$	$	$309	$309	$	$	$	$	$	$
SCHMAT	415829	Reg Asset - Post - Ret MMT -UT	UT	$279	$	$	$	$	$	$279	$	$	$	$	$
SCHMAT	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	$503	$	$	$	$	$	$	$	$	$	$503	$
SCHMAT	415850	UNRECOVERED PLANT-POWERDALE	SG	$104	$2	$27	$8	$13	$16	$45	$6	$3	$	$	$
SCHMAT	415872	Deferred Excess Net Power Costs - WY 08	OTHER	$9,971	$	$	$	$	$	$	$	$	$	$9,971	$
SCHMAT	415873	Deferred Excess Net Power Costs - WA Hyd	WA	$1,694	$	$	$1,694	$	$	$	$	$	$	$	$
SCHMAT	415880	Deferred UT Independent Evaluation Fee	UT	$4	$	$	$	$	$	$4	$	$	$	$	$
SCHMAT	415890	ID MEHC 2006 Transistion Costs	IDU	$610	$	$	$	$	$	$	$610	$	$	$	$
SCHMAT	415891	WY - 2006 Transition Severance Costs	WYP	$1,062	$	$	$	$1,062	$1,062	$	$	$	$	$	$
SCHMAT	415895	OR RCAC Sept-Dec 07 deferred	OR	$4,567	$	$4,567	$	$	$	$	$	$	$	$	$
SCHMAT	415896	WA - Chehalis Plant Revenue Requirement	WA	$3,000	$	$	$3,000	$	$	$	$	$	$	$	$
SCHMAT	415900	OR SB 408 Recovery	OTHER	$8,675	$	$	$	$	$	$	$	$	$	$8,675	$
SCHMAT	425100	Deferred Regulatory Expense	IDU	$18	$	$	$	$	$	$	$18	$	$	$	$
SCHMAT	425125	Deferred Coal Cost - Arch	SE	$1,650	$26	$401	$122	$218	$280	$711	$104	$62	$6	$	$
SCHMAT	425215	Unearned Joint Use Pole Contact Revenu	SNPD	$20	$1	$5	$1	$2	$2	$10	$1	$	$	$	$
SCHMAT	425250	TGS Buyout-SG	SG	$15	$	$4	$1	$2	$2	$7	$1	$1	$	$	$
SCHMAT	425280	Joseph Settlement-SG	SG	$137	$2	$35	$11	$17	$21	$60	$8	$4	$	$	$
SCHMAT	425360	Hermiston Swap	SG	$172	$3	$44	$13	$21	$26	$74	$10	$6	$1	$	$
SCHMAT	430100	Customer Service / Weatherization	SO	$28,319	$654	$7,693	$2,169	$3,198	$3,999	$12,174	$1,563	$800	$67	$	$
SCHMAT	430111	Reg Asset - SB 1149 Balance Reclass	OTHER	$68	$	$	$	$	$	$	$	$	$	$68	$
SCHMAT	430112	Reg Asset - Other - Balance Reclass	OTHER	$39	$	$	$	$	$	$	$	$	$	$39	$
SCHMAT	430113	Reg Asset - Def NPC Balance Reclass	OTHER	$2,604	$	$	$	$	$	$	$	$	$	$2,604	$
SCHMAT	505510	PMIVacationBonus Adjustment	SE	$17	$	$4	$1	$2	$3	$8	$1	$1	$	$	$
SCHMAT	505600	Sick Leave Vacation & Personal Time	SO	$816	$19	$222	$63	$92	$115	$351	$45	$23	$2	$	$
SCHMAT	605100	Trojan Decomissioning Costs	TROJD	$1,902	$32	$485	$148	$234	$298	$823	$109	$64	$6	$	$
SCHMAT	605710	Reverse Accrued Final Reclamation	SE	$214	$3	$52	$16	$28	$36	$92	$14	$8	$1	$	$
SCHMAT	610111	PMIBCC Gain/Loss on Assets Disposed	SE	$167	$3	$41	$12	$22	$28	$72	$11	$6	$1	$	$
SCHMAT	610114	PMI EITF Pre-Stripping Costs	SE	$907	$14	$221	$67	$120	$154	$391	$57	$34	$3	$	$
SCHMAT	610143	Reg Liability - WA Low Energy Program	WA	$241	$	$	$241	$	$	$	$	$	$	$	$
SCHMAT	610145	Reg Liab-OR Balance Consol	OR	$2,626	$	$2,626	$	$	$	$	$	$	$	$	$
SCHMAT	610146	OR Reg Asset/Liability Consolidation	OR	$61	$	$61	$	$	$	$	$	$	$	$	$
SCHMAT	705240	CA Alternative Rate for Energy Program(C	CA	$1,143	$1,143	$	$	$	$	$	$	$	$	$	$
SCHMAT	705260	March 2006 Transition Plan costs-WA	WA	$319	$	$	$319	$	$	$	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Schedule M (Actuals)
Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
SCHMAT	705261	Reg Liability - Sale of renewable Energy	OTHER	$3,922	$	$	$	$	$	$	$	$	$	$3,922	$
SCHMAT	705265	Reg Liab - OR Energy Conservation Charge	OR	$1,516	$	$1,516	$	$	$	$	$	$	$	$	$
SCHMAT	705337	Regulatory Liability - Sale of Renewable	OTHER	$3,594	$	$	$	$	$	$	$	$	$	$3,594	$
SCHMAT	715105	MCI FOG Wire Lease	SG	$1	$	$	$	$	$	$	$	$	$	$	$
SCHMAT	715720	NW Power Act-WA	OTHER	$579	$	$	$	$	$	$	$	$	$	$579	$
SCHMAT	720200	Deferred Comp Plan Benefits-PPL	SO	$15	$	$4	$1	$2	$2	$6	$1	$	$	$	$
SCHMAT	740100	Post Merger Loss-Reacquired Debt	SNP	$2,331	$50	$611	$174	$264	$331	$1,032	$128	$67	$6	$	$
SCHMAT	910530	Injuries and Damages Reserve	SO	$1,011	$23	$275	$77	$114	$143	$435	$56	$29	$2	$	$
SCHMAT	910910	PMIBridger Section 471 Adj	SE	$1,071	$17	$260	$79	$142	$182	$462	$68	$40	$4	$	$
SCHMAT	920110	PMIWY Extraction Tax	SE	$1,897	$30	$461	$140	$251	$322	$818	$120	$71	$7	$	$
SCHMAT	920150	FAS 112 Book Reserve	SO	$1,581	$37	$429	$121	$179	$223	$680	$87	$45	$4	$	$
SCHMAT Total				**$808,193**	**$18,851**	**$217,508**	**$64,665**	**$88,003**	**$109,460**	**$323,345**	**$41,879**	**$21,456**	**$1,772**	**$30,712**	**$**
SCHMDP	105127	Book Depreciation Allocated to Medicare	SCHMDEXP	$109	$3	$30	$9	$13	$16	$46	$6	$3	$	$	$
SCHMDP	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	$407	$6	$99	$30	$54	$69	$176	$26	$15	$2	$	$
SCHMDP	120100	Preferred Dividend - PPL	SNP	$361	$8	$95	$27	$41	$51	$160	$20	$10	$1	$	$
SCHMDP	130560	MEHC Insurance Services-Receivable	SO	$13,565	$313	$3,685	$1,039	$1,532	$1,915	$5,831	$749	$383	$32	$	$
SCHMDP	720105	MEDICARE SUBSIDY	SO	$7,246	$167	$1,968	$555	$818	$1,023	$3,115	$400	$205	$17	$	$
SCHMDP	910918	PMI Overriding Royalty	SE	$14	$	$3	$1	$2	$2	$6	$1	$1	$	$	$
SCHMDP	920105	PMI Tax Exempt Interest Income	SE	$22	$	$5	$2	$3	$4	$10	$1	$1	$	$	$
SCHMDP	920106	PMI DIVIDEND RECEIVED DEDUCTION	SE	$131	$2	$32	$10	$17	$22	$56	$8	$5	$	$	$
SCHMDP Total				**$21,857**	**$500**	**$5,918**	**$1,672**	**$2,480**	**$3,103**	**$9,400**	**$1,211**	**$623**	**$52**	**$**	**$**
SCHMDT	105122	Repair Deduction	SG	$60,469	$1,018	$15,587	$4,751	$7,334	$9,309	$26,208	$3,398	$1,974	$198	$	$
SCHMDT	105125	Tax Depreciation	TAXDEPR	$2,847,400	$59,348	$744,563	$198,278	$323,759	$407,566	$1,256,838	$154,735	$83,807	$7,334	$	$18,738
SCHMDT	105126	PMITax Depreciation	SE	$27,643	$430	$6,721	$2,037	$3,657	$4,695	$11,913	$1,744	$1,038	$103	$	$
SCHMDT	105137	Capitalized Depreciation	SO	$5,038	$116	$1,369	$386	$569	$711	$2,166	$278	$142	$12	$	$
SCHMDT	105141	AFUDC	SNP	$67,486	$1,453	$17,679	$5,047	$7,635	$9,573	$29,872	$3,697	$1,938	$165	$	$
SCHMDT	1051411	AFUDC - Equity	SNP	$21,349	$460	$5,593	$1,597	$2,415	$3,028	$9,450	$1,170	$613	$52	$	$
SCHMDT	105143	Basis Intangible Difference	SO	$5,490	$127	$1,491	$421	$620	$775	$2,360	$303	$155	$13	$	$
SCHMDT	105147	Sec 1031 Like Kind Exchange	SO	$15	$	$4	$1	$2	$2	$7	$1	$	$	$	$
SCHMDT	105148	Mine Safety Sec. 179E Election - PPW	SE	$1,042	$16	$253	$77	$138	$177	$449	$66	$39	$4	$	$
SCHMDT	105149	Mine Safety Sec. 179E Election - PMI	SE	$8	$	$2	$1	$1	$1	$3	$1	$	$	$	$
SCHMDT	105152	Gain/(Loss) on Prop Dispositions	GPS	$13,485	$312	$3,663	$1,033	$1,523	$1,904	$5,797	$744	$381	$32	$	$
SCHMDT	105165	Coal Mine Development	SE	$325	$5	$79	$24	$43	$55	$140	$20	$12	$1	$	$
SCHMDT	105170	Coal Mine Receding Face (Extension)	SE	$1,070	$17	$260	$79	$141	$182	$461	$67	$40	$4	$	$
SCHMDT	105171	PMI Coal Mine Receding Face (Extension)	SE	$3,952	$62	$961	$291	$523	$671	$1,703	$249	$148	$15	$	$
SCHMDT	105175	Removal Cost (net of salvage)	GPS	$47,132	$1,089	$12,803	$3,610	$5,323	$6,655	$20,261	$2,602	$1,332	$111	$	$
SCHMDT	1052203	Cholla SHL-NOPA (Lease Amortization)	SG	$83	$1	$21	$6	$10	$13	$36	$5	$3	$	$	$
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	$3,034	$70	$824	$232	$343	$428	$1,304	$168	$86	$7	$	$
SCHMDT	110200	Depletion - Tax Percentage Deduction	SE	$513	$8	$125	$38	$68	$87	$221	$32	$19	$2	$	$
SCHMDT	110205	SRC Depletion - Tax Percentage Deduction	SG	$170	$3	$44	$13	$21	$26	$74	$10	$6	$1	$	$
SCHMDT	120105	Willow Wind Account Receivable	WA	$8	$	$	$8	$	$	$	$	$	$	$	$
SCHMDT	205200	Coal M&S Inventory Write-Off	SE	$169	$3	$41	$12	$22	$29	$73	$11	$6	$1	$	$
SCHMDT	210130	Prepaid Taxes-ID PUC	IDU	$26	$	$	$	$	$	$	$26	$	$	$	$
SCHMDT	210200	Prepaid Taxes-property taxes	GPS	$4,908	$113	$1,333	$376	$554	$693	$2,110	$271	$139	$12	$	$
SCHMDT	287396	Regulatory Liabilities - Interim Provisi	OTHER	-$7,394	$	$	$	$	$	$	$	$	$	-$7,394	$
SCHMDT	287616	Regulatory Assets - Interim Provisions	OTHER	$58,921	$	$	$	$	$	$	$	$	$	$58,921	$
SCHMDT	320115	Misc - Reg Liab	OTHER	$	$	$	$	$	$	$	$	$	$	$	$
SCHMDT	3201151	MISC - REG LIAB	OTHER	$	$	$	$	$	$	$	$	$	$	$	$
SCHMDT	320210	Research & Exper. Sec. 174 Amort.	SO	$2,951	$68	$802	$226	$333	$417	$1,269	$163	$83	$7	$	$
SCHMDT	415120	DEFERRED REG ASSET - FOOTE CREEK CONTRAC	SG	$138	$2	$35	$11	$17	$21	$60	$8	$4	$	$	$
SCHMDT	415300	Hazardous Waste Clean-up Costs	SO	$6,710	$155	$1,823	$514	$758	$947	$2,884	$370	$190	$16	$	$
SCHMDT	415501	Cholla Plt Transact Costs- APS Amort - I	IDU	$33	$	$	$	$	$	$	$33	$	$	$	$
SCHMDT	415502	Cholla Plt Transact Costs- APS Amort - O	OR	$54	$	$54	$	$	$	$	$	$	$	$	$
SCHMDT	415503	Cholla Plt Transact Costs- APS Amort - W	WA	$97	$	$	$97	$	$	$	$	$	$	$	$
SCHMDT	415680	Deferred Intervenor Funding Grants-OR	OR	$212	$	$212	$	$	$	$	$	$	$	$	$
SCHMDT	415705	Reg Liability - Tax Revenue Adjustment -	WYP	$100	$	$	$	$100	$100	$	$	$	$	$	$
SCHMDT	415821	Contra Pension Reg Asset MMT & CTG_WY	WYP	$1,370	$	$	$	$1,370	$1,370	$	$	$	$	$	$
SCHMDT	415852	Powerdale Decommissioning Reg Asset - ID	IDU	$305	$	$	$	$	$	$	$305	$	$	$	$
SCHMDT	415853	Powerdale Decommissioning Reg Asset - OR	OR	$493	$	$493	$	$	$	$	$	$	$	$	$
SCHMDT	415854	Powerdale Decommissioning Reg Asset - WA	WA	$852	$	$	$852	$	$	$	$	$	$	$	$
SCHMDT	415855	Ca - January 2010 Storm Costs	OTHER	$1,230	$	$	$	$	$	$	$	$	$	$1,230	$
SCHMDT	415856	Powerdale Decommissioning Reg Asset - WY	WYP	$34	$	$	$	$34	$34	$	$	$	$	$	$
SCHMDT	415857	ID - Deferred Overburden Costs	OTHER	$249	$	$	$	$	$	$	$	$	$	$249	$
SCHMDT	415858	WY - Deferred Overburden Costs	WYP	$666	$	$	$	$666	$666	$	$	$	$	$	$
SCHMDT	415859	WY - Deferred Advertising Costs	OTHER	$52	$	$	$	$	$	$	$	$	$	$52	$
SCHMDT	415865	Reg Asset - Utah MPA	OTHER	$15,725	$	$	$	$	$	$	$	$	$	$15,725	$
SCHMDT	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	$227	$	$	$	$	$	$	$	$	$	$227	$
SCHMDT	415870	CA Def Excess NPC	CA	$4,514	$4,514	$	$	$	$	$	$	$	$	$	$
SCHMDT	415874	Deferred Excess Net Power Costs - WY 08	OTHER	$14,550	$	$	$	$	$	$	$	$	$	$14,550	$
SCHMDT	415876	Deferred Excess Net Power Costs - OR	OTHER	$3,526	$	$	$	$	$	$	$	$	$	$3,526	$
SCHMDT	415892	Deferred Excess Net Power Costs - ID 09	OTHER	$10,341	$	$	$	$	$	$	$	$	$	$10,341	$
SCHMDT	415893	OR - MEHC Transition Service Costs	OTHER	$2,969	$	$	$	$	$	$	$	$	$	$2,969	$
SCHMDT	415897	Reg Asset MEHC Transition Service Costs	CA	$223	$223	$	$	$	$	$	$	$	$	$	$
SCHMDT	415898	Deferred Coal Costs - Naughton Contract	SE	$8,257	$129	$2,008	$608	$1,092	$1,402	$3,558	$521	$310	$31	$	$
SCHMDT	425110	Tenant Lease Allow-PSU Call Cntr	CN	$48	$1	$14	$3	$3	$4	$24	$2	$	$	$	$
SCHMDT	425225	Duke/Hermiston Contract Renegotiation	SG	$755	$13	$195	$59	$92	$116	$327	$42	$25	$2	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Schedule M (Actuals)
Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
SCHMDT	425380	Idaho Customer Balancing Account	OTHER	$604	$	$	$	$	$	$	$	$	$	$604	$
SCHMDT	430110	Reg Asset balance reclass	SO	$2,626	$61	$713	$201	$297	$371	$1,129	$145	$74	$6	$	$
SCHMDT	505125	Accrued Royalties	SE	$1,015	$16	$247	$75	$134	$172	$437	$64	$38	$4	$	$
SCHMDT	505150	Misc Current & Accrued Liability-SO	SO	$67	$2	$18	$5	$8	$9	$29	$4	$2	$	$	$
SCHMDT	505400	Bonus Liability	SO	$38	$1	$10	$3	$4	$5	$16	$2	$1	$	$	$
SCHMDT	605101	Trojan Decommissioning Costs - WA	WA	$276	$	$	$276	$	$	$	$	$	$	$	$
SCHMDT	605102	Trojan Decommissioning Costs - OR	OR	$68	$	$68	$	$	$	$	$	$	$	$	$
SCHMDT	610000	PMI Coal Mine Development	SE	$55	$1	$13	$4	$7	$9	$24	$3	$2	$	$	$
SCHMDT	610100	PMIDEVT COST AMORT	SE	$3,013	$47	$733	$222	$399	$512	$1,298	$190	$113	$11	$	$
SCHMDT	6101001	AMORT NOPAS 99-00 RAR	SO	$58	$1	$16	$4	$7	$8	$25	$3	$2	$	$	$
SCHMDT	610130	781 Shopping Incentive_OR	OR	$68	$	$68	$	$	$	$	$	$	$	$	$
SCHMDT	610140	OR Rate Refunds	OTHER	$80	$	$	$	$	$	$	$	$	$	$80	$
SCHMDT	610141	WA Rate Refunds	OTHER	$229	$	$	$	$	$	$	$	$	$	$229	$
SCHMDT	610142	Reg. Liability - UT Home Energy Lifeline	UT	$210	$	$	$	$	$	$210	$	$	$	$	$
SCHMDT	610148	Reg Liability - Def NPC Balance Reclass	OTHER	$2,604	$	$	$	$	$	$	$	$	$	$2,604	$
SCHMDT	610149	Reg Liability - SB 1149 Balance Reclass	OTHER	$68	$	$	$	$	$	$	$	$	$	$68	$
SCHMDT	705200	Oregon Gain on Sale of Halsey-OR	OTHER	$386	$	$	$	$	$	$	$	$	$	$386	$
SCHMDT	705210	Property Insurance(Injuries & Damages)	SO	$110	$3	$30	$8	$12	$15	$47	$6	$3	$	$	$
SCHMDT	705300	Reg. Liability - Deferred Benefit_Arch S	SE	$1,173	$18	$285	$86	$155	$199	$506	$74	$44	$4	$	$
SCHMDT	705305	Reg Liability-CA Gain on Sale of Asset	CA	$41	$41	$	$	$	$	$	$	$	$	$	$
SCHMDT	715800	Redding Renegotiated Contract	SG	$550	$9	$142	$43	$67	$85	$238	$31	$18	$2	$	$
SCHMDT	720300	PENSION / RETIREMENT ACCRUAL - CASH BASI	SO	$120	$3	$33	$9	$14	$17	$52	$7	$3	$	$	$
SCHMDT	720500	Severance Accrual	SO	$24	$1	$7	$2	$3	$3	$10	$1	$1	$	$	$
SCHMDT	910560	283SMUD REVENUE IMPUTATION-UT REG LIAB	OTHER	$10,989	$	$	$	$	$	$	$	$	$	$10,989	$
SCHMDT	910580	Wasach workers comp reserve	SO	$97	$2	$26	$7	$11	$14	$42	$5	$3	$	$	$
SCHMDT	910905	PMI Underground Mine Cost Depletion	SE	$165	$3	$40	$12	$22	$28	$71	$10	$6	$1	$	$
SCHMDT Total				**$3,263,754**	**$69,964**	**$821,500**	**$221,648**	**$360,305**	**$453,108**	**$1,383,703**	**$171,587**	**$92,803**	**$8,151**	**$115,355**	**$18,738**
Grand Total				**$4,107,633**	**$89,633**	**$1,048,670**	**$289,041**	**$452,348**	**$567,622**	**$1,722,385**	**$215,441**	**$115,273**	**$10,009**	**$146,096**	**$18,738**
Total Schedule M Additions				**$822,023**	**$19,169**	**$221,252**	**$65,720**	**$89,563**	**$111,411**	**$329,283**	**$42,643**	**$21,848**	**$1,805**	**$30,741**	**$**
Total Schedule M Deductions				**$3,285,610**	**$70,464**	**$827,418**	**$223,320**	**$362,785**	**$456,211**	**$1,393,102**	**$172,798**	**$93,426**	**$8,204**	**$115,355**	**$18,738**
Total Schedule M				**-$2,463,587**	**-$51,295**	**-$606,166**	**-$157,600**	**-$273,222**	**-$344,800**	**-$1,063,820**	**-$130,156**	**-$71,578**	**-$6,399**	**-$84,614**	**-$18,738**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Interest Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC
4191000	AFUDC - OTHER	SNP	-$59,310	-$1,277	-$15,537	-$4,436	-$8,413	-$26,253	-$3,249	-$145
4270000	INT ON LNG-TRM DBT	SNP	$364,205	$7,843	$95,408	$27,239	$51,663	$161,210	$19,953	$889
4280000	AMT DBT DISC & EXP	SNP	$3,785	$82	$992	$283	$537	$1,675	$207	$9
4281000	AMORTZN OF LOSS	SNP	$1,995	$43	$523	$149	$283	$883	$109	$5
4290000	AMT PREM ON DEBT	SNP	-$3	$	-$1	$	$	-$1	$	$
4310000	OTHER INTEREST EXP	SNP	$12,944	$279	$3,391	$968	$1,836	$5,729	$709	$32
4313000	INT EXP ON REG LIAB	SNP	$666	$14	$174	$50	$94	$295	$36	$2
4320000	AFUDC - BORROWED	SNP	-$32,692	-$704	-$8,564	-$2,445	-$4,637	-$14,471	-$1,791	-$80
4091000	INC TX UTIL OP INC	SG	-$58,459	-$984	-$15,069	-$4,593	-$8,999	-$25,337	-$3,285	-$191
4091000	INC TX UTIL OP INC	SG	-$71	-$1	-$18	-$6	-$11	-$31	-$4	$
4091000	INC TX UTIL OP INC	SE	-$64	-$1	-$16	-$5	-$11	-$28	-$4	$
4091000	INC TX UTIL OP INC	SE	-$40	-$1	-$10	-$3	-$7	-$17	-$3	$
4091000	INC TX UTIL OP INC	SE	-$16	$	-$4	-$1	-$3	-$7	-$1	$
4091000	INC TX UTIL OP INC	SO	-$29	-$1	-$8	-$2	-$4	-$12	-$2	$
4091100	STATE INC TAX-ELEC	SG	-$289	-$5	-$74	-$23	-$44	-$125	-$16	-$1
Grand Total			**$232,622**	**$5,287**	**$61,187**	**$17,175**	**$32,283**	**$103,511**	**$12,661**	**$518**

B7. D.I.T. EXPENSE & I.T.C. ADJ.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4101000	105122	Repair Deduction	SG	$22,949	$386	$5,915	$1,803	$2,783	$3,533	$9,946	$1,289	$749	$75	$	$
4101000	105125	Tax Depreciation	TAXDEPR	$1,080,617	$22,523	$282,569	$75,249	$122,870	$154,675	$476,983	$58,724	$31,805	$2,783	$	$7,111
4101000	105126	282DIT PMIDepreciation-Tax	SE	$10,491	$163	$2,551	$773	$1,388	$1,782	$4,521	$662	$394	$39	$	$
4101000	105137	Capitalized Depreciation	SO	$1,912	$44	$519	$146	$216	$270	$822	$106	$54	$5	$	$
4101000	105141	AFUDC Debt	SNP	$25,612	$552	$6,709	$1,916	$2,898	$3,633	$11,337	$1,403	$735	$62	$	$
4101000	1051411	AFUDC Equity	SNP	$8,102	$174	$2,122	$606	$917	$1,149	$3,586	$444	$233	$20	$	$
4101000	105143	282Basis Intangible Difference	SO	$2,083	$48	$566	$160	$235	$294	$896	$115	$59	$5	$	$
4101000	105147	Sec 1031 Like Kind Exchange	SO	$6	$	$2	$	$1	$1	$2	$	$	$	$	$
4101000	105148	Mine Safety Sec. 179E Election - PPW	SE	$396	$6	$96	$29	$52	$67	$170	$25	$15	$1	$	$
4101000	105149	Mine Safety Sec. 179E Election - PMI	SE	$3	$	$1	$	$	$1	$1	$	$	$	$	$
4101000	105152	Gain / (Loss) on Prop. Disposition	GPS	$5,118	$118	$1,390	$392	$578	$723	$2,200	$283	$145	$12	$	$
4101000	105165	Coal Mine Development	SE	$123	$2	$30	$9	$16	$21	$53	$8	$5	$	$	$
4101000	105170	Coal Mine Extension	SE	$406	$6	$99	$30	$54	$69	$175	$26	$15	$2	$	$
4101000	105171	PMI Coal Mine Extension Costs	SE	$1,500	$23	$365	$110	$198	$255	$646	$95	$56	$6	$	$
4101000	105175	Cost of Removal	GPS	$17,887	$413	$4,859	$1,370	$2,020	$2,526	$7,689	$987	$506	$42	$	$
4101000	1052203	Cholla SHL NOPA (Lease Amortization)	SG	$31	$1	$8	$2	$4	$5	$14	$2	$1	$	$	$
4101000	105470	282Book Gain/Loss on Land Sales	GPS	$1,152	$27	$313	$88	$130	$163	$495	$64	$33	$3	$	$
4101000	110200	IGC Tax Percentage Depletion Deduct	SE	$195	$3	$47	$14	$26	$33	$84	$12	$7	$1	$	$
4101000	110205	SRC Tax Percentage Depletion Deduct	SG	$65	$1	$17	$5	$8	$10	$28	$4	$2	$	$	$
4101000	120105	Willow Wind Account Receivable	WA	$3	$	$	$3	$	$	$	$	$	$	$	$
4101000	205200	M&S INVENTORY WRITE-OFF	SE	$64	$1	$16	$5	$8	$11	$28	$4	$2	$	$	$
4101000	210130	283ID PUC Prepaid Taxes	IDU	$10	$	$	$	$	$	$	$10	$	$	$	$
4101000	210200	283Prepaid Taxes-Property Taxes	GPS	$1,863	$43	$506	$143	$210	$263	$801	$103	$53	$4	$	$
4101000	287396	Regulatory Liabilities - Interim Provisi	OTHER	-$610	$	$	$	$	$	$	$	$	$	-$610	$
4101000	287616	Regulatory Assets - Interim Provisions	OTHER	$10,812	$	$	$	$	$	$	$	$	$	$10,812	$
4101000	320115	283INTERIM PROVISION_TOTAL REG ASSETS_LI	OTHER	$11,549	$	$	$	$	$	$	$	$	$	$11,549	$
4101000	3201151	283Interim Provision_Total reg assets_li	OTHER	-$2,196	$	$	$	$	$	$	$	$	$	-$2,196	$
4101000	320210	190R&E Expense Sec174 Deduction	SO	$1,120	$26	$304	$86	$126	$158	$481	$62	$32	$3	$	$
4101000	415120	190DEF REG ASSET-FOOTE CREEK CONTRACT	SG	$52	$1	$13	$4	$6	$8	$23	$3	$2	$	$	$
4101000	415300	283Hazardous Waste/Environmental Cleanup	SO	$2,547	$59	$692	$195	$288	$360	$1,095	$141	$72	$6	$	$
4101000	415501	Cholla Plt Transact Costs- APS Amort - I	IDU	$13	$	$	$	$	$	$	$13	$	$	$	$
4101000	415502	Cholla Plt Transact Costs- APS Amort - O	OR	$20	$	$20	$	$	$	$	$	$	$	$	$
4101000	415503	Cholla Plt Transact Costs- APS Amort - W	WA	$37	$	$	$37	$	$	$	$	$	$	$	$
4101000	415680	190Def Intervenor Funding Grants-OR	OR	$80	$	$80	$	$	$	$	$	$	$	$	$
4101000	415705	Reg Liability - Tax Revenue Adjustment -	WYP	$38	$	$	$	$38	$38	$	$	$	$	$	$
4101000	415821	Contra Pension Reg Asset MMT & CTG WY	WYP	$520	$	$	$	$520	$520	$	$	$	$	$	$
4101000	415852	Powerdale Decommissioning Reg Asset - ID	IDU	$116	$	$	$	$	$	$	$116	$	$	$	$
4101000	415853	Powerdale Decommissioning Reg Asset - OR	OR	$187	$	$187	$	$	$	$	$	$	$	$	$
4101000	415854	Powerdale Decommissioning Reg Asset - WA	WA	$323	$	$	$323	$	$	$	$	$	$	$	$
4101000	415855	Ca - January 2010 Storm Costs	OTHER	$467	$	$	$	$	$	$	$	$	$	$467	$
4101000	415856	Powerdale Decommissioning Reg Asset - WY	WYP	$13	$	$	$	$13	$13	$	$	$	$	$	$
4101000	415857	ID - Deferred Overburden Costs	OTHER	$95	$	$	$	$	$	$	$	$	$	$95	$
4101000	415858	WY - Deferred Overburden Costs	WYP	$253	$	$	$	$253	$253	$	$	$	$	$	$
4101000	415859	WY - Deferred Advertising Costs	OTHER	$20	$	$	$	$	$	$	$	$	$	$20	$
4101000	415865	Reg Asset - Utah MPA	OTHER	$5,968	$	$	$	$	$	$	$	$	$	$5,968	$
4101000	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	$86	$	$	$	$	$	$	$	$	$	$86	$
4101000	415870	Deferred Excess Net Power Costs CA	CA	$1,713	$1,713	$	$	$	$	$	$	$	$	$	$
4101000	415874	Deferred Excess Net Power Costs - WY 09	OTHER	$5,522	$	$	$	$	$	$	$	$	$	$5,522	$
4101000	415876	Deferred Excess Net Power Costs - OR	OTHER	$1,338	$	$	$	$	$	$	$	$	$	$1,338	$
4101000	415892	Deferred Excess Net Power Costs - ID 09	OTHER	$3,925	$	$	$	$	$	$	$	$	$	$3,925	$
4101000	415893	OR - MEHC Transition Service Costs	OTHER	$1,127	$	$	$	$	$	$	$	$	$	$1,127	$
4101000	415897	Reg Asset MEHC Transition Service Costs	CA	$85	$85	$	$	$	$	$	$	$	$	$	$
4101000	415898	Deferred Coal Costs - Naughton Contract	SE	$3,134	$49	$762	$231	$414	$532	$1,350	$198	$118	$12	$	$
4101000	425110	190Tenant Lease Allow-PSU Cali Cntr	CN	$18	$	$5	$1	$1	$1	$9	$1	$	$	$	$
4101000	425225	Duke/Hermiston Contract Renegotiation	SG	$286	$5	$74	$23	$35	$44	$124	$16	$9	$1	$	$
4101000	425380	190Idaho Customer Bal Acct	OTHER	$229	$	$	$	$	$	$	$	$	$	$229	$
4101000	430110	Reg Asset Balance Reclass	SO	$997	$23	$271	$76	$113	$141	$428	$55	$28	$2	$	$
4101000	505125	190Accrued Royalties	SE	$385	$6	$94	$28	$51	$65	$166	$24	$14	$1	$	$
4101000	505150	190Misc Current and Accrued Liability-SO	SO	$25	$1	$7	$2	$3	$4	$11	$1	$1	$	$	$
4101000	505400	190Bonus Liability	SO	$14	$	$4	$1	$2	$2	$6	$1	$	$	$	$
4101000	605101	Trojan Decommissioning Costs - WA	WA	$105	$	$	$105	$	$	$	$	$	$	$	$
4101000	605102	Trojan Decommissioning Costs - OR	OR	$26	$	$26	$	$	$	$	$	$	$	$	$
4101000	610000	283PMI Development Costs	SE	$21	$	$5	$2	$3	$4	$9	$1	$1	$	$	$
4101000	610100	283PMI AMORT DEVELOPMENT	SE	$1,143	$18	$278	$84	$151	$194	$493	$72	$43	$4	$	$
4101000	6101001	190NOPA 103-99-00 RAR	SO	$22	$1	$6	$2	$3	$3	$10	$1	$1	$	$	$
4101000	610130	283781 Shopping Incentive-OR	OR	$26	$	$26	$	$	$	$	$	$	$	$	$
4101000	610140	190 OR Rate Refunds	OTHER	$30	$	$	$	$	$	$	$	$	$	$30	$
4101000	610141	190WA Rate Refunds	OTHER	$87	$	$	$	$	$	$	$	$	$	$87	$
4101000	610142	283Reg Liability-UT Home Energy Lifeline	UT	$80	$	$	$	$	$	$80	$	$	$	$	$
4101000	610148	Reg Liability - Def NPC Balance Reclass	OTHER	$988	$	$	$	$	$	$	$	$	$	$988	$

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Deferred Income Tax Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4101000	610149	Reg Liability - SB 1149 Balance Reclass	OTHER	$26	$	$	$	$	$	$	$	$	$	$26	$
4101000	705200	190OR Gain on Sale of Halsey-OR	OTHER	$146	$	$	$	$	$	$	$	$	$	$146	$
4101000	705210	190Property Insurance	SO	$42	$1	$11	$3	$5	$6	$18	$2	$1	$	$	$
4101000	705300	Reg. Liability - Deferred Benefit_Arch S	SE	$445	$7	$108	$33	$59	$76	$192	$28	$17	$2	$	$
4101000	705305	Reg Liability-CA Gain on Sale of Asset	CA	$16	$16	$	$	$	$	$	$	$	$	$	$
4101000	715800	190Redding Contract	SG	$209	$4	$54	$16	$25	$32	$90	$12	$7	$1	$	$
4101000	7201051	Contra Medicare Subsidy	SO	-$1,029	-$24	-$279	-$79	-$116	-$145	-$442	-$57	-$29	-$2	$	$
4101000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	$46	$1	$12	$3	$5	$6	$20	$3	$1	$	$	$
4101000	720500	190Severance	SO	$9	$	$2	$1	$1	$1	$4	$1	$	$	$	$
4101000	910560	283SMUD Revenue Imputation-UT Reg Liab	OTHER	$4,170	$	$	$	$	$	$	$	$	$	$4,170	$
4101000	910580	190Wasatch workers comp reserve	SO	$37	$1	$10	$3	$4	$5	$16	$2	$1	$	$	$
4101000	910905	283PMI BCC Underground Mine Cost Deplet	SE	$62	$1	$15	$5	$8	$11	$27	$4	$2	$	$	$
4101000 Total				**$1,237,599**	**$26,528**	**$311,488**	**$84,039**	**$136,623**	**$171,814**	**$524,687**	**$65,062**	**$35,190**	**$3,091**	**$43,778**	**$7,111**
4111000	100105	283FAS 109 Def Tax Liab WA-NUTIL	WA	$2,162	$	$	$2,162	$	$	$	$	$	$	$	$
4111000	105100	190CAPITALIZED LABOR COSTS	SO	-$4,722	-$109	-$1,283	-$362	-$533	-$667	-$2,030	-$261	-$133	-$11	$	$
4111000	1051151	Depreciation Flow-Through - CA	CA	-$798	-$798	$	$	$	$	$	$	$	$	$	$
4111000	1051152	Depreciation Flow-Through - FERC	FERC	-$58	$	$	$	$	$	$	$	$	-$58	$	$
4111000	1051153	Depreciation Flow-Through - ID	IDU	-$1,426	$	$	$	$	$	$	-$1,426	$	$	$	$
4111000	1051154	Depreciation Flow-Through - OR	OR	-$579	$	-$579	$	$	$	$	$	$	$	$	$
4111000	1051155	Depreciation Flow-Through - OTHER	OTHER	$6	$	$	$	$	$	$	$	$	$	$6	$
4111000	1051156	Depreciation Flow-Through - UT	UT	-$6,320	$	$	$	$	$	-$6,320	$	$	$	$	$
4111000	1051157	Depreciation Flow-Through - WA	WA	$729	$	$	$729	$	$	$	$	$	$	$	$
4111000	1051158	Depreciation Flow-Through - WYP	WYP	-$24	$	$	$	-$24	-$24	$	$	$	$	$	$
4111000	1051159	Depreciation Flow-Through - WYU	WYU	-$133	$	$	$	$	-$133	$	$	-$133	$	$	$
4111000	105120	Book Depreciation	SCHMDEXP	-$215,825	-$5,063	-$59,381	-$17,260	-$24,894	-$31,044	-$90,825	-$11,737	-$6,151	-$515	$	$
4111000	105121	282DIT PMIDepreciation-Book	SE	-$6,761	-$105	-$1,644	-$498	-$894	-$1,148	-$2,914	-$427	-$254	-$25	$	$
4111000	105123	Sec 481a Adj- Repair Deduction	SG	-$5,874	-$99	-$1,514	-$462	-$713	-$904	-$2,546	-$330	-$192	-$19	$	$
4111000	105130	CIAC	CIAC	-$10,561	-$376	-$2,842	-$668	-$912	-$1,090	-$5,080	-$505	-$178	$	$	$
4111000	105140	Highway Relocation	SNPD	-$2,541	-$90	-$684	-$161	-$219	-$262	-$1,222	-$122	-$43	$	$	$
4111000	105142	Avoided Costs	SNP	-$18,348	-$395	-$4,806	-$1,372	-$2,076	-$2,603	-$8,121	-$1,005	-$527	-$45	$	$
4111000	105146	Capitalization of Test Energy	SG	-$211	-$4	-$54	-$17	-$26	-$32	-$91	-$12	-$7	-$1	$	$
4111000	105220	282CHOLLA TAX LEASE	SG	-$511	-$9	-$132	-$40	-$62	-$79	-$221	-$29	-$17	-$2	$	$
4111000	110100	283BOOK COST DEPLETION ADDBACK	SE	-$817	-$13	-$199	-$60	-$108	-$139	-$352	-$52	-$31	-$3	$	$
4111000	145030	190Distribution O&M	SNPD	-$1,090	-$39	-$293	-$69	-$94	-$113	-$524	-$52	-$18	$	$	$
4111000	205025	PMI - Fuel Cost Adjustment	SE	-$1,141	-$18	-$277	-$84	-$151	-$194	-$492	-$72	-$43	-$4	$	$
4111000	205100	190COAL PILE INVENTORY	SE	-$1,420	-$22	-$345	-$105	-$188	-$241	-$612	-$90	-$53	-$5	$	$
4111000	205411	190PMI Sec263A	SE	-$46	-$1	-$11	-$3	-$6	-$8	-$20	-$3	-$2	$	$	$
4111000	210100	283OR PUC Prepaid Taxes	OR	-$135	$	-$135	$	$	$	$	$	$	$	$	$
4111000	210120	283UT PUC Prepaid Taxes	UT	-$109	$	$	$	$	$	-$109	$	$	$	$	$
4111000	210180	190 Other - Pension(Prepaid)	SO	-$416	-$10	-$113	-$32	-$47	-$59	-$179	-$23	-$12	-$1	$	$
4111000	220100	190Bad Debt Allowance	BADDEBT	-$499	-$20	-$233	-$66	-$25	-$26	-$138	-$17	$	$	$	$
4111000	320140	283May 2000 Transition Plan Costs-OR	OR	-$861	$	-$861	$	$	$	$	$	$	$	$	$
4111000	320220	283GLENROCK EXCLUDING RECLAMATION-UT	UT	-$43	$	$	$	$	$	-$43	$	$	$	$	$
4111000	415110	283Def Reg Asset-Transm Svc Deposit	SG	-$159	-$3	-$41	-$12	-$19	-$24	-$69	-$9	-$5	-$1	$	$
4111000	415301	190Hazardous Waste/Environmental-WA	WA	-$22	$	$	-$22	$	$	$	$	$	$	$	$
4111000	415500	283Cholla Plt Trans-APS Amort	SGCT	-$426	-$7	-$110	-$34	-$52	-$66	-$185	-$24	-$14	$	$	$
4111000	415510	283WA DISALLOWED COLSTRIP #3 WRITE-OFF	WA	-$20	$	$	-$20	$	$	$	$	$	$	$	$
4111000	415700	190Reg Assets BPA balancing accounts-OR	OTHER	-$287	$	$	$	$	$	$	$	$	$	-$287	$
4111000	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	-$10	$	$	$	-$10	-$10	$	$	$	$	$	$
4111000	415703	Goodnoe Hills Liquidation Damages - WY	WYP	-$8	$	$	$	-$8	-$8	$	$	$	$	$	$
4111000	415704	Reg Liability - Tax Revenue Adjustment -	UT	-$19	$	$	$	$	$	-$19	$	$	$	$	$
4111000	415803	RTO Grid West N/R Writeoff WA	WA	-$18	$	$	-$18	$	$	$	$	$	$	$	$
4111000	415804	RTO Grid West Notes Receivable-OR	OR	-$112	$	-$112	$	$	$	$	$	$	$	$	$
4111000	415805	RTO Grid West Notes Receivable - WY	WYP	-$35	$	$	$	-$35	-$35	$	$	$	$	$	$
4111000	415806	RTO Grid West N/R Writeoff ID	IDU	-$10	$	$	$	$	$	$	-$10	$	$	$	$
4111000	415822	Reg Asset _ Pension MMT -UT	UT	-$107	$	$	$	$	$	-$107	$	$	$	$	$
4111000	415828	Reg Asset Post Retirement MMT - WY	WYP	-$117	$	$	$	-$117	-$117	$	$	$	$	$	$
4111000	415829	Reg Asset - Post - Ret MMT -UT	UT	-$106	$	$	$	$	$	-$106	$	$	$	$	$
4111000	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	-$191	$	$	$	$	$	$	$	$	$	-$191	$
4111000	415850	Unrecovered Plant-Powerdale	SG	-$39	-$1	-$10	-$3	-$5	-$6	-$17	-$2	-$1	$	$	$
4111000	415872	Deferred Excess Net Power Costs - WY 08	OTHER	-$3,784	$	$	$	$	$	$	$	$	$	-$3,784	$
4111000	415873	Deferred Excess Net Power Costs - WA Hyd	WA	-$643	$	$	-$643	$	$	$	$	$	$	$	$
4111000	415880	Deferred UT Independent Evaluation Fee	UT	-$1	$	$	$	$	$	-$1	$	$	$	$	$
4111000	415890	ID MEHC 2006 Transition Costs	IDU	-$232	$	$	$	$	$	$	-$232	$	$	$	$
4111000	415891	WY - 2006 Transition Severance Costs	WYP	-$403	$	$	$	-$403	-$403	$	$	$	$	$	$
4111000	415895	OR_RCAC SEP-DEC 07 DEFERRED	OR	-$1,733	$	-$1,733	$	$	$	$	$	$	$	$	$
4111000	415896	WA - Chehalis Plant Revenue Requirement	WA	-$1,139	$	$	-$1,139	$	$	$	$	$	$	$	$
4111000	415900	OR SB 409 Recovery	OTHER	-$3,292	$	$	$	$	$	$	$	$	$	-$3,292	$
4111000	425100	Deferred Regulatory Expense	IDU	-$7	$	$	$	$	$	$	-$7	$	$	$	$
4111000	425125	Deferred Coal Cost - Arch	SE	-$626	-$10	-$152	-$46	-$83	-$106	-$270	-$40	-$24	-$2	$	$

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Deferred Income Tax Expense (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4111000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	-$8	$	-$2	$	-$1	-$1	-$4	$	$	$	$	$
4111000	425250	283TGS BUYOUT-SG	SG	-$6	$	-$2	$	-$1	-$1	-$3	$	$	$	$	$
4111000	425280	283JOSEPH SETTLEMENT-SG	SG	-$52	-$1	-$13	-$4	-$6	-$8	-$23	-$3	-$2	$	$	$
4111000	425360	190Hermiston Swap	SG	-$65	-$1	-$17	-$5	-$8	-$10	-$28	-$4	-$2	$	$	$
4111000	430100	283Weatherization	SO	-$10,747	-$248	-$2,919	-$823	-$1,214	-$1,518	-$4,620	-$593	-$304	-$25	$	$
4111000	430111	Reg Asset - SB 1149 Balance Reclass	OTHER	-$26	$	$	$	$	$	$	$	$	$	-$26	$
4111000	430112	Reg Asset - Other - Balance Reclass	OTHER	-$15	$	$	$	$	$	$	$	$	$	-$15	$
4111000	430113	Reg Asset - Def NPC Balance Reclass	OTHER	-$988	$	$	$	$	$	$	$	$	$	-$988	$
4111000	505510	190PMIVacation Bonus	SE	-$7	$	-$2	$	-$1	-$1	-$3	$	$	$	$	$
4111000	505600	190Vacation Sickleave & PT Accrual	SO	-$310	-$7	-$84	-$24	-$35	-$44	-$133	-$17	-$9	-$1	$	$
4111000	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	-$722	-$12	-$184	-$56	-$89	-$113	-$313	-$41	-$24	-$2	$	$
4111000	605710	REVERSE ACCRUED FINAL RECLAMATION	SE	-$81	-$1	-$20	-$6	-$11	-$14	-$35	-$5	-$3	$	$	$
4111000	610111	282PMI Sale of Assets	SE	-$63	-$1	-$15	-$5	-$8	-$11	-$27	-$4	-$2	$	$	$
4111000	610114	PMI EITF04-06 Pre-Stripping Cost	SE	-$344	-$5	-$84	-$25	-$46	-$58	-$148	-$22	-$13	-$1	$	$
4111000	610143	283Reg Liability-WA Low Energy Program	WA	-$92	$	$	-$92	$	$	$	$	$	$	$	$
4111000	610145	190Reg Liab_OR Balance Consol	OR	-$997	$	-$997	$	$	$	$	$	$	$	$	$
4111000	610146	OR Reg Asset/Liability Consolidation	OR	-$23	$	-$23	$	$	$	$	$	$	$	$	$
4111000	705240	283CA Alternative Rate for Energy Progra	CA	-$434	-$434	$	$	$	$	$	$	$	$	$	$
4111000	705260	MEHC Transition Costs-WA	WA	-$121	$	$	-$121	$	$	$	$	$	$	$	$
4111000	705261	Reg Liability - Sale of renewable Energy	OTHER	-$1,489	$	$	$	$	$	$	$	$	$	-$1,489	$
4111000	705265	Reg Liability - OR Energy Conservation C	OR	-$575	$	-$575	$	$	$	$	$	$	$	$	$
4111000	705337	Regulatory Liability - Sale of Renewable	OTHER	-$1,364	$	$	$	$	$	$	$	$	$	-$1,364	$
4111000	715105	MCI FOG Wire Lease	SG	$	$	$	$	$	$	$	$	$	$	$	$
4111000	715720	190NW Power Act(BPA Regional Crs)-WA	OTHER	-$220	$	$	$	$	$	$	$	$	$	-$220	$
4111000	720200	190Deferred Compensation Payout	SO	-$6	$	-$2	$	-$1	-$1	-$2	$	$	$	$	$
4111000	740100	283Post Merger Debt Loss	SNP	-$885	-$19	-$232	-$66	-$100	-$126	-$392	-$48	-$25	-$2	$	$
4111000	910530	190Injuries & Damages	SO	-$384	-$9	-$104	-$29	-$43	-$54	-$165	-$21	-$11	-$1	$	$
4111000	910910	190PMISec 471 Adjustment	SE	-$407	-$6	-$99	-$30	-$54	-$69	-$175	-$26	-$15	-$2	$	$
4111000	920110	190PMIWYExtractionTax	SE	-$720	-$11	-$175	-$53	-$95	-$122	-$310	-$45	-$27	-$3	$	$
4111000	920150	190FAS112 Book Reserve Postretirement Be	SO	-$600	-$14	-$163	-$46	-$68	-$85	-$258	-$33	-$17	-$1	$	$
4111000	9301001	190OR BETC Credit	SG	-$1,800	-$30	-$464	-$141	-$218	-$277	-$780	-$101	-$59	-$6	$	$
4111000 Total				**-$315,468**	**-$7,991**	**-$83,721**	**-$21,831**	**-$33,702**	**-$42,053**	**-$130,034**	**-$17,449**	**-$8,351**	**-$738**	**-$11,650**	**$**
Grand Total				**$922,131**	**$18,537**	**$227,767**	**$62,208**	**$102,921**	**$129,760**	**$394,652**	**$47,613**	**$26,839**	**$2,353**	**$32,128**	**$7,111**

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Investment Tax Credit Amortization (Actuals)

Twelve Months Ending - June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	-$1,874	$	$	$	$	-$116	-$1,546	-$200	-$116	-$12	$	$
4114000 Total					**-$1,874**	**$**	**$**	**$**	**$**	**-$116**	**-$1,546**	**-$200**	**-$116**	**-$12**	**$**	**$**
Grand Total					**-$1,874**	**$**	**$**	**$**	**$**	**-$116**	**-$1,546**	**-$200**	**-$116**	**-$12**	**$**	**$**

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Electric Plant in Service with Unclassified Plant (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3020000	FRANCHISES AND CONSENTS	IDU	$1,000	$	$	$	$	$	$	$1,000	$	$	$	$
1010000	3020000	FRANCHISES AND CONSENTS	SG	$10,266	$173	$2,646	$807	$1,245	$1,580	$4,449	$577	$335	$34	$	$
1010000	3020000	FRANCHISES AND CONSENTS	SG-I	$173,622	$2,922	$44,755	$13,642	$21,059	$26,728	$75,251	$9,755	$5,669	$568	$	$
1010000	3020000	FRANCHISES AND CONSENTS	SG-U	$9,790	$165	$2,524	$769	$1,187	$1,507	$4,243	$550	$320	$32	$	$
1010000	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	$531	$	$531	$	$	$	$	$	$	$	$	$
1010000	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	$34,828	$586	$8,978	$2,737	$4,224	$5,362	$15,095	$1,957	$1,137	$114	$	$
1010000	3031050	RCMS - REGION CONSTRUCTION MGMT SYSTEM	SO	$10,936	$253	$2,971	$838	$1,235	$1,544	$4,701	$604	$309	$26	$	$
1010000	3031080	FUEL MANAGEMENT SYSTEM	SO	$3,293	$76	$894	$252	$372	$465	$1,415	$182	$93	$8	$	$
1010000	3031230	AUTOMATE POLE CARD SYSTEM	SO	$4,410	$102	$1,198	$338	$498	$623	$1,896	$243	$125	$10	$	$
1010000	3031470	RILDA CANYON ROAD IMPROVEMENTS	SE	$3,381	$53	$822	$249	$447	$574	$1,457	$213	$127	$13	$	$
1010000	3031680	DISTRIBUTION AUTOMATION PILOT PROJECT	SO	$13,072	$302	$3,551	$1,001	$1,476	$1,846	$5,619	$722	$369	$31	$	$
1010000	3031760	RECORD CENTER MANAGEMENT SOFTWARE	SO	$291	$7	$79	$22	$33	$41	$125	$16	$8	$1	$	$
1010000	3031780	OUTAGE REPORTING SYSTEM	SO	$3,498	$81	$950	$268	$395	$494	$1,504	$193	$99	$8	$	$
1010000	3031830	CUSTOMER SERVICE SYSTEM (CSS)	CN	$111,921	$2,689	$32,863	$7,507	$7,234	$8,171	$56,480	$4,211	$937	$	$	$
1010000	3032040	S A P	SO	$167,554	$3,871	$45,516	$12,835	$18,924	$23,659	$72,028	$9,250	$4,736	$395	$	$
1010000	3032090	ENERGY COMMODITY SYSTEM SOFTWARE	SO	$9,974	$230	$2,709	$764	$1,126	$1,408	$4,287	$551	$282	$24	$	$
1010000	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	$1,660	$38	$451	$127	$187	$234	$714	$92	$47	$4	$	$
1010000	3032260	DWHS - DATA WAREHOUSE	SO	$1,158	$27	$315	$89	$131	$164	$498	$64	$33	$3	$	$
1010000	3032270	ENTERPRISE DATA WAREHOUSE	SO	$5,872	$136	$1,595	$450	$663	$829	$2,524	$324	$166	$14	$	$
1010000	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	$2,908	$67	$790	$223	$328	$411	$1,250	$161	$82	$7	$	$
1010000	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	$1,905	$44	$517	$146	$215	$269	$819	$105	$54	$4	$	$
1010000	3032360	2002 GRID NET POWER COST MODELING	SO	$8,933	$206	$2,427	$684	$1,009	$1,261	$3,840	$493	$252	$21	$	$
1010000	3032400	INCEDENT MANAGEMENT ANALYSIS PROGRAM	SO	$5,286	$122	$1,436	$405	$597	$746	$2,272	$292	$149	$12	$	$
1010000	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	$12,489	$289	$3,393	$957	$1,411	$1,764	$5,369	$689	$353	$29	$	$
1010000	3032480	OUTAGE CALL HANDLING INTEGRATION	CN	$1,981	$48	$582	$133	$128	$145	$1,000	$75	$17	$	$	$
1010000	3032510	OPERATIONS MAPPING SYSTEM	SO	$10,386	$240	$2,821	$796	$1,173	$1,467	$4,465	$573	$294	$24	$	$
1010000	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	$1,892	$44	$514	$145	$214	$267	$814	$104	$53	$4	$	$
1010000	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	$2,299	$53	$625	$176	$260	$325	$988	$127	$65	$5	$	$
1010000	3032600	SINGLE PERSON SCHEDULING	SO	$9,035	$209	$2,454	$692	$1,020	$1,276	$3,884	$499	$255	$21	$	$
1010000	3032640	TIBCO SOFTWARE	SO	$4,061	$94	$1,103	$311	$459	$573	$1,746	$224	$115	$10	$	$
1010000	3032670	C&T OFFICIAL RECORD INFO SYSTEM	SO	$1,586	$37	$431	$122	$179	$224	$682	$88	$45	$4	$	$
1010000	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	$1,581	$27	$408	$124	$192	$243	$685	$89	$52	$5	$	$
1010000	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	$196	$3	$50	$15	$24	$30	$85	$11	$6	$1	$	$
1010000	3032730	IMPROVEMENTS TO PLANT OWNED BY JAMES RIV	SG	$13,873	$233	$3,576	$1,090	$1,683	$2,136	$6,013	$780	$453	$45	$	$
1010000	3032760	SWIFT 2 IMPROVEMENTS	SG	$23,200	$390	$5,980	$1,823	$2,814	$3,571	$10,055	$1,304	$758	$76	$	$
1010000	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	$434	$7	$112	$34	$53	$67	$188	$24	$14	$1	$	$
1010000	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	$117	$2	$30	$9	$14	$18	$51	$7	$4	$	$	$
1010000	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	$2,179	$50	$592	$167	$246	$308	$937	$120	$62	$5	$	$
1010000	3032860	WEB SOFTWARE	SO	$2,680	$62	$728	$205	$303	$378	$1,152	$148	$76	$6	$	$
1010000	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	$6,271	$106	$1,616	$493	$761	$965	$2,718	$352	$205	$21	$	$
1010000	3032910	WYOMING VHF (VPC) SPECTRUM	WYP	$545	$	$	$	$545	$545	$	$	$	$	$	$
1010000	3032920	IDAHO VHF (VPC) SPECTRUM	IDU	$426	$	$	$	$	$	$	$426	$	$	$	$
1010000	3032930	UTAH VHF (VPC) SPECTRUM	UT	$2,937	$	$	$	$	$	$2,937	$	$	$	$	$
1010000	3032990	P8DM - FILENET P8	SO	$3,998	$92	$1,086	$306	$452	$565	$1,719	$221	$113	$9	$	$
1010000	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	$40,233	$677	$10,371	$3,161	$4,880	$6,194	$17,438	$2,261	$1,314	$132	$	$
1010000	3033120	RANGER EMS/SCADA SYSTEM	SG	$141	$2	$36	$11	$17	$22	$61	$8	$5	$	$	$
1010000	3033120	RANGER EMS/SCADA SYSTEM	SO	$37,422	$865	$10,166	$2,867	$4,226	$5,284	$16,087	$2,066	$1,058	$88	$	$
1010000	3033120	RANGER EMS/SCADA SYSTEM	WYP	$463	$	$	$	$463	$463	$	$	$	$	$	$
1010000	3033140	ETAGM - Electronic Tagging Sys-Merchant	SO	$1,417	$33	$385	$109	$160	$200	$609	$78	$40	$3	$	$
1010000	3033150	ROUTT CITY ROAD FOR HAYDEN HAULAGE	SG	$2,943	$50	$759	$231	$357	$453	$1,275	$165	$96	$10	$	$
1010000	3033170	GTX VERSION 7 SOFTWARE	CN	$3,368	$81	$989	$226	$218	$246	$1,700	$127	$28	$	$	$
1010000	3033180	HPOV - HP Open Software	SO	$2,016	$47	$548	$154	$228	$285	$867	$111	$57	$5	$	$
1010000	3033190	ITRON METER READING SOFTWARE	CN	$2,665	$64	$782	$179	$172	$195	$1,345	$100	$22	$	$	$
1010000	3033300	SECID - CUST SECURE WEB LOGIN	CN	$1,085	$26	$319	$73	$70	$79	$548	$41	$9	$	$	$
1010000	3033310	C&T - Energy Trading System	SO	$13,702	$317	$3,722	$1,050	$1,548	$1,935	$5,890	$756	$387	$32	$	$
1010000	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	$4,548	$77	$1,172	$357	$552	$700	$1,971	$256	$149	$15	$	$
1010000	3033330	OR VHF (VPC) SPECTRUM	OR	$1,311	$	$1,311	$	$	$	$	$	$	$	$	$
1010000	3033340	WA VHF (VPC) SPECTRUM	WA	$625	$	$	$625	$	$	$	$	$	$	$	$
1010000	3033350	CA VHF (VPC) SPECTRUM	CA	$216	$216	$	$	$	$	$	$	$	$	$	$
1010000	3033360	DSM REPORTING & TRACKING SOFTWARE	SO	$1,224	$28	$332	$94	$138	$173	$526	$68	$35	$3	$	$
1010000	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	$1,601	$27	$413	$126	$194	$246	$694	$90	$52	$5	$	$
1010000	3034900	MISC - MISCELLANEOUS	CN	$57	$1	$17	$4	$4	$4	$29	$2	$	$	$	$
1010000	3034900	MISC - MISCELLANEOUS	IDU	$2	$	$	$	$	$	$	$2	$	$	$	$
1010000	3034900	MISC - MISCELLANEOUS	OR	$12	$	$12	$	$	$	$	$	$	$	$	$

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3034900	MISC - MISCELLANEOUS	SE	$273	$4	$66	$20	$36	$46	$118	$17	$10	$1	$	$
1010000	3034900	MISC - MISCELLANEOUS	SG	$1,165	$20	$300	$92	$141	$179	$505	$65	$38	$4	$	$
1010000	3034900	MISC - MISCELLANEOUS	SO	$28,753	$664	$7,811	$2,203	$3,247	$4,060	$12,360	$1,587	$813	$68	$	$
1010000	3034900	MISC - MISCELLANEOUS	UT	$66	$	$	$	$	$	$66	$	$	$	$	$
1010000	3034900	MISC - MISCELLANEOUS	WA	$2	$	$	$2	$	$	$	$	$	$	$	$
1010000	3034900	MISC - MISCELLANEOUS	WYP	$372	$	$	$	$372	$372	$	$	$	$	$	$
1010000	3100000	LAND & LAND RIGHTS	SG	$1,306	$22	$337	$103	$158	$201	$566	$73	$43	$4	$	$
1010000	3101000	LAND OWNED IN FEE	SG	$11,865	$200	$3,058	$932	$1,439	$1,827	$5,143	$667	$387	$39	$	$
1010000	3102000	LAND RIGHTS	SG	$42,991	$724	$11,082	$3,378	$5,214	$6,618	$18,633	$2,416	$1,404	$141	$	$
1010000	3103000	WATER RIGHTS	SG	$39,700	$668	$10,233	$3,119	$4,815	$6,112	$17,207	$2,231	$1,296	$130	$	$
1010000	3108000	FEE LAND - LEASED	SG	$37	$1	$9	$3	$4	$6	$16	$2	$1	$	$	$
1010000	3110000	STRUCTURES AND IMPROVEMENTS	SG	$923,527	$15,542	$238,059	$72,566	$112,016	$142,171	$400,275	$51,891	$30,155	$3,023	$	$
1010000	3120000	BOILER PLANT EQUIPMENT	SG	$3,685,952	$62,032	$950,134	$289,621	$447,075	$567,430	$1,597,563	$207,104	$120,355	$12,067	$	$
1010000	3140000	TURBOGENERATOR UNITS	SG	$925,839	$15,581	$238,655	$72,747	$112,297	$142,527	$401,277	$52,021	$30,231	$3,031	$	$
1010000	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	$417,510	$7,026	$107,622	$32,806	$50,641	$64,273	$180,957	$23,459	$13,633	$1,367	$	$
1010000	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	$63	$1	$16	$5	$8	$10	$27	$4	$2	$	$	$
1010000	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	$33,355	$561	$8,598	$2,621	$4,046	$5,135	$14,457	$1,874	$1,089	$109	$	$
1010000	3300000	LAND AND LAND RIGHTS	SG-U	$119	$2	$31	$9	$14	$18	$52	$7	$4	$	$	$
1010000	3301000	LAND OWNED IN FEE	SG-P	$11,504	$194	$2,966	$904	$1,395	$1,771	$4,986	$646	$376	$38	$	$
1010000	3301000	LAND OWNED IN FEE	SG-U	$5,528	$93	$1,425	$434	$670	$851	$2,396	$311	$180	$18	$	$
1010000	3302000	LAND RIGHTS	SG-P	$8,035	$135	$2,071	$631	$975	$1,237	$3,483	$451	$262	$26	$	$
1010000	3302000	LAND RIGHTS	SG-U	$65	$1	$17	$5	$8	$10	$28	$4	$2	$	$	$
1010000	3303000	WATER RIGHTS	SG-U	$140	$2	$36	$11	$17	$22	$61	$8	$5	$	$	$
1010000	3304000	FLOOD RIGHTS	SG-P	$260	$4	$67	$20	$31	$40	$113	$15	$8	$1	$	$
1010000	3304000	FLOOD RIGHTS	SG-U	$91	$2	$23	$7	$11	$14	$39	$5	$3	$	$	$
1010000	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	$310	$5	$80	$24	$38	$48	$134	$17	$10	$1	$	$
1010000	3310000	STRUCTURES AND IMPROVE	SG-P	$7	$	$2	$1	$1	$1	$3	$	$	$	$	$
1010000	3310000	STRUCTURES AND IMPROVE	SG-U	$7,443	$125	$1,919	$585	$903	$1,146	$3,226	$418	$243	$24	$	$
1010000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	$49,967	$841	$12,880	$3,926	$6,061	$7,692	$21,657	$2,807	$1,632	$164	$	$
1010000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	$3,543	$60	$913	$278	$430	$545	$1,536	$199	$116	$12	$	$
1010000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	$27,789	$468	$7,163	$2,184	$3,371	$4,278	$12,044	$1,561	$907	$91	$	$
1010000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	$364	$6	$94	$29	$44	$56	$158	$20	$12	$1	$	$
1010000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	$13,272	$223	$3,421	$1,043	$1,610	$2,043	$5,752	$746	$433	$43	$	$
1010000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	$1,985	$33	$512	$156	$241	$306	$861	$112	$65	$7	$	$
1010000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	$10,134	$171	$2,612	$796	$1,229	$1,560	$4,392	$569	$331	$33	$	$
1010000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-U	$185	$3	$48	$15	$22	$28	$80	$10	$6	$1	$	$
1010000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	$7,010	$118	$1,807	$551	$850	$1,079	$3,038	$394	$229	$23	$	$
1010000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	$23,034	$388	$5,938	$1,810	$2,794	$3,546	$9,984	$1,294	$752	$75	$	$
1010000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	$249,699	$4,202	$64,365	$19,620	$30,286	$38,440	$108,224	$14,030	$8,153	$817	$	$
1010000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	$45,478	$765	$11,723	$3,573	$5,516	$7,001	$19,711	$2,555	$1,485	$149	$	$
1010000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	$9,089	$153	$2,343	$714	$1,102	$1,399	$3,939	$511	$297	$30	$	$
1010000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	$546	$9	$141	$43	$66	$84	$237	$31	$18	$2	$	$
1010000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	$425	$7	$110	$33	$52	$65	$184	$24	$14	$1	$	$
1010000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	$63	$1	$16	$5	$8	$10	$28	$4	$2	$	$	$
1010000	3326000	RESERVOIR, DAMS, WATERWAYS, LEASE HOLDS	SG-U	$529	$9	$136	$42	$64	$81	$229	$30	$17	$2	$	$
1010000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	$76,445	$1,287	$19,705	$6,007	$9,272	$11,768	$33,133	$4,295	$2,496	$250	$	$
1010000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	$39,059	$657	$10,068	$3,069	$4,737	$6,013	$16,929	$2,195	$1,275	$128	$	$
1010000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	$46,160	$777	$11,899	$3,627	$5,599	$7,106	$20,007	$2,594	$1,507	$151	$	$
1010000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	$10,930	$184	$2,817	$859	$1,326	$1,683	$4,737	$614	$357	$36	$	$
1010000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	$3,217	$54	$829	$253	$390	$495	$1,394	$181	$105	$11	$	$
1010000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	$46	$1	$12	$4	$6	$7	$20	$3	$1	$	$	$
1010000	3350000	MISC POWER PLANT EQUIP	SG-U	$174	$3	$45	$14	$21	$27	$75	$10	$6	$1	$	$
1010000	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	$2,129	$36	$549	$167	$258	$328	$923	$120	$70	$7	$	$
1010000	3353000	MISC POWER PLANT EQUIP - RECREATION	SG-P	$9	$	$2	$1	$1	$1	$4	$1	$	$	$	$
1010000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	$14,977	$252	$3,861	$1,177	$1,817	$2,306	$6,491	$842	$489	$49	$	$
1010000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	$1,497	$25	$386	$118	$182	$230	$649	$84	$49	$5	$	$
1010000	3401000	LAND OWNED IN FEE	SG	$11,493	$193	$2,962	$903	$1,394	$1,769	$4,981	$646	$375	$38	$	$
1010000	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	$17,420	$293	$4,490	$1,369	$2,113	$2,682	$7,550	$979	$569	$57	$	$
1010000	3410000	STRUCTURES & IMPROVEMENTS	SG	$163,227	$2,747	$42,075	$12,825	$19,798	$25,128	$70,746	$9,171	$5,330	$534	$	$
1010000	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	$10,830	$182	$2,792	$851	$1,314	$1,667	$4,694	$609	$354	$35	$	$
1010000	3430000	PRIME MOVERS	SG	$2,492,844	$41,953	$642,584	$195,874	$302,361	$383,758	$1,080,447	$140,067	$81,397	$8,161	$	$
1010000	3440000	GENERATORS	SG	$353,976	$5,957	$91,245	$27,813	$42,934	$54,493	$153,420	$19,889	$11,558	$1,159	$	$
1010000	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	$247,410	$4,164	$63,775	$19,440	$30,009	$38,087	$107,232	$13,901	$8,079	$810	$	$
1010000	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	$12,371	$208	$3,189	$972	$1,501	$1,904	$5,362	$695	$404	$41	$	$

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1010000	3500000	LAND AND LAND RIGHTS	SG	$841	$14	$217	$66	$102	$130	$365	$47	$27	$3	$	$
1010000	3501000	LAND OWNED IN FEE	SG	$49,375	$831	$12,727	$3,880	$5,989	$7,601	$21,400	$2,774	$1,612	$162	$	$
1010000	3502000	LAND RIGHTS	SG	$137,271	$2,310	$35,385	$10,786	$16,650	$21,132	$59,496	$7,713	$4,482	$449	$	$
1010000	3520000	STRUCTURES & IMPROVEMENTS	SG	$137,067	$2,307	$35,332	$10,770	$16,625	$21,101	$59,408	$7,701	$4,476	$449	$	$
1010000	3530000	STATION EQUIPMENT	SG	$122	$2	$31	$10	$15	$19	$53	$7	$4	$	$	$
1010000	3530000	STATION EQUIPMENT	SG	$1,442,290	$24,273	$371,781	$113,327	$174,938	$222,032	$625,117	$81,039	$47,094	$4,722	$	$
1010000	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	$128,605	$2,164	$33,151	$10,105	$15,599	$19,798	$55,740	$7,226	$4,199	$421	$	$
1010000	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	$22,988	$387	$5,926	$1,806	$2,788	$3,539	$9,963	$1,292	$751	$75	$	$
1010000	3540000	TOWERS AND FIXTURES	SG	$952,438	$16,029	$245,512	$74,837	$115,523	$146,622	$412,805	$53,515	$31,099	$3,118	$	$
1010000	3550000	POLES AND FIXTURES	SG	$625,478	$10,526	$161,230	$49,147	$75,865	$96,289	$271,094	$35,144	$20,423	$2,048	$	$
1010000	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	$883,463	$14,868	$227,732	$69,418	$107,157	$136,004	$382,910	$49,640	$28,847	$2,892	$	$
1010000	3570000	UNDERGROUND CONDUIT	SG	$3,259	$55	$840	$256	$395	$502	$1,413	$183	$106	$11	$	$
1010000	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	$7,475	$126	$1,927	$587	$907	$1,151	$3,240	$420	$244	$24	$	$
1010000	3590000	ROADS AND TRAILS	SG	$11,599	$195	$2,990	$911	$1,407	$1,786	$5,027	$652	$379	$38	$	$
1010000	3600000	LAND AND LAND RIGHTS	IDU	$1	$	$	$	$	$	$	$1	$	$	$	$
1010000	3600000	LAND AND LAND RIGHTS	OR	$8	$	$8	$	$	$	$	$	$	$	$	$
1010000	3600000	LAND AND LAND RIGHTS	UT	$168	$	$	$	$	$	$168	$	$	$	$	$
1010000	3600000	LAND AND LAND RIGHTS	WA	$	$	$	$	$	$	$	$	$	$	$	$
1010000	3600000	LAND AND LAND RIGHTS	WYP	$4	$	$	$	$4	$4	$	$	$	$	$	$
1010000	3600000	LAND AND LAND RIGHTS	WYU	$2	$	$	$	$	$2	$	$	$2	$	$	$
1010000	3601000	LAND OWNED IN FEE	CA	$729	$729	$	$	$	$	$	$	$	$	$	$
1010000	3601000	LAND OWNED IN FEE	IDU	$297	$	$	$	$	$	$	$297	$	$	$	$
1010000	3601000	LAND OWNED IN FEE	OR	$8,441	$	$8,441	$	$	$	$	$	$	$	$	$
1010000	3601000	LAND OWNED IN FEE	UT	$23,630	$	$	$	$	$	$23,630	$	$	$	$	$
1010000	3601000	LAND OWNED IN FEE	WA	$1,258	$	$	$1,258	$	$	$	$	$	$	$	$
1010000	3601000	LAND OWNED IN FEE	WYP	$594	$	$	$	$594	$594	$	$	$	$	$	$
1010000	3601000	LAND OWNED IN FEE	WYU	$48	$	$	$	$	$48	$	$	$48	$	$	$
1010000	3602000	LAND RIGHTS	CA	$942	$942	$	$	$	$	$	$	$	$	$	$
1010000	3602000	LAND RIGHTS	IDU	$1,063	$	$	$	$	$	$	$1,063	$	$	$	$
1010000	3602000	LAND RIGHTS	OR	$4,211	$	$4,211	$	$	$	$	$	$	$	$	$
1010000	3602000	LAND RIGHTS	UT	$7,751	$	$	$	$	$	$7,751	$	$	$	$	$
1010000	3602000	LAND RIGHTS	WA	$247	$	$	$247	$	$	$	$	$	$	$	$
1010000	3602000	LAND RIGHTS	WYP	$1,969	$	$	$	$1,969	$1,969	$	$	$	$	$	$
1010000	3602000	LAND RIGHTS	WYU	$1,946	$	$	$	$	$1,946	$	$	$1,946	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	CA	$3,866	$3,866	$	$	$	$	$	$	$	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	IDU	$1,719	$	$	$	$	$	$	$1,719	$	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	OR	$19,645	$	$19,645	$	$	$	$	$	$	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	UT	$43,155	$	$	$	$	$	$43,155	$	$	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	WA	$2,241	$	$	$2,241	$	$	$	$	$	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	WYP	$8,479	$	$	$	$8,479	$8,479	$	$	$	$	$	$
1010000	3610000	STRUCTURES & IMPROVEMENTS	WYU	$175	$	$	$	$	$175	$	$	$175	$	$	$
1010000	3620000	STATION EQUIPMENT	CA	$21,499	$21,499	$	$	$	$	$	$	$	$	$	$
1010000	3620000	STATION EQUIPMENT	IDU	$27,915	$	$	$	$	$	$	$27,915	$	$	$	$
1010000	3620000	STATION EQUIPMENT	OR	$198,147	$	$198,147	$	$	$	$	$	$	$	$	$
1010000	3620000	STATION EQUIPMENT	UT	$400,033	$	$	$	$	$	$400,033	$	$	$	$	$
1010000	3620000	STATION EQUIPMENT	WA	$46,136	$	$	$46,136	$	$	$	$	$	$	$	$
1010000	3620000	STATION EQUIPMENT	WYP	$104,881	$	$	$	$104,881	$104,881	$	$	$	$	$	$
1010000	3620000	STATION EQUIPMENT	WYU	$11,655	$	$	$	$	$11,655	$	$	$11,655	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	$217	$217	$	$	$	$	$	$	$	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	$389	$	$	$	$	$	$	$389	$	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	$3,102	$	$3,102	$	$	$	$	$	$	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	$5,757	$	$	$	$	$	$5,757	$	$	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	$919	$	$	$919	$	$	$	$	$	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	$1,975	$	$	$	$1,975	$1,975	$	$	$	$	$	$
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	$61	$	$	$	$	$61	$	$	$61	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	CA	$52,563	$52,563	$	$	$	$	$	$	$	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	IDU	$65,960	$	$	$	$	$	$	$65,960	$	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	OR	$322,560	$	$322,560	$	$	$	$	$	$	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	UT	$307,378	$	$	$	$	$	$307,378	$	$	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	WA	$90,114	$	$	$90,114	$	$	$	$	$	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	WYP	$95,145	$	$	$	$95,145	$95,145	$	$	$	$	$	$
1010000	3640000	"POLES, TOWERS AND FIXTURES"	WYU	$20,010	$	$	$	$	$20,010	$	$	$20,010	$	$	$
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	$32,262	$32,262	$	$	$	$	$	$	$	$	$	$
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	$34,571	$	$	$	$	$	$	$34,571	$	$	$	$

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	$231,283	$	$231,283	$	$	$	$	$	$	$	$	$
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	$205,064	$	$	$	$	$	$205,064	$	$	$	$	$
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	$57,266	$	$	$57,266	$	$	$	$	$	$	$	$
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	$81,809	$	$	$	$81,809	$81,809	$	$	$	$	$	$
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	$11,131	$	$	$	$	$11,131	$	$	$11,131	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	CA	$15,426	$15,426	$	$	$	$	$	$	$	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	IDU	$7,729	$	$	$	$	$	$	$7,729	$	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	OR	$83,120	$	$83,120	$	$	$	$	$	$	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	UT	$165,209	$	$	$	$	$	$165,209	$	$	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	WA	$15,852	$	$	$15,852	$	$	$	$	$	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	WYP	$13,308	$	$	$	$13,308	$13,308	$	$	$	$	$	$
1010000	3660000	UNDERGROUND CONDUIT	WYU	$3,808	$	$	$	$	$3,808	$	$	$3,808	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	$16,886	$16,886	$	$	$	$	$	$	$	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	$24,377	$	$	$	$	$	$	$24,377	$	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	$154,355	$	$154,355	$	$	$	$	$	$	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	$458,730	$	$	$	$	$	$458,730	$	$	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	$21,517	$	$	$21,517	$	$	$	$	$	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	$31,178	$	$	$	$31,178	$31,178	$	$	$	$	$	$
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	$16,352	$	$	$	$	$16,352	$	$	$16,352	$	$	$
1010000	3680000	LINE TRANSFORMERS	CA	$47,245	$47,245	$	$	$	$	$	$	$	$	$	$
1010000	3680000	LINE TRANSFORMERS	IDU	$68,515	$	$	$	$	$	$	$68,515	$	$	$	$
1010000	3680000	LINE TRANSFORMERS	OR	$387,652	$	$387,652	$	$	$	$	$	$	$	$	$
1010000	3680000	LINE TRANSFORMERS	UT	$414,614	$	$	$	$	$	$414,614	$	$	$	$	$
1010000	3680000	LINE TRANSFORMERS	WA	$96,600	$	$	$96,600	$	$	$	$	$	$	$	$
1010000	3680000	LINE TRANSFORMERS	WYP	$80,239	$	$	$	$80,239	$80,239	$	$	$	$	$	$
1010000	3680000	LINE TRANSFORMERS	WYU	$12,720	$	$	$	$	$12,720	$	$	$12,720	$	$	$
1010000	3691000	SERVICES - OVERHEAD	CA	$8,478	$8,478	$	$	$	$	$	$	$	$	$	$
1010000	3691000	SERVICES - OVERHEAD	IDU	$6,697	$	$	$	$	$	$	$6,697	$	$	$	$
1010000	3691000	SERVICES - OVERHEAD	OR	$73,373	$	$73,373	$	$	$	$	$	$	$	$	$
1010000	3691000	SERVICES - OVERHEAD	UT	$70,123	$	$	$	$	$	$70,123	$	$	$	$	$
1010000	3691000	SERVICES - OVERHEAD	WA	$18,216	$	$	$18,216	$	$	$	$	$	$	$	$
1010000	3691000	SERVICES - OVERHEAD	WYP	$13,602	$	$	$	$13,602	$13,602	$	$	$	$	$	$
1010000	3691000	SERVICES - OVERHEAD	WYU	$2,168	$	$	$	$	$2,168	$	$	$2,168	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	CA	$14,403	$14,403	$	$	$	$	$	$	$	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	IDU	$22,971	$	$	$	$	$	$	$22,971	$	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	OR	$148,577	$	$148,577	$	$	$	$	$	$	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	UT	$149,232	$	$	$	$	$	$149,232	$	$	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	WA	$32,091	$	$	$32,091	$	$	$	$	$	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	WYP	$24,574	$	$	$	$24,574	$24,574	$	$	$	$	$	$
1010000	3692000	SERVICES - UNDERGROUND	WYU	$7,727	$	$	$	$	$7,727	$	$	$7,727	$	$	$
1010000	3700000	METERS	CA	$3,886	$3,886	$	$	$	$	$	$	$	$	$	$
1010000	3700000	METERS	IDU	$14,127	$	$	$	$	$	$	$14,127	$	$	$	$
1010000	3700000	METERS	OR	$59,950	$	$59,950	$	$	$	$	$	$	$	$	$
1010000	3700000	METERS	UT	$73,083	$	$	$	$	$	$73,083	$	$	$	$	$
1010000	3700000	METERS	WA	$13,889	$	$	$13,889	$	$	$	$	$	$	$	$
1010000	3700000	METERS	WYP	$11,417	$	$	$	$11,417	$11,417	$	$	$	$	$	$
1010000	3700000	METERS	WYU	$2,591	$	$	$	$	$2,591	$	$	$2,591	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	CA	$272	$272	$	$	$	$	$	$	$	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	$169	$	$	$	$	$	$	$169	$	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	OR	$2,470	$	$2,470	$	$	$	$	$	$	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	UT	$4,433	$	$	$	$	$	$4,433	$	$	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	WA	$524	$	$	$524	$	$	$	$	$	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	$781	$	$	$	$781	$781	$	$	$	$	$	$
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	$150	$	$	$	$	$150	$	$	$150	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	$672	$672	$	$	$	$	$	$	$	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	$617	$	$	$	$	$	$	$617	$	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	$21,965	$	$21,965	$	$	$	$	$	$	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	$23,643	$	$	$	$	$	$23,643	$	$	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	$3,986	$	$	$3,986	$	$	$	$	$	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	$7,652	$	$	$	$7,652	$7,652	$	$	$	$	$	$
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	$2,223	$	$	$	$	$2,223	$	$	$2,223	$	$	$
1010000	3890000	LAND AND LAND RIGHTS	IDU	$93	$	$	$	$	$	$	$93	$	$	$	$
1010000	3890000	LAND AND LAND RIGHTS	OR	$228	$	$228	$	$	$	$	$	$	$	$	$
1010000	3890000	LAND AND LAND RIGHTS	UT	$1,441	$	$	$	$	$	$1,441	$	$	$	$	$

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3890000	LAND AND LAND RIGHTS	WYU	$434	$	$	$	$	$434	$	$	$434	$	$	$
1010000	3891000	LAND OWNED IN FEE	CA	$218	$218	$	$	$	$	$	$	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	CN	$1,129	$27	$331	$76	$73	$82	$569	$42	$9	$	$	$
1010000	3891000	LAND OWNED IN FEE	IDU	$100	$	$	$	$	$	$	$100	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	OR	$2,818	$	$2,818	$	$	$	$	$	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	SG	$	$	$	$	$	$	$	$	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	SO	$5,597	$129	$1,520	$429	$632	$790	$2,406	$309	$158	$13	$	$
1010000	3891000	LAND OWNED IN FEE	UT	$2,543	$	$	$	$	$	$2,543	$	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	WA	$1,099	$	$	$1,099	$	$	$	$	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	WYP	$313	$	$	$	$313	$313	$	$	$	$	$	$
1010000	3891000	LAND OWNED IN FEE	WYU	$72	$	$	$	$	$72	$	$	$72	$	$	$
1010000	3892000	LAND RIGHTS	IDU	$5	$	$	$	$	$	$	$5	$	$	$	$
1010000	3892000	LAND RIGHTS	SG	$1	$	$	$	$	$	$1	$	$	$	$	$
1010000	3892000	LAND RIGHTS	UT	$34	$	$	$	$	$	$34	$	$	$	$	$
1010000	3892000	LAND RIGHTS	WYP	$52	$	$	$	$52	$52	$	$	$	$	$	$
1010000	3892000	LAND RIGHTS	WYU	$22	$	$	$	$	$22	$	$	$22	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	CA	$1,520	$1,520	$	$	$	$	$	$	$	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	CN	$7,976	$192	$2,342	$535	$516	$582	$4,025	$300	$67	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	IDU	$9,892	$	$	$	$	$	$	$9,892	$	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	OR	$25,363	$	$25,363	$	$	$	$	$	$	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	SG	$7,261	$122	$1,872	$570	$881	$1,118	$3,147	$408	$237	$24	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	SO	$76,840	$1,775	$20,874	$5,886	$8,678	$10,850	$33,032	$4,242	$2,172	$181	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	UT	$37,656	$	$	$	$	$	$37,656	$	$	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	WA	$10,968	$	$	$10,968	$	$	$	$	$	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	WYP	$3,315	$	$	$	$3,315	$3,315	$	$	$	$	$	$
1010000	3900000	STRUCTURES AND IMPROVEMENTS	WYU	$2,338	$	$	$	$	$2,338	$	$	$2,338	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	$1,419	$1,419	$	$	$	$	$	$	$	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CN	$3,401	$82	$999	$228	$220	$248	$1,716	$128	$28	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	$7,957	$	$7,957	$	$	$	$	$	$	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	$16,613	$384	$4,513	$1,273	$1,876	$2,346	$7,141	$917	$470	$39	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	$19	$	$	$	$	$	$19	$	$	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	$2,820	$	$	$2,820	$	$	$	$	$	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	$8,288	$	$	$	$8,288	$8,288	$	$	$	$	$	$
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYU	$56	$	$	$	$	$56	$	$	$56	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CA	$84	$84	$	$	$	$	$	$	$	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CN	$936	$22	$275	$63	$61	$68	$472	$35	$8	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	IDU	$13	$	$	$	$	$	$	$13	$	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	OR	$511	$	$511	$	$	$	$	$	$	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SG	$75	$1	$19	$6	$9	$12	$33	$4	$2	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SO	$10,489	$242	$2,849	$803	$1,185	$1,481	$4,509	$579	$296	$25	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	UT	$195	$	$	$	$	$	$195	$	$	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WA	$16	$	$	$16	$	$	$	$	$	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYP	$304	$	$	$	$304	$304	$	$	$	$	$	$
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYU	$7	$	$	$	$	$7	$	$	$7	$	$	$
1010000	3910000	OFFICE FURNITURE	CA	$76	$76	$	$	$	$	$	$	$	$	$	$
1010000	3910000	OFFICE FURNITURE	CN	$1,989	$48	$584	$133	$129	$145	$1,004	$75	$17	$	$	$
1010000	3910000	OFFICE FURNITURE	IDU	$111	$	$	$	$	$	$	$111	$	$	$	$
1010000	3910000	OFFICE FURNITURE	OR	$1,799	$	$1,799	$	$	$	$	$	$	$	$	$
1010000	3910000	OFFICE FURNITURE	SG	$2,730	$46	$704	$215	$331	$420	$1,183	$153	$89	$9	$	$
1010000	3910000	OFFICE FURNITURE	SO	$12,242	$283	$3,326	$938	$1,383	$1,729	$5,263	$676	$346	$29	$	$
1010000	3910000	OFFICE FURNITURE	UT	$611	$	$	$	$	$	$611	$	$	$	$	$
1010000	3910000	OFFICE FURNITURE	WA	$544	$	$	$544	$	$	$	$	$	$	$	$
1010000	3910000	OFFICE FURNITURE	WYP	$463	$	$	$	$463	$463	$	$	$	$	$	$
1010000	3910000	OFFICE FURNITURE	WYU	$40	$	$	$	$	$40	$	$	$40	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	$153	$153	$	$	$	$	$	$	$	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	$6,321	$152	$1,856	$424	$409	$462	$3,190	$238	$53	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	$604	$	$	$	$	$	$	$604	$	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	$1,432	$	$1,432	$	$	$	$	$	$	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	$68	$1	$17	$5	$9	$12	$29	$4	$3	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	$1,423	$24	$367	$112	$173	$219	$617	$80	$46	$5	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	$42,397	$980	$11,517	$3,248	$4,788	$5,987	$18,226	$2,341	$1,198	$100	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	$1,852	$	$	$	$	$	$1,852	$	$	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	$873	$	$	$873	$	$	$	$	$	$	$	$
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	$2,319	$	$	$	$2,319	$2,319	$	$	$	$	$	$

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Balance as of June 2011
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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	$53	$	$	$	$	$53	$	$	$53	$	$	$
1010000	3913000	OFFICE EQUIPMENT	CN	$6	$	$2	$	$	$	$3	$	$	$	$	$
1010000	3913000	OFFICE EQUIPMENT	OR	$21	$	$21	$	$	$	$	$	$	$	$	$
1010000	3913000	OFFICE EQUIPMENT	SG	$546	$9	$141	$43	$66	$84	$237	$31	$18	$2	$	$
1010000	3913000	OFFICE EQUIPMENT	SO	$154	$4	$42	$12	$17	$22	$66	$9	$4	$	$	$
1010000	3913000	OFFICE EQUIPMENT	UT	$25	$	$	$	$	$	$25	$	$	$	$	$
1010000	3913000	OFFICE EQUIPMENT	WYP	$18	$	$	$	$18	$18	$	$	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	$95	$95	$	$	$	$	$	$	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	$414	$	$	$	$	$	$	$414	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	$2,036	$	$2,036	$	$	$	$	$	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	$593	$10	$153	$47	$72	$91	$257	$33	$19	$2	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	$1,004	$23	$273	$77	$113	$142	$432	$55	$28	$2	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	$2,566	$	$	$	$	$	$2,566	$	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	$398	$	$	$398	$	$	$	$	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	$485	$	$	$	$485	$485	$	$	$	$	$	$
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYU	$47	$	$	$	$	$47	$	$	$47	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	IDU	$14	$	$	$	$	$	$	$14	$	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	OR	$313	$	$313	$	$	$	$	$	$	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	SG	$54	$1	$14	$4	$7	$8	$23	$3	$2	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	SO	$211	$5	$57	$16	$24	$30	$90	$12	$6	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	UT	$382	$	$	$	$	$	$382	$	$	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	WA	$57	$	$	$57	$	$	$	$	$	$	$	$
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	$119	$	$	$	$119	$119	$	$	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	$556	$556	$	$	$	$	$	$	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	$1,295	$	$	$	$	$	$	$1,295	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	$6,240	$	$6,240	$	$	$	$	$	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	$147	$2	$36	$11	$19	$25	$63	$9	$6	$1	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	$6,517	$110	$1,680	$512	$790	$1,003	$2,824	$366	$213	$21	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	$978	$23	$266	$75	$110	$138	$420	$54	$28	$2	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	$7,605	$	$	$	$	$	$7,605	$	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	$929	$	$	$929	$	$	$	$	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	$1,939	$	$	$	$1,939	$1,939	$	$	$	$	$	$
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	$411	$	$	$	$	$411	$	$	$411	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	$767	$767	$	$	$	$	$	$	$	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	$2,527	$	$	$	$	$	$	$2,527	$	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	$9,208	$	$9,208	$	$	$	$	$	$	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	$206	$3	$50	$15	$27	$35	$89	$13	$8	$1	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	$5,441	$92	$1,403	$428	$660	$838	$2,358	$306	$178	$18	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	$543	$13	$147	$42	$61	$77	$233	$30	$15	$1	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	$14,797	$	$	$	$	$	$14,797	$	$	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	$2,371	$	$	$2,371	$	$	$	$	$	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	$3,157	$	$	$	$3,157	$3,157	$	$	$	$	$	$
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	$719	$	$	$	$	$719	$	$	$719	$	$	$
1010000	3920600	DUMP TRUCKS	OR	$76	$	$76	$	$	$	$	$	$	$	$	$
1010000	3920600	DUMP TRUCKS	SE	$4	$	$1	$	$	$1	$2	$	$	$	$	$
1010000	3920600	DUMP TRUCKS	SG	$3,206	$54	$826	$252	$389	$494	$1,390	$180	$105	$10	$	$
1010000	3920600	DUMP TRUCKS	UT	$125	$	$	$	$	$	$125	$	$	$	$	$
1010000	3920900	TRAILERS	CA	$365	$365	$	$	$	$	$	$	$	$	$	$
1010000	3920900	TRAILERS	IDU	$766	$	$	$	$	$	$	$766	$	$	$	$
1010000	3920900	TRAILERS	OR	$2,863	$	$2,863	$	$	$	$	$	$	$	$	$
1010000	3920900	TRAILERS	SE	$49	$1	$12	$4	$6	$8	$21	$3	$2	$	$	$
1010000	3920900	TRAILERS	SG	$2,178	$37	$561	$171	$264	$335	$944	$122	$71	$7	$	$
1010000	3920900	TRAILERS	SO	$513	$12	$139	$39	$58	$72	$221	$28	$15	$1	$	$
1010000	3920900	TRAILERS	UT	$4,395	$	$	$	$	$	$4,395	$	$	$	$	$
1010000	3920900	TRAILERS	WA	$602	$	$	$602	$	$	$	$	$	$	$	$
1010000	3920900	TRAILERS	WYP	$1,863	$	$	$	$1,863	$1,863	$	$	$	$	$	$
1010000	3920900	TRAILERS	WYU	$306	$	$	$	$	$306	$	$	$306	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	$49	$49	$	$	$	$	$	$	$	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	$50	$	$	$	$	$	$	$50	$	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	$275	$	$275	$	$	$	$	$	$	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	$222	$4	$57	$17	$27	$34	$96	$12	$7	$1	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	$16	$	$4	$1	$2	$2	$7	$1	$	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	$188	$	$	$	$	$	$188	$	$	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	$47	$	$	$47	$	$	$	$	$	$	$	$

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	$103	$	$	$	$103	$103	$	$	$	$	$	$
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	$16	$	$	$	$	$16	$	$	$16	$	$	$
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	$170	$	$170	$	$	$	$	$	$	$	$	$
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	$373	$6	$96	$29	$45	$57	$162	$21	$12	$1	$	$
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	$381	$9	$104	$29	$43	$54	$164	$21	$11	$1	$	$
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	$860	$	$	$	$	$	$860	$	$	$	$	$
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	$170	$	$	$170	$	$	$	$	$	$	$	$
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	$86	$	$	$	$86	$86	$	$	$	$	$	$
1010000	3923000	TRANSPORTATION EQUIPMENT	SO	$3,643	$84	$990	$279	$412	$514	$1,566	$201	$103	$9	$	$
1010000	3930000	STORES EQUIPMENT	CA	$198	$198	$	$	$	$	$	$	$	$	$	$
1010000	3930000	STORES EQUIPMENT	IDU	$442	$	$	$	$	$	$	$442	$	$	$	$
1010000	3930000	STORES EQUIPMENT	OR	$2,673	$	$2,673	$	$	$	$	$	$	$	$	$
1010000	3930000	STORES EQUIPMENT	SG	$4,519	$76	$1,165	$355	$548	$696	$1,959	$254	$148	$15	$	$
1010000	3930000	STORES EQUIPMENT	SO	$325	$8	$88	$25	$37	$46	$140	$18	$9	$1	$	$
1010000	3930000	STORES EQUIPMENT	UT	$3,399	$	$	$	$	$	$3,399	$	$	$	$	$
1010000	3930000	STORES EQUIPMENT	WA	$579	$	$	$579	$	$	$	$	$	$	$	$
1010000	3930000	STORES EQUIPMENT	WYP	$1,053	$	$	$	$1,053	$1,053	$	$	$	$	$	$
1010000	3930000	STORES EQUIPMENT	WYU	$99	$	$	$	$	$99	$	$	$99	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	$757	$757	$	$	$	$	$	$	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	$1,817	$	$	$	$	$	$	$1,817	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	$10,249	$	$10,249	$	$	$	$	$	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	$7	$	$2	$1	$1	$1	$3	$	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	$24,935	$420	$6,427	$1,959	$3,024	$3,839	$10,807	$1,401	$814	$82	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	$3,802	$88	$1,033	$291	$429	$537	$1,634	$210	$107	$9	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	$12,002	$	$	$	$	$	$12,002	$	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	$2,597	$	$	$2,597	$	$	$	$	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	$3,803	$	$	$	$3,803	$3,803	$	$	$	$	$	$
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	$514	$	$	$	$	$514	$	$	$514	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	CA	$431	$431	$	$	$	$	$	$	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	IDU	$1,326	$	$	$	$	$	$	$1,326	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	OR	$9,316	$	$9,316	$	$	$	$	$	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	SE	$8	$	$2	$1	$1	$1	$3	$	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	SG	$6,596	$111	$1,700	$518	$800	$1,015	$2,859	$371	$215	$22	$	$
1010000	3950000	LABORATORY EQUIPMENT	SO	$5,706	$132	$1,550	$437	$644	$806	$2,453	$315	$161	$13	$	$
1010000	3950000	LABORATORY EQUIPMENT	UT	$7,161	$	$	$	$	$	$7,161	$	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	WA	$1,861	$	$	$1,861	$	$	$	$	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	WYP	$2,809	$	$	$	$2,809	$2,809	$	$	$	$	$	$
1010000	3950000	LABORATORY EQUIPMENT	WYU	$614	$	$	$	$	$614	$	$	$614	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	$936	$936	$	$	$	$	$	$	$	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	$1,410	$	$	$	$	$	$	$1,410	$	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	$3,849	$	$3,849	$	$	$	$	$	$	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	$456	$8	$118	$36	$55	$70	$198	$26	$15	$1	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	$3,736	$	$	$	$	$	$3,736	$	$	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	$1,004	$	$	$1,004	$	$	$	$	$	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	$1,900	$	$	$	$1,900	$1,900	$	$	$	$	$	$
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	$489	$	$	$	$	$489	$	$	$489	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	$173	$173	$	$	$	$	$	$	$	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	$171	$	$	$	$	$	$	$171	$	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	$833	$	$833	$	$	$	$	$	$	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	$124	$2	$32	$10	$15	$19	$54	$7	$4	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	$1,740	$	$	$	$	$	$1,740	$	$	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	$205	$	$	$	$205	$205	$	$	$	$	$	$
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	$210	$	$	$	$	$210	$	$	$210	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	$1,510	$1,510	$	$	$	$	$	$	$	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	$2,366	$	$	$	$	$	$	$2,366	$	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	$12,924	$	$12,924	$	$	$	$	$	$	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	$1,215	$20	$313	$95	$147	$187	$527	$68	$40	$4	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	$13,427	$	$	$	$	$	$13,427	$	$	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	$3,270	$	$	$3,270	$	$	$	$	$	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	$3,763	$	$	$	$3,763	$3,763	$	$	$	$	$	$
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	$967	$	$	$	$	$967	$	$	$967	$	$	$
1010000	3961000	CRANES	OR	$368	$	$368	$	$	$	$	$	$	$	$	$
1010000	3961000	CRANES	SG	$3,482	$59	$898	$274	$422	$536	$1,509	$196	$114	$11	$	$
1010000	3961000	CRANES	SO	$43	$1	$12	$3	$5	$6	$19	$2	$1	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Plant in Service with Unclassified Plant (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3961000	CRANES	UT	$3	$	$	$	$	$	$3	$	$	$	$	$
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	$928	$	$928	$	$	$	$	$	$	$	$	$
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SE	$35	$1	$9	$3	$5	$6	$15	$2	$1	$	$	$
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	$24,125	$406	$6,219	$1,896	$2,926	$3,714	$10,456	$1,356	$788	$79	$	$
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	$844	$19	$229	$65	$95	$119	$363	$47	$24	$2	$	$
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	$1,028	$	$	$	$	$	$1,028	$	$	$	$	$
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	$164	$	$	$	$164	$164	$	$	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	$689	$689	$	$	$	$	$	$	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	$1,957	$	$	$	$	$	$	$1,957	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	$8,831	$	$8,831	$	$	$	$	$	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	$154	$3	$40	$12	$19	$24	$67	$9	$5	$1	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	$143	$3	$39	$11	$16	$20	$61	$8	$4	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	$11,590	$	$	$	$	$	$11,590	$	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	$1,908	$	$	$1,908	$	$	$	$	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	$3,132	$	$	$	$3,132	$3,132	$	$	$	$	$	$
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	$507	$	$	$	$	$507	$	$	$507	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	$399	$399	$	$	$	$	$	$	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	$1,062	$	$	$	$	$	$	$1,062	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	$1,576	$	$1,576	$	$	$	$	$	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	$10	$	$2	$1	$1	$2	$4	$1	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	$5,110	$86	$1,317	$402	$620	$787	$2,215	$287	$167	$17	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	$107	$2	$29	$8	$12	$15	$46	$6	$3	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	$3,471	$	$	$	$	$	$3,471	$	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	$578	$	$	$578	$	$	$	$	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	$977	$	$	$	$977	$977	$	$	$	$	$	$
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	$648	$	$	$	$	$648	$	$	$648	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	CA	$2,889	$2,889	$	$	$	$	$	$	$	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	CN	$2,855	$69	$838	$191	$185	$208	$1,441	$107	$24	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	IDU	$6,522	$	$	$	$	$	$	$6,522	$	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	OR	$36,013	$	$36,013	$	$	$	$	$	$	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	SE	$125	$2	$30	$9	$17	$21	$54	$8	$5	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	SG	$100,624	$1,693	$25,938	$7,906	$12,205	$15,490	$43,612	$5,654	$3,286	$329	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	SO	$57,422	$1,327	$15,599	$4,399	$6,485	$8,108	$24,684	$3,170	$1,623	$135	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	UT	$33,207	$	$	$	$	$	$33,207	$	$	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	WA	$9,126	$	$	$9,126	$	$	$	$	$	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	WYP	$16,825	$	$	$	$16,825	$16,825	$	$	$	$	$	$
1010000	3970000	COMMUNICATION EQUIPMENT	WYU	$3,335	$	$	$	$	$3,335	$	$	$3,335	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	CA	$28	$28	$	$	$	$	$	$	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	IDU	$100	$	$	$	$	$	$	$100	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	OR	$485	$	$485	$	$	$	$	$	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	SE	$1	$	$	$	$	$	$1	$	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	SG	$431	$7	$111	$34	$52	$66	$187	$24	$14	$1	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	SO	$420	$10	$114	$32	$47	$59	$181	$23	$12	$1	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	UT	$1,179	$	$	$	$	$	$1,179	$	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	WA	$284	$	$	$284	$	$	$	$	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	WYP	$392	$	$	$	$392	$392	$	$	$	$	$	$
1010000	3972000	MOBILE RADIO EQUIPMENT	WYU	$38	$	$	$	$	$38	$	$	$38	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	CA	$40	$40	$	$	$	$	$	$	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	CN	$213	$5	$62	$14	$14	$16	$107	$8	$2	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	IDU	$64	$	$	$	$	$	$	$64	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	OR	$670	$	$670	$	$	$	$	$	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	SE	$2	$	$	$	$	$	$1	$	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	SG	$1,911	$32	$492	$150	$232	$294	$828	$107	$62	$6	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	SO	$2,924	$68	$794	$224	$330	$413	$1,257	$161	$83	$7	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	UT	$431	$	$	$	$	$	$431	$	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	WA	$127	$	$	$127	$	$	$	$	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	WYP	$170	$	$	$	$170	$170	$	$	$	$	$	$
1010000	3980000	MISCELLANEOUS EQUIPMENT	WYU	$19	$	$	$	$	$19	$	$	$19	$	$	$
1010000	3992100	LAND OWNED IN FEE	SE	$2,635	$41	$641	$194	$349	$447	$1,136	$166	$99	$10	$	$
1010000	3992200	LAND RIGHTS	SE	$52,551	$818	$12,777	$3,872	$6,951	$8,924	$22,648	$3,315	$1,973	$196	$	$
1010000	3993000	"ENGINEERING SUPP-OFF WORK(SECY,MAP,DRAF	SE	$39,997	$623	$9,725	$2,947	$5,291	$6,793	$17,237	$2,523	$1,502	$149	$	$
1010000	3994100	SURFACE - PLANT EQUIPMENT	SE	$12,776	$199	$3,106	$941	$1,690	$2,170	$5,506	$806	$480	$48	$	$
1010000	3994400	SURFACE - ELECTRIC POWER FACILITIES	SE	$3,425	$53	$833	$252	$453	$582	$1,476	$216	$129	$13	$	$
1010000	3994500	UNDERGROUND - COAL MINE EQUIPMENT	SE	$72,360	$1,127	$17,593	$5,332	$9,571	$12,289	$31,185	$4,565	$2,717	$270	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Plant in Service with Unclassified Plant (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1010000	3994600	LONGWALL SHIELDS	SE	$24,482	$381	$5,952	$1,804	$3,238	$4,158	$10,551	$1,545	$919	$91	$	$
1010000	3994700	LONGWALL EQUIPMENT	SE	$7,815	$122	$1,900	$576	$1,034	$1,327	$3,368	$493	$293	$29	$	$
1010000	3994800	MAINLINE EXTENSION	SE	$18,671	$291	$4,540	$1,376	$2,470	$3,171	$8,047	$1,178	$701	$70	$	$
1010000	3994900	SECTION EXTENSION	SE	$4,516	$70	$1,098	$333	$597	$767	$1,946	$285	$170	$17	$	$
1010000	3995100	VEHICLES	SE	$1,238	$19	$301	$91	$164	$210	$534	$78	$46	$5	$	$
1010000	3995200	HEAVY CONSTRUCTION EQUIPMENT	SE	$5,306	$83	$1,290	$391	$702	$901	$2,287	$335	$199	$20	$	$
1010000	3996000	MISCELLANEOUS GENERAL EQUIPMENT	SE	$2,241	$35	$545	$165	$296	$381	$966	$141	$84	$8	$	$
1010000	3996100	COMPUTERS - MAINFRAME	SE	$503	$8	$122	$37	$67	$85	$217	$32	$19	$2	$	$
1010000	3997000	MINE DEVELOPMENT AND ROAD EXTENSION	SE	$38,147	$594	$9,275	$2,811	$5,046	$6,478	$16,440	$2,407	$1,432	$142	$	$
1010000 Total				**$22,073,910**	**$507,601**	**$6,017,664**	**$1,700,541**	**$2,473,555**	**$3,097,528**	**$9,486,751**	**$1,212,189**	**$623,973**	**$51,635**	**$**	**$**
1019000	140139	PRODUCTION PLANT-NON-RECONCILED	SG	-$4,995	-$84	-$1,288	-$393	-$606	-$769	-$2,165	-$281	-$163	-$16	$	$
1019000	140139	PRODUCTION PLANT-NON-RECONCILED	SG-I	$	$	$	$	$	$	$	$	$	$	$	$
1019000	140149	TRANS PLANT NON-RECONCILED	SG	-$1,803	-$30	-$465	-$142	-$219	-$278	-$781	-$101	-$59	-$6	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	CA	-$59	-$59	$	$	$	$	$	$	$	$	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	IDU	$13	$	$	$	$	$	$	$13	$	$	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	OR	$224	$	$224	$	$	$	$	$	$	$	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	SNP	$	$	$	$	$	$	$	$	$	$	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	UT	-$858	$	$	$	$	$	-$858	$	$	$	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	WA	-$182	$	$	-$182	$	$	$	$	$	$	$	$
1019000	140169	DISTRIBN- NON-RECONCILED	WYU	-$322	$	$	$	$	-$322	$	$	-$322	$	$	$
1019000	140189	MOTOR VEH/MOBILE PLANT - IN SERVICE-NON-	SG	$	$	$	$	$	$	$	$	$	$	$	$
1019000	140189	MOTOR VEH/MOBILE PLANT - IN SERVICE-NON-	SO	-$3,490	-$81	-$948	-$267	-$394	-$493	-$1,500	-$193	-$99	-$8	$	$
1019000	140209	ELECTRIC PLANT IN SERVICE - OTHER	SG	-$54	-$1	-$14	-$4	-$6	-$8	-$23	-$3	-$2	$	$	$
1019000	141209	OTHER INTANGIBLE NON-RECONCILED	SO	$	$	$	$	$	$	$	$	$	$	$	$
1019000 Total				**-$11,525**	**-$254**	**-$2,490**	**-$988**	**-$1,225**	**-$1,870**	**-$5,328**	**-$564**	**-$645**	**-$31**	**$**	**$**
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	$691	$691	$	$	$	$	$	$	$	$	$	$
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	$1,879	$	$	$	$	$	$	$1,879	$	$	$	$
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	$4,626	$	$4,626	$	$	$	$	$	$	$	$	$
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	$12,820	$	$	$	$	$	$12,820	$	$	$	$	$
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	$988	$	$	$988	$	$	$	$	$	$	$	$
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	$4,023	$	$	$	$	$4,023	$	$	$4,023	$	$	$
1061000 Total				**$25,028**	**$691**	**$4,626**	**$988**	**$**	**$4,023**	**$12,820**	**$1,879**	**$4,023**	**$**	**$**	**$**
1062000	0	TRANSM COMPLETED CONSTRUCTN NOT CLASSIFI	SG	$54,616	$919	$14,078	$4,291	$6,624	$8,408	$23,672	$3,069	$1,783	$179	$	$
1062000 Total				**$54,616**	**$919**	**$14,078**	**$4,291**	**$6,624**	**$8,408**	**$23,672**	**$3,069**	**$1,783**	**$179**	**$**	**$**
1063000	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	$10,216	$172	$2,633	$803	$1,239	$1,573	$4,428	$574	$334	$33	$	$
1063000 Total				**$10,216**	**$172**	**$2,633**	**$803**	**$1,239**	**$1,573**	**$4,428**	**$574**	**$334**	**$33**	**$**	**$**
1064000	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSIF	SO	$5,039	$116	$1,369	$386	$569	$712	$2,166	$278	$142	$12	$	$
1064000 Total				**$5,039**	**$116**	**$1,369**	**$386**	**$569**	**$712**	**$2,166**	**$278**	**$142**	**$12**	**$**	**$**
Grand Total				**$22,157,284**	**$509,245**	**$6,037,881**	**$1,706,021**	**$2,480,763**	**$3,110,373**	**$9,524,509**	**$1,217,425**	**$629,611**	**$51,829**	**$**	**$**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Capital Lease (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1011000	3908000	CAPITAL LEASE COMMON	OR	$5,882	$	$5,882	$	$	$	$	$	$	$	$	$
1011000	3908000	CAPITAL LEASE COMMON	SG	$33,745	$568	$8,698	$2,651	$4,093	$5,195	$14,626	$1,896	$1,102	$110	$	$
1011000	3908000	CAPITAL LEASE COMMON	SO	$12,664	$293	$3,440	$970	$1,430	$1,788	$5,444	$699	$358	$30	$	$
1011000	3908000	CAPITAL LEASE COMMON	UT	$11,714	$	$	$	$	$	$11,714	$	$	$	$	$
1011000	3908000	CAPITAL LEASE COMMON	WYP	$1,388	$	$	$	$1,388	$1,388	$	$	$	$	$	$
1011000 Total				**$65,393**	**$860**	**$18,021**	**$3,622**	**$6,911**	**$8,371**	**$31,784**	**$2,595**	**$1,460**	**$140**	**$**	**$**
1110000	3908000	CAPITAL LEASE COMMON	OR	-$2,003	$	-$2,003	$	$	$	$	$	$	$	$	$
1110000	3908000	CAPITAL LEASE COMMON	SG	-$4,391	-$74	-$1,132	-$345	-$533	-$676	-$1,903	-$247	-$143	-$14	$	$
1110000	3908000	CAPITAL LEASE COMMON	SO	$1,056	$24	$287	$81	$119	$149	$454	$58	$30	$2	$	$
1110000	3908000	CAPITAL LEASE COMMON	UT	-$2,695	$	$	$	$	$	-$2,695	$	$	$	$	$
1110000	3908000	CAPITAL LEASE COMMON	WYP	-$795	$	$	$	-$795	-$795	$	$	$	$	$	$
1110000 Total				**-$8,827**	**-$49**	**-$2,848**	**-$264**	**-$1,208**	**-$1,322**	**-$4,144**	**-$188**	**-$114**	**-$12**	**$**	**$**
Grand Total				**$56,566**	**$811**	**$15,173**	**$3,357**	**$5,703**	**$7,049**	**$27,640**	**$2,407**	**$1,346**	**$128**	**$**	**$**

B10. PLANT HELD FOR FUTURE USE

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Plant Held for Future Use (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC
1050000	3401000	LAND OWNED IN FEE	SG	$8,923	$150	$2,300	$701	$1,374	$3,868	$501	$29
1050000	3501000	LAND OWNED IN FEE	SG	$2,788	$47	$719	$219	$429	$1,209	$157	$9
1050000	3502000	LAND RIGHTS	SG	$156	$3	$40	$12	$24	$68	$9	$1
1050000	3601000	LAND OWNED IN FEE	OR	$746	$	$746	$	$	$	$	$
1050000	3601000	LAND OWNED IN FEE	UT	$2,920	$	$	$	$	$2,920	$	$
1050000	3891000	LAND OWNED IN FEE	OR	$3,508	$	$3,508	$	$	$	$	$
1050000	3992200	LAND RIGHTS	SE	$953	$15	$232	$70	$162	$411	$60	$4
1059000	0	ELECTRIC PLANT HELD FOR FUTURE USE-OTHER	SE	$25,026	$390	$6,085	$1,844	$4,250	$10,785	$1,579	$93
Grand Total				**$45,021**	**$604**	**$13,630**	**$2,847**	**$6,239**	**$19,260**	**$2,306**	**$136**

B11. MISC. DEFERRED DEBTS

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Debits (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1861000	185016	EMISSION REDUCTION CREDITS PURCHASED	SE	$591	$9	$144	$44	$78	$100	$255	$37	$22	$2	$
1861000 Total				**$591**	**$9**	**$144**	**$44**	**$78**	**$100**	**$255**	**$37**	**$22**	**$2**	**$**
1861200	185025	FINANCING COST DEFERRED	SO	$	$	$	$	$	$	$	$	$	$	$
1861200	185026	DEFERRED - S-3 SHELF REGISTRATION COSTS	SO	$	$	$	$	$	$	$	$	$	$	$
1861200	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	$823	$	$	$	$	$	$	$	$	$	$823
1861200	185028	UNAMORTIZED PCRB LOC/SBBPA COSTS	OTHER	$290	$	$	$	$	$	$	$	$	$	$290
1861200	185029	UNAMORTIZED PCRB MADE CONVERSION COSTS	OTHER	$341	$	$	$	$	$	$	$	$	$	$341
1861200	185030	UNAMORTIZED '94 SERIES RESTRUCTURING COS	OTHER	$930	$	$	$	$	$	$	$	$	$	$930
1861200 Total				**$2,384**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$2,384**
1861310	184690	Deferred Development Costs	SG	$	$	$	$	$	$	$	$	$	$	$
1861310 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1863500	188498	ENVIRONMENTAL DEFERRED	SO	$	$	$	$	$	$	$	$	$	$	$
1863500 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1865000	134200	Deferred Longwall Costs	SE	$1,028	$16	$250	$76	$136	$175	$443	$65	$39	$4	$
1865000	184404	TRAIL MOUNTAIN - DRILLING	SE	$	$	$	$	$	$	$	$	$	$	$
1865000	184405	BRIDGER DEFERRED BILLINGS	SE	$	$	$	$	$	$	$	$	$	$	$
1865000	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	SE	$3,855	$60	$937	$284	$510	$655	$1,661	$243	$145	$14	$
1865000	184416	Deferred Coal Costs - Naughton Contract	SE	$7,569	$118	$1,840	$558	$1,001	$1,285	$3,262	$478	$284	$28	$
1865000 Total				**$12,451**	**$194**	**$3,027**	**$917**	**$1,647**	**$2,115**	**$5,366**	**$786**	**$468**	**$46**	**$**
1867000	134300	DEFERRED CHARGES	SE	$94	$1	$23	$7	$12	$16	$40	$6	$4	$	$
1867000 Total				**$94**	**$1**	**$23**	**$7**	**$12**	**$16**	**$40**	**$6**	**$4**	**$**	**$**
1868000	134360	LAKE SIDE MAINT. PREPAYMENT - CURRENT	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	134361	PREPAID OUTAGE MAINTENANCE	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	185303	HPT OPTION	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	185306	TGS BUYOUT	SG	$133	$2	$34	$10	$16	$20	$58	$7	$4	$	$
1868000	185309	LAKEVIEW BUYOUT	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	185310	BUFFALO SETTLEMENT	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	185311	JOSEPH SETTLEMENT	SG	$904	$15	$233	$71	$110	$139	$392	$51	$30	$3	$
1868000	185312	TRI-STATE FIRM WHEELING	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	185313	MEAD-PHOENIX-AVAILABILITY & TRANS CHARGE	SG	$13,568	$228	$3,497	$1,066	$1,646	$2,089	$5,881	$762	$443	$44	$
1868000	185318	BOGUS CREEK SETTLEMENT	SG	$	$	$	$	$	$	$	$	$	$	$
1868000	185335	LACOMB IRRIGATION	SG	$484	$8	$125	$38	$59	$74	$210	$27	$16	$2	$
1868000	185336	BOGUS CREEK	SG	$1,180	$20	$304	$93	$143	$182	$511	$66	$39	$4	$
1868000	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	$4,438	$75	$1,144	$349	$538	$683	$1,923	$249	$145	$15	$
1868000	185340	TRANSITION COSTS - WASHINGTON STATE	WA	$	$	$	$	$	$	$	$	$	$	$
1868000	185342	JIM BOYD HYDRO BUYOUT	SG	$214	$4	$55	$17	$26	$33	$93	$12	$7	$1	$
1868000	185349	LGIA LT Transmission Prepaid	OTHER	$2,506	$	$	$	$	$	$	$	$	$	$2,506
1868000	185351	BPA LT TRANSMISSION PREPAID	OTHER	$8,860	$	$	$	$	$	$	$	$	$	$8,860
1868000	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	$8,231	$139	$2,122	$647	$998	$1,267	$3,567	$462	$269	$27	$
1868000	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	$5,927	$100	$1,528	$466	$719	$912	$2,569	$333	$194	$19	$
1868000	185362	LT Currant Creek CSA Maint Prepayment	SG	$8,523	$143	$2,197	$670	$1,034	$1,312	$3,694	$479	$278	$28	$
1868000 Total				**$54,968**	**$734**	**$11,239**	**$3,426**	**$5,289**	**$6,712**	**$18,898**	**$2,450**	**$1,424**	**$143**	**$11,366**
1868200	184441	DEFERRED MONTANA COLSTRIP PLANT COSTS	SG	$1,375	$23	$354	$108	$167	$212	$596	$77	$45	$5	$
1868200 Total				**$1,375**	**$23**	**$354**	**$108**	**$167**	**$212**	**$596**	**$77**	**$45**	**$5**	**$**
1869000	135033	BETC SUPER GOOD CENTS	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	135034	BETC WZ TAX CREDIT LOAN PROGRAM	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	135037	BETC INDUSTRIAL FINANSWER	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	135039	BETC CASH REBATE/INCENTIVE	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	135049	BETC - COMMERCIAL RETROFIT	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	135051	BETC - COMMERCIAL SMALL RETROFIT	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	135052	BETC-INDUSTRIAL SMALL RETRO FIT	OTHER	$	$	$	$	$	$	$	$	$	$	$
1869000	185326	STRATEGIC PLANNING SOLAR II PROJECT	SG	$	$	$	$	$	$	$	$	$	$	$
1869000	185327	FIRTH COGENERATION BUYOUT	SG	$	$	$	$	$	$	$	$	$	$	$
1869000	185329	Firth Cogeneration Buyout-MT	SG	$	$	$	$	$	$	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Debits (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1869000	185333	OPTION PURCHASES	SG	$	$	$	$	$	$	$	$	$	$	$
1869000	185334	HERMISTON SWAP	SG	$4,307	$72	$1,110	$338	$522	$663	$1,867	$242	$141	$14	$
1869000	185345	YAKIMA HYDRO - TRANSACTION COSTS	SG	$	$	$	$	$	$	$	$	$	$	$
1869000 Total				**$4,307**	**$72**	**$1,110**	**$338**	**$522**	**$663**	**$1,867**	**$242**	**$141**	**$14**	**$**
Grand Total				**$76,170**	**$1,034**	**$15,898**	**$4,840**	**$7,715**	**$9,818**	**$27,022**	**$3,598**	**$2,103**	**$210**	**$13,750**

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PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Material & Supplies (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1511100	0	COAL INVENTORY - CARBON	SE	$2,195	$34	$534	$162	$290	$373	$946	$138	$82	$8
1511100 Total				**$2,195**	**$34**	**$534**	**$162**	**$290**	**$373**	**$946**	**$138**	**$82**	**$8**
1511120	0	COAL INVENTORY - HUNTER	SE	$62,958	$980	$15,307	$4,639	$8,328	$10,692	$27,133	$3,972	$2,364	$235
1511120 Total				**$62,958**	**$980**	**$15,307**	**$4,639**	**$8,328**	**$10,692**	**$27,133**	**$3,972**	**$2,364**	**$235**
1511130	0	COAL INVENTORY - HUNTINGTON	SE	$25,574	$398	$6,218	$1,884	$3,383	$4,343	$11,022	$1,614	$960	$95
1511130 Total				**$25,574**	**$398**	**$6,218**	**$1,884**	**$3,383**	**$4,343**	**$11,022**	**$1,614**	**$960**	**$95**
1511140	0	COAL INVENTORY - JIM BRIDGER	SE	$33,739	$525	$8,203	$2,486	$4,463	$5,730	$14,540	$2,129	$1,267	$126
1511140 Total				**$33,739**	**$525**	**$8,203**	**$2,486**	**$4,463**	**$5,730**	**$14,540**	**$2,129**	**$1,267**	**$126**
1511160	0	COAL INVENTORY - NAUGHTON	SE	$9,005	$140	$2,190	$664	$1,191	$1,529	$3,881	$568	$338	$34
1511160 Total				**$9,005**	**$140**	**$2,190**	**$664**	**$1,191**	**$1,529**	**$3,881**	**$568**	**$338**	**$34**
1511170	0	COAL INVENTORY - COAL PREP PLANT	SE	$35,710	$556	$8,682	$2,631	$4,724	$6,065	$15,390	$2,253	$1,341	$133
1511170 Total				**$35,710**	**$556**	**$8,682**	**$2,631**	**$4,724**	**$6,065**	**$15,390**	**$2,253**	**$1,341**	**$133**
1511180	0	COAL INVENTORY - WYODAK	SE	$	$	$	$	$	$	$	$	$	$
1511180 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1511200	0	COAL INVENTORY - CHOLLA	SE	$10,592	$165	$2,575	$780	$1,401	$1,799	$4,565	$668	$398	$40
1511200 Total				**$10,592**	**$165**	**$2,575**	**$780**	**$1,401**	**$1,799**	**$4,565**	**$668**	**$398**	**$40**
1511300	0	COAL INVENTORY - COLSTIP	SE	$1,392	$22	$338	$103	$184	$236	$600	$88	$52	$5
1511300 Total				**$1,392**	**$22**	**$338**	**$103**	**$184**	**$236**	**$600**	**$88**	**$52**	**$5**
1511400	0	COAL INVENTORY - CRAIG	SE	$6,029	$94	$1,466	$444	$797	$1,024	$2,598	$380	$226	$22
1511400 Total				**$6,029**	**$94**	**$1,466**	**$444**	**$797**	**$1,024**	**$2,598**	**$380**	**$226**	**$22**
1511500	0	COAL INVENTORY - DEER CREEK	SE	$31	$	$8	$2	$4	$5	$13	$2	$1	$
1511500 Total				**$31**	**$**	**$8**	**$2**	**$4**	**$5**	**$13**	**$2**	**$1**	**$**
1511600	0	COAL INVENTORY - DAVE JOHNSTON	SE	$8,712	$136	$2,118	$642	$1,152	$1,480	$3,755	$550	$327	$33
1511600 Total				**$8,712**	**$136**	**$2,118**	**$642**	**$1,152**	**$1,480**	**$3,755**	**$550**	**$327**	**$33**
1511700	0	COAL INVENTORY ROCK GARDEN PILE	SE	$17,121	$267	$4,163	$1,262	$2,265	$2,908	$7,379	$1,080	$643	$64
1511700 Total				**$17,121**	**$267**	**$4,163**	**$1,262**	**$2,265**	**$2,908**	**$7,379**	**$1,080**	**$643**	**$64**
1511800	0	COAL INVENTORY	SE	$	$	$	$	$	$	$	$	$	$
1511800 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1511900	0	COAL INVENTORY - HAYDEN	SE	$2,231	$35	$542	$164	$295	$379	$961	$141	$84	$8
1511900 Total				**$2,231**	**$35**	**$542**	**$164**	**$295**	**$379**	**$961**	**$141**	**$84**	**$8**
1512000	0	NATURAL GAS	SE	$	$	$	$	$	$	$	$	$	$
1512000 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512110	0	NATURAL GAS - HERMISTON	SE	$557	$9	$135	$41	$74	$95	$240	$35	$21	$2
1512110 Total				**$557**	**$9**	**$135**	**$41**	**$74**	**$95**	**$240**	**$35**	**$21**	**$2**
1512150	0	NATURAL GAS - LITTLE MOUNTAIN	SE	$	$	$	$	$	$	$	$	$	$
1512150 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512160	0	NATURAL GAS - NAUGHTON	SE	$	$	$	$	$	$	$	$	$	$
1512160 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512170	0	NATURAL GAS - WEST VALLEY	SE	$	$	$	$	$	$	$	$	$	$
1512170 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512180	0	NATURAL GAS - CLAY BASIN	SE	$2,820	$44	$686	$208	$373	$479	$1,215	$178	$106	$11
1512180 Total				**$2,820**	**$44**	**$686**	**$208**	**$373**	**$479**	**$1,215**	**$178**	**$106**	**$11**
1512190	0	NATURAL GAS - CHEHALIS	SE	$	$	$	$	$	$	$	$	$	$
1512190 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512210	0	Natural Gas Inventory-Jackson Prairie	SE	$	$	$	$	$	$	$	$	$	$
1512210 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512700	0	NATURAL GAS - GADSBY	SE	$	$	$	$	$	$	$	$	$	$
1512700 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1512800	0	OIL INVENTORY - BLACK HILLS POWER & LIGH	SE	$413	$6	$100	$30	$55	$70	$178	$26	$15	$2
1512800 Total				**$413**	**$6**	**$100**	**$30**	**$55**	**$70**	**$178**	**$26**	**$15**	**$2**
1514000	0	FUEL STOCK COAL MINE	SE	$3,717	$58	$904	$274	$492	$631	$1,602	$234	$140	$14
1514000 Total				**$3,717**	**$58**	**$904**	**$274**	**$492**	**$631**	**$1,602**	**$234**	**$140**	**$14**
1514300	0	OIL INVENTORY - COLSTRIP	SE	$123	$2	$30	$9	$16	$21	$53	$8	$5	$
1514300 Total				**$123**	**$2**	**$30**	**$9**	**$16**	**$21**	**$53**	**$8**	**$5**	**$**
1514400	0	OIL INVENTORY - CRAIG	SE	$62	$1	$15	$5	$8	$11	$27	$4	$2	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Material & Supplies (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1514400 Total				**$62**	**$1**	**$15**	**$5**	**$8**	**$11**	**$27**	**$4**	**$2**	**$**
1514800	0	OIL INVENTORY - OTHER	SE	$	$	$	$	$	$	$	$	$	$
1514800 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1514900	0	OIL INVENTORY - HAYDEN	SE	$73	$1	$18	$5	$10	$12	$32	$5	$3	$
1514900 Total				**$73**	**$1**	**$18**	**$5**	**$10**	**$12**	**$32**	**$5**	**$3**	**$**
1541000	0	MATERIAL CONTROL ADJUST	SO	-$148	-$3	-$40	-$11	-$17	-$21	-$64	-$8	-$4	$
1541000	1510	JIM BRIDGER STORE ROOM	SG	$17,603	$296	$4,538	$1,383	$2,135	$2,710	$7,630	$989	$575	$58
1541000	1515	DAVE JOHNSTON STORE ROOM	SG	$9,147	$154	$2,358	$719	$1,110	$1,408	$3,965	$514	$299	$30
1541000	1520	WYODAK STORE ROOM	SG	$4,482	$75	$1,155	$352	$544	$690	$1,943	$252	$146	$15
1541000	1525	GADSBY STORE ROOM	SG	$4,285	$72	$1,105	$337	$520	$660	$1,857	$241	$140	$14
1541000	1530	CARBON STORE ROOM	SG	$3,922	$66	$1,011	$308	$476	$604	$1,700	$220	$128	$13
1541000	1535	NAUGHTON STORE ROOM	SG	$12,273	$207	$3,164	$964	$1,489	$1,889	$5,319	$690	$401	$40
1541000	1540	HUNTINGTON STORE ROOM	SG	$12,323	$207	$3,177	$968	$1,495	$1,897	$5,341	$692	$402	$40
1541000	1545	HUNTER STORE ROOM	SG	$20,043	$337	$5,167	$1,575	$2,431	$3,086	$8,687	$1,126	$654	$66
1541000	1550	BLUNDELL STORE ROOM	SG	$980	$17	$253	$77	$119	$151	$425	$55	$32	$3
1541000	1560	WEST VALLEY GAS PLANT	SG	$	$	$	$	$	$	$	$	$	$
1541000	1565	CURRANT CREEK PLANT	SG	$2,905	$49	$749	$228	$352	$447	$1,259	$163	$95	$10
1541000	1570	LAKESIDE PLANT	SG	$2,461	$41	$634	$193	$298	$379	$1,067	$138	$80	$8
1541000	1580	CHEHALIS PLANT	SG	$2,333	$39	$601	$183	$283	$359	$1,011	$131	$76	$8
1541000	1605	HYDRO NORTH - LEWIS RIVER	SG	$	$	$	$	$	$	$	$	$	$
1541000	1635	HYDRO SOUTH - NORTH UMPQUA	SG	$	$	$	$	$	$	$	$	$	$
1541000	1650	HYDRO SOUTH - KLAMATH RIVER - CA	SG	$	$	$	$	$	$	$	$	$	$
1541000	1675	HYDRO EAST - UTAH	SG	$	$	$	$	$	$	$	$	$	$
1541000	1700	LEANING JUNIPER STOREROOM	SG	$834	$14	$215	$66	$101	$128	$361	$47	$27	$3
1541000	1705	GOODNOE HILLS WIND	SG	$486	$8	$125	$38	$59	$75	$211	$27	$16	$2
1541000	1715	MARENGO WIND	SG	$415	$7	$107	$33	$50	$64	$180	$23	$14	$1
1541000	1725	Glenrock/Rolling Hills	SG	$1,379	$23	$356	$108	$167	$212	$598	$78	$45	$5
1541000	1730	Seven Mile Hill	SG	$690	$12	$178	$54	$84	$106	$299	$39	$23	$2
1541000	1740	High Plains/McFadden	SG	$357	$6	$92	$28	$43	$55	$155	$20	$12	$1
1541000	1745	Dunlap Wind Project	SG	$186	$3	$48	$15	$23	$29	$81	$10	$6	$1
1541000	1799	WIND OFFICE	SG	$1	$	$	$	$	$	$	$	$	$
1541000	2005	CASPER STORE ROOM	WYP	$456	$	$	$	$456	$456	$	$	$	$
1541000	2010	BUFFALO STORE ROOM	WYP	$156	$	$	$	$156	$156	$	$	$	$
1541000	2015	DOUGLAS STORE ROOM	WYP	$322	$	$	$	$322	$322	$	$	$	$
1541000	2020	CODY STORE ROOM	WYP	$711	$	$	$	$711	$711	$	$	$	$
1541000	2030	WORLAND STORE ROOM	WYP	$726	$	$	$	$726	$726	$	$	$	$
1541000	2035	RIVERTON STORE ROOM	WYP	$345	$	$	$	$345	$345	$	$	$	$
1541000	2040	EVANSTON STORE ROOM	WYU	$758	$	$	$	$	$758	$	$	$758	$
1541000	2045	KEMMERER STORE ROOM	WYU	$11	$	$	$	$	$11	$	$	$11	$
1541000	2050	PINEDALE STORE ROOM	WYU	$622	$	$	$	$	$622	$	$	$622	$
1541000	2060	ROCK SPRINGS STORE ROOM	WYP	$1,382	$	$	$	$1,382	$1,382	$	$	$	$
1541000	2065	RAWLINS STORE ROOM	WYP	$597	$	$	$	$597	$597	$	$	$	$
1541000	2070	LARAMIE STORE ROOM	WYP	$313	$	$	$	$313	$313	$	$	$	$
1541000	2075	REXBERG STORE ROOM	IDU	$1,179	$	$	$	$	$	$	$1,179	$	$
1541000	2085	SHELLY STORE ROOM	IDU	$702	$	$	$	$	$	$	$702	$	$
1541000	2090	PRESTON STORE ROOM	IDU	$104	$	$	$	$	$	$	$104	$	$
1541000	2095	LAVA HOT SPRINGS STORE ROOM	IDU	$162	$	$	$	$	$	$	$162	$	$
1541000	2100	MONTPELIER STORE ROOM	IDU	$209	$	$	$	$	$	$	$209	$	$
1541000	2110	BRIDGERLAND STORE ROOM	UT	$567	$	$	$	$	$	$567	$	$	$
1541000	2205	TREMONTON STORE ROOM	UT	$213	$	$	$	$	$	$213	$	$	$
1541000	2210	OGDEN STORE ROOM	UT	$1,373	$	$	$	$	$	$1,373	$	$	$
1541000	2215	LAYTON STORE ROOM	UT	$524	$	$	$	$	$	$524	$	$	$
1541000	2220	SALT LAKE METRO STORE ROOM	UT	$9,246	$	$	$	$	$	$9,246	$	$	$
1541000	2225	SALT LAKE TOOL ROOM	UT	$202	$	$	$	$	$	$202	$	$	$
1541000	2230	JORDAN VALLEY STORE ROOM	UT	$1,469	$	$	$	$	$	$1,469	$	$	$
1541000	2235	PARK CITY STORE ROOM	UT	$689	$	$	$	$	$	$689	$	$	$

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1541000	2240	TOOELE STORE ROOM	UT	$496	$	$	$	$	$	$496	$	$	$
1541000	2245	WASATCH RESTORATION CENTER	UT	$494	$	$	$	$	$	$494	$	$	$
1541000	2405	AMERICAN FORK STORE ROOM	UT	$1,306	$	$	$	$	$	$1,306	$	$	$
1541000	2410	SANTAQUIN STORE ROOM	UT	$386	$	$	$	$	$	$386	$	$	$
1541000	2415	DELTA STORE ROOM	UT	$299	$	$	$	$	$	$299	$	$	$
1541000	2420	VERNAL STORE ROOM	UT	$600	$	$	$	$	$	$600	$	$	$
1541000	2425	PRICE STORE ROOM	UT	$604	$	$	$	$	$	$604	$	$	$
1541000	2430	MOAB STORE ROOM	UT	$588	$	$	$	$	$	$588	$	$	$
1541000	2435	BLANDING STORE ROOM	UT	$190	$	$	$	$	$	$190	$	$	$
1541000	2445	RICHFIELD STORE ROOM	UT	$106	$	$	$	$	$	$106	$	$	$
1541000	2450	CEDAR CITY STORE ROOM	UT	$1,010	$	$	$	$	$	$1,010	$	$	$
1541000	2455	MILFORD STORE ROOM	UT	$288	$	$	$	$	$	$288	$	$	$
1541000	2460	WASHINGTON STORE ROOM	UT	$435	$	$	$	$	$	$435	$	$	$
1541000	2620	WALLA WALLA STORE ROOM	WA	$1,180	$	$	$1,180	$	$	$	$	$	$
1541000	2625	SUNNYSIDE STORE ROOM	WA	$285	$	$	$285	$	$	$	$	$	$
1541000	2630	YAKIMA STORE ROOM	WA	$316	$	$	$316	$	$	$	$	$	$
1541000	2635	ENTERPRISE STORE ROOM	OR	$229	$	$229	$	$	$	$	$	$	$
1541000	2640	PENDLETON STORE ROOM	OR	$652	$	$652	$	$	$	$	$	$	$
1541000	2650	HOOD RIVER STORE ROOM	OR	$168	$	$168	$	$	$	$	$	$	$
1541000	2655	PORTLAND METRO - STORE ROOM	OR	$6,817	$	$6,817	$	$	$	$	$	$	$
1541000	2660	ASTORIA STORE ROOM	OR	$1,182	$	$1,182	$	$	$	$	$	$	$
1541000	2665	MADRAS STORE ROOM	OR	$600	$	$600	$	$	$	$	$	$	$
1541000	2675	BEND STORE ROOM	OR	$801	$	$801	$	$	$	$	$	$	$
1541000	2805	ALBANY STORE ROOM	OR	$198	$	$198	$	$	$	$	$	$	$
1541000	2810	LINCOLN CITY STORE ROOM	OR	$181	$	$181	$	$	$	$	$	$	$
1541000	2830	ROSEBURG STORE ROOM	OR	$2,508	$	$2,508	$	$	$	$	$	$	$
1541000	2835	COOS BAY STORE ROOM	OR	$625	$	$625	$	$	$	$	$	$	$
1541000	2840	GRANTS PASS STORE ROOM	OR	$688	$	$688	$	$	$	$	$	$	$
1541000	2845	MEDFORD STORE ROOM	OR	$845	$	$845	$	$	$	$	$	$	$
1541000	2850	KLAMATH FALLS STORE ROOM	OR	$1,883	$	$1,883	$	$	$	$	$	$	$
1541000	2855	LAKEVIEW STORE ROOM	OR	$111	$	$111	$	$	$	$	$	$	$
1541000	2860	ALTURAS STORE ROOM	CA	$78	$78	$	$	$	$	$	$	$	$
1541000	2865	MT SHASTA STORE ROOM	CA	$188	$188	$	$	$	$	$	$	$	$
1541000	2870	YREKA STORE ROOM	CA	$624	$624	$	$	$	$	$	$	$	$
1541000	2875	CRESENT CITY STORE ROOM	CA	$404	$404	$	$	$	$	$	$	$	$
1541000	5005	TREMONTON STORE ROOM	SO	$144	$3	$39	$11	$16	$20	$62	$8	$4	$
1541000	5110	MATERIAL PACKAGING CENTER - WEST	OR	$	$	$	$	$	$	$	$	$	$
1541000	5115	DEMC - SLC	SNPD	$124	$4	$33	$8	$11	$13	$59	$6	$2	$
1541000	5120	DEMC - MEDFORD	OR	$148	$	$148	$	$	$	$	$	$	$
1541000	5125	DEMC - OREGON	OR	$5,598	$	$5,598	$	$	$	$	$	$	$
1541000	5130	MEDFORD HUB	OR	$4,622	$	$4,622	$	$	$	$	$	$	$
1541000	5135	YAKIMA HUB	WA	$4,251	$	$	$4,251	$	$	$	$	$	$
1541000	5140	PRESTON HUB	IDU	$2,654	$	$	$	$	$	$	$2,654	$	$
1541000	5145	RAWLINS HUB	WYU	$3	$	$	$	$	$3	$	$	$3	$
1541000	5150	RICHFIELD HUB	UT	$3,520	$	$	$	$	$	$3,520	$	$	$
1541000	5155	CASPER HUB	WYP	$4,334	$	$	$	$4,334	$4,334	$	$	$	$
1541000	5160	SALT LAKE METRO HUB	UT	$13,102	$	$	$	$	$	$13,102	$	$	$
1541000	5200	UTAH TRANSPORTATION BUILDING	SNPD	$191	$7	$51	$12	$16	$20	$92	$9	$3	$
1541000	5300	METER TEST WAREHOUSE	UT	$8	$	$	$	$	$	$8	$	$	$
1541000 Total				**$186,060**	**$2,939**	**$52,972**	**$13,681**	**$21,147**	**$25,717**	**$79,952**	**$10,482**	**$4,570**	**$318**
1541500	0	M&S GLENROCK COAL MINE	SE	$198	$3	$48	$15	$26	$34	$85	$12	$7	$1
1541500	0	M&S GLENROCK COAL MINE	SG	$	$	$	$	$	$	$	$	$	$
1541500	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	-$198	-$3	-$48	-$15	-$26	-$34	-$85	-$12	-$7	-$1
1541500	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SG	$	$	$	$	$	$	$	$	$	$
1541500	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	$96	$2	$26	$7	$11	$14	$41	$5	$3	$
1541500 Total				**$96**	**$2**	**$26**	**$7**	**$11**	**$14**	**$41**	**$5**	**$3**	**$**

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1541900	0	PLANT M&S - GENERATION JV CUTBACK	SG	$	$	$	$	$	$	$	$	$	$
1541900	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	$2,091	$35	$539	$164	$254	$322	$906	$117	$68	$7
1541900 Total				**$2,091**	**$35**	**$539**	**$164**	**$254**	**$322**	**$906**	**$117**	**$68**	**$7**
1544200	0	M&S - OPER SUPPLIES-DEER CREEK MINE	SE	$6,159	$96	$1,498	$454	$815	$1,046	$2,654	$389	$231	$23
1544200 Total				**$6,159**	**$96**	**$1,498**	**$454**	**$815**	**$1,046**	**$2,654**	**$389**	**$231**	**$23**
1545000	0	CREDIT OFFSET CENTRALIA - WWP	SG	$	$	$	$	$	$	$	$	$	$
1545000	120005	CREDIT OFFSET CENTRALIA - WWP	SG	$	$	$	$	$	$	$	$	$	$
1545000	1510	CREDIT OFFSET CENTRALIA - WWP	SG	$	$	$	$	$	$	$	$	$	$
1545000 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1549900	102930	SB Asset # 120930	SO	-$27	-$1	-$7	-$2	-$3	-$4	-$12	-$2	-$1	$
1549900	120930	INVENTORY RESERVE POWER SUPPLY	SG	-$303	-$5	-$78	-$24	-$37	-$47	-$131	-$17	-$10	-$1
1549900	120930	INVENTORY RESERVE POWER SUPPLY	SO	-$12	$	-$3	-$1	-$1	-$2	-$5	-$1	$	$
1549900	120931	INVENTORY RESERVE POWER DELIVERY	SNPD	-$2,792	-$99	-$751	-$177	-$241	-$288	-$1,343	-$134	-$47	$
1549900 Total				**-$3,135**	**-$105**	**-$840**	**-$203**	**-$282**	**-$341**	**-$1,492**	**-$153**	**-$58**	**-$1**
1630000	0	STORES UNDISTRIBUTED	SO	$	$	$	$	$	$	$	$	$	$
1630000 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2531600	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	-$2,777	-$43	-$675	-$205	-$367	-$472	-$1,197	-$175	-$104	-$10
2531600 Total				**-$2,777**	**-$43**	**-$675**	**-$205**	**-$367**	**-$472**	**-$1,197**	**-$175**	**-$104**	**-$10**
2531700	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	-$2,023	-$31	-$492	-$149	-$268	-$344	-$872	-$128	-$76	-$8
2531700 Total				**-$2,023**	**-$31**	**-$492**	**-$149**	**-$268**	**-$344**	**-$872**	**-$128**	**-$76**	**-$8**
2531800	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	-$273	-$5	-$70	-$21	-$33	-$42	-$118	-$15	-$9	-$1
2531800 Total				**-$273**	**-$5**	**-$70**	**-$21**	**-$33**	**-$42**	**-$118**	**-$15**	**-$9**	**-$1**
Grand Total				**$409,252**	**$6,361**	**$107,189**	**$30,163**	**$50,780**	**$63,781**	**$176,004**	**$24,595**	**$13,000**	**$1,160**

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1430000	OTHER ACCTS REC	0	OTHER ACCOUNTS RECEIVABLE	SO	$3	$	$1	$	$	$	$1	$	$	$
1430000 Total					**$3**	**$**	**$1**	**$**	**$**	**$**	**$1**	**$**	**$**	**$**
1431000	EMP ACCOUNTS REC	0	EMPLOYEE RECEIVABLES	SO	$4,636	$107	$1,259	$355	$524	$655	$1,993	$256	$131	$11
1431000 Total					**$4,636**	**$107**	**$1,259**	**$355**	**$524**	**$655**	**$1,993**	**$256**	**$131**	**$11**
1431200	MISC OTHER LOANS-CSS	0	MISC OTHER LOANS	SO	$	$	$	$	$	$	$	$	$	$
1431200 Total					**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1432600	P C LOANS - EMPL	0	PC LOANS - EMPLOYEE	SO	$	$	$	$	$	$	$	$	$	$
1432600 Total					**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1433000	JOINT OWNER REC	0	JOINT OWNER RECEIVABLE	SO	$23,617	$546	$6,415	$1,809	$2,667	$3,335	$10,152	$1,304	$667	$56
1433000 Total					**$23,617**	**$546**	**$6,415**	**$1,809**	**$2,667**	**$3,335**	**$10,152**	**$1,304**	**$667**	**$56**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	$27,321	$631	$7,422	$2,093	$3,086	$3,858	$11,745	$1,508	$772	$64
1436000 Total					**$27,321**	**$631**	**$7,422**	**$2,093**	**$3,086**	**$3,858**	**$11,745**	**$1,508**	**$772**	**$64**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	$2,349	$54	$638	$180	$265	$332	$1,010	$130	$66	$6
1437000 Total					**$2,349**	**$54**	**$638**	**$180**	**$265**	**$332**	**$1,010**	**$130**	**$66**	**$6**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	-$2,170	-$50	-$589	-$166	-$245	-$306	-$933	-$120	-$61	-$5
1437100 Total					**-$2,170**	**-$50**	**-$589**	**-$166**	**-$245**	**-$306**	**-$933**	**-$120**	**-$61**	**-$5**
2300000	ASSET RETIREMENT OBL	284915	ARO LIAB - DEER CREEK MINE RECLAMATION	SE	-$2,516	-$39	-$612	-$185	-$333	-$427	-$1,084	-$159	-$94	-$9
2300000	ASSET RETIREMENT OBL	284917	ARO LIAB-GLENROCK RECLAM - REGULATED	SE	$	$	$	$	$	$	$	$	$	$
2300000 Total					**-$2,516**	**-$39**	**-$612**	**-$185**	**-$333**	**-$427**	**-$1,084**	**-$159**	**-$94**	**-$9**
2320000	ACCOUNTS PAYABLE	0	ACCOUNTS PAYABLE	SE	-$1,668	-$26	-$406	-$123	-$221	-$283	-$719	-$105	-$63	-$6
2320000	ACCOUNTS PAYABLE	210412	Marengo Wind Proj Accrual	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	210460	JOINT OWNER RECEIVABLES - CREDIT	SE	-$1,813	-$28	-$441	-$134	-$240	-$308	-$781	-$114	-$68	-$7
2320000	ACCOUNTS PAYABLE	210470	Minority Plant Accrual-Idaho Power (T&D)	SG	-$172	-$3	-$44	-$14	-$21	-$26	-$75	-$10	-$6	-$1
2320000	ACCOUNTS PAYABLE	210643	Mountain Fuel Supply Co	SE	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	210648	Spring Creek Coal - Centralia Purchases	SE	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	210651	Genwal Coal Co Inc	SE	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	210656	Foidel Creek/Cypress Coal Purchase	SE	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	210674	America West Resources - Coal Purchases	SE	-$107	-$2	-$26	-$8	-$14	-$18	-$46	-$7	-$4	$
2320000	ACCOUNTS PAYABLE	211100	MEDICAL INSURANCE WITHHOLDING	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211103	LIFE INSURANCE WITHHOLDING	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211104	Spouse Life Insurance Withholding	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211105	Dependent Life Insurance Withholding	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211107	MUTUAL AID WITHHOLDING	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211108	UNION DUES/CONTRIBUTIONS WITHHOLDING	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211109	MET PAY HOME & AUTO WITHHOLDINGS	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211110	CREDIT UNION WITHHOLDINGS	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211111	SAVINGS BONDS WITHHOLDINGS	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211112	UNITED FUND/CHARITABLE WITHHOLDINGS	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211116	DEPENDENT SUPPORT/LEVY WITHHOLDINGS	SO	-$4	$	-$1	$	$	-$1	-$2	$	$	$
2320000	ACCOUNTS PAYABLE	211119	Pre-Tax Medical Withholdings	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211123	Accidental Death & Disability Liability	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	211149	OTHER PAYROLL LIABILITY	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215077	K-PLUS EMPLOYER CONTRIBUTIONS - ENHANCED	SO	-$553	-$13	-$150	-$42	-$62	-$78	-$238	-$31	-$16	-$1
2320000	ACCOUNTS PAYABLE	215078	K-Plus Employer Contributions - Fixed	SO	-$1,241	-$29	-$337	-$95	-$140	-$175	-$534	-$69	-$35	-$3
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	-$2,577	-$60	-$700	-$197	-$291	-$364	-$1,108	-$142	-$73	-$6
2320000	ACCOUNTS PAYABLE	215081	OTHER EMPLOYEE BENEFITS	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215082	METLIFE DENTAL INSURANCE	SO	-$66	-$2	-$18	-$5	-$7	-$9	-$28	-$4	-$2	$
2320000	ACCOUNTS PAYABLE	215084	METLIFE VISION INSURANCE	SO	-$2	$	-$1	$	$	$	-$1	$	$	$
2320000	ACCOUNTS PAYABLE	215090	LUMENOS HEALTH PLAN	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215095	HMO HEALTH PLAN	SO	-$15	$	-$4	-$1	-$2	-$2	-$7	-$1	$	$
2320000	ACCOUNTS PAYABLE	215096	DELTA DENTAL	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215112	Minnesota Life Insurance	SO	-$7	$	-$2	-$1	-$1	-$1	-$3	$	$	$
2320000	ACCOUNTS PAYABLE	215116	IBEW 57 MEDICAL INSURANCE	SO	-$13	$	-$4	-$1	-$2	-$2	-$6	-$1	$	$
2320000	ACCOUNTS PAYABLE	215136	ESOP ACCRUAL	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215198	WEST VALLEY CITY STORM DRAINS FEE	SO	-$165	-$4	-$45	-$13	-$19	-$23	-$71	-$9	-$5	$
2320000	ACCOUNTS PAYABLE	215211	DRAPER CITY STORM DRAIN	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215350	"IBEW 57 HEALTH REIMBURSEMENT, CURRENT Y	SO	-$2	$	-$1	$	$	$	-$1	$	$	$
2320000	ACCOUNTS PAYABLE	215351	"IBEW 57 DEPENDENT CARE REIMBURSEMENT, C	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215356	"HEALTH REIMBURSEMENT, CURRENT YEAR"	SO	$27	$1	$7	$2	$3	$4	$12	$1	$1	$

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
2320000	ACCOUNTS PAYABLE	215357	"DEPENDENT CARE REIMBURSEMENT, CURRENT Y	SO	-$42	-$1	-$12	-$3	-$5	-$6	-$18	-$2	-$1	$
2320000	ACCOUNTS PAYABLE	215660	659 Training Trust-Comp Match	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215725	Medicare Subsidies Payable to FAS 106 Tr	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	215901	FLATHEAD ELECTRIC CO-OP LIABILITY	SE	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235195	Miscellaneous Payroll	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235502	Payroll Reconciliation	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235504	Sales Incentive Accrual	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235509	Non-Officer Vehicle Allowance	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235511	Incentive Plan - Power Supply	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235513	Incentive Plan - Wt&T	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235516	GUL Cash Fund (Met Life)	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235529	Met Pay	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235543	Suppl Pay Project	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235545	IBEW Universal Life	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235554	Continuation Pay	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235561	International Assign Adj	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	235599	Safety Award	SO	$	$	$	$	$	$	$	$	$	$
2320000	ACCOUNTS PAYABLE	240330	PROVISION FOR WORKERS' COMPENSATION	SO	-$97	-$2	-$26	-$7	-$11	-$14	-$42	-$5	-$3	$
2320000	ACCOUNTS PAYABLE	249995	Accrued Severance - Reclass to Long-Term	SO	$28	$1	$8	$2	$3	$4	$12	$2	$1	$
2320000 Total					**-$8,491**	**-$168**	**-$2,202**	**-$640**	**-$1,030**	**-$1,304**	**-$3,655**	**-$497**	**-$274**	**-$25**
2533000	O DEF CR-MISC PPL	288307	TRAIL MTN MINE RECLAMATION	SE	-$1,087	-$17	-$264	-$80	-$144	-$185	-$469	-$69	-$41	-$4
2533000	O DEF CR-MISC PPL	289511	DESERET MINE RECLAMATION	SE	-$530	-$8	-$129	-$39	-$70	-$90	-$228	-$33	-$20	-$2
2533000	O DEF CR-MISC PPL	289513	TRAIL MTN MINE RECLAMATION	SE	$	$	$	$	$	$	$	$	$	$
2533000	O DEF CR-MISC PPL	289514	FINAL & INTERIM RECLAMATION - DJ MINE	SE	$	$	$	$	$	$	$	$	$	$
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	-$4,746	-$74	-$1,154	-$350	-$628	-$806	-$2,046	-$299	-$178	-$18
2533000 Total					**-$6,364**	**-$99**	**-$1,547**	**-$469**	**-$842**	**-$1,081**	**-$2,743**	**-$402**	**-$239**	**-$24**
2541050	FAS143 ARO REG LIAB	00111920	REG LIAB-ARO/REGDIFF DEER CREEK MINE REC	SE	-$20	$	-$5	-$1	-$3	-$3	-$9	-$1	-$1	$
2541050	FAS143 ARO REG LIAB	111594	ARO/REG DIFF - DEER CREEK MINE RECLAIMAT	SE	$	$	$	$	$	$	$	$	$	$
2541050	FAS143 ARO REG LIAB	111920	REG LIAB-ARO/REGDIFF DEER CREEK MINE REC	SE	$20	$	$5	$1	$3	$3	$9	$1	$1	$
2541050	FAS143 ARO REG LIAB	288503	ARO/REG DIFF - DEER CREEK MINE RECLAMA	SE	-$898	-$14	-$218	-$66	-$119	-$153	-$387	-$57	-$34	-$3
2541050 Total					**-$898**	**-$14**	**-$218**	**-$66**	**-$119**	**-$153**	**-$387**	**-$57**	**-$34**	**-$3**
Grand Total					**$37,487**	**$968**	**$10,567**	**$2,910**	**$3,974**	**$4,909**	**$16,100**	**$1,964**	**$935**	**$70**

B15. MISCELLANEOUS RATE BASE

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Miscellaneous Rate Base (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1140000	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	SG	$159,176	$2,679	$41,031	$12,507	$19,307	$24,504	$68,990	$8,944	$5,197	$521	$	$
1140000 Total				**$159,176**	**$2,679**	**$41,031**	**$12,507**	**$19,307**	**$24,504**	**$68,990**	**$8,944**	**$5,197**	**$521**	**$**	**$**
1150000	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	-$104,607	-$1,760	-$26,965	-$8,219	-$12,688	-$16,104	-$45,339	-$5,878	-$3,416	-$342	$	$
1150000 Total				**-$104,607**	**-$1,760**	**-$26,965**	**-$8,219**	**-$12,688**	**-$16,104**	**-$45,339**	**-$5,878**	**-$3,416**	**-$342**	**$**	**$**
1651000	132000	PREPAID INSURANCE	SE	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132001	PREPAID INSURANCE - SPECIAL COVERAGE	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132002	PREPAID INSURANCE - BURGLARY & ROBBERY	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132004	PREPAID INSURANCE - FOREIGN LIABILITY	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132005	PREPAID INSURANCE - JIM BRIDGER OPERATIO	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132006	PREPAID INSURANCE - LEASEBACK LIABILITY	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132007	PREPAID INSURANCE - WYODAK OPERATIONS	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	$460	$11	$125	$35	$52	$65	$198	$25	$13	$1	$	$
1651000	132009	PREPAID INSURANCE - JOINT VENTURE HUNTER	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132010	PREPAID INSURANCE - JOINT VENTURE HUNTER	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132011	PREPAID INSURANCE - CENTRALIA OPERATIONS	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132012	PREPAID INSURANCE - ALLPURPOSE INSURANCE	SO	$2,356	$54	$640	$180	$266	$333	$1,013	$130	$67	$6	$	$
1651000	132013	PREPAID INSURANCE - D&O LIABILITY	SO	$234	$5	$64	$18	$26	$33	$100	$13	$7	$1	$	$
1651000	132015	PREPAID INSURANCE - FOOTE CREEK	SG	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	$442	$10	$120	$34	$50	$62	$190	$24	$13	$1	$	$
1651000	132045	PREPAID WORKERS COMPENSATION	SO	$672	$16	$182	$51	$76	$95	$289	$37	$19	$2	$	$
1651000	132050	PREPAID IBEW 57 MEDICAL	SO	$	$	$	$	$	$	$	$	$	$	$	$
1651000	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	$23	$1	$6	$2	$3	$3	$10	$1	$1	$	$	$
1651000 Total				**$4,187**	**$97**	**$1,138**	**$321**	**$473**	**$591**	**$1,800**	**$231**	**$118**	**$10**	**$**	**$**
1652000	132101	PREPAID PROPERTY TAX	GPS	$	$	$	$	$	$	$	$	$	$	$	$
1652000	132102	CA - PREPAID PROPERTY TAX	GPS	$	$	$	$	$	$	$	$	$	$	$	$
1652000	132103	UT - PREPAID PROPERTY TAX	GPS	$	$	$	$	$	$	$	$	$	$	$	$
1652000	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	$15	$	$4	$1	$2	$2	$6	$1	$	$	$	$
1652000	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	$91	$2	$25	$7	$10	$13	$39	$5	$3	$	$	$
1652000	132111	Goshute - Prepaid Possessory Interest	GPS	$	$	$	$	$	$	$	$	$	$	$	$
1652000	132200	"Prepaid Taxes (Federal, State, Local)"	SO	$6	$	$2	$	$1	$1	$3	$	$	$	$	$
1652000	132902	PREP FEES-WASH UTIL & TRANSP COMMISSION	WA	$	$	$	$	$	$	$	$	$	$	$	$
1652000	132910	PREPAYMENT OF HARDWARE & SOFTWARE	SO	$	$	$	$	$	$	$	$	$	$	$	$
1652000	132924	OTH PREPAY-OREGON DOE FEE	SO	$	$	$	$	$	$	$	$	$	$	$	$
1652000 Total				**$112**	**$3**	**$30**	**$9**	**$13**	**$16**	**$48**	**$6**	**$3**	**$**	**$**	**$**
1652100	132040	PREPAID PENSION COSTS	SO	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132095	PREPAID EMISSIONS PERMIT FEES (UT)	SG	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132310	PREPAID RATING AGNCY	SO	$169	$4	$46	$13	$19	$24	$73	$9	$5	$	$	$
1652100	132602	OTH PREPAY - MEDFORD ENTERPRISE - RENT	SO	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132603	OTH PREPAY - ASHTON PLANT LAND	SG	$7	$	$2	$1	$1	$1	$3	$	$	$	$	$
1652100	132605	GADSBY GAS TURBINES	SG	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132606	OTHER PREPAY - LEASE COMMISSIONS	SO	$16	$	$4	$1	$2	$2	$7	$1	$	$	$	$
1652100	132607	OTHER PREP-FERC LAND	SG	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132608	Prepaid - Records Management Costs	SG	$53	$1	$14	$4	$6	$8	$23	$3	$2	$	$	$
1652100	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	$537	$9	$138	$42	$65	$83	$233	$30	$18	$2	$	$
1652100	132621	Prepayments - Water Rights (Ferron Canal	SG	$89	$2	$23	$7	$11	$14	$39	$5	$3	$	$	$
1652100	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	$74	$1	$19	$6	$9	$11	$32	$4	$2	$	$	$
1652100	132625	PREPAYMENTS-CES/WAY/SEMPRA-DSM ENERGY S	SG	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132630	PREPAID OR RENEWAL & HABITAT RESTORATION	OTHER	$805	$	$	$	$	$	$	$	$	$	$805	$
1652100	132650	PREPAID DUES	SE	$2,458	$38	$598	$181	$325	$417	$1,059	$155	$92	$9	$	$
1652100	132700	PREPAID RENT	GPS	$178	$4	$48	$14	$20	$25	$77	$10	$5	$	$	$
1652100	132701	INTERCO PREPAID RENT	GPS	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132705	Prepaid Pole Contact	SG	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132740	PREPAID O&M WIND	SG	$148	$2	$38	$12	$18	$23	$64	$8	$5	$	$	$
1652100	132825	Prepaid LGIA Transmission	SG	$872	$15	$225	$69	$106	$134	$378	$49	$28	$3	$	$
1652100	132831	PREPAID BPA TRANSM - WINE COUNTRY	SG	$863	$15	$223	$68	$105	$133	$374	$49	$28	$3	$	$
1652100	132900	PREPAYMENTS - OTHER	SE	$72	$1	$18	$5	$10	$12	$31	$5	$3	$	$	$
1652100	132900	PREPAYMENTS - OTHER	SO	$624	$14	$169	$48	$70	$88	$268	$34	$18	$1	$	$
1652100	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	$2,210	$	$2,210	$	$	$	$	$	$	$	$	$
1652100	132902	PREP FEES-WASH UTIL & TRANSP COMMISSION	WA	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	$4,616	$	$	$	$	$	$4,616	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Miscellaneous Rate Base (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
1652100	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	$237	$	$	$	$	$	$	$237	$	$	$	$
1652100	132905	PREP FEES-WYO PUBLIC SERVICE COMMISSION	WYP	$	$	$	$	$	$	$	$	$	$	$	$
1652100	132909	Prepaid Licensing Fees	SO	$339	$8	$92	$26	$38	$48	$146	$19	$10	$1	$	$
1652100	132910	Prepayments - Hardware & Software	SO	$8,943	$207	$2,429	$685	$1,010	$1,263	$3,844	$494	$253	$21	$	$
1652100	132926	PREPAID ROYALTIES	SE	$833	$13	$203	$61	$110	$141	$359	$53	$31	$3	$	$
1652100	132999	PREPAY - RECLASS TO LT	SO	-$1,606	-$37	-$436	-$123	-$181	-$227	-$690	-$89	-$45	-$4	$	$
1652100	134000	L/T PREPAY RECLASS	SO	$1,606	$37	$436	$123	$181	$227	$690	$89	$45	$4	$	$
1652100	182600	PREPAYMENT-OTHER	SE	$	$	$	$	$	$	$	$	$	$	$	$
1652100 Total				**$24,144**	**$334**	**$6,498**	**$1,242**	**$1,925**	**$2,428**	**$11,626**	**$1,165**	**$503**	**$45**	**$805**	**$**
1655000	132400	PREPAID - TAXES	SE	$	$	$	$	$	$	$	$	$	$	$	$
1655000 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2281100	280301	ACC. PROV. PROP INS. - THERMAL	SO	$	$	$	$	$	$	$	$	$	$	$	$
2281100 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2281200	280290	STORM REIMBURSEMENTS	SO	$	$	$	$	$	$	$	$	$	$	$	$
2281200	280302	ACC. PROV. PROP INS. - T&D LINES	SO	$	$	$	$	$	$	$	$	$	$	$	$
2281200	280307	Accum Prov For Prop Ins - Pac Power T&D	SO	$	$	$	$	$	$	$	$	$	$	$	$
2281200	280308	Accum Prov For Prop Ins - RMP T&D	SO	$	$	$	$	$	$	$	$	$	$	$	$
2281200 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2282100	280311	ACC. PROV. I & D - EXCL. AUTO	SO	-$6,485	-$150	-$1,762	-$497	-$732	-$916	-$2,788	-$358	-$183	-$15	$	$
2282100 Total				**-$6,485**	**-$150**	**-$1,762**	**-$497**	**-$732**	**-$916**	**-$2,788**	**-$358**	**-$183**	**-$15**	**$**	**$**
2282200	280312	ACC. PROV. I & D - AUTO	SO	$	$	$	$	$	$	$	$	$	$	$	$
2282200 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2282300	280313	ACC. PROV. I&D - CONST.	SO	$	$	$	$	$	$	$	$	$	$	$	$
2282300 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2283000	187240	CONTRA REG ASSET - TRANSITION PLAN SEVER	SO	$	$	$	$	$	$	$	$	$	$	$	$
2283000	280319	ACCRUAL-TRANSITION PLAN SEVERANCE PAYMEN	SO	$	$	$	$	$	$	$	$	$	$	$	$
2283000	280330	FAS 112 BOOK RESERVE	SO	-$21,615	-$499	-$5,872	-$1,656	-$2,441	-$3,052	-$9,292	-$1,193	-$611	-$51	$	$
2283000	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	-$2,325	-$54	-$632	-$178	-$263	-$328	-$999	-$128	-$66	-$5	$	$
2283000 Total				**-$23,940**	**-$553**	**-$6,503**	**-$1,834**	**-$2,704**	**-$3,380**	**-$10,291**	**-$1,322**	**-$677**	**-$56**	**$**	**$**
2283400	280321	FAS 106 - PACIFICORP EXCL. COAL MINES	SO	$	$	$	$	$	$	$	$	$	$	$	$
2283400 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2283500	280340	PENSION	SO	$	$	$	$	$	$	$	$	$	$	$	$
2283500	280350	Pension - Local 57	SO	-$1,386	-$32	-$377	-$106	-$157	-$196	-$596	-$77	-$39	-$3	$	$
2283500 Total				**-$1,386**	**-$32**	**-$377**	**-$106**	**-$157**	**-$196**	**-$596**	**-$77**	**-$39**	**-$3**	**$**	**$**
2284100	284901	BLACK LUNG RESERVE	SE	$	$	$	$	$	$	$	$	$	$	$	$
2284100	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	-$1,500	-$25	-$387	-$118	-$182	-$231	-$650	-$84	-$49	-$5	$	$
2284100 Total				**-$1,500**	**-$25**	**-$387**	**-$118**	**-$182**	**-$231**	**-$650**	**-$84**	**-$49**	**-$5**	**$**	**$**
2284200	284910	DECOMMISSIONING LIABILITY	TROJD	$	$	$	$	$	$	$	$	$	$	$	$
2284200	284912	TROJAN WORKING FUNDS BALANCES - NET	TROJD	$	$	$	$	$	$	$	$	$	$	$	$
2284200 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2300000	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJP	-$1,661	-$28	-$424	-$129	-$204	-$260	-$719	-$95	-$55	-$6	$	$
2300000 Total				**-$1,661**	**-$28**	**-$424**	**-$129**	**-$204**	**-$260**	**-$719**	**-$95**	**-$55**	**-$6**	**$**	**$**
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	CA	-$62	-$62	$	$	$	$	$	$	$	$	$	$
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	IDU	-$21	$	$	$	$	$	$	-$21	$	$	$	$
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	OR	-$622	$	-$622	$	$	$	$	$	$	$	$	$
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	UT	-$272	$	$	$	$	$	-$272	$	$	$	$	$
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WA	-$99	$	$	-$99	$	$	$	$	$	$	$	$
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WYP	-$30	$	$	$	-$30	-$30	$	$	$	$	$	$
2530000	289009	OREGON DSM LOANS NPV UNEARNED INCOME	OTHER	-$187	$	$	$	$	$	$	$	$	$	-$187	$
2530000 Total				**-$1,293**	**-$62**	**-$622**	**-$99**	**-$30**	**-$30**	**-$272**	**-$21**	**$**	**$**	**-$187**	**$**
2532500	289301	PARIBAS FUTURES 5310	SE	$	$	$	$	$	$	$	$	$	$	$	$
2532500 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2539900	0	Fossil Rock Fuels Entries	SE	-$5,006	-$78	-$1,217	-$369	-$662	-$850	-$2,158	-$316	-$188	-$19	$	$
2539900	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	-$7	-$7	$	$	$	$	$	$	$	$	$	$
2539900	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	SG	-$1	$	$	$	$	$	$	$	$	$	$	$
2539900	289025	DEF REV-DUKE/HERMISTON GAS SALE NOVATION	SE	-$31	$	-$8	-$2	-$4	-$5	-$14	-$2	-$1	$	$	$
2539900	289530	SOFTWARE LICENSE PAYMENTS - MICROSOFT	SE	$	$	$	$	$	$	$	$	$	$	$	$
2539900	289904	LAKEVIEW BUYOUT	SG	$	$	$	$	$	$	$	$	$	$	$	$
2539900	289906	HERMISTON BREAKAGE FEE	SG	$	$	$	$	$	$	$	$	$	$	$	$
2539900	289907	FIRTH COGENERATION BUYOUT	SG	$	$	$	$	$	$	$	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Miscellaneous Rate Base (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other	Nutil
2539900	289908	MONSANTO CONTRACT	SE	$	$	$	$	$	$	$	$	$	$	$	$
2539900	289909	REDDING CONTRACT	SG	-$2,475	-$42	-$638	-$194	-$300	-$381	-$1,073	-$139	-$81	-$8	$	$
2539900	289912	OPTION SALES	SG	$	$	$	$	$	$	$	$	$	$	$	$
2539900	289913	MCI - F.O.G. WIRE LEASE	SG	-$2,235	-$38	-$576	-$176	-$271	-$344	-$969	-$126	-$73	-$7	$	$
2539900	289914	AMERICAN ELECTRIC POWER CRP	SG	-$2,205	-$37	-$568	-$173	-$267	-$339	-$956	-$124	-$72	-$7	$	$
2539900	289915	FOOTCREEK CONTRACT	SG	-$499	-$8	-$129	-$39	-$61	-$77	-$216	-$28	-$16	-$2	$	$
2539900	289917	West Valley Contract Term	SG	$	$	$	$	$	$	$	$	$	$	$	$
2539900	289925	TRANSM CONST SECURITY DEPOSITS	SG	-$1,460	-$25	-$376	-$115	-$177	-$225	-$633	-$82	-$48	-$5	$	$
2539900 Total				**-$13,920**	**-$235**	**-$3,513**	**-$1,069**	**-$1,743**	**-$2,222**	**-$6,018**	**-$817**	**-$479**	**-$48**	**$**	**$**
2540000	288115	REG LIABILITY PROP INS RESERVE	SO	$	$	$	$	$	$	$	$	$	$	$	$
2540000	288140	Reg Liability - WA A&G Credit	WA	$	$	$	$	$	$	$	$	$	$	$	$
2540000	288165	Reg Liab - OR Enrgy	OTHER	-$1,792	$	$	$	$	$	$	$	$	$	-$1,792	$
2540000	288180	Reg Liability - Sale of REC's - OR	OTHER	-$3,310	$	$	$	$	$	$	$	$	$	-$3,310	$
2540000	288181	Reg Liability - Sale of RECs - UT	OTHER	-$24,697	$	$	$	$	$	$	$	$	$	-$24,697	$
2540000	288184	Reg Liability - Sale of RECs - WA	OTHER	-$37	$	$	$	$	$	$	$	$	$	-$37	$
2540000	288187	Reg Liability - UT Dunlap REC	OTHER	$386	$	$	$	$	$	$	$	$	$	$386	$
2540000	288188	Reg Liability - UT Recs Sur-credit Refun	OTHER	$	$	$	$	$	$	$	$	$	$	$	$
2540000	288189	Reg Liability - Sale of RECs - UT Contra	OTHER	$24,311	$	$	$	$	$	$	$	$	$	$24,311	$
2540000	288250	Reg Liability -Tax Rev Req Adj - UT	UT	-$49	$	$	$	$	$	-$49	$	$	$	$	$
2540000	288400	Regulatory Liability - OR Balance Consol	OTHER	-$2,608	$	$	$	$	$	$	$	$	$	-$2,608	$
2540000	288415	REGULATORY LIABILITY - DEF. BENEFIT- ARC	SE	$	$	$	$	$	$	$	$	$	$	$	$
2540000	288700	REG LIAB - OR INJURIES & DAMAGES RESERVE	OR	-$62	$	-$62	$	$	$	$	$	$	$	$	$
2540000	288712	REG LIAB - OR PROPERTY INSURANCE RESERVE	OR	-$1,251	$	-$1,251	$	$	$	$	$	$	$	$	$
2540000	288714	Reg Liab - ID Property Insurance Reserve	IDU	-$36	$	$	$	$	$	$	-$36	$	$	$	$
2540000	288715	Reg Liab - UT Property Insurance Reserve	UT	-$473	$	$	$	$	$	-$473	$	$	$	$	$
2540000	288716	Reg Liab - WY Property Insurance Reserve	WYP	-$97	$	$	$	-$97	-$97	$	$	$	$	$	$
2540000 Total				**-$9,715**	**$**	**-$1,313**	**$**	**-$97**	**-$97**	**-$522**	**-$36**	**$**	**$**	**-$7,747**	**$**
2541050	111595	ARO/REG DIFF - TROJAN NUCLEAR PLANT	TROJP	$	$	$	$	$	$	$	$	$	$	$	$
2541050	111650	ARO/REG DIFF - TROJAN NUCLEAR PLANT	TROJP	$	$	$	$	$	$	$	$	$	$	$	$
2541050	288506	ARO/REG DIFF - TROJAN NUCLEAR PLANT	TROJP	-$3,464	-$58	-$885	-$270	-$426	-$542	-$1,500	-$198	-$116	-$12	$	$
2541050 Total				**-$3,464**	**-$58**	**-$885**	**-$270**	**-$426**	**-$542**	**-$1,500**	**-$198**	**-$116**	**-$12**	**$**	**$**
Grand Total				**$19,647**	**$209**	**$5,947**	**$1,739**	**$2,755**	**$3,562**	**$13,768**	**$1,461**	**$808**	**$89**	**-$7,128**	**$**

B16. WEATHERIZATION REG. ASSETS

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Regulatory Assests (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1242000	0	INT FREE-PPL	OTHER	$1,663	$	$	$	$	$	$	$	$	$	$1,663
1242000	0	INT FREE-PPL	WA	$8	$	$	$8	$	$	$	$	$	$	$
1242000 Total			**0**	**$1,671**	**$**	**$**	**$8**	**$**	**$**	**$**	**$**	**$**	**$**	**$1,663**
1242100	0	INT FREE 5 YR-PPL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1242100 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1242300	0	IDAHO-UPL	IDU	$15	$	$	$	$	$	$	$15	$	$	$
1242300	0	IDAHO-UPL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1242300	0	IDAHO-UPL	UT	$	$	$	$	$	$	$	$	$	$	$
1242300	0	IDAHO-UPL	WYP	$	$	$	$	$	$	$	$	$	$	$
1242300 Total			**0**	**$15**	**$**	**$**	**$**	**$**	**$**	**$**	**$15**	**$**	**$**	**$**
1243000	0	INT BEARING 6.5%-PPL	OTHER	$1	$	$	$	$	$	$	$	$	$	$1
1243000 Total			**0**	**$1**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$1**
1243200	0	INT BEARING VAR%-PPL	OR	$	$	$	$	$	$	$	$	$	$	$
1243200	0	INT BEARING VAR%-PPL	OTHER	$1	$	$	$	$	$	$	$	$	$	$1
1243200	0	INT BEARING VAR%-PPL	WA	$	$	$	$	$	$	$	$	$	$	$
1243200 Total			**0**	**$1**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$1**
1243300	0	TAX CREDIT-PPL	OR	$	$	$	$	$	$	$	$	$	$	$
1243300	0	TAX CREDIT-PPL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1243300 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1243400	0	NEW 0% INT-PPL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1243400 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1244100	0	ENERGY FINANSWER	OTHER	$100	$	$	$	$	$	$	$	$	$	$100
1244100	0	ENERGY FINANSWER	SO	$	$	$	$	$	$	$	$	$	$	$
1244100	0	ENERGY FINANSWER	UT	$277	$	$	$	$	$	$277	$	$	$	$
1244100	0	ENERGY FINANSWER	WA	$19	$	$	$19	$	$	$	$	$	$	$
1244100	0	ENERGY FINANSWER	WYP	$	$	$	$	$	$	$	$	$	$	$
1244100 Total			**0**	**$396**	**$**	**$**	**$19**	**$**	**$**	**$277**	**$**	**$**	**$**	**$100**
1244200	0	PACIFIC ENVIRON	OR	$	$	$	$	$	$	$	$	$	$	$
1244200 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1244300	0	INDUST FINANSWER	OTHER	$	$	$	$	$	$	$	$	$	$	$
1244300 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1244500	0	HOME COMFORT	CA	$13	$13	$	$	$	$	$	$	$	$	$
1244500	0	HOME COMFORT	OTHER	$6	$	$	$	$	$	$	$	$	$	$6
1244500	0	HOME COMFORT	SO	-$4	$	-$1	$	-$1	-$1	-$2	$	$	$	$
1244500	0	HOME COMFORT	WA	$36	$	$	$36	$	$	$	$	$	$	$
1244500 Total			**0**	**$50**	**$13**	**-$1**	**$35**	**-$1**	**-$1**	**-$2**	**$**	**$**	**$**	**$6**
1244900	0	"FINANSWER 12,000"	OTHER	$18	$	$	$	$	$	$	$	$	$	$18
1244900	0	"FINANSWER 12,000"	UT	$1	$	$	$	$	$	$1	$	$	$	$
1244900	0	"FINANSWER 12,000"	WYU	$4	$	$	$	$	$4	$	$	$4	$	$
1244900 Total			**0**	**$23**	**$**	**$**	**$**	**$**	**$4**	**$1**	**$**	**$4**	**$**	**$18**
1245300	0	IRRIGATION FINANSWER	CA	$20	$20	$	$	$	$	$	$	$	$	$
1245300	0	IRRIGATION FINANSWER	OTHER	-$20	$	$	$	$	$	$	$	$	$	-$20
1245300 Total			**0**	**$**	**$20**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**-$20**
1245400	0	RETRO ENERGY FINANS	OTHER	$6	$	$	$	$	$	$	$	$	$	$6
1245400	0	RETRO ENERGY FINANS	UT	-$4	$	$	$	$	$	-$4	$	$	$	$
1245400 Total			**0**	**$2**	**$**	**$**	**$**	**$**	**$**	**-$4**	**$**	**$**	**$**	**$6**
1247000	0	ELI/GAWL SYSTEM	CA	$362	$362	$	$	$	$	$	$	$	$	$
1247000	0	ELI/GAWL SYSTEM	IDU	$20	$	$	$	$	$	$	$20	$	$	$
1247000	0	ELI/GAWL SYSTEM	OTHER	-$6,998	$	$	$	$	$	$	$	$	$	-$6,998
1247000	0	ELI/GAWL SYSTEM	UT	$4,631	$	$	$	$	$	$4,631	$	$	$	$
1247000	0	ELI/GAWL SYSTEM	WA	$1,913	$	$	$1,913	$	$	$	$	$	$	$
1247000	0	ELI/GAWL SYSTEM	WYP	$117	$	$	$	$117	$117	$	$	$	$	$
1247000	0	ELI/GAWL SYSTEM	WYU	$5	$	$	$	$	$5	$	$	$5	$	$
1247000 Total			**0**	**$50**	**$362**	**$**	**$1,913**	**$117**	**$122**	**$4,631**	**$20**	**$5**	**$**	**-$6,998**
1247100	0	CSS/ELI SYSTEM	OTHER	-$46	$	$	$	$	$	$	$	$	$	-$46

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Regulatory Assests (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1247100 Total			**0**	**-$46**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**-$46**
1249000	0	ESC - RESERVE	CA	$	$	$	$	$	$	$	$	$	$	$
1249000	0	ESC - RESERVE	IDU	-$15	$	$	$	$	$	$	-$15	$	$	$
1249000	0	ESC - RESERVE	OTHER	-$71	$	$	$	$	$	$	$	$	$	-$71
1249000	0	ESC - RESERVE	SO	$	$	$	$	$	$	$	$	$	$	$
1249000	0	ESC - RESERVE	UT	-$109	$	$	$	$	$	-$109	$	$	$	$
1249000	0	ESC - RESERVE	WA	-$2	$	$	-$2	$	$	$	$	$	$	$
1249000	0	ESC - RESERVE	WYU	$	$	$	$	$	$	$	$	$	$	$
1249000 Total			**0**	**-$199**	**$**	**$**	**-$2**	**$**	**$**	**-$109**	**-$15**	**$**	**$**	**-$71**
1822200	185801	UNRECOVD PLANT - TROJAN-DR	TROJP	$	$	$	$	$	$	$	$	$	$	$
1822200	185802	UNRECOVD PLANT - TROJAN-CR-DEP'N	TROJP	$	$	$	$	$	$	$	$	$	$	$
1822200	185804	UNRECOVD PLANT - TROJAN-DECOM-CR	TROJD	$	$	$	$	$	$	$	$	$	$	$
1822200 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1822230	185808	UNREC PLANT TROJAN - WA	WA	$	$	$	$	$	$	$	$	$	$	$
1822230 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1822600	111614	REG ASSET-TRAIL MTN MINE UNRECOVD INVEST	SE	$	$	$	$	$	$	$	$	$	$	$
1822600	187058	Trail Mountain Mine Closure Costs	SE	$	$	$	$	$	$	$	$	$	$	$
1822600	187059	TRAIL MTN MINE UNRECOVERED INVEST	SE	$	$	$	$	$	$	$	$	$	$	$
1822600 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1822700	185821	UNRECOVERED PLANT - POWERDALE HYDRO PLAN	SG-P	$	$	$	$	$	$	$	$	$	$	$
1822700 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1823000	101218	ENERGY FINANSWER - UT 1996	UT	$12	$	$	$	$	$	$12	$	$	$	$
1823000 Total			**0**	**$12**	**$**	**$**	**$**	**$**	**$**	**$12**	**$**	**$**	**$**	**$**
1823040	187002	OREGON DIRECT ACCESS	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187711	SCH 781 DIRECT ACCESS SHOPPING IN	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187743	SCH 294-25 TRANSITION ADJ BAL ACCT	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187765	IMPLEMENTATION COST II - NONRESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187766	IMPLEMENTATION COST II - NONRESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187767	IMPLEMENTATION COST 3 - RESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187768	IMPLEMENTATION COST 3 - NON RES SMALL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040	187769	IMPLEMENTATION COST 3 - NON RES LARGE	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823040 Total			**0**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1823870	187104	FAS 87/88 PENSION UT	UT	$	$	$	$	$	$	$	$	$	$	$
1823870	187601	Contra Pension Reg Asset MMT & CTG - WY	WYP	-$832	$	$	$	-$832	-$832	$	$	$	$	$
1823870	187623	Reg Asset - Post-Ret MMT - WY	WYP	$154	$	$	$	$154	$154	$	$	$	$	$
1823870 Total			**0**	**-$678**	**$**	**$**	**$**	**-$678**	**-$678**	**$**	**$**	**$**	**$**	**$**
1823910	102191	ASTORIA YOUNGS BAY CLEANUP	SO	$64	$1	$17	$5	$7	$9	$27	$4	$2	$	$
1823910	102193	UTAH METALS CLEANUP	SO	$	$	$	$	$	$	$	$	$	$	$
1823910	102194	DSM RETAIL MINOR SITES	SO	$26	$1	$7	$2	$3	$4	$11	$1	$1	$	$
1823910	102324	DSM RETAIL MINOR SITES	SO	$38	$1	$10	$3	$4	$5	$16	$2	$1	$	$
1823910	102325	ASTORIA YOUNG'S BAY CLEANUP	SO	$19	$	$5	$1	$2	$3	$8	$1	$1	$	$
1823910	102326	UTAH METALS CLEANUP	SO	$6	$	$2	$	$1	$1	$2	$	$	$	$
1823910	102463	D-SM RETAIL MINOR SITES	SO	$63	$1	$17	$5	$7	$9	$27	$3	$2	$	$
1823910	102464	ASTORIA YOUNGS BAY CLEANUP	SO	$9	$	$2	$1	$1	$1	$4	$	$	$	$
1823910	102467	THIRD WEST SUBSTATION CLEANUP	SO	$1,156	$27	$314	$89	$131	$163	$497	$64	$33	$3	$
1823910	102477	SALT LAKE CITY AUTO	SO	$10	$	$3	$1	$1	$1	$4	$1	$	$	$
1823910	102570	D-SM RETAIL MINOR SITES	SO	$5,407	$125	$1,469	$414	$611	$764	$2,324	$298	$153	$13	$
1823910	102571	SALT LAKE CITY AUTO	SO	$3	$	$1	$	$	$	$1	$	$	$	$
1823910	102584	WASHINGTON NON-DEFERRED COSTS	WA	-$691	$	$	-$691	$	$	$	$	$	$	$
1823910	102661	ASTORIA YOUNG BAY CLEANUP	SO	$874	$20	$237	$67	$99	$123	$376	$48	$25	$2	$
1823910	102771	ENVIRONMENTAL COST UNDER AMORTIZATION	SO	$1,167	$27	$317	$89	$132	$165	$502	$64	$33	$3	$
1823910 Total			**0**	**$8,150**	**$204**	**$2,402**	**-$14**	**$999**	**$1,248**	**$3,801**	**$488**	**$250**	**$21**	**$**
1823920	101185	IND FINANSWER 96	UT	$5	$	$	$	$	$	$5	$	$	$	$
1823920	101190	COMM BUILDING 96	UT	$1	$	$	$	$	$	$1	$	$	$	$
1823920	101948	SPECIAL CONTRACTS-DSM-WY-PPL 2001	WYP	$	$	$	$	$	$	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Regulatory Assests (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1823920	102030	ENERGY FINANSWER - WASHINGTON	OTHER	$4,427	$	$	$	$	$	$	$	$	$	$4,427
1823920	102032	INDUSTRIAL FINANSWER - WASHINGTON	OTHER	$21,528	$	$	$	$	$	$	$	$	$	$21,528
1823920	102033	LOW INCOME - WASHINGTON	OTHER	$7,021	$	$	$	$	$	$	$	$	$	$7,021
1823920	102034	SELF AUDIT - WASHINGTON	OTHER	$14	$	$	$	$	$	$	$	$	$	$14
1823920	102036	COMMERCIAL SMALL RETROFIT - WASHINGTON	OTHER	$788	$	$	$	$	$	$	$	$	$	$788
1823920	102037	INDUSTRIAL SMALL RETROFIT - WASHINGTON	OTHER	$13	$	$	$	$	$	$	$	$	$	$13
1823920	102038	COMMERCIAL RETROFIT LIGHTING - WASHINGTO	OTHER	$624	$	$	$	$	$	$	$	$	$	$624
1823920	102039	INDUSTRIAL RETROFIT LIGHTING-WA	OTHER	$88	$	$	$	$	$	$	$	$	$	$88
1823920	102040	NEEA - WASHINGTON	OTHER	$5,454	$	$	$	$	$	$	$	$	$	$5,454
1823920	102043	ENERGY CODE DEVELOPMENT	OTHER	$2	$	$	$	$	$	$	$	$	$	$2
1823920	102044	HOME COMFORT - WASHINGTON	OTHER	$159	$	$	$	$	$	$	$	$	$	$159
1823920	102045	WEATHERIZATION - WASHINGTON	OTHER	$22	$	$	$	$	$	$	$	$	$	$22
1823920	102046	HASSLE FREE	OTHER	$41	$	$	$	$	$	$	$	$	$	$41
1823920	102067	COMMERCIAL RETROFIT - WYOMING - PPL 2001	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102068	ENERGY FINANSWER - WYOMING PPL - 2001	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102069	INDUSTRIAL FINANSWER-WYOMING - PPL 2001	WYP	$5	$	$	$	$5	$5	$	$	$	$	$
1823920	102070	SELF AUDIT - WYOMING - PPL 2001	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102071	SELF AUDIT - WYOMING - UP&L 2001	WYU	$	$	$	$	$	$	$	$	$	$	$
1823920	102072	COMPACT FLUORESCENT LAMPS - WASHINGTON	OTHER	$1,183	$	$	$	$	$	$	$	$	$	$1,183
1823920	102127	RESIDENTIAL PROGRAM RESEARCH - WA	OTHER	$24	$	$	$	$	$	$	$	$	$	$24
1823920	102128	WA REVENUE RECOVERY - SBC OFFSET	OTHER	-$58,388	$	$	$	$	$	$	$	$	$	-$58,388
1823920	102131	ENERGY FINANSWER - UTAH 2001/2002	OTHER	$1,280	$	$	$	$	$	$	$	$	$	$1,280
1823920	102133	INDUSTRIAL FINANSWER - UTAH 2001/2002	OTHER	$1,353	$	$	$	$	$	$	$	$	$	$1,353
1823920	102138	COMPACT FLUOR LAMPS (CFL) UT 2001/2002	OTHER	$4,202	$	$	$	$	$	$	$	$	$	$4,202
1823920	102147	COMMERCIAL SMALL RETROFIT - UT 2001/2002	OTHER	$848	$	$	$	$	$	$	$	$	$	$848
1823920	102148	INDUSTRIAL SMALL RETROFIT - UT 2002	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	102149	COMMERCIAL RETROFIT LIGHTING - UT 2001/2	OTHER	$498	$	$	$	$	$	$	$	$	$	$498
1823920	102150	INDUSTRIAL RETROFIT LIGHTING - UT 2001/2	OTHER	$82	$	$	$	$	$	$	$	$	$	$82
1823920	102158	ENERGY FINANSWER - WYP - 2002	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102159	INDUSTRIAL FINANSWER - WYP - 2002	WYP	$7	$	$	$	$7	$7	$	$	$	$	$
1823920	102160	SELF AUDIT - WYP - 2002	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102161	SELF AUDIT - WYU - 2002	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102185	WEB AUDIT PILOT - WA	OTHER	$527	$	$	$	$	$	$	$	$	$	$527
1823920	102186	APPLIANCE REBATE - WA	OTHER	$18	$	$	$	$	$	$	$	$	$	$18
1823920	102195	INDUSTRIAL RETROFIT LIGHTING - UT 2002	OTHER	$71	$	$	$	$	$	$	$	$	$	$71
1823920	102196	POWER FORWARD UT 2002	OTHER	$115	$	$	$	$	$	$	$	$	$	$115
1823920	102205	A/C LOAD CONTROL PGM - RESIDENTIAL - UT	OTHER	$28	$	$	$	$	$	$	$	$	$	$28
1823920	102206	SCHOOL ENERGY EDUCATION - WA	OTHER	$2,997	$	$	$	$	$	$	$	$	$	$2,997
1823920	102208	COMPACT FLUORESCENT LAMPS (CFL) - WYP 20	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102209	AIR CONDITIONING - UT 2002	OTHER	$24	$	$	$	$	$	$	$	$	$	$24
1823920	102210	HASSELFREE EFFICIENCY - IDU 2003	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823920	102213	REFRIGERATOR RECYCLING PGM - UT 2003	OTHER	$1,509	$	$	$	$	$	$	$	$	$	$1,509
1823920	102214	REFRIGERATOR RECYCLING PGM - WA	OTHER	$2,686	$	$	$	$	$	$	$	$	$	$2,686
1823920	102215	REFRIGERATOR RECYCLING - WYP 2003	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102223	A/C LOAD CONTROL - RESIDENTIAL UT 2003	OTHER	$460	$	$	$	$	$	$	$	$	$	$460
1823920	102225	AIR CONDITIONING - UT 2003	OTHER	$2,564	$	$	$	$	$	$	$	$	$	$2,564
1823920	102226	COMMERCIAL RETROFIT LIGHTING - UT 2003	OTHER	$1,187	$	$	$	$	$	$	$	$	$	$1,187
1823920	102227	COMMERCIAL SMALL RETROFIT - UT 2003	OTHER	$895	$	$	$	$	$	$	$	$	$	$895
1823920	102228	COMPACT FLOURESCENT LAMP (CFL) - UT 2002	OTHER	$13	$	$	$	$	$	$	$	$	$	$13
1823920	102229	ENERGY FINANSWER - UT 2003	OTHER	$1,542	$	$	$	$	$	$	$	$	$	$1,542
1823920	102230	INDUSTRIAL FINANSWER - UT 2003	OTHER	$1,658	$	$	$	$	$	$	$	$	$	$1,658
1823920	102231	INDUSTRIAL RETROFIT LIGHTING - UT 2003	OTHER	$191	$	$	$	$	$	$	$	$	$	$191
1823920	102232	INDUSTRIAL SMALL RETROFIT - UTAH - 2003	OTHER	$14	$	$	$	$	$	$	$	$	$	$14
1823920	102233	POWER FORWARD - UT 2003	OTHER	-$27	$	$	$	$	$	$	$	$	$	-$27
1823920	102236	COMPACT FLUORESCENT LAMPS - WYP 2003	WYP	$1	$	$	$	$1	$1	$	$	$	$	$

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1823920	102237	ENERGY FINANSWER - WYP 2003	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102238	INDUSTRIAL FINANSWER - WYP 2003	WYP	$10	$	$	$	$10	$10	$	$	$	$	$
1823920	102239	SELF AUDIT - WYOMING - PPL 2003	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102245	CA REVENUE RECOVERY - BALANCING ACCT	OTHER	-$3,673	$	$	$	$	$	$	$	$	$	-$3,673
1823920	102327	COMMERCIAL SELF-DIRECT UT 2003	OTHER	$4	$	$	$	$	$	$	$	$	$	$4
1823920	102328	INDUSTRIAL SELF-DIRECT UT 2003	OTHER	$7	$	$	$	$	$	$	$	$	$	$7
1823920	102336	LOW INCOME - UTAH - 2004	OTHER	$22	$	$	$	$	$	$	$	$	$	$22
1823920	102337	REFRIGERATOR RECYCLING PGM - UT 2004	OTHER	$3,581	$	$	$	$	$	$	$	$	$	$3,581
1823920	102338	AC LOAD CONTROL - RESIDENTIAL UT 2004	OTHER	$2,910	$	$	$	$	$	$	$	$	$	$2,910
1823920	102339	AIR CONDITIONING - UT 2004	OTHER	$3,026	$	$	$	$	$	$	$	$	$	$3,026
1823920	102340	COMMERCIAL RETROFIT LIGHTING - UT 2004	OTHER	$1,547	$	$	$	$	$	$	$	$	$	$1,547
1823920	102341	COMMERCIAL SMALL RETROFIT - UT 2004	OTHER	$285	$	$	$	$	$	$	$	$	$	$285
1823920	102342	COMPACT FLOURESCENT LAMPS (CFL) UT 2004	OTHER	-$1	$	$	$	$	$	$	$	$	$	-$1
1823920	102343	ENERGY FINANSWER - UT 2004	OTHER	$1,227	$	$	$	$	$	$	$	$	$	$1,227
1823920	102344	INDUSTRIAL FINANSWER - UT 2004	OTHER	$2,562	$	$	$	$	$	$	$	$	$	$2,562
1823920	102345	INDUSTRIAL RETROFIT - UT 2004	OTHER	$230	$	$	$	$	$	$	$	$	$	$230
1823920	102346	INDUSTRIAL SMALL RETROFIT - UT 2004	OTHER	$51	$	$	$	$	$	$	$	$	$	$51
1823920	102347	POWER FORWARD - UT 2004	OTHER	$54	$	$	$	$	$	$	$	$	$	$54
1823920	102348	COMMERCIAL SELF-DIRECT - UT 2004	OTHER	$89	$	$	$	$	$	$	$	$	$	$89
1823920	102349	INDUSTRIAL SELF-DIRECT - UT 2004	OTHER	$129	$	$	$	$	$	$	$	$	$	$129
1823920	102351	ENERGY FINANSWER - ID/UT 2004	IDU	$3	$	$	$	$	$	$	$3	$	$	$
1823920	102360	REFRIGERATOR RECYCLING PGM - WYP 2004	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102362	ENERGY FINANSWER - WYP 2004	WYP	$6	$	$	$	$6	$6	$	$	$	$	$
1823920	102363	INDUSTRIAL FINANSWER - WYP 2004	WYP	$15	$	$	$	$15	$15	$	$	$	$	$
1823920	102364	SELF AUDIT - WYOMING - PPL 2004	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102443	ESIDENTIAL NEW CONSTRUCTION - WASHINGTON	OTHER	$561	$	$	$	$	$	$	$	$	$	$561
1823920	102444	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$76	$	$	$	$	$	$	$	$	$	$76
1823920	102458	COMMERCIAL FINANSWER EXPRESS - WASHINGTO	OTHER	$4,353	$	$	$	$	$	$	$	$	$	$4,353
1823920	102459	INDUSTRIAL FINANSWER EXPRESS - WASHINGTO	OTHER	$1,665	$	$	$	$	$	$	$	$	$	$1,665
1823920	102460	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$446	$	$	$	$	$	$	$	$	$	$446
1823920	102461	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$146	$	$	$	$	$	$	$	$	$	$146
1823920	102462	UTAH REVENUE RECOVERY - SBC OFFSET	OTHER	-$267,338	$	$	$	$	$	$	$	$	$	-$267,338
1823920	102502	RETROFIT COMMISSIONING PROGRAM - UTAH	OTHER	$2	$	$	$	$	$	$	$	$	$	$2
1823920	102503	C&I LIGHTING LOAD CONTROL - UTAH - 2004	OTHER	$23	$	$	$	$	$	$	$	$	$	$23
1823920	102504	REFRIGERATOR RECYCLING PGM - IDAHO - 200	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823920	102506	COMMERCIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$2	$	$	$	$	$	$	$2	$	$	$
1823920	102507	INDUSTRIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$2	$	$	$	$	$	$	$2	$	$	$
1823920	102508	IRRIGATION EFFICIENCY PROGRAM - IDAHO -	IDU	$3	$	$	$	$	$	$	$3	$	$	$
1823920	102518	ENERGY FINANSWER - ID/UT 2005	IDU	$9	$	$	$	$	$	$	$9	$	$	$
1823920	102525	REFRIGERATOR RECYCLING PGM - IDAHO - 200	IDU	$2	$	$	$	$	$	$	$2	$	$	$
1823920	102528	COMMERCIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$2	$	$	$	$	$	$	$2	$	$	$
1823920	102529	INDUSTRIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823920	102530	IRRIGATION EFFICIENCY PROGRAM - IDAHO -	IDU	$21	$	$	$	$	$	$	$21	$	$	$
1823920	102532	LOW INCOME - UTAH - 2005	OTHER	$48	$	$	$	$	$	$	$	$	$	$48
1823920	102533	REFRIGERATOR RECYCLING PGM- UTAH - 2005	OTHER	$3,306	$	$	$	$	$	$	$	$	$	$3,306
1823920	102534	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$3,060	$	$	$	$	$	$	$	$	$	$3,060
1823920	102535	AIR CONDITIONING - UTAH - 2005	OTHER	$2,347	$	$	$	$	$	$	$	$	$	$2,347
1823920	102536	COMMERCIAL RETROFIT LIGHTING - UTAH - 20	OTHER	$65	$	$	$	$	$	$	$	$	$	$65
1823920	102537	COMMERCIAL SMALL RETROFIT - UTAH - 2005	OTHER	$223	$	$	$	$	$	$	$	$	$	$223
1823920	102539	ENERGY FINANSWER - UTAH - 2005	OTHER	$1,476	$	$	$	$	$	$	$	$	$	$1,476
1823920	102540	INDUSTRIAL FINANSWER - UTAH - 2005	OTHER	$3,485	$	$	$	$	$	$	$	$	$	$3,485
1823920	102541	INDUSTRIAL RETROFIT LIGHTING - UTAH - 20	OTHER	$60	$	$	$	$	$	$	$	$	$	$60
1823920	102543	POWER FORWARD - UTAH - 2005	OTHER	$50	$	$	$	$	$	$	$	$	$	$50
1823920	102544	COMMERCIAL SELF-DIRECT - UTAH - 2005	OTHER	$67	$	$	$	$	$	$	$	$	$	$67
1823920	102545	INDUSTRIAL SELF-DIRECT - UTAH - 2005	OTHER	$103	$	$	$	$	$	$	$	$	$	$103

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1823920	102546	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$944	$	$	$	$	$	$	$	$	$	$944
1823920	102547	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$1,967	$	$	$	$	$	$	$	$	$	$1,967
1823920	102548	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$421	$	$	$	$	$	$	$	$	$	$421
1823920	102549	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$105	$	$	$	$	$	$	$	$	$	$105
1823920	102550	C&I LIGHTING LOAD CONTROL - UTAH - 2005	OTHER	$36	$	$	$	$	$	$	$	$	$	$36
1823920	102552	ENERGY FINANSWER - WYOMING PPL - 2005	WYP	$3	$	$	$	$3	$3	$	$	$	$	$
1823920	102553	INDUSTRIAL FINANSWER-WYOMING - PPL 2005	WYP	$11	$	$	$	$11	$11	$	$	$	$	$
1823920	102554	SELF AUDIT - WYOMING - PPL 2005	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102555	REFRIGERATOR RECYCLING - PPL WYOMING - 2	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102556	1823920/102556	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	102562	APPLIANCE INCENTIVE - WASHWISE - WASHING	OTHER	$53	$	$	$	$	$	$	$	$	$	$53
1823920	102586	IRRIGATION LOAD CONTROL - UTAH - 2005	OTHER	$3	$	$	$	$	$	$	$	$	$	$3
1823920	102702	ENERGY FINANSWER - WYOMING PPL - 2006	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102703	INDUSTRIAL FINANSWER-WYOMING-PPL 2006	WYP	$3	$	$	$	$3	$3	$	$	$	$	$
1823920	102706	LOW INCOME-UTAH-2006	OTHER	$119	$	$	$	$	$	$	$	$	$	$119
1823920	102707	REFRIGERATOR RECYCLING PGM-UTAH-2006	OTHER	$3,752	$	$	$	$	$	$	$	$	$	$3,752
1823920	102708	A/C LOAD CONTROL-RESIDENTIAL/UTAH-2006	OTHER	$8,624	$	$	$	$	$	$	$	$	$	$8,624
1823920	102709	AIR CONDITIONING-UTAH-2006	OTHER	$1,499	$	$	$	$	$	$	$	$	$	$1,499
1823920	102712	ENERGY FINANSWER-UTAH-2006	OTHER	$2,187	$	$	$	$	$	$	$	$	$	$2,187
1823920	102713	INDUSTRIAL FINANSWER-WYOMING-UTAH-2006	OTHER	$2,748	$	$	$	$	$	$	$	$	$	$2,748
1823920	102717	COMMERCIAL SELF-DIRECT-UTAH-2006	OTHER	$65	$	$	$	$	$	$	$	$	$	$65
1823920	102718	INDUSTRIAL SELF-DIRECT-UTAH-2006	OTHER	$122	$	$	$	$	$	$	$	$	$	$122
1823920	102719	RESIDENTIAL NEW CONSTRUCTION-UTAH-2006	OTHER	$1,848	$	$	$	$	$	$	$	$	$	$1,848
1823920	102720	COMMERCIAL FINANSWER EXPRESS-UTAH-2006	OTHER	$2,469	$	$	$	$	$	$	$	$	$	$2,469
1823920	102721	INDUSTRIAL FINANSWER-UTAH-2006	OTHER	$536	$	$	$	$	$	$	$	$	$	$536
1823920	102722	RETROFIT COMMISSIONING PROGRAM -UTAH-200	OTHER	$211	$	$	$	$	$	$	$	$	$	$211
1823920	102723	C&I LIGHTING LOAD CONTROL -UTAH-2006	OTHER	$8	$	$	$	$	$	$	$	$	$	$8
1823920	102725	CALIFORNIA DSM EXPENSE-2006	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	102759	HOME ENERGY EFF INCENTIVE PROG-UTAH-2006	OTHER	$241	$	$	$	$	$	$	$	$	$	$241
1823920	102760	HOME ENERGY EFF INCENTIVE PROG-WA-2006	OTHER	$4,736	$	$	$	$	$	$	$	$	$	$4,736
1823920	102761	HOME ENERGY EFF INCENTIVE PROG-PPL WYOMI	WYP	$8	$	$	$	$8	$8	$	$	$	$	$
1823920	102767	DSR COSTS BEING AMORTIZED	OTHER	-$20,817	$	$	$	$	$	$	$	$	$	-$20,817
1823920	102788	DSR COSTS BEING AMORTIZED	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102789	DSR COSTS BEING AMORTIZED	WYP	$3	$	$	$	$3	$3	$	$	$	$	$
1823920	102790	DSR COSTS BEING AMORTIZED	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102791	DSR COSTS BEING AMORTIZED	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102792	DSR COSTS BEING AMORTIZED	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102796	DSR COSTS BEING AMORTIZED	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	102798	ENERGY FINANSWER - WYOMING PPL - 2007	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102799	MAJOR CUSTOMER 99	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102802	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	WYP	$6	$	$	$	$6	$6	$	$	$	$	$
1823920	102803	LOW-INCOME WEATHERIZATION - WYOMING PPL-	WYP	$3	$	$	$	$3	$3	$	$	$	$	$
1823920	102804	COMMERCIAL FINANSWER EXPRESS - WY - 2007	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102805	INDUSTRIAL FINANSWER EXPRESS - WY - 2007	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102806	SELF DIRECT - COMMERCIAL - WY - 2007	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102807	SELF DIRECT - INDUSTRIAL - WY - 2007	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102819	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$5,982	$	$	$	$	$	$	$	$	$	$5,982
1823920	102820	AIR CONDITIONING - UTAH - 2007	OTHER	$883	$	$	$	$	$	$	$	$	$	$883
1823920	102821	ENERGY FINANSWER - UTAH - 2007	OTHER	$1,952	$	$	$	$	$	$	$	$	$	$1,952
1823920	102822	INDUSTRIAL FINANSWER - UTAH - 2007	OTHER	$3,369	$	$	$	$	$	$	$	$	$	$3,369
1823920	102823	LOW INCOME - UTAH - 2007	OTHER	$117	$	$	$	$	$	$	$	$	$	$117
1823920	102824	POWER FORWARD - UTAH - 2007	OTHER	$50	$	$	$	$	$	$	$	$	$	$50
1823920	102825	REFRIGERATOR RECYCLING PGM- UTAH - 2007	OTHER	$3,399	$	$	$	$	$	$	$	$	$	$3,399
1823920	102826	COMMERCIAL SELF-DIRECT - UTAH - 2007	OTHER	$61	$	$	$	$	$	$	$	$	$	$61
1823920	102827	INDUSTRIAL SELF-DIRECT - UTAH - 2007	OTHER	$108	$	$	$	$	$	$	$	$	$	$108

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1823920	102828	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$1,936	$	$	$	$	$	$	$	$	$	$1,936
1823920	102829	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$3,277	$	$	$	$	$	$	$	$	$	$3,277
1823920	102830	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$968	$	$	$	$	$	$	$	$	$	$968
1823920	102831	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$187	$	$	$	$	$	$	$	$	$	$187
1823920	102833	IRRIGATION LOAD CONTROL - UTAH - 2007	OTHER	$277	$	$	$	$	$	$	$	$	$	$277
1823920	102834	HOME ENERGY EFF INCENTIVE PROG - UT 2007	OTHER	$3,034	$	$	$	$	$	$	$	$	$	$3,034
1823920	102883	CALIFORNIA DSM EXPENSE - 2008	CA	$	$	$	$	$	$	$	$	$	$	$
1823920	102885	ENERGY FINANSWER - WYOMING PPL - 2008	WYP	$4	$	$	$	$4	$4	$	$	$	$	$
1823920	102886	INDUSTRIAL FINANSWER - WYOMING PPL - 200	WYP	$5	$	$	$	$5	$5	$	$	$	$	$
1823920	102888	REFRIGERATOR RECYCLING - WYOMING 2008	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102889	HOME ENERGY EFF INCENTIVE PROGRAM - WYOM	WYP	$5	$	$	$	$5	$5	$	$	$	$	$
1823920	102890	LOW INCOME WEATHERIZATION - WYOMING 2008	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102891	COMMERCIAL FINANSWER EXPRESS - WYOMING 2	WYP	$1	$	$	$	$1	$1	$	$	$	$	$
1823920	102892	INDUSTRIAL FINANSWER EXPRESS - WY - 2008	WYP	$	$	$	$	$	$	$	$	$	$	$
1823920	102893	SELF DIRECT COMMERCIAL - WYOMING 2008	WYP	$2	$	$	$	$2	$2	$	$	$	$	$
1823920	102894	SELF DIRECT INDUSTRIAL - WYOMING 2008	WYP	$3	$	$	$	$3	$3	$	$	$	$	$
1823920	102906	AC LOAD CONTROL - RESIDENTIAL - UTAH 200	OTHER	$7,175	$	$	$	$	$	$	$	$	$	$7,175
1823920	102907	AIR CONDITIONING - UTAH 2008	OTHER	$526	$	$	$	$	$	$	$	$	$	$526
1823920	102908	ENERGY FINANSWER - UTAH - 2008	OTHER	$3,466	$	$	$	$	$	$	$	$	$	$3,466
1823920	102909	INDUSTRIAL FINANSWER - UTAH - 2008	OTHER	$4,289	$	$	$	$	$	$	$	$	$	$4,289
1823920	102910	LOW INCOME - UTAH 2008	OTHER	$127	$	$	$	$	$	$	$	$	$	$127
1823920	102911	POWER FORWARD - UTAH - 2008	OTHER	$50	$	$	$	$	$	$	$	$	$	$50
1823920	102912	REFRIGERATOR RECYCLING - UTAH - 2008	OTHER	$2,570	$	$	$	$	$	$	$	$	$	$2,570
1823920	102913	COMMERCIAL SELF DIRECT - UTAH - 2008	OTHER	$83	$	$	$	$	$	$	$	$	$	$83
1823920	102914	INDUSTRIAL SELF DIRECT - UTAH - 2008	OTHER	$126	$	$	$	$	$	$	$	$	$	$126
1823920	102915	RESIDENTIAL NEW CONSTRUCTION - UTAH 2008	OTHER	$1,664	$	$	$	$	$	$	$	$	$	$1,664
1823920	102916	COMMERCIAL FINANSWER EXPRESS - UTAH 2008	OTHER	$3,791	$	$	$	$	$	$	$	$	$	$3,791
1823920	102917	INDUSTRIAL FINANSWER EXPRESS - UTAH 2008	OTHER	$1,133	$	$	$	$	$	$	$	$	$	$1,133
1823920	102918	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$1,053	$	$	$	$	$	$	$	$	$	$1,053
1823920	102919	C&I LIGHTING LOAD CONTROL - UTAH - 2008	OTHER	$4	$	$	$	$	$	$	$	$	$	$4
1823920	102920	IRRIGATION LOAD CONTROL - UTAH	OTHER	$762	$	$	$	$	$	$	$	$	$	$762
1823920	102921	HOME ENERGY EFF INCENTIVE PROGRAM - UTAH	OTHER	$7,817	$	$	$	$	$	$	$	$	$	$7,817
1823920	102964	CALIFORNIA DSM EXPENSE - 2009	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	102976	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$9,817	$	$	$	$	$	$	$	$	$	$9,817
1823920	102977	AIR CONDITIONING - UTAH - 2009	OTHER	$500	$	$	$	$	$	$	$	$	$	$500
1823920	102978	ENERGY FINANSWER - UTAH - 2009	OTHER	$2,532	$	$	$	$	$	$	$	$	$	$2,532
1823920	102979	INDUSTRIAL FINANSWER - UTAH - 2009	OTHER	$5,215	$	$	$	$	$	$	$	$	$	$5,215
1823920	102980	LOW INCOME - UTAH - 2009	OTHER	$162	$	$	$	$	$	$	$	$	$	$162
1823920	102981	POWER FORWARD - UTAH - 2009	OTHER	$50	$	$	$	$	$	$	$	$	$	$50
1823920	102982	REFRIGERATOR RECYCLING PGM- UTAH - 2009	OTHER	$2,339	$	$	$	$	$	$	$	$	$	$2,339
1823920	102983	COMMERCIAL SELF-DIRECT - UTAH - 2009	OTHER	$53	$	$	$	$	$	$	$	$	$	$53
1823920	102984	INDUSTRIAL SELF-DIRECT - UTAH - 2009	OTHER	$72	$	$	$	$	$	$	$	$	$	$72
1823920	102985	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$1,446	$	$	$	$	$	$	$	$	$	$1,446
1823920	102986	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$3,258	$	$	$	$	$	$	$	$	$	$3,258
1823920	102987	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$776	$	$	$	$	$	$	$	$	$	$776
1823920	102988	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$947	$	$	$	$	$	$	$	$	$	$947
1823920	102990	IRRIGATION LOAD CONTROL - UTAH - 2009	OTHER	$2,732	$	$	$	$	$	$	$	$	$	$2,732
1823920	102991	HOME ENERGY EFF INCENTIVE PROG - UT 2009	OTHER	$25,439	$	$	$	$	$	$	$	$	$	$25,439
1823920	102992	ENERGY FINANSWER - WYOMING PPL - 2009	OTHER	$21	$	$	$	$	$	$	$	$	$	$21
1823920	102993	INDUSTRIAL FINANSWER-WYOMING - PPL 2009	OTHER	$96	$	$	$	$	$	$	$	$	$	$96
1823920	102995	REFRIGERATOR RECYCLING - PPL WYOMING - 2	OTHER	$140	$	$	$	$	$	$	$	$	$	$140
1823920	102996	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	OTHER	$439	$	$	$	$	$	$	$	$	$	$439
1823920	102997	LOW-INCOME WEATHERIZATION - WYOMING PPL	OTHER	$86	$	$	$	$	$	$	$	$	$	$86
1823920	102998	COMMERCIAL FINANSWER EXPRESS - WY - 2009	OTHER	$139	$	$	$	$	$	$	$	$	$	$139
1823920	102999	INDUSTRIAL FINANSWER EXPRESS - WY - 2009	OTHER	$59	$	$	$	$	$	$	$	$	$	$59

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1823920	103000	SELF DIRECT - COMMERCIAL - WY - 2009	OTHER	$5	$	$	$	$	$	$	$	$	$	$5
1823920	103001	SELF DIRECT - INDUSTRIAL - WY - 2009	OTHER	$12	$	$	$	$	$	$	$	$	$	$12
1823920	103003	MAIN CHECK DISB-WIRES/ACH IN CLEAR ACCT	OTHER	$2	$	$	$	$	$	$	$	$	$	$2
1823920	103004	MAIN CHECK DISB-WIRES/ACH OUT CLEAR ACCT	OTHER	$2	$	$	$	$	$	$	$	$	$	$2
1823920	103005	COMMERCIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	$236	$	$	$	$	$	$	$	$	$	$236
1823920	103006	INDUSTRIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	$34	$	$	$	$	$	$	$	$	$	$34
1823920	103007	ENERGY FINANSWER Cat 2 - WY 2009	OTHER	$40	$	$	$	$	$	$	$	$	$	$40
1823920	103008	INDUSTRIAL FINANSWER Cat 2 -WY 2009	OTHER	$34	$	$	$	$	$	$	$	$	$	$34
1823920	103012	WYOMING REV RECOVERY - SBC OFFSET CAT 1	OTHER	-$3,400	$	$	$	$	$	$	$	$	$	-$3,400
1823920	103013	WYOMING REV RECOVERY - SBC OFFSET CAT 2	OTHER	-$2,182	$	$	$	$	$	$	$	$	$	-$2,182
1823920	103014	WYOMING REV RECOVERY - SBC OFFSET CAT 3	OTHER	-$2,720	$	$	$	$	$	$	$	$	$	-$2,720
1823920	103031	OUTREACH and COMMUNICATIONS - UT 2009	OTHER	$571	$	$	$	$	$	$	$	$	$	$571
1823920	103059	CALIFORNIA DSM EXPENSE - 2010	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	103071	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$4,836	$	$	$	$	$	$	$	$	$	$4,836
1823920	103072	AIR CONDITIONING - UTAH - 2010	OTHER	$1,490	$	$	$	$	$	$	$	$	$	$1,490
1823920	103073	ENERGY FINANSWER - UTAH - 2010	OTHER	$3,246	$	$	$	$	$	$	$	$	$	$3,246
1823920	103074	INDUSTRIAL FINANSWER - UTAH - 2010	OTHER	$4,524	$	$	$	$	$	$	$	$	$	$4,524
1823920	103075	LOW INCOME - UTAH - 2010	OTHER	$258	$	$	$	$	$	$	$	$	$	$258
1823920	103076	POWER FORWARD - UTAH # 2010	OTHER	$50	$	$	$	$	$	$	$	$	$	$50
1823920	103077	REFRIGERATOR RECYCLING PGM- UTAH - 2010	OTHER	$2,370	$	$	$	$	$	$	$	$	$	$2,370
1823920	103078	COMMERCIAL SELF-DIRECT - UTAH - 2010	OTHER	$187	$	$	$	$	$	$	$	$	$	$187
1823920	103079	INDUSTRIAL SELF-DIRECT - UTAH - 2010	OTHER	$330	$	$	$	$	$	$	$	$	$	$330
1823920	103080	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$2,605	$	$	$	$	$	$	$	$	$	$2,605
1823920	103081	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$4,107	$	$	$	$	$	$	$	$	$	$4,107
1823920	103082	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$1,019	$	$	$	$	$	$	$	$	$	$1,019
1823920	103083	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$986	$	$	$	$	$	$	$	$	$	$986
1823920	103085	IRRIGATION LOAD CONTROL - UTAH - 2010	OTHER	$2,513	$	$	$	$	$	$	$	$	$	$2,513
1823920	103086	HOME ENERGY EFF INCENTIVE PROG - UT 2010	OTHER	$16,876	$	$	$	$	$	$	$	$	$	$16,876
1823920	103087	OUTREACH and COMMUNICATIONS - UT 2010	OTHER	$1,485	$	$	$	$	$	$	$	$	$	$1,485
1823920	103089	ENERGY FINANSWER-WY-2010 CAT3	OTHER	$11	$	$	$	$	$	$	$	$	$	$11
1823920	103090	INDUSTRIAL FINANSWER-WY-2010 CAT3	OTHER	$669	$	$	$	$	$	$	$	$	$	$669
1823920	103092	REFRIGERATOR RECYCLING-WY -2010 CAT1	OTHER	$176	$	$	$	$	$	$	$	$	$	$176
1823920	103093	HOME ENERGY EFF INCENT PROG Y-2010 CAT1	OTHER	$740	$	$	$	$	$	$	$	$	$	$740
1823920	103094	LOW-INCOME WEATHERZTN - WY 2010 CAT1	OTHER	$49	$	$	$	$	$	$	$	$	$	$49
1823920	103095	COMMERCIAL FINANSWER EXP WY-2010 CAT3	OTHER	$65	$	$	$	$	$	$	$	$	$	$65
1823920	103096	INDUSTRIAL FINANSWER EXP WY-2010 CAT3	OTHER	$127	$	$	$	$	$	$	$	$	$	$127
1823920	103097	SELF DIRECT - COMMERCIAL -WY-2010 CAT3	OTHER	$3	$	$	$	$	$	$	$	$	$	$3
1823920	103098	SELF DIRECT -INDUSTRIAL -WY-2010 CAT3	OTHER	$12	$	$	$	$	$	$	$	$	$	$12
1823920	103099	COMMERCIAL FINANSWER EXP- WY-2010 CAT2	OTHER	$587	$	$	$	$	$	$	$	$	$	$587
1823920	103100	INDUSTRIAL FINAN EXPRESS WY-2010 CAT2	OTHER	$55	$	$	$	$	$	$	$	$	$	$55
1823920	103101	ENERGY FINANSWER -WY 2010 CAT2	OTHER	$186	$	$	$	$	$	$	$	$	$	$186
1823920	103102	INDUSTRIAL FINANSWER -WY 2010 CAT2	OTHER	$125	$	$	$	$	$	$	$	$	$	$125
1823920	103103	Check Disb-Wires/ACH In Clearing - BT	OTHER	$1	$	$	$	$	$	$	$	$	$	$1
1823920	103104	Check Disb-Wires/ACH Out Clearing - BT	OTHER	$3	$	$	$	$	$	$	$	$	$	$3
1823920	103137	Company Initiatives DEI Study- Washingto	OTHER	$385	$	$	$	$	$	$	$	$	$	$385
1823920	103163	Commercial Direct Install - Utah - 2011	OTHER	$3	$	$	$	$	$	$	$	$	$	$3
1823920	103164	Commercial Curtailment - Utah - 2011	OTHER	$22	$	$	$	$	$	$	$	$	$	$22
1823920	103166	Commercial Curtailment - Washington	OTHER	$2	$	$	$	$	$	$	$	$	$	$2
1823920	103168	CALIFORNIA DSM EXPENSE - 2011	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	103169	Commercial Curtailment - Oregon	OTHER	$21	$	$	$	$	$	$	$	$	$	$21
1823920	103181	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$1,944	$	$	$	$	$	$	$	$	$	$1,944
1823920	103182	AIR CONDITIONING - UTAH - 2011	OTHER	$375	$	$	$	$	$	$	$	$	$	$375
1823920	103183	ENERGY FINANSWER - UTAH - 2011	OTHER	$1,109	$	$	$	$	$	$	$	$	$	$1,109
1823920	103184	INDUSTRIAL FINANSWER - UTAH - 2011	OTHER	$890	$	$	$	$	$	$	$	$	$	$890
1823920	103185	LOW INCOME - UTAH - 2011	OTHER	$151	$	$	$	$	$	$	$	$	$	$151

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1823920	103186	Power Forward - Utah - 2011	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823920	103187	REFRIGERATOR RECYCLING PGM- UTAH - 2011	OTHER	$697	$	$	$	$	$	$	$	$	$	$697
1823920	103188	COMMERCIAL SELF-DIRECT - UTAH - 2011	OTHER	$75	$	$	$	$	$	$	$	$	$	$75
1823920	103189	INDUSTRIAL SELF-DIRECT - UTAH - 2011	OTHER	$137	$	$	$	$	$	$	$	$	$	$137
1823920	103190	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$1,531	$	$	$	$	$	$	$	$	$	$1,531
1823920	103191	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$2,037	$	$	$	$	$	$	$	$	$	$2,037
1823920	103192	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$647	$	$	$	$	$	$	$	$	$	$647
1823920	103193	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$233	$	$	$	$	$	$	$	$	$	$233
1823920	103195	IRRIGATION LOAD CONTROL - UTAH - 2011	OTHER	$533	$	$	$	$	$	$	$	$	$	$533
1823920	103196	HOME ENERGY EFF INCENTIVE PROG - UT 2011	OTHER	$5,711	$	$	$	$	$	$	$	$	$	$5,711
1823920	103197	OUTREACH and COMMUNICATIONS - UT 2011	OTHER	$940	$	$	$	$	$	$	$	$	$	$940
1823920	103199	ENERGY FINANSWER-WY-2011 CAT3	OTHER	$22	$	$	$	$	$	$	$	$	$	$22
1823920	103200	INDUSTRIAL FINANSWER-WY-2011 CAT3	OTHER	$266	$	$	$	$	$	$	$	$	$	$266
1823920	103202	REFRIGERATOR RECYCLING-WY -2011 CAT1	OTHER	$57	$	$	$	$	$	$	$	$	$	$57
1823920	103203	HOME ENERGY EFF INCENT PROG Y-2011 CAT1	OTHER	$563	$	$	$	$	$	$	$	$	$	$563
1823920	103204	Low-Income Weatherztn - Wy 2011 CAT1	OTHER	$8	$	$	$	$	$	$	$	$	$	$8
1823920	103205	COMMERCIAL FINANSWER EXP WY-2011 CAT3	OTHER	$24	$	$	$	$	$	$	$	$	$	$24
1823920	103206	INDUSTRIAL FINANSWER EXP WY-2011 CAT3	OTHER	$59	$	$	$	$	$	$	$	$	$	$59
1823920	103207	Self Direct - Commercial -Wy-2011 CAT3	OTHER	$3	$	$	$	$	$	$	$	$	$	$3
1823920	103208	Self Direct -Industrial -Wy-2011 CAT3	OTHER	$92	$	$	$	$	$	$	$	$	$	$92
1823920	103209	COMMERCIAL FINANSWER EXP- WY-2011 CAT2	OTHER	$347	$	$	$	$	$	$	$	$	$	$347
1823920	103210	INDUSTRIAL FINAN EXPRESS WY-2011 CAT2	OTHER	$23	$	$	$	$	$	$	$	$	$	$23
1823920	103211	ENERGY FINANSWER -WY 2011 CAT2	OTHER	$19	$	$	$	$	$	$	$	$	$	$19
1823920	103212	INDUSTRIAL FINANSWER -WY 2011 CAT2	OTHER	$19	$	$	$	$	$	$	$	$	$	$19
1823920	103213	Self Direct - Commercial Wy-2011 CAT2	OTHER	$1	$	$	$	$	$	$	$	$	$	$1
1823920	103214	Self Direct- Industrial Wy-2011 CAT2	OTHER	$4	$	$	$	$	$	$	$	$	$	$4
1823920	103277	OUTREACH & COMM- WATTSMART - EVALUATION	OTHER	$116	$	$	$	$	$	$	$	$	$	$116
1823920 Total			**0**	**-$35,991**	**$**	**$**	**$**	**$127**	**$127**	**$6**	**$48**	**$**	**$**	**-$36,172**
1823930	101881	HASSEL FREE EFFICIENCY IDAHO-UT 1999	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101883	LOW INCOME WEATHER - 1999	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101884	SELF AUDIT - 1999	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101886	ENERGY FINANSWER - IDAHO UP&L - 1999	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101887	INDUSTRIAL FINANSWER - IDAHO UP&L - 199	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101914	NEEA - IDAHO UTAH 1999	IDU	$16	$	$	$	$	$	$	$16	$	$	$
1823930	101917	WEATHERIZATION LOANS - IDAHO UP&L - 1999	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	101920	LOW INCOME BID WZ - IDU 1999	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101926	ENERGY FINANSWER - IDAHO-UT 2000	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	101927	HASSLEFREE EFFICIENCY - IDAHO-UT 2000	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101928	INDUSTRIAL FINANSWER - IDAHO-UT 2000	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	101929	LOW INCOME WZ - IDAHO-UT 2000	IDU	$4	$	$	$	$	$	$	$4	$	$	$
1823930	101930	SELF AUDIT - IDAHO-UT 2000	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101950	"LOW INCOME BID WZ, ID 2000"	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	101955	NEEA - IDAHO-UT 2000	IDU	$39	$	$	$	$	$	$	$39	$	$	$
1823930	102062	ENERGY FINANSWER - ID-UT 2001	IDU	$9	$	$	$	$	$	$	$9	$	$	$
1823930	102063	HASSLEFREE EFFICIENCY - ID-UT 2001	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	102064	INDUSTRIAL FINANSWER - ID-UT 2001	IDU	$4	$	$	$	$	$	$	$4	$	$	$
1823930	102065	LOW INCOME WZ - ID-UT 2001	IDU	$12	$	$	$	$	$	$	$12	$	$	$
1823930	102066	SELF AUDIT - ID-UT 2001	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	102079	NEEA - IDAHO - UTAH 2001	IDU	$56	$	$	$	$	$	$	$56	$	$	$
1823930	102180	HASSLEFREE EFFICIENCY - IDU - 2002	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102181	INDUSTRIAL FINANSWER - IDU - 2002	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102182	LOW INCOME WZ - IDU - 2002	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	102183	SELF AUDIT - IDU - 2002	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102184	NEEA - IDU - 2002 ACTUALS	IDU	$74	$	$	$	$	$	$	$74	$	$	$
1823930	102204	COMPACT FLUORESCENT - UT 2002	IDU	$2	$	$	$	$	$	$	$2	$	$	$

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1823930	102216	WEATHERIZATION LOANS - RES UT 2003	IDU	$3	$	$	$	$	$	$	$3	$	$	$
1823930	102217	COMPACT FLOURESCENT - IDU 2002	IDU	$5	$	$	$	$	$	$	$5	$	$	$
1823930	102218	ENERGY FINANSWER - IDU 2003	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102219	INDUSTRIAL FINANSWER - IDU 2003	IDU	$72	$	$	$	$	$	$	$72	$	$	$
1823930	102220	LOAN INCOME WZ - IDU 2003	IDU	$5	$	$	$	$	$	$	$5	$	$	$
1823930	102221	NEEA - IDU 2003	IDU	$159	$	$	$	$	$	$	$159	$	$	$
1823930	102222	SELF AUDIT - IDAHO-UT 2003	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102263	IRRIGATION INTERRUPTIBLE IDAHO - UT 2003	IDU	$108	$	$	$	$	$	$	$108	$	$	$
1823930	102352	INDUSTRIAL FINANSWER - IDU 2004	IDU	$46	$	$	$	$	$	$	$46	$	$	$
1823930	102353	LOW INCOME WZ - IDU 2004	IDU	$21	$	$	$	$	$	$	$21	$	$	$
1823930	102354	NEEA - IDU 2004	IDU	$95	$	$	$	$	$	$	$95	$	$	$
1823930	102355	SELF AUDIT - IDAHO-UT 2004	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102356	IRRIGATION INTERRUPTIBLE - IDU 2004	IDU	$136	$	$	$	$	$	$	$136	$	$	$
1823930	102358	WEATHERIZATION LOANS - RESIDENTIAL UT 20	IDU	$3	$	$	$	$	$	$	$3	$	$	$
1823930	102519	INDUSTRIAL FINANSWER - IDAHO-UT 2005	IDU	$28	$	$	$	$	$	$	$28	$	$	$
1823930	102520	LOW INCOME WZ - IDAHO-UT 2005	IDU	$32	$	$	$	$	$	$	$32	$	$	$
1823930	102521	NEEA - IDAHO - UTAH 2005	IDU	$141	$	$	$	$	$	$	$141	$	$	$
1823930	102522	SELF AUDIT - IDAHO-UT 2005	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102523	IRRIGATION INTERRUPTIBLE IDAHO - UT 2005	IDU	$207	$	$	$	$	$	$	$207	$	$	$
1823930	102524	WEATHERIZATION LOANS - RESIDENTIAL/ID-UT	IDU	$1	$	$	$	$	$	$	$1	$	$	$
1823930	102573	ENERGY FINANSWER ID/UT 2006	IDU	$	$	$	$	$	$	$	$	$	$	$
1823930	102574	INDUSTRIAL FINANSWER-ID-UT 2006	IDU	$3	$	$	$	$	$	$	$3	$	$	$
1823930	102575	LOW INCOME WZ -ID-UT 2006	IDU	$144	$	$	$	$	$	$	$144	$	$	$
1823930	102576	NEEA-IDAHO-UTAH 2006	IDU	$359	$	$	$	$	$	$	$359	$	$	$
1823930	102577	IRRIGATION INTERRUPTIBLE ID-UT 2006	IDU	$361	$	$	$	$	$	$	$361	$	$	$
1823930	102578	WEATHERIZATION LOANS-RESDL/ID-UT 2006	IDU	$2	$	$	$	$	$	$	$2	$	$	$
1823930	102579	REFRIGERATOR RECYCLING PGM-ID-UT 2006	IDU	$143	$	$	$	$	$	$	$143	$	$	$
1823930	102580	COMMERCIAL FINANSWER EXPR-ID-UT 2006	IDU	$117	$	$	$	$	$	$	$117	$	$	$
1823930	102581	INDUSTRIAL FINANSWER EXPR-ID-UT 2006	IDU	$47	$	$	$	$	$	$	$47	$	$	$
1823930	102582	IRRIGATION EFFICIENCY PRGRM-ID-UT 2006	IDU	$246	$	$	$	$	$	$	$246	$	$	$
1823930	102758	HOME ENERGY EFFICIENCY INCENTIVE PROGM-I	IDU	$103	$	$	$	$	$	$	$103	$	$	$
1823930	102808	WEATHERIZATION LOANS RESIDTL/ ID-UT 2007	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823930	102809	ENERGY FINANSWER IDU 2007	OTHER	$4	$	$	$	$	$	$	$	$	$	$4
1823930	102810	Industrial Finanswer ID - 2007	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823930	102811	IRRIGATION INTERRUPTIBLE ID-UT 2007	OTHER	$846	$	$	$	$	$	$	$	$	$	$846
1823930	102812	LOW INCOME WZ - ID-UT 2007	OTHER	$101	$	$	$	$	$	$	$	$	$	$101
1823930	102813	NEEA - IDAHO - UTAH 2007	OTHER	$361	$	$	$	$	$	$	$	$	$	$361
1823930	102814	REFRIGERATOR RECYCLING PGM - ID-UT 2007	OTHER	$123	$	$	$	$	$	$	$	$	$	$123
1823930	102815	COMMERCIAL FINANSWER EXPR - ID-UT 2007	OTHER	$61	$	$	$	$	$	$	$	$	$	$61
1823930	102816	INDUSTRIAL FINANSWER EXPR - ID-UT 2007	OTHER	$120	$	$	$	$	$	$	$	$	$	$120
1823930	102817	IRRIGATION EFFICIENCY PRGRM - ID-UT 2007	OTHER	$275	$	$	$	$	$	$	$	$	$	$275
1823930	102818	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$229	$	$	$	$	$	$	$	$	$	$229
1823930	102896	ENERGY FINANSWER - ID/UT 2008	OTHER	$19	$	$	$	$	$	$	$	$	$	$19
1823930	102897	INDUSTRIAL FINANSWER - ID-UT 2008	OTHER	$102	$	$	$	$	$	$	$	$	$	$102
1823930	102898	IRRIGATION INTERRUPTIBLE - IDAHO - 2008	OTHER	$3,127	$	$	$	$	$	$	$	$	$	$3,127
1823930	102899	LOW INCOME WEATHERIZATION - IDAHO 2008	OTHER	$165	$	$	$	$	$	$	$	$	$	$165
1823930	102900	NEEA - IDAHO - 2008	OTHER	$317	$	$	$	$	$	$	$	$	$	$317
1823930	102901	REFRIGERATOR RECYCLING PRGM - IDAHO 2008	OTHER	$113	$	$	$	$	$	$	$	$	$	$113
1823930	102902	COMMERCIAL FINANSWER EXPRESS - IDAHO 200	OTHER	$108	$	$	$	$	$	$	$	$	$	$108
1823930	102903	INDUSTRIAL FINANSWER - IDAHO - 2008	OTHER	$58	$	$	$	$	$	$	$	$	$	$58
1823930	102904	IRRIGATION EFFICIENCY PRGM - IDAHO - 200	OTHER	$268	$	$	$	$	$	$	$	$	$	$268
1823930	102905	HOME ENERGY EFF INCENTIVE PROGRAM - IDAH	OTHER	$490	$	$	$	$	$	$	$	$	$	$490
1823930	102957	CATEGORY 1 - WYOMING - 2008	OTHER	$17	$	$	$	$	$	$	$	$	$	$17
1823930	102958	CATEGORY 2 - WYOMING - 2008	OTHER	$9	$	$	$	$	$	$	$	$	$	$9
1823930	102959	CATEGORY 3 - WYOMING - 2008	OTHER	$33	$	$	$	$	$	$	$	$	$	$33

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1823930	102966	ENERGY FINANSWER - ID/UT 2009	OTHER	$50	$	$	$	$	$	$	$	$	$	$50
1823930	102967	INDUSTRIAL FINANSWER - ID-UT 2009	OTHER	$309	$	$	$	$	$	$	$	$	$	$309
1823930	102968	IRRIGATION INTERRUPTIBLE ID-UT 2009	OTHER	$3,816	$	$	$	$	$	$	$	$	$	$3,816
1823930	102969	LOW INCOME WZ - ID-UT 2009	OTHER	$198	$	$	$	$	$	$	$	$	$	$198
1823930	102970	NEEA - IDAHO - UTAH 2009	OTHER	$287	$	$	$	$	$	$	$	$	$	$287
1823930	102971	REFRIGERATOR RECYCLING PGM - ID-UT 2009	OTHER	$108	$	$	$	$	$	$	$	$	$	$108
1823930	102972	COMMERCIAL FINANSWER EXPR - ID-UT 2009	OTHER	$190	$	$	$	$	$	$	$	$	$	$190
1823930	102973	INDUSTRIAL FINANSWER EXPR - ID-UT 2009	OTHER	$74	$	$	$	$	$	$	$	$	$	$74
1823930	102974	IRRIGATION EFFICIENCY PRGRM - ID-UT 2009	OTHER	$807	$	$	$	$	$	$	$	$	$	$807
1823930	102975	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$594	$	$	$	$	$	$	$	$	$	$594
1823930	103061	ENERGY FINANSWER - ID/UT 2010	OTHER	$47	$	$	$	$	$	$	$	$	$	$47
1823930	103062	INDUSTRIAL FINANSWER - ID-UT 2010	OTHER	$322	$	$	$	$	$	$	$	$	$	$322
1823930	103063	IRRIGATION INTERRUPTIBLE ID-UT 2010	OTHER	$4,283	$	$	$	$	$	$	$	$	$	$4,283
1823930	103064	LOW INCOME WZ - ID-UT 2010	OTHER	$134	$	$	$	$	$	$	$	$	$	$134
1823930	103065	NEEA - IDAHO - UTAH 2010	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823930	103066	REFRIGERATOR RECYCLING PGM - ID-UT 2010	OTHER	$166	$	$	$	$	$	$	$	$	$	$166
1823930	103067	COMMERCIAL FINANSWER EXPR - ID-UT 2010	OTHER	$513	$	$	$	$	$	$	$	$	$	$513
1823930	103068	INDUSTRIAL FINANSWER EXPR - ID-UT 2010	OTHER	$107	$	$	$	$	$	$	$	$	$	$107
1823930	103069	IRRIGATION EFFICIENCY PRGRM - ID-UT 2010	OTHER	$637	$	$	$	$	$	$	$	$	$	$637
1823930	103070	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$1,305	$	$	$	$	$	$	$	$	$	$1,305
1823930	103171	ENERGY FINANSWER - ID/UT 2011	OTHER	$10	$	$	$	$	$	$	$	$	$	$10
1823930	103172	INDUSTRIAL FINANSWER - ID-UT 2011	OTHER	$54	$	$	$	$	$	$	$	$	$	$54
1823930	103173	IRRIGATION INTERRUPTIBLE ID-UT 2011	OTHER	$36	$	$	$	$	$	$	$	$	$	$36
1823930	103174	LOW INCOME WZ - ID-UT 2011	OTHER	$240	$	$	$	$	$	$	$	$	$	$240
1823930	103176	REFRIGERATOR RECYCLING PGM - ID-UT 2011	OTHER	$34	$	$	$	$	$	$	$	$	$	$34
1823930	103177	COMMERCIAL FINANSWER EXPR - ID-UT 2011	OTHER	$239	$	$	$	$	$	$	$	$	$	$239
1823930	103178	INDUSTRIAL FINANSWER EXPR - ID-UT 2011	OTHER	$39	$	$	$	$	$	$	$	$	$	$39
1823930	103179	IRRIGATION EFFICIENCY PRGRM - ID-UT 2011	OTHER	$135	$	$	$	$	$	$	$	$	$	$135
1823930	103180	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$355	$	$	$	$	$	$	$	$	$	$355
1823930 Total			**0**	**$24,848**	**$**	**$**	**$**	**$**	**$**	**$**	**$2,810**	**$**	**$**	**$22,038**
1823940	101471	ENERGY FINANSWER96	UT	$1	$	$	$	$	$	$1	$	$	$	$
1823940	101474	IND FINANSWER 96	UT	$	$	$	$	$	$	$	$	$	$	$
1823940	102146	UT CARRYING CHARGE - 2001/2002	OTHER	$4,943	$	$	$	$	$	$	$	$	$	$4,943
1823940	102188	WA REVENUE RECOVERY - CARRYING CHG PENAL	OTHER	-$680	$	$	$	$	$	$	$	$	$	-$680
1823940	102766	DSR CARRYING CHARGES	IDU	$159	$	$	$	$	$	$	$159	$	$	$
1823940	103140	Wy DSM - Cat1 - Carrying Charges	OTHER	-$62	$	$	$	$	$	$	$	$	$	-$62
1823940	103141	Wy DSM - Cat2 - Carrying Charges	OTHER	-$37	$	$	$	$	$	$	$	$	$	-$37
1823940	103142	Wy DSM - Cat3 - Carrying Charges	OTHER	-$53	$	$	$	$	$	$	$	$	$	-$53
1823940	103279	CA CARRYING CHRG LIEE - 2011	OTHER	-$16	$	$	$	$	$	$	$	$	$	-$16
1823940 Total			**0**	**$4,255**	**$**	**$**	**$**	**$**	**$**	**$**	**$159**	**$**	**$**	**$4,095**
1823960	101664	UTAH NET LOST REV - COMM. FINANSWER 1996	UT	$5	$	$	$	$	$	$5	$	$	$	$
1823960	101675	NET LOST REVN 12000	UT	$	$	$	$	$	$	$	$	$	$	$
1823960	101683	NET LOST REVN COMM	UT	$11	$	$	$	$	$	$11	$	$	$	$
1823960	101684	NET LOST REVN COMM	UT	$4	$	$	$	$	$	$4	$	$	$	$
1823960	101687	NET LOST REVN IND	UT	$1	$	$	$	$	$	$1	$	$	$	$
1823960	101688	NET LOST REVN IND	UT	$1	$	$	$	$	$	$1	$	$	$	$
1823960	101691	NET LOST EF RETRO	UT	$3	$	$	$	$	$	$3	$	$	$	$
1823960	101692	NET LOST EF RETRO	UT	$4	$	$	$	$	$	$4	$	$	$	$
1823960	101695	NET LOST EF CUSTOM	UT	$5	$	$	$	$	$	$5	$	$	$	$
1823960	101696	NET LOST EF CUSTOM	UT	$13	$	$	$	$	$	$13	$	$	$	$
1823960	101697	NET LOST EF PRESCRIPT	UT	$	$	$	$	$	$	$	$	$	$	$
1823960	101698	NET LOST EF PRESCRIPT	UT	$1	$	$	$	$	$	$1	$	$	$	$
1823960	101699	NET LOST EF COMMERCIAL	UT	$	$	$	$	$	$	$	$	$	$	$
1823960	101700	NET LOST EF COMMERCIAL	UT	$8	$	$	$	$	$	$8	$	$	$	$
1823960 Total			**0**	**$58**	**$**	**$**	**$**	**$**	**$**	**$58**	**$**	**$**	**$**	**$**

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1823990	186099	Regulatory Asset - Balance Reclass	OTHER	$11,439	$	$	$	$	$	$	$	$	$	$11,439
1823990	186100	Calif Alternative Rate for Energy (CARE)	OTHER	$179	$	$	$	$	$	$	$	$	$	$179
1823990	186501	Powerdale Hydro Decom Reg Asset - CA	CA	$52	$52	$	$	$	$	$	$	$	$	$
1823990	186502	POWERDALE HYDRO DECOM REG ASSET - ID	IDU	$315	$	$	$	$	$	$	$315	$	$	$
1823990	186503	POWERDALE HYDRO DECOM REG ASSET - OR	OR	$265	$	$265	$	$	$	$	$	$	$	$
1823990	186504	POWERDALE HYDRO DECOM REG ASSET - WA	WA	$781	$	$	$781	$	$	$	$	$	$	$
1823990	187003	RETAIL ACCESS PROJECT - INC	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187004	ENERGY TRUST OF OREGON - SB 1149	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187005	SB1149 IMPLEMENT - PHASE 1 RESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187006	SB1149 IMPLEMENT - SMALL NONRESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187028	TRANSITION COSTS-RETIREMENT & DISPLACE	SO	$	$	$	$	$	$	$	$	$	$	$
1823990	187050	CHOLLA PLANT TRANSACTION COSTS	SGCT	$6,828	$115	$1,766	$538	$831	$1,055	$2,969	$385	$224	$	$
1823990	187051	WASHINGTON COLSTRIP #3 REGULATORY ASSET	WA	$500	$	$	$500	$	$	$	$	$	$	$
1823990	187058	TRAIL MOUNTAIN MINE CLOSURE COSTS	SE	$	$	$	$	$	$	$	$	$	$	$
1823990	187059	TRAIL MTN MINE UNRECOVERED INVEST	SE	$	$	$	$	$	$	$	$	$	$	$
1823990	187070	Trail Mtn Mine Costs - Deseret Settlemen	SE	$	$	$	$	$	$	$	$	$	$	$
1823990	187090	REGULATORY ASSET - FEDERAL INT EXP	UT	$2,163	$	$	$	$	$	$2,163	$	$	$	$
1823990	187091	Regulatory Asset - Federal Int Exp (WY)	OTHER	$583	$	$	$	$	$	$	$	$	$	$583
1823990	187092	Reg Asset - Federal Repair Interest (ID)	OTHER	$298	$	$	$	$	$	$	$	$	$	$298
1823990	187096	Reg Asset - Tax Rev Req Adj-WY	WYU	$100	$	$	$	$	$100	$	$	$100	$	$
1823990	187107	GLENROCK MINE EXCLUDING RECLAMATION - UT	UT	$	$	$	$	$	$	$	$	$	$	$
1823990	187110	TRANSITION TEAM COSTS - UT	UT	$	$	$	$	$	$	$	$	$	$	$
1823990	187111	NOELL KEMPF CAP - UT	UT	$	$	$	$	$	$	$	$	$	$	$
1823990	187112	P&M STRIKE AMORT - UT	UT	$	$	$	$	$	$	$	$	$	$	$
1823990	187114	94-98 FED/STATE INCOME TAX AUDIT PAYMENT	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187204	MAY 2000 TRANSITION PLAN COSTS - UT	UT	$	$	$	$	$	$	$	$	$	$	$
1823990	187205	MAY 2000 TRANSITION PLAN COSTS - WYP	WYP	$	$	$	$	$	$	$	$	$	$	$
1823990	187214	OR - MEHC Transition Service Costs	OTHER	$1,892	$	$	$	$	$	$	$	$	$	$1,892
1823990	187215	CA - MEHC Transition Severance Costs	CA	$134	$134	$	$	$	$	$	$	$	$	$
1823990	187221	Reg Asset - Tax Adj on PR Benefits - CA	OTHER	$327	$	$	$	$	$	$	$	$	$	$327
1823990	187222	Reg Asset - Tax Adj on PR Benefits - ID	OTHER	$730	$	$	$	$	$	$	$	$	$	$730
1823990	187223	Reg Asset - Tax Adj on PR Benefits - OR	OTHER	$4,078	$	$	$	$	$	$	$	$	$	$4,078
1823990	187224	Reg Asset - Tax Adj on PR Benefits - UT	OTHER	$5,200	$	$	$	$	$	$	$	$	$	$5,200
1823990	187226	Reg Asset - Tax Adj on PR Benefits - WY	OTHER	$1,991	$	$	$	$	$	$	$	$	$	$1,991
1823990	187300	CA - Jan 2010 Storm Costs	OTHER	$664	$	$	$	$	$	$	$	$	$	$664
1823990	187350	ID - Deferred Overburden Costs	OTHER	$406	$	$	$	$	$	$	$	$	$	$406
1823990	187351	WY - Deferred Overburden Costs	WYP	$1,116	$	$	$	$1,116	$1,116	$	$	$	$	$
1823990	187358	Reg Asset - UT MPA Balancing Account	OTHER	$4,753	$	$	$	$	$	$	$	$	$	$4,753
1823990	187359	Reg Asset - UT Major Plant Additions	OTHER	$6,169	$	$	$	$	$	$	$	$	$	$6,169
1823990	187360	Reg Asset - WY Def Advertising Costs	OTHER	$52	$	$	$	$	$	$	$	$	$	$52
1823990	187370	Reg Asset - OR Solar Feed-In Tariff	OTHER	$582	$	$	$	$	$	$	$	$	$	$582
1823990	187371	REG ASSET - CA SOLAR FEED-IN TARIFF	OTHER	-$33	$	$	$	$	$	$	$	$	$	-$33
1823990	187764	IMPLEMENTATION COST II - RESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187765	IMPLEMENTATION COST II - NONRESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187767	IMPLEMENTATION COST 3 - RESIDENTIAL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187768	IMPLEMENTATION COST 3 - NON RES SMALL	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187769	IMPLEMENTATION COST 3 - NON RES LARGE	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187902	UT - DEFERRED NET POWER COSTS	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187904	ID - DEFERRED NET POWER COSTS	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187905	CA - DEF NET POWER COSTS	OTHER	$1,072	$	$	$	$	$	$	$	$	$	$1,072
1823990	187906	DEF EXCESS NPC - OR UE116 BRIDGE	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	$991	$	$	$	$991	$991	$	$	$	$	$
1823990	187912	CONTRA - REGULATORY ASSETS	CA	$	$	$	$	$	$	$	$	$	$	$
1823990	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	$478	$	$	$	$478	$478	$	$	$	$	$
1823990	187920	OR-RCAC REV REQUIREMENT	OTHER	$220	$	$	$	$	$	$	$	$	$	$220

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Regulatory Assests (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1823990	187921	WA-Chehalis Plant Rev Reqmt - Reg Asset	WA	$13,500	$	$	$13,500	$	$	$	$	$	$	$
1823990	187922	Reg Asset-RECs & SO2 Revenue Req - WY	OTHER	$1,982	$	$	$	$	$	$	$	$	$	$1,982
1823990	187930	OR SB 408 REG ASSET	OTHER	$14,378	$	$	$	$	$	$	$	$	$	$14,378
1823990	187936	SB 408 REG ASSET - MCBIT (EVEN YEAR 1)	OTHER	-$132	$	$	$	$	$	$	$	$	$	-$132
1823990	187937	SB 408 REG ASSET - MCBIT (ODD YEAR 1)	OTHER	-$141	$	$	$	$	$	$	$	$	$	-$141
1823990	187938	SB 408 REG ASSET - MCBIT (EVEN YEAR 2)	OTHER	$192	$	$	$	$	$	$	$	$	$	$192
1823990	187951	DEFERRED COST OF TOU GUARANTEE	OR	$	$	$	$	$	$	$	$	$	$	$
1823990	187955	Defd UT Ind Eval Fee	UT	$36	$	$	$	$	$	$36	$	$	$	$
1823990	187957	DEFERRED OR INDEPENDENT EVALUATOR FEES	OTHER	-$152	$	$	$	$	$	$	$	$	$	-$152
1823990	187958	ID Deferred Intervenor Funding	IDU	$69	$	$	$	$	$	$	$69	$	$	$
1823990	187971	Deferred Net Power Costs - WY 10	OTHER	$13,058	$	$	$	$	$	$	$	$	$	$13,058
1823990	187972	Deferred Net Power Costs - WY 11	OTHER	$18,643	$	$	$	$	$	$	$	$	$	$18,643
1823990	187975	Reg Asset - CA ECAC	OTHER	$765	$	$	$	$	$	$	$	$	$	$765
1823990	187980	Deferred Net Power Costs - ID 09	OTHER	$	$	$	$	$	$	$	$	$	$	$
1823990	187981	Deferred Net Power Costs - ID 10	OTHER	$11,240	$	$	$	$	$	$	$	$	$	$11,240
1823990	187982	Deferred Net Power Costs - ID 11	OTHER	$9,596	$	$	$	$	$	$	$	$	$	$9,596
1823990	187985	Utah ECAM Regulatory Asset	OTHER	$122,062	$	$	$	$	$	$	$	$	$	$122,062
1823990	187988	Deferred Net Power Costs - OR	OTHER	$1,506	$	$	$	$	$	$	$	$	$	$1,506
1823990	187992	Contra Reg Asset - CA - Def NPC	OTHER	-$135	$	$	$	$	$	$	$	$	$	-$135
1823990	187993	Contra Reg Asset - ID - Def NPC	OTHER	-$816	$	$	$	$	$	$	$	$	$	-$816
1823990	187994	Contra Reg Asset - WY - Def NPC	OTHER	-$6,683	$	$	$	$	$	$	$	$	$	-$6,683
1823990	187995	Utah ECAM Regulatory Asset - Contra	OTHER	-$122,062	$	$	$	$	$	$	$	$	$	-$122,062
1823990 Total			**0**	**$131,231**	**$301**	**$2,031**	**$15,319**	**$3,416**	**$3,740**	**$5,168**	**$768**	**$324**	**$**	**$103,903**
1823993	187060	CHOLLA PLANT TRANSACTION COSTS-OR	OR	-$327	$	-$327	$	$	$	$	$	$	$	$
1823993 Total			**0**	**-$327**	**$**	**-$327**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1823994	187061	CHOLLA PLANT TRANSACTION COSTS-WA	WA	-$590	$	$	-$590	$	$	$	$	$	$	$
1823994 Total			**0**	**-$590**	**$**	**$**	**-$590**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
1823995	187062	CHOLLA PLANT TRANSACTION COSTS-ID	IDU	-$201	$	$	$	$	$	$	-$201	$	$	$
1823995 Total			**0**	**-$201**	**$**	**$**	**$**	**$**	**$**	**$**	**-$201**	**$**	**$**	**$**
1823999	186001	DSM Regulatory Assets-Accruals	OTHER	$4,852	$	$	$	$	$	$	$	$	$	$4,852
1823999 Total			**0**	**$4,852**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$4,852**
Grand Total			**0**	**$137,583**	**$899**	**$4,105**	**$16,689**	**$3,981**	**$4,563**	**$13,837**	**$4,092**	**$582**	**$21**	**$93,377**

B17. DEPRECIATION RESERVE

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Depreciation Reserve (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1080000	3102000	LAND RIGHTS	SG	-$24,595	-$414	-$6,340	-$1,933	-$2,983	-$3,786	-$10,660	-$1,382	-$803	-$81
1080000	3103000	WATER RIGHTS	SG	-$15,156	-$255	-$3,907	-$1,191	-$1,838	-$2,333	-$6,569	-$852	-$495	-$50
1080000	3110000	STRUCTURES AND IMPROVEMENTS	SG	-$455,387	-$7,664	-$117,386	-$35,782	-$55,235	-$70,104	-$197,374	-$25,587	-$14,869	-$1,491
1080000	3120000	BOILER PLANT EQUIPMENT	SG	-$1,345,217	-$22,639	-$346,759	-$105,700	-$163,164	-$207,088	-$583,043	-$75,584	-$43,924	-$4,404
1080000	3140000	TURBOGENERATOR UNITS	SG	-$380,522	-$6,404	-$98,088	-$29,899	-$46,154	-$58,579	-$164,926	-$21,381	-$12,425	-$1,246
1080000	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	-$193,132	-$3,250	-$49,784	-$15,175	-$23,425	-$29,731	-$83,707	-$10,852	-$6,306	-$632
1080000	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	-$34	-$1	-$9	-$3	-$4	-$5	-$15	-$2	-$1	$
1080000	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	-$14,180	-$239	-$3,655	-$1,114	-$1,720	-$2,183	-$6,146	-$797	-$463	-$46
1080000	3302000	LAND RIGHTS	SG-P	-$4,704	-$79	-$1,213	-$370	-$571	-$724	-$2,039	-$264	-$154	-$15
1080000	3302000	LAND RIGHTS	SG-U	-$42	-$1	-$11	-$3	-$5	-$6	-$18	-$2	-$1	$
1080000	3303000	WATER RIGHTS	SG-U	-$113	-$2	-$29	-$9	-$14	-$17	-$49	-$6	-$4	$
1080000	3304000	FLOOD RIGHTS	SG-P	-$168	-$3	-$43	-$13	-$20	-$26	-$73	-$9	-$5	-$1
1080000	3304000	FLOOD RIGHTS	SG-U	-$74	-$1	-$19	-$6	-$9	-$11	-$32	-$4	-$2	$
1080000	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	-$205	-$3	-$53	-$16	-$25	-$32	-$89	-$12	-$7	-$1
1080000	3310000	STRUCTURES AND IMPROVE	SG-P	$	$	$	$	$	$	$	$	$	$
1080000	3310000	STRUCTURES AND IMPROVE	SG-U	-$4,673	-$79	-$1,205	-$367	-$567	-$719	-$2,025	-$263	-$153	-$15
1080000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	-$19,727	-$332	-$5,085	-$1,550	-$2,393	-$3,037	-$8,550	-$1,108	-$644	-$65
1080000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	-$805	-$14	-$207	-$63	-$98	-$124	-$349	-$45	-$26	-$3
1080000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	-$6,069	-$102	-$1,564	-$477	-$736	-$934	-$2,630	-$341	-$198	-$20
1080000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	-$135	-$2	-$35	-$11	-$16	-$21	-$58	-$8	-$4	$
1080000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	-$4,319	-$73	-$1,113	-$339	-$524	-$665	-$1,872	-$243	-$141	-$14
1080000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	-$700	-$12	-$181	-$55	-$85	-$108	-$304	-$39	-$23	-$2
1080000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	-$899	-$15	-$232	-$71	-$109	-$138	-$390	-$50	-$29	-$3
1080000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	-$15,812	-$266	-$4,076	-$1,242	-$1,918	-$2,434	-$6,853	-$888	-$516	-$52
1080000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	-$115,871	-$1,950	-$29,868	-$9,104	-$14,054	-$17,838	-$50,221	-$6,510	-$3,783	-$379
1080000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	-$10,738	-$181	-$2,768	-$844	-$1,302	-$1,653	-$4,654	-$603	-$351	-$35
1080000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	-$1,488	-$25	-$384	-$117	-$181	-$229	-$645	-$84	-$49	-$5
1080000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	-$99	-$2	-$26	-$8	-$12	-$15	-$43	-$6	-$3	$
1080000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	-$158	-$3	-$41	-$12	-$19	-$24	-$68	-$9	-$5	-$1
1080000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	-$22	$	-$6	-$2	-$3	-$3	-$9	-$1	-$1	$
1080000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	-$32,684	-$550	-$8,425	-$2,568	-$3,964	-$5,031	-$14,166	-$1,836	-$1,067	-$107
1080000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	-$9,818	-$165	-$2,531	-$771	-$1,191	-$1,511	-$4,256	-$552	-$321	-$32
1080000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	-$11,890	-$200	-$3,065	-$934	-$1,442	-$1,830	-$5,153	-$668	-$388	-$39
1080000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	-$4,043	-$68	-$1,042	-$318	-$490	-$622	-$1,752	-$227	-$132	-$13
1080000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	-$1,321	-$22	-$341	-$104	-$160	-$203	-$573	-$74	-$43	-$4
1080000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	-$23	$	-$6	-$2	-$3	-$4	-$10	-$1	-$1	$
1080000	3350000	MISC POWER PLANT EQUIP	SG-U	-$103	-$2	-$26	-$8	-$12	-$16	-$44	-$6	-$3	$
1080000	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	-$1,030	-$17	-$266	-$81	-$125	-$159	-$447	-$58	-$34	-$3
1080000	3353000	MISC POWER PLANT EQUIP - RECREATION	SG-P	-$4	$	-$1	$	$	-$1	-$2	$	$	$
1080000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	-$5,521	-$93	-$1,423	-$434	-$670	-$850	-$2,393	-$310	-$180	-$18
1080000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	-$709	-$12	-$183	-$56	-$86	-$109	-$307	-$40	-$23	-$2
1080000	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	$	$	$	$	$	$	$	$	$	$
1080000	3410000	STRUCTURES & IMPROVEMENTS	SG	-$23,601	-$397	-$6,084	-$1,854	-$2,863	-$3,633	-$10,229	-$1,326	-$771	-$77
1080000	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	-$1,857	-$31	-$479	-$146	-$225	-$286	-$805	-$104	-$61	-$6
1080000	3430000	PRIME MOVERS	SG	-$317,413	-$5,342	-$81,820	-$24,941	-$38,500	-$48,864	-$137,573	-$17,835	-$10,364	-$1,039
1080000	3440000	GENERATORS	SG	-$58,633	-$987	-$15,114	-$4,607	-$7,112	-$9,026	-$25,412	-$3,294	-$1,914	-$192
1080000	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	-$32,496	-$547	-$8,376	-$2,553	-$3,941	-$5,003	-$14,084	-$1,826	-$1,061	-$106
1080000	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	-$1,699	-$29	-$438	-$134	-$206	-$262	-$736	-$95	-$55	-$6
1080000	3502000	LAND RIGHTS	SG	-$28,305	-$476	-$7,296	-$2,224	-$3,433	-$4,357	-$12,268	-$1,590	-$924	-$93
1080000	3520000	STRUCTURES & IMPROVEMENTS	SG	-$18,470	-$311	-$4,761	-$1,451	-$2,240	-$2,843	-$8,005	-$1,038	-$603	-$60
1080000	3530000	STATION EQUIPMENT	SG	-$257,361	-$4,331	-$66,340	-$20,222	-$31,216	-$39,619	-$111,545	-$14,460	-$8,403	-$843
1080000	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	-$24,034	-$404	-$6,195	-$1,888	-$2,915	-$3,700	-$10,417	-$1,350	-$785	-$79
1080000	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	-$8,803	-$148	-$2,269	-$692	-$1,068	-$1,355	-$3,815	-$495	-$287	-$29
1080000	3540000	TOWERS AND FIXTURES	SG	-$193,440	-$3,255	-$49,863	-$15,199	-$23,463	-$29,779	-$83,841	-$10,869	-$6,316	-$633
1080000	3550000	POLES AND FIXTURES	SG	-$267,769	-$4,506	-$69,023	-$21,040	-$32,478	-$41,221	-$116,056	-$15,045	-$8,743	-$877
1080000	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	-$394,426	-$6,638	-$101,672	-$30,992	-$47,841	-$60,720	-$170,952	-$22,162	-$12,879	-$1,291
1080000	3570000	UNDERGROUND CONDUIT	SG	-$594	-$10	-$153	-$47	-$72	-$91	-$258	-$33	-$19	-$2
1080000	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	-$1,428	-$24	-$368	-$112	-$173	-$220	-$619	-$80	-$47	-$5
1080000	3590000	ROADS AND TRAILS	SG	-$3,429	-$58	-$884	-$269	-$416	-$528	-$1,486	-$193	-$112	-$11
1080000	3602000	LAND RIGHTS	CA	-$526	-$526	$	$	$	$	$	$	$	$
1080000	3602000	LAND RIGHTS	IDU	-$456	$	$	$	$	$	$	-$456	$	$
1080000	3602000	LAND RIGHTS	OR	-$2,374	$	-$2,374	$	$	$	$	$	$	$
1080000	3602000	LAND RIGHTS	UT	-$2,561	$	$	$	$	$	-$2,561	$	$	$
1080000	3602000	LAND RIGHTS	WA	-$133	$	$	-$133	$	$	$	$	$	$

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Depreciation Reserve (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1080000	3602000	LAND RIGHTS	WYP	-$1,035	$	$	$	-$1,035	-$1,035	$	$	$	$
1080000	3602000	LAND RIGHTS	WYU	-$518	$	$	$	$	-$518	$	$	-$518	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	CA	-$602	-$602	$	$	$	$	$	$	$	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	IDU	-$474	$	$	$	$	$	$	-$474	$	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	OR	-$3,599	$	-$3,599	$	$	$	$	$	$	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	UT	-$7,400	$	$	$	$	$	-$7,400	$	$	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	WA	-$615	$	$	-$615	$	$	$	$	$	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	WYP	-$2,268	$	$	$	-$2,268	-$2,268	$	$	$	$
1080000	3610000	STRUCTURES & IMPROVEMENTS	WYU	-$77	$	$	$	$	-$77	$	$	-$77	$
1080000	3620000	STATION EQUIPMENT	CA	-$4,134	-$4,134	$	$	$	$	$	$	$	$
1080000	3620000	STATION EQUIPMENT	IDU	-$9,241	$	$	$	$	$	$	-$9,241	$	$
1080000	3620000	STATION EQUIPMENT	OR	-$56,235	$	-$56,235	$	$	$	$	$	$	$
1080000	3620000	STATION EQUIPMENT	UT	-$82,847	$	$	$	$	$	-$82,847	$	$	$
1080000	3620000	STATION EQUIPMENT	WA	-$14,492	$	$	-$14,492	$	$	$	$	$	$
1080000	3620000	STATION EQUIPMENT	WYP	-$38,207	$	$	$	-$38,207	-$38,207	$	$	$	$
1080000	3620000	STATION EQUIPMENT	WYU	-$2,520	$	$	$	$	-$2,520	$	$	-$2,520	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	-$158	-$158	$	$	$	$	$	$	$	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	-$277	$	$	$	$	$	$	-$277	$	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	-$1,862	$	-$1,862	$	$	$	$	$	$	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	-$2,435	$	$	$	$	$	-$2,435	$	$	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	-$602	$	$	-$602	$	$	$	$	$	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	-$1,709	$	$	$	-$1,709	-$1,709	$	$	$	$
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	-$18	$	$	$	$	-$18	$	$	-$18	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	CA	-$26,327	-$26,327	$	$	$	$	$	$	$	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	IDU	-$37,830	$	$	$	$	$	$	-$37,830	$	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	OR	-$209,418	$	-$209,418	$	$	$	$	$	$	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	UT	-$149,378	$	$	$	$	$	-$149,378	$	$	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	WA	-$47,736	$	$	-$47,736	$	$	$	$	$	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	WYP	-$37,521	$	$	$	-$37,521	-$37,521	$	$	$	$
1080000	3640000	"POLES, TOWERS AND FIXTURES"	WYU	-$6,266	$	$	$	$	-$6,266	$	$	-$6,266	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	-$12,395	-$12,395	$	$	$	$	$	$	$	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	-$11,618	$	$	$	$	$	$	-$11,618	$	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	-$127,166	$	-$127,166	$	$	$	$	$	$	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	-$58,914	$	$	$	$	$	-$58,914	$	$	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	-$28,261	$	$	-$28,261	$	$	$	$	$	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	-$35,624	$	$	$	-$35,624	-$35,624	$	$	$	$
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	-$3,169	$	$	$	$	-$3,169	$	$	-$3,169	$
1080000	3660000	UNDERGROUND CONDUIT	CA	-$7,781	-$7,781	$	$	$	$	$	$	$	$
1080000	3660000	UNDERGROUND CONDUIT	IDU	-$3,399	$	$	$	$	$	$	-$3,399	$	$
1080000	3660000	UNDERGROUND CONDUIT	OR	-$35,884	$	-$35,884	$	$	$	$	$	$	$
1080000	3660000	UNDERGROUND CONDUIT	UT	-$60,753	$	$	$	$	$	-$60,753	$	$	$
1080000	3660000	UNDERGROUND CONDUIT	WA	-$10,412	$	$	-$10,412	$	$	$	$	$	$
1080000	3660000	UNDERGROUND CONDUIT	WYP	-$7,235	$	$	$	-$7,235	-$7,235	$	$	$	$
1080000	3660000	UNDERGROUND CONDUIT	WYU	-$2,479	$	$	$	$	-$2,479	$	$	-$2,479	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	-$13,862	-$13,862	$	$	$	$	$	$	$	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	-$11,098	$	$	$	$	$	$	-$11,098	$	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	-$59,114	$	-$59,114	$	$	$	$	$	$	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	-$171,918	$	$	$	$	$	-$171,918	$	$	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	-$8,960	$	$	-$8,960	$	$	$	$	$	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	-$17,552	$	$	$	-$17,552	-$17,552	$	$	$	$
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	-$12,574	$	$	$	$	-$12,574	$	$	-$12,574	$
1080000	3680000	LINE TRANSFORMERS	CA	-$21,996	-$21,996	$	$	$	$	$	$	$	$
1080000	3680000	LINE TRANSFORMERS	IDU	-$24,015	$	$	$	$	$	$	-$24,015	$	$
1080000	3680000	LINE TRANSFORMERS	OR	-$168,090	$	-$168,090	$	$	$	$	$	$	$
1080000	3680000	LINE TRANSFORMERS	UT	-$92,636	$	$	$	$	$	-$92,636	$	$	$
1080000	3680000	LINE TRANSFORMERS	WA	-$42,778	$	$	-$42,778	$	$	$	$	$	$
1080000	3680000	LINE TRANSFORMERS	WYP	-$28,397	$	$	$	-$28,397	-$28,397	$	$	$	$
1080000	3680000	LINE TRANSFORMERS	WYU	-$4,372	$	$	$	$	-$4,372	$	$	-$4,372	$
1080000	3691000	SERVICES - OVERHEAD	CA	-$3,402	-$3,402	$	$	$	$	$	$	$	$
1080000	3691000	SERVICES - OVERHEAD	IDU	-$3,586	$	$	$	$	$	$	-$3,586	$	$
1080000	3691000	SERVICES - OVERHEAD	OR	-$22,813	$	-$22,813	$	$	$	$	$	$	$
1080000	3691000	SERVICES - OVERHEAD	UT	-$25,022	$	$	$	$	$	-$25,022	$	$	$
1080000	3691000	SERVICES - OVERHEAD	WA	-$6,739	$	$	-$6,739	$	$	$	$	$	$
1080000	3691000	SERVICES - OVERHEAD	WYP	-$4,049	$	$	$	-$4,049	-$4,049	$	$	$	$

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1080000	3691000	SERVICES - OVERHEAD	WYU	-$567	$	$	$	$	-$567	$	$	-$567	$
1080000	3692000	SERVICES - UNDERGROUND	CA	-$5,606	-$5,606	$	$	$	$	$	$	$	$
1080000	3692000	SERVICES - UNDERGROUND	IDU	-$7,510	$	$	$	$	$	$	-$7,510	$	$
1080000	3692000	SERVICES - UNDERGROUND	OR	-$44,900	$	-$44,900	$	$	$	$	$	$	$
1080000	3692000	SERVICES - UNDERGROUND	UT	-$33,184	$	$	$	$	$	-$33,184	$	$	$
1080000	3692000	SERVICES - UNDERGROUND	WA	-$10,671	$	$	-$10,671	$	$	$	$	$	$
1080000	3692000	SERVICES - UNDERGROUND	WYP	-$9,610	$	$	$	-$9,610	-$9,610	$	$	$	$
1080000	3692000	SERVICES - UNDERGROUND	WYU	-$2,125	$	$	$	$	-$2,125	$	$	-$2,125	$
1080000	3700000	METERS	CA	-$1,761	-$1,761	$	$	$	$	$	$	$	$
1080000	3700000	METERS	IDU	-$8,415	$	$	$	$	$	$	-$8,415	$	$
1080000	3700000	METERS	OR	-$32,859	$	-$32,859	$	$	$	$	$	$	$
1080000	3700000	METERS	UT	-$25,206	$	$	$	$	$	-$25,206	$	$	$
1080000	3700000	METERS	WA	-$1,967	$	$	-$1,967	$	$	$	$	$	$
1080000	3700000	METERS	WYP	-$3,282	$	$	$	-$3,282	-$3,282	$	$	$	$
1080000	3700000	METERS	WYU	-$1,423	$	$	$	$	-$1,423	$	$	-$1,423	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	CA	-$213	-$213	$	$	$	$	$	$	$	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	-$134	$	$	$	$	$	$	-$134	$	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	OR	-$2,493	$	-$2,493	$	$	$	$	$	$	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	UT	-$3,570	$	$	$	$	$	-$3,570	$	$	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	WA	-$281	$	$	-$281	$	$	$	$	$	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	-$938	$	$	$	-$938	-$938	$	$	$	$
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	-$149	$	$	$	$	-$149	$	$	-$149	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	-$565	-$565	$	$	$	$	$	$	$	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	-$484	$	$	$	$	$	$	-$484	$	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	-$8,584	$	-$8,584	$	$	$	$	$	$	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	-$12,100	$	$	$	$	$	-$12,100	$	$	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	-$2,133	$	$	-$2,133	$	$	$	$	$	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	-$2,609	$	$	$	-$2,609	-$2,609	$	$	$	$
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	-$864	$	$	$	$	-$864	$	$	-$864	$
1080000	3892000	LAND RIGHTS	IDU	-$3	$	$	$	$	$	$	-$3	$	$
1080000	3892000	LAND RIGHTS	SG	$	$	$	$	$	$	$	$	$	$
1080000	3892000	LAND RIGHTS	UT	-$19	$	$	$	$	$	-$19	$	$	$
1080000	3892000	LAND RIGHTS	WYP	-$4	$	$	$	-$4	-$4	$	$	$	$
1080000	3892000	LAND RIGHTS	WYU	-$2	$	$	$	$	-$2	$	$	-$2	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	CA	-$642	-$642	$	$	$	$	$	$	$	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	CN	-$1,684	-$40	-$494	-$113	-$109	-$123	-$850	-$63	-$14	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	IDU	-$3,837	$	$	$	$	$	$	-$3,837	$	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	OR	-$5,632	$	-$5,632	$	$	$	$	$	$	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	SG	-$2,126	-$36	-$548	-$167	-$258	-$327	-$922	-$119	-$69	-$7
1080000	3900000	STRUCTURES AND IMPROVEMENTS	SO	-$20,094	-$464	-$5,458	-$1,539	-$2,269	-$2,837	-$8,638	-$1,109	-$568	-$47
1080000	3900000	STRUCTURES AND IMPROVEMENTS	UT	-$11,149	$	$	$	$	$	-$11,149	$	$	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	WA	-$5,157	$	$	-$5,157	$	$	$	$	$	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	WYP	-$1,154	$	$	$	-$1,154	-$1,154	$	$	$	$
1080000	3900000	STRUCTURES AND IMPROVEMENTS	WYU	-$1,107	$	$	$	$	-$1,107	$	$	-$1,107	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CA	-$30	-$30	$	$	$	$	$	$	$	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CN	-$651	-$16	-$191	-$44	-$42	-$48	-$328	-$24	-$5	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	IDU	-$9	$	$	$	$	$	$	-$9	$	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	OR	-$158	$	-$158	$	$	$	$	$	$	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SG	-$21	$	-$5	-$2	-$3	-$3	-$9	-$1	-$1	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SO	-$6,600	-$152	-$1,793	-$506	-$745	-$932	-$2,837	-$364	-$187	-$16
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	UT	-$76	$	$	$	$	$	-$76	$	$	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WA	-$8	$	$	-$8	$	$	$	$	$	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYP	-$129	$	$	$	-$129	-$129	$	$	$	$
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYU	-$2	$	$	$	$	-$2	$	$	-$2	$
1080000	3910000	OFFICE FURNITURE	CA	-$56	-$56	$	$	$	$	$	$	$	$
1080000	3910000	OFFICE FURNITURE	CN	-$1,207	-$29	-$354	-$81	-$78	-$88	-$609	-$45	-$10	$
1080000	3910000	OFFICE FURNITURE	IDU	-$82	$	$	$	$	$	$	-$82	$	$
1080000	3910000	OFFICE FURNITURE	OR	-$1,007	$	-$1,007	$	$	$	$	$	$	$
1080000	3910000	OFFICE FURNITURE	SG	-$1,514	-$25	-$390	-$119	-$184	-$233	-$656	-$85	-$49	-$5
1080000	3910000	OFFICE FURNITURE	SO	-$7,673	-$177	-$2,085	-$588	-$867	-$1,084	-$3,299	-$424	-$217	-$18
1080000	3910000	OFFICE FURNITURE	UT	-$422	$	$	$	$	$	-$422	$	$	$
1080000	3910000	OFFICE FURNITURE	WA	-$392	$	$	-$392	$	$	$	$	$	$
1080000	3910000	OFFICE FURNITURE	WYP	-$324	$	$	$	-$324	-$324	$	$	$	$
1080000	3910000	OFFICE FURNITURE	WYU	-$30	$	$	$	$	-$30	$	$	-$30	$

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1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	-$89	-$89	$	$	$	$	$	$	$	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	-$3,613	-$87	-$1,061	-$242	-$234	-$264	-$1,823	-$136	-$30	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	-$353	$	$	$	$	$	$	-$353	$	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	-$861	$	-$861	$	$	$	$	$	$	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	-$52	-$1	-$13	-$4	-$7	-$9	-$22	-$3	-$2	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	-$688	-$12	-$177	-$54	-$83	-$106	-$298	-$39	-$22	-$2
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	-$20,829	-$481	-$5,658	-$1,595	-$2,352	-$2,941	-$8,954	-$1,150	-$589	-$49
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	-$1,083	$	$	$	$	$	-$1,083	$	$	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	-$446	$	$	-$446	$	$	$	$	$	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	-$1,221	$	$	$	-$1,221	-$1,221	$	$	$	$
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	-$33	$	$	$	$	-$33	$	$	-$33	$
1080000	3913000	OFFICE EQUIPMENT	CN	-$1	$	$	$	$	$	$	$	$	$
1080000	3913000	OFFICE EQUIPMENT	OR	-$9	$	-$9	$	$	$	$	$	$	$
1080000	3913000	OFFICE EQUIPMENT	SG	-$373	-$6	-$96	-$29	-$45	-$57	-$162	-$21	-$12	-$1
1080000	3913000	OFFICE EQUIPMENT	SO	-$86	-$2	-$23	-$7	-$10	-$12	-$37	-$5	-$2	$
1080000	3913000	OFFICE EQUIPMENT	UT	-$18	$	$	$	$	$	-$18	$	$	$
1080000	3913000	OFFICE EQUIPMENT	WYP	-$17	$	$	$	-$17	-$17	$	$	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	-$40	-$40	$	$	$	$	$	$	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	-$208	$	$	$	$	$	$	-$208	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	-$796	$	-$796	$	$	$	$	$	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	-$325	-$5	-$84	-$26	-$39	-$50	-$141	-$18	-$11	-$1
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	-$438	-$10	-$119	-$34	-$49	-$62	-$188	-$24	-$12	-$1
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	-$1,183	$	$	$	$	$	-$1,183	$	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	-$166	$	$	-$166	$	$	$	$	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	-$157	$	$	$	-$157	-$157	$	$	$	$
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYU	-$20	$	$	$	$	-$20	$	$	-$20	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	IDU	-$10	$	$	$	$	$	$	-$10	$	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	OR	-$142	$	-$142	$	$	$	$	$	$	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	SG	-$29	$	-$7	-$2	-$3	-$4	-$12	-$2	-$1	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	SO	-$102	-$2	-$28	-$8	-$11	-$14	-$44	-$6	-$3	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	UT	-$184	$	$	$	$	$	-$184	$	$	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	WA	-$29	$	$	-$29	$	$	$	$	$	$
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	-$45	$	$	$	-$45	-$45	$	$	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	-$227	-$227	$	$	$	$	$	$	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	-$730	$	$	$	$	$	$	-$730	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	-$2,320	$	-$2,320	$	$	$	$	$	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	-$52	-$1	-$13	-$4	-$7	-$9	-$22	-$3	-$2	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	-$3,030	-$51	-$781	-$238	-$367	-$466	-$1,313	-$170	-$99	-$10
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	-$459	-$11	-$125	-$35	-$52	-$65	-$197	-$25	-$13	-$1
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	-$3,765	$	$	$	$	$	-$3,765	$	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	-$456	$	$	-$456	$	$	$	$	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	-$676	$	$	$	-$676	-$676	$	$	$	$
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	-$176	$	$	$	$	-$176	$	$	-$176	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	-$249	-$249	$	$	$	$	$	$	$	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	-$810	$	$	$	$	$	$	-$810	$	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	-$2,699	$	-$2,699	$	$	$	$	$	$	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	-$117	-$2	-$29	-$9	-$16	-$20	-$51	-$7	-$4	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	-$1,826	-$31	-$471	-$143	-$221	-$281	-$791	-$103	-$60	-$6
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	-$272	-$6	-$74	-$21	-$31	-$38	-$117	-$15	-$8	-$1
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	-$5,101	$	$	$	$	$	-$5,101	$	$	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	-$1,028	$	$	-$1,028	$	$	$	$	$	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	-$970	$	$	$	-$970	-$970	$	$	$	$
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	-$220	$	$	$	$	-$220	$	$	-$220	$
1080000	3920600	DUMP TRUCKS	OR	-$40	$	-$40	$	$	$	$	$	$	$
1080000	3920600	DUMP TRUCKS	SE	-$2	$	-$1	$	$	$	-$1	$	$	$
1080000	3920600	DUMP TRUCKS	SG	-$1,281	-$22	-$330	-$101	-$155	-$197	-$555	-$72	-$42	-$4
1080000	3920600	DUMP TRUCKS	UT	-$74	$	$	$	$	$	-$74	$	$	$
1080000	3920900	TRAILERS	CA	-$110	-$110	$	$	$	$	$	$	$	$
1080000	3920900	TRAILERS	IDU	-$225	$	$	$	$	$	$	-$225	$	$
1080000	3920900	TRAILERS	OR	-$572	$	-$572	$	$	$	$	$	$	$
1080000	3920900	TRAILERS	SE	-$26	$	-$6	-$2	-$3	-$4	-$11	-$2	-$1	$
1080000	3920900	TRAILERS	SG	-$625	-$11	-$161	-$49	-$76	-$96	-$271	-$35	-$20	-$2
1080000	3920900	TRAILERS	SO	-$217	-$5	-$59	-$17	-$25	-$31	-$93	-$12	-$6	-$1
1080000	3920900	TRAILERS	UT	-$1,414	$	$	$	$	$	-$1,414	$	$	$

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1080000	3920900	TRAILERS	WA	-$140	$	$	-$140	$	$	$	$	$	$
1080000	3920900	TRAILERS	WYP	-$647	$	$	$	-$647	-$647	$	$	$	$
1080000	3920900	TRAILERS	WYU	-$126	$	$	$	$	-$126	$	$	-$126	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	-$17	-$17	$	$	$	$	$	$	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	-$17	$	$	$	$	$	$	-$17	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	-$74	$	-$74	$	$	$	$	$	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	-$102	-$2	-$26	-$8	-$12	-$16	-$44	-$6	-$3	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	-$13	$	-$4	-$1	-$1	-$2	-$6	-$1	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	-$79	$	$	$	$	$	-$79	$	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	-$14	$	$	-$14	$	$	$	$	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	-$36	$	$	$	-$36	-$36	$	$	$	$
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	-$4	$	$	$	$	-$4	$	$	-$4	$
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	-$80	$	-$80	$	$	$	$	$	$	$
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	-$176	-$3	-$45	-$14	-$21	-$27	-$76	-$10	-$6	-$1
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	-$156	-$4	-$42	-$12	-$18	-$22	-$67	-$9	-$4	$
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	-$406	$	$	$	$	$	-$406	$	$	$
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	-$92	$	$	-$92	$	$	$	$	$	$
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	-$39	$	$	$	-$39	-$39	$	$	$	$
1080000	3923000	TRANSPORTATION EQUIPMENT	SO	-$670	-$15	-$182	-$51	-$76	-$95	-$288	-$37	-$19	-$2
1080000	3930000	STORES EQUIPMENT	CA	-$114	-$114	$	$	$	$	$	$	$	$
1080000	3930000	STORES EQUIPMENT	IDU	-$159	$	$	$	$	$	$	-$159	$	$
1080000	3930000	STORES EQUIPMENT	OR	-$1,156	$	-$1,156	$	$	$	$	$	$	$
1080000	3930000	STORES EQUIPMENT	SG	-$1,569	-$26	-$404	-$123	-$190	-$241	-$680	-$88	-$51	-$5
1080000	3930000	STORES EQUIPMENT	SO	-$196	-$5	-$53	-$15	-$22	-$28	-$84	-$11	-$6	$
1080000	3930000	STORES EQUIPMENT	UT	-$1,491	$	$	$	$	$	-$1,491	$	$	$
1080000	3930000	STORES EQUIPMENT	WA	-$236	$	$	-$236	$	$	$	$	$	$
1080000	3930000	STORES EQUIPMENT	WYP	-$528	$	$	$	-$528	-$528	$	$	$	$
1080000	3930000	STORES EQUIPMENT	WYU	-$87	$	$	$	$	-$87	$	$	-$87	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	-$387	-$387	$	$	$	$	$	$	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	-$573	$	$	$	$	$	$	-$573	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	-$4,696	$	-$4,696	$	$	$	$	$	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	-$5	$	-$1	$	-$1	-$1	-$2	$	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	-$11,456	-$193	-$2,953	-$900	-$1,389	-$1,764	-$4,965	-$644	-$374	-$38
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	-$2,073	-$48	-$563	-$159	-$234	-$293	-$891	-$114	-$59	-$5
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	-$4,711	$	$	$	$	$	-$4,711	$	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	-$1,305	$	$	-$1,305	$	$	$	$	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	-$1,741	$	$	$	-$1,741	-$1,741	$	$	$	$
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	-$243	$	$	$	$	-$243	$	$	-$243	$
1080000	3950000	LABORATORY EQUIPMENT	CA	-$254	-$254	$	$	$	$	$	$	$	$
1080000	3950000	LABORATORY EQUIPMENT	IDU	-$590	$	$	$	$	$	$	-$590	$	$
1080000	3950000	LABORATORY EQUIPMENT	OR	-$5,081	$	-$5,081	$	$	$	$	$	$	$
1080000	3950000	LABORATORY EQUIPMENT	SE	-$7	$	-$2	-$1	-$1	-$1	-$3	$	$	$
1080000	3950000	LABORATORY EQUIPMENT	SG	-$3,107	-$52	-$801	-$244	-$377	-$478	-$1,347	-$175	-$101	-$10
1080000	3950000	LABORATORY EQUIPMENT	SO	-$2,642	-$61	-$718	-$202	-$298	-$373	-$1,136	-$146	-$75	-$6
1080000	3950000	LABORATORY EQUIPMENT	UT	-$3,311	$	$	$	$	$	-$3,311	$	$	$
1080000	3950000	LABORATORY EQUIPMENT	WA	-$998	$	$	-$998	$	$	$	$	$	$
1080000	3950000	LABORATORY EQUIPMENT	WYP	-$1,520	$	$	$	-$1,520	-$1,520	$	$	$	$
1080000	3950000	LABORATORY EQUIPMENT	WYU	-$429	$	$	$	$	-$429	$	$	-$429	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	-$351	-$351	$	$	$	$	$	$	$	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	-$821	$	$	$	$	$	$	-$821	$	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	-$1,762	$	-$1,762	$	$	$	$	$	$	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	-$318	-$5	-$82	-$25	-$39	-$49	-$138	-$18	-$10	-$1
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	-$1,891	$	$	$	$	$	-$1,891	$	$	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	-$628	$	$	-$628	$	$	$	$	$	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	-$845	$	$	$	-$845	-$845	$	$	$	$
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	-$190	$	$	$	$	-$190	$	$	-$190	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	-$72	-$72	$	$	$	$	$	$	$	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	-$48	$	$	$	$	$	$	-$48	$	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	-$230	$	-$230	$	$	$	$	$	$	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	-$61	-$1	-$16	-$5	-$7	-$9	-$26	-$3	-$2	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	-$759	$	$	$	$	$	-$759	$	$	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	-$67	$	$	$	-$67	-$67	$	$	$	$
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	-$72	$	$	$	$	-$72	$	$	-$72	$
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	-$275	-$275	$	$	$	$	$	$	$	$

PACIFICORP
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Depreciation Reserve (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	-$434	$	$	$	$	$	$	-$434	$	$
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	-$2,005	$	-$2,005	$	$	$	$	$	$	$
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	-$328	-$6	-$84	-$26	-$40	-$50	-$142	-$18	-$11	-$1
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	-$3,225	$	$	$	$	$	-$3,225	$	$	$
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	-$788	$	$	-$788	$	$	$	$	$	$
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	-$538	$	$	$	-$538	-$538	$	$	$	$
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	-$225	$	$	$	$	-$225	$	$	-$225	$
1080000	3961000	CRANES	OR	-$65	$	-$65	$	$	$	$	$	$	$
1080000	3961000	CRANES	SG	-$1,061	-$18	-$274	-$83	-$129	-$163	-$460	-$60	-$35	-$3
1080000	3961000	CRANES	SO	-$26	-$1	-$7	-$2	-$3	-$4	-$11	-$1	-$1	$
1080000	3961000	CRANES	UT	-$1	$	$	$	$	$	-$1	$	$	$
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	-$37	$	-$37	$	$	$	$	$	$	$
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SE	-$21	$	-$5	-$2	-$3	-$4	-$9	-$1	-$1	$
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	-$6,071	-$102	-$1,565	-$477	-$736	-$935	-$2,631	-$341	-$198	-$20
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	-$490	-$11	-$133	-$38	-$55	-$69	-$211	-$27	-$14	-$1
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	-$361	$	$	$	$	$	-$361	$	$	$
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	-$88	$	$	$	-$88	-$88	$	$	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	-$348	-$348	$	$	$	$	$	$	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	-$403	$	$	$	$	$	$	-$403	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	-$2,156	$	-$2,156	$	$	$	$	$	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	-$53	-$1	-$14	-$4	-$6	-$8	-$23	-$3	-$2	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	-$74	-$2	-$20	-$6	-$8	-$10	-$32	-$4	-$2	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	-$4,085	$	$	$	$	$	-$4,085	$	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	-$651	$	$	-$651	$	$	$	$	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	-$651	$	$	$	-$651	-$651	$	$	$	$
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	-$86	$	$	$	$	-$86	$	$	-$86	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	-$163	-$163	$	$	$	$	$	$	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	-$209	$	$	$	$	$	$	-$209	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	-$406	$	-$406	$	$	$	$	$	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	-$7	$	-$2	$	-$1	-$1	-$3	$	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	-$1,880	-$32	-$484	-$148	-$228	-$289	-$815	-$106	-$61	-$6
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	-$63	-$1	-$17	-$5	-$7	-$9	-$27	-$4	-$2	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	-$1,109	$	$	$	$	$	-$1,109	$	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	-$245	$	$	-$245	$	$	$	$	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	-$214	$	$	$	-$214	-$214	$	$	$	$
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	-$190	$	$	$	$	-$190	$	$	-$190	$
1080000	3970000	COMMUNICATION EQUIPMENT	CA	-$941	-$941	$	$	$	$	$	$	$	$
1080000	3970000	COMMUNICATION EQUIPMENT	CN	-$489	-$12	-$144	-$33	-$32	-$36	-$247	-$18	-$4	$
1080000	3970000	COMMUNICATION EQUIPMENT	IDU	-$1,143	$	$	$	$	$	$	-$1,143	$	$
1080000	3970000	COMMUNICATION EQUIPMENT	OR	-$12,790	$	-$12,790	$	$	$	$	$	$	$
1080000	3970000	COMMUNICATION EQUIPMENT	SE	-$19	$	-$5	-$1	-$3	-$3	-$8	-$1	-$1	$
1080000	3970000	COMMUNICATION EQUIPMENT	SG	-$23,876	-$402	-$6,155	-$1,876	-$2,896	-$3,676	-$10,349	-$1,342	-$780	-$78
1080000	3970000	COMMUNICATION EQUIPMENT	SO	-$13,202	-$305	-$3,586	-$1,011	-$1,491	-$1,864	-$5,675	-$729	-$373	-$31
1080000	3970000	COMMUNICATION EQUIPMENT	UT	-$8,198	$	$	$	$	$	-$8,198	$	$	$
1080000	3970000	COMMUNICATION EQUIPMENT	WA	-$4,171	$	$	-$4,171	$	$	$	$	$	$
1080000	3970000	COMMUNICATION EQUIPMENT	WYP	-$5,800	$	$	$	-$5,800	-$5,800	$	$	$	$
1080000	3970000	COMMUNICATION EQUIPMENT	WYU	-$919	$	$	$	$	-$919	$	$	-$919	$
1080000	3972000	MOBILE RADIO EQUIPMENT	CA	-$13	-$13	$	$	$	$	$	$	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	IDU	-$45	$	$	$	$	$	$	-$45	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	OR	-$228	$	-$228	$	$	$	$	$	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	SE	$	$	$	$	$	$	$	$	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	SG	-$148	-$2	-$38	-$12	-$18	-$23	-$64	-$8	-$5	$
1080000	3972000	MOBILE RADIO EQUIPMENT	SO	-$68	-$2	-$18	-$5	-$8	-$10	-$29	-$4	-$2	$
1080000	3972000	MOBILE RADIO EQUIPMENT	UT	-$707	$	$	$	$	$	-$707	$	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	WA	-$166	$	$	-$166	$	$	$	$	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	WYP	-$188	$	$	$	-$188	-$188	$	$	$	$
1080000	3972000	MOBILE RADIO EQUIPMENT	WYU	-$28	$	$	$	$	-$28	$	$	-$28	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	CA	-$13	-$13	$	$	$	$	$	$	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	CN	-$117	-$3	-$34	-$8	-$8	-$9	-$59	-$4	-$1	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	IDU	-$33	$	$	$	$	$	$	-$33	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	OR	-$213	$	-$213	$	$	$	$	$	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	SE	-$1	$	$	$	$	$	-$1	$	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	SG	-$669	-$11	-$172	-$53	-$81	-$103	-$290	-$38	-$22	-$2
1080000	3980000	MISCELLANEOUS EQUIPMENT	SO	-$1,546	-$36	-$420	-$118	-$175	-$218	-$665	-$85	-$44	-$4

PACIFICORP
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Depreciation Reserve (Actuals)

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1080000	3980000	MISCELLANEOUS EQUIPMENT	UT	-$165	$	$	$	$	$	-$165	$	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	WA	-$52	$	$	-$52	$	$	$	$	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	WYP	-$102	$	$	$	-$102	-$102	$	$	$	$
1080000	3980000	MISCELLANEOUS EQUIPMENT	WYU	-$10	$	$	$	$	-$10	$	$	-$10	$
1080000	3992200	LAND RIGHTS	SE	-$35,967	-$560	-$8,745	-$2,650	-$4,758	-$6,108	-$15,501	-$2,269	-$1,351	-$134
1080000	3993000	"ENGINEERING SUPP-OFF WORK(SECY,MAP,DRAF	SE	-$25,332	-$394	-$6,159	-$1,866	-$3,351	-$4,302	-$10,917	-$1,598	-$951	-$95
1080000	3994100	SURFACE - PLANT EQUIPMENT	SE	-$8,247	-$128	-$2,005	-$608	-$1,091	-$1,401	-$3,554	-$520	-$310	-$31
1080000	3994400	SURFACE - ELECTRIC POWER FACILITIES	SE	-$1,301	-$20	-$316	-$96	-$172	-$221	-$561	-$82	-$49	-$5
1080000	3994500	UNDERGROUND - COAL MINE EQUIPMENT	SE	-$37,585	-$585	-$9,138	-$2,769	-$4,972	-$6,383	-$16,198	-$2,371	-$1,411	-$140
1080000	3994600	LONGWALL SHIELDS	SE	-$2,186	-$34	-$532	-$161	-$289	-$371	-$942	-$138	-$82	-$8
1080000	3994700	LONGWALL EQUIPMENT	SE	-$558	-$9	-$136	-$41	-$74	-$95	-$241	-$35	-$21	-$2
1080000	3994800	MAINLINE EXTENSION	SE	-$9,795	-$153	-$2,381	-$722	-$1,296	-$1,663	-$4,221	-$618	-$368	-$37
1080000	3994900	SECTION EXTENSION	SE	-$1,754	-$27	-$426	-$129	-$232	-$298	-$756	-$111	-$66	-$7
1080000	3995100	VEHICLES	SE	-$720	-$11	-$175	-$53	-$95	-$122	-$310	-$45	-$27	-$3
1080000	3995200	HEAVY CONSTRUCTION EQUIPMENT	SE	-$2,818	-$44	-$685	-$208	-$373	-$479	-$1,214	-$178	-$106	-$11
1080000	3996000	MISCELLANEOUS GENERAL EQUIPMENT	SE	-$1,130	-$18	-$275	-$83	-$150	-$192	-$487	-$71	-$42	-$4
1080000	3996100	COMPUTERS - MAINFRAME	SE	-$435	-$7	-$106	-$32	-$58	-$74	-$187	-$27	-$16	-$2
1080000	3997000	MINE DEVELOPMENT AND ROAD EXTENSION	SE	-$28,519	-$444	-$6,934	-$2,101	-$3,772	-$4,843	-$12,291	-$1,799	-$1,071	-$106
1080000 Total				**-$6,899,596**	**-$181,839**	**-$2,010,854**	**-$555,037**	**-$768,866**	**-$961,311**	**-$2,785,666**	**-$389,785**	**-$192,445**	**-$15,104**
1085000	144135	PRODUCTION PLANT - ACCUM DEPN-NON-CLASSI	SG	$	$	$	$	$	$	$	$	$	$
1085000	144135	PRODUCTION PLANT - ACCUM DEPN-NON-CLASSI	SG-P	$	$	$	$	$	$	$	$	$	$
1085000	144145	TRANSMISSION PLANT ACCUM DEPN-NON-CLASSI	SG	$	$	$	$	$	$	$	$	$	$
1085000	144165	DISTRIBUTION - ACCUM DEPN-NON-CLASSIFIED	CA	$	$	$	$	$	$	$	$	$	$
1085000	144165	DISTRIBUTION - ACCUM DEPN-NON-CLASSIFIED	OR	$	$	$	$	$	$	$	$	$	$
1085000	144165	DISTRIBUTION - ACCUM DEPN-NON-CLASSIFIED	WA	$	$	$	$	$	$	$	$	$	$
1085000	144165	DISTRIBUTION - ACCUM DEPN-NON-CLASSIFIED	WYP	$	$	$	$	$	$	$	$	$	$
1085000	144205	GENERAL PLANT- ACCUM DEPN-NON-CLASS	SO	$	$	$	$	$	$	$	$	$	$
1085000	145129	BUILDINGS - ACCUMULATED DEPRECIATION-NON	SE	$	$	$	$	$	$	$	$	$	$
1085000	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	-$16,120	-$271	-$4,155	-$1,267	-$1,955	-$2,482	-$6,987	-$906	-$526	-$53
1085000	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	$1,077	$18	$278	$85	$131	$166	$467	$60	$35	$4
1085000	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	$4,995	$84	$1,288	$393	$606	$769	$2,165	$281	$163	$16
1085000	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	$1,803	$30	$465	$142	$219	$278	$781	$101	$59	$6
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	$59	$59	$	$	$	$	$	$	$	$
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	-$13	$	$	$	$	$	$	-$13	$	$
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	-$224	$	-$224	$	$	$	$	$	$	$
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	$858	$	$	$	$	$	$858	$	$	$
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	$182	$	$	$182	$	$	$	$	$	$
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	$322	$	$	$	$	$322	$	$	$322	$
1085000	145189	MOTOR VEHICLES & MOBILE PLANT - ACCUM DE	SO	$3,198	$74	$869	$245	$361	$452	$1,375	$177	$90	$8
1085000	145209	OTHER GEN'L PLANT & EQUIP - ACCUM DEPR-N	SO	$54	$1	$15	$4	$6	$8	$23	$3	$2	$
1085000	145219	MINING ASSETS - ACCUM DEPR - NON-REC	SE	$	$	$	$	$	$	$	$	$	$
1085000 Total				**-$3,810**	**-$5**	**-$1,466**	**-$217**	**-$633**	**-$488**	**-$1,317**	**-$297**	**$145**	**-$19**
Grand Total				**-$6,903,406**	**-$181,844**	**-$2,012,320**	**-$555,254**	**-$769,499**	**-$961,799**	**-$2,786,983**	**-$390,082**	**-$192,300**	**-$15,123**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Reserve (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1110000	3020000	FRANCHISES AND CONSENTS	IDU	-$765	$	$	$	$	$	$	-$765	$	$
1110000	3020000	FRANCHISES AND CONSENTS	SG	-$2,167	-$36	-$559	-$170	-$263	-$334	-$939	-$122	-$71	-$7
1110000	3020000	FRANCHISES AND CONSENTS	SG-P	-$19,512	-$328	-$5,030	-$1,533	-$2,367	-$3,004	-$8,457	-$1,096	-$637	-$64
1110000	3020000	FRANCHISES AND CONSENTS	SG-U	-$3,880	-$65	-$1,000	-$305	-$471	-$597	-$1,682	-$218	-$127	-$13
1110000	3031040	INTANGIBLE PLANT	OR	-$45	$	-$45	$	$	$	$	$	$	$
1110000	3031040	INTANGIBLE PLANT	SG	-$5,603	-$94	-$1,444	-$440	-$680	-$863	-$2,428	-$315	-$183	-$18
1110000	3031050	REGIONAL CONST MGMT SYS	SO	-$10,745	-$248	-$2,919	-$823	-$1,214	-$1,517	-$4,619	-$593	-$304	-$25
1110000	3031080	FUEL MGMT SYSTEM	SO	-$3,275	-$76	-$890	-$251	-$370	-$462	-$1,408	-$181	-$93	-$8
1110000	3031230	AUTOMATE POLE CARD SYSTEM	SO	-$4,410	-$102	-$1,198	-$338	-$498	-$623	-$1,896	-$243	-$125	-$10
1110000	3031470	RILDA CANYON ROAD IMPROVEMENTS	SE	-$1,412	-$22	-$343	-$104	-$187	-$240	-$609	-$89	-$53	-$5
1110000	3031680	DISTRIBUTION AUTOMATION PILOT	SO	-$12,003	-$277	-$3,261	-$919	-$1,356	-$1,695	-$5,160	-$663	-$339	-$28
1110000	3031760	RECORD CENTER MGMT SOFTWARE	SO	-$282	-$7	-$76	-$22	-$32	-$40	-$121	-$16	-$8	-$1
1110000	3031780	OUTAGE REPORTING SYSTEM	SO	-$3,498	-$81	-$950	-$268	-$395	-$494	-$1,504	-$193	-$99	-$8
1110000	3031830	CUSTOMER SERVICE SYSTEM	CN	-$91,888	-$2,208	-$26,981	-$6,163	-$5,939	-$6,709	-$46,370	-$3,457	-$769	$
1110000	3032040	SAP	SO	-$122,662	-$2,834	-$33,321	-$9,396	-$13,854	-$17,320	-$52,730	-$6,771	-$3,467	-$289
1110000	3032090	ENERGY COMMODITY SYS SOFTWARE	SO	-$9,974	-$230	-$2,709	-$764	-$1,126	-$1,408	-$4,287	-$551	-$282	-$24
1110000	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	-$1,660	-$38	-$451	-$127	-$187	-$234	-$714	-$92	-$47	-$4
1110000	3032260	DWHS - DATA WAREHOUSE	SO	-$1,158	-$27	-$315	-$89	-$131	-$164	-$498	-$64	-$33	-$3
1110000	3032270	ENTERPRISE DATA WAREHOUSE	SO	-$5,155	-$119	-$1,400	-$395	-$582	-$728	-$2,216	-$285	-$146	-$12
1110000	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	-$2,908	-$67	-$790	-$223	-$328	-$411	-$1,250	-$161	-$82	-$7
1110000	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	-$1,652	-$38	-$449	-$127	-$187	-$233	-$710	-$91	-$47	-$4
1110000	3032360	2002 GRID NET POWER COST MODELING	SO	-$8,699	-$201	-$2,363	-$666	-$982	-$1,228	-$3,740	-$480	-$246	-$21
1110000	3032400	INCEDENT MANAGEMENT ANALYSIS PROGRAM	SO	-$5,286	-$122	-$1,436	-$405	-$597	-$746	-$2,272	-$292	-$149	-$12
1110000	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	-$12,489	-$289	-$3,393	-$957	-$1,411	-$1,764	-$5,369	-$689	-$353	-$29
1110000	3032480	OUTAGE CALL HANDLING INTEGRATION	CN	-$1,981	-$48	-$582	-$133	-$128	-$145	-$1,000	-$75	-$17	$
1110000	3032510	OPERATIONS MAPPING SYSTEM	SO	-$10,349	-$239	-$2,811	-$793	-$1,169	-$1,461	-$4,449	-$571	-$292	-$24
1110000	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	-$1,892	-$44	-$514	-$145	-$214	-$267	-$814	-$104	-$53	-$4
1110000	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	-$2,175	-$50	-$591	-$167	-$246	-$307	-$935	-$120	-$61	-$5
1110000	3032600	SINGLE PERSON SCHEDULING	SO	-$8,157	-$188	-$2,216	-$625	-$921	-$1,152	-$3,506	-$450	-$231	-$19
1110000	3032640	TIBCO SOFTWARE	SO	-$3,782	-$87	-$1,027	-$290	-$427	-$534	-$1,626	-$209	-$107	-$9
1110000	3032670	C&T OFFICIAL RECORD INFO SYSTEM	SO	-$1,586	-$37	-$431	-$122	-$179	-$224	-$682	-$88	-$45	-$4
1110000	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	-$1,581	-$27	-$408	-$124	-$192	-$243	-$685	-$89	-$52	-$5
1110000	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	-$34	-$1	-$9	-$3	-$4	-$5	-$15	-$2	-$1	$
1110000	3032730	IMPROVEMENTS TO PLANT OWNED BY JAMES RIV	SG	-$10,723	-$180	-$2,764	-$843	-$1,301	-$1,651	-$4,647	-$602	-$350	-$35
1110000	3032760	SWIFT 2 IMPROVEMENTS	SG	-$2,962	-$50	-$764	-$233	-$359	-$456	-$1,284	-$166	-$97	-$10
1110000	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	-$29	$	-$7	-$2	-$3	-$4	-$12	-$2	-$1	$
1110000	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	-$17	$	-$4	-$1	-$2	-$3	-$7	-$1	-$1	$
1110000	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	-$1	$	$	$	$	$	-$1	$	$	$
1110000	3032830	VCPRO - VISUALCOMPUSETPRO XEROX CUST STM	SO	-$2,179	-$50	-$592	-$167	-$246	-$308	-$937	-$120	-$62	-$5
1110000	3032860	WEB SOFTWARE	SO	-$731	-$17	-$199	-$56	-$83	-$103	-$314	-$40	-$21	-$2
1110000	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	-$222	-$4	-$57	-$17	-$27	-$34	-$96	-$12	-$7	-$1
1110000	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	-$3,691	-$85	-$1,003	-$283	-$417	-$521	-$1,587	-$204	-$104	-$9
1110000	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	-$5,867	-$99	-$1,512	-$461	-$712	-$903	-$2,543	-$330	-$192	-$19
1110000	3033120	RANGER EMS/SCADA SYSTEM	SG	-$44	-$1	-$11	-$3	-$5	-$7	-$19	-$2	-$1	$
1110000	3033120	RANGER EMS/SCADA SYSTEM	SO	-$20,097	-$464	-$5,459	-$1,539	-$2,270	-$2,838	-$8,639	-$1,109	-$568	-$47
1110000	3033120	RANGER EMS/SCADA SYSTEM	WYP	-$140	$	$	$	-$140	-$140	$	$	$	$
1110000	3033140	ETAGM - Electronic Tagging Sys-Merchant	SO	-$1,417	-$33	-$385	-$109	-$160	-$200	-$609	-$78	-$40	-$3
1110000	3033150	ROUTT CTY ROAD FOR HAYDEN HAULAGE	SG	-$2,943	-$50	-$759	-$231	-$357	-$453	-$1,275	-$165	-$96	-$10
1110000	3033170	GTX VERSION 7 SOFTWARE	CN	-$1,783	-$43	-$524	-$120	-$115	-$130	-$900	-$67	-$15	$
1110000	3033180	HPOV - HP Openview Software	SO	-$1,378	-$32	-$374	-$106	-$156	-$195	-$592	-$76	-$39	-$3
1110000	3033190	ITRON METER READING SOFTWARE	CN	-$1,597	-$38	-$469	-$107	-$103	-$117	-$806	-$60	-$13	$
1110000	3033300	SECID - CUST SECURE WEB LOGIN	CN	-$605	-$15	-$178	-$41	-$39	-$44	-$305	-$23	-$5	$
1110000	3033310	C&T - ENERGY TRADING SYSTEM	SO	-$1,888	-$44	-$513	-$145	-$213	-$267	-$812	-$104	-$53	-$4
1110000	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	-$1,756	-$30	-$453	-$138	-$213	-$270	-$761	-$99	-$57	-$6

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Reserve (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1110000	3033360	DSM REPORTING & TRACKING SOFTWARE	SO	-$373	-$9	-$101	-$29	-$42	-$53	-$160	-$21	-$11	-$1
1110000	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	-$247	-$4	-$64	-$19	-$30	-$38	-$107	-$14	-$8	-$1
1110000	3034900	MISC - MISCELLANEOUS	CN	$	$	$	$	$	$	$	$	$	$
1110000	3034900	MISC - MISCELLANEOUS	IDU	-$2	$	$	$	$	$	$	-$2	$	$
1110000	3034900	MISC - MISCELLANEOUS	OR	-$7	$	-$7	$	$	$	$	$	$	$
1110000	3034900	MISC - MISCELLANEOUS	SE	-$40	-$1	-$10	-$3	-$5	-$7	-$17	-$3	-$2	$
1110000	3034900	MISC - MISCELLANEOUS	SG	-$15,269	-$257	-$3,936	-$1,200	-$1,852	-$2,351	-$6,618	-$858	-$499	-$50
1110000	3034900	MISC - MISCELLANEOUS	SG-P	-$3	$	-$1	$	$	$	-$1	$	$	$
1110000	3034900	MISC - MISCELLANEOUS	SO	-$1,217	-$28	-$331	-$93	-$137	-$172	-$523	-$67	-$34	-$3
1110000	3034900	MISC - MISCELLANEOUS	UT	-$34	$	$	$	$	$	-$34	$	$	$
1110000	3034900	MISC - MISCELLANEOUS	WA	-$2	$	$	-$2	$	$	$	$	$	$
1110000	3034900	MISC - MISCELLANEOUS	WYP	-$133	$	$	$	-$133	-$133	$	$	$	$
1110000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	-$241	-$4	-$62	-$19	-$29	-$37	-$104	-$14	-$8	-$1
1110000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-U	-$84	-$1	-$22	-$7	-$10	-$13	-$37	-$5	-$3	$
1110000	3326000	RESERVOIR, DAMS, WATERWAYS, LEASE HOLDS	SG-U	-$376	-$6	-$97	-$30	-$46	-$58	-$163	-$21	-$12	-$1
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	-$1,199	-$1,199	$	$	$	$	$	$	$	$
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CN	-$2,861	-$69	-$840	-$192	-$185	-$209	-$1,444	-$108	-$24	$
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	-$6,522	$	-$6,522	$	$	$	$	$	$	$
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	-$11,321	-$262	-$3,075	-$867	-$1,279	-$1,599	-$4,867	-$625	-$320	-$27
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	-$12	$	$	$	$	$	-$12	$	$	$
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	-$1,516	$	$	-$1,516	$	$	$	$	$	$
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	-$7,088	$	$	$	-$7,088	-$7,088	$	$	$	$
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYU	-$36	$	$	$	$	-$36	$	$	-$36	$
1110000 Total				**-$471,318**	**-$11,305**	**-$131,005**	**-$35,461**	**-$54,393**	**-$65,589**	**-$202,924**	**-$24,133**	**-$11,196**	**-$902**
1119000	146209	Other Intangible Assets-Non-Rec	SG	$	$	$	$	$	$	$	$	$	$
1119000	146209	Other Intangible Assets-Non-Rec	SO	$	$	$	$	$	$	$	$	$	$
1119000 Total				**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Grand Total				**-$471,318**	**-$11,305**	**-$131,005**	**-$35,461**	**-$54,393**	**-$65,589**	**-$202,924**	**-$24,133**	**-$11,196**	**-$902**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Balance (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1901000	287267	DTA 415.704 RL- Tax Rev Req Adj -UT	UT	$19	$	$	$	$	$	$19	$	$	$
1901000	287270	Valuation Allowance for DTA	SO	-$815	-$19	-$221	-$62	-$92	-$115	-$350	-$45	-$23	-$2
1901000	287272	DTA 705.337 RL - Sale of RECs - WY	OTHER	$1,364	$	$	$	$	$	$	$	$	$
1901000	287274	DTA 705.261 Reg Liab-Sale of RECs-OR	OTHER	$1,489	$	$	$	$	$	$	$	$	$
1901000	287277	DTA 605.101 Trojan Decommissioning Costs	WA	$9	$	$	$9	$	$	$	$	$	$
1901000	287278	DTA 605.102 Trojan Decommissioning Costs	OR	$2	$	$2	$	$	$	$	$	$	$
1901000	287281	DTA - CA AMT CREDIT	OTHER	$72	$	$	$	$	$	$	$	$	$
1901000	287282	DTA 105.149 PMI MINE SAFETY SEC 179E ELE	SE	-$155	-$2	-$38	-$11	-$21	-$26	-$67	-$10	-$6	-$1
1901000	287289	DTA 425.130 Rogue River-Habitat Enhancem	SG	$23	$	$6	$2	$3	$3	$10	$1	$1	$
1901000	287290	DTA 425.150 Lewis River- LWD Fund Liabil	SG	$187	$3	$48	$15	$23	$29	$81	$11	$6	$1
1901000	287291	DTA 705.300 Reg Liability - Deferred Ben	SG	$17	$	$4	$1	$2	$3	$7	$1	$1	$
1901000	287292	DTA 705.305 Reg Liab- CA Gain on Sale of	CA	$1	$1	$	$	$	$	$	$	$	$
1901000	287299	DTA 705.265 Reg Liab-OR Energy Conservat	OR	$888	$	$888	$	$	$	$	$	$	$
1901000	287302	DTA-610.114 PMI EITF 04-06 PRE STRIPPING	SE	$549	$9	$134	$40	$73	$93	$237	$35	$21	$2
1901000	287303	DTA-PMI 105.171 PP&E	SE	-$151	-$2	-$37	-$11	-$20	-$26	-$65	-$10	-$6	-$1
1901000	287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	$73	$	$73	$	$	$	$	$	$	$
1901000	287309	DTA 705.200 Oregon Gain on Sale-Halsey	OTHER	$28	$	$	$	$	$	$	$	$	$
1901000	287314	DTA 415.700 Reg liability BPA balancing	OTHER	$1,205	$	$	$	$	$	$	$	$	$
1901000	287323	DTA 505.400 Bonus Liab. Elec.-Cash Basis	SO	$10	$	$3	$1	$1	$1	$4	$1	$	$
1901000	287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	$3,736	$86	$1,015	$286	$422	$528	$1,606	$206	$106	$9
1901000	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	$14	$	$4	$1	$2	$2	$6	$1	$	$
1901000	287327	DTA 720.300 Pension/Retirement Accrual -	SO	$891	$21	$242	$68	$101	$126	$383	$49	$25	$2
1901000	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	$14,698	$340	$3,993	$1,126	$1,660	$2,075	$6,318	$811	$415	$35
1901000	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	$212	$4	$55	$17	$26	$33	$92	$12	$7	$1
1901000	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	$878	$15	$226	$69	$106	$135	$380	$49	$29	$3
1901000	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	$3,844	$155	$1,794	$505	$196	$197	$1,064	$129	$1	$
1901000	287341	DTA 910.530 Injuries & Damages Accrual -	SO	$3,225	$75	$876	$247	$364	$455	$1,387	$178	$91	$8
1901000	287343	DTA 415.120 Def Reg Asset-Foote Creek Co	SG	$215	$4	$56	$17	$26	$33	$93	$12	$7	$1
1901000	287344	DTA 715.800 Redding Contract - Prepaid	SG	$1,044	$18	$269	$82	$127	$161	$452	$59	$34	$3
1901000	287345	DTA 145.030 Distribution O&M Amort of Wr	SNPD	$1,794	$64	$483	$113	$155	$185	$863	$86	$30	$
1901000	287349	DTA 505.100 Trail Mountain Accrued Liabi	SE	$445	$7	$108	$33	$59	$76	$192	$28	$17	$2
1901000	287354	DTA 505.140 MISC CURRENT & ACCRUED LIAB	SO	$2,413	$56	$656	$185	$273	$341	$1,037	$133	$68	$6
1901000	287357	DTA 715.350 OTHER ENVIROMENTAL LIABILITI	SO	$3,563	$82	$968	$273	$402	$503	$1,532	$197	$101	$8
1901000	287370	DTA 425.215 Unearned Joint Use Pole Cont	OTHER	$1,276	$	$	$	$	$	$	$	$	$
1901000	287373	DTA 910.580 Wasach workers comp reserve	SO	$1,590	$37	$432	$122	$180	$224	$683	$88	$45	$4
1901000	287389	DTA 610.145, OR CONSOLIDATION	OTHER	$2,730	$	$	$	$	$	$	$	$	$
1901000	287393	DTA 425.110 TENANT LEASE ALLOW - PSU CAL	CN	$47	$1	$14	$3	$3	$3	$24	$2	$	$
1901000	287396	DTA425.110 Tenant Lease Allowances	OTHER	$610	$	$	$	$	$	$	$	$	$
1901000	287399	DTA 920.150 FAS 112	SO	$7,708	$178	$2,094	$590	$871	$1,088	$3,314	$426	$218	$18
1901000	287413	DTA 720.550 ACCRUED CIC SEVERANCE	SO	-$10	$	-$3	-$1	-$1	-$1	-$4	-$1	$	$
1901000	287415	DTA 205.200 M&S INV	SE	$1,337	$21	$325	$98	$177	$227	$576	$84	$50	$5
1901000	287417	DTA 605.710 REVERSE	OTHER	$4,337	$	$	$	$	$	$	$	$	$
1901000	287429	DTA 425.225 Duke Contract Novation	SG	$155	$3	$40	$12	$19	$24	$67	$9	$5	$1
1901000	287431	DTA 505.160 Cal PUC Fee	CA	$9	$9	$	$	$	$	$	$	$	$
1901000	287433	DTA 425.295 BPA CONSERVATION DISCOUNT	SE	$263	$4	$64	$19	$35	$45	$113	$17	$10	$1
1901000	287435	DTA 105.154 SECTION 383 CAPITAL LOSS CAR	OTHER	$37	$	$	$	$	$	$	$	$	$
1901000	287437	DTA Net Operating Loss Carryforwrd-State	SO	$64,667	$1,494	$17,567	$4,954	$7,304	$9,131	$27,799	$3,570	$1,828	$153
1901000	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	$1,913	$32	$488	$149	$236	$300	$828	$110	$64	$6
1901000	287442	DTA 610.135 SB 1149 Costs	OTHER	$372	$	$	$	$	$	$	$	$	$
1901000	287446	DTA 205.100 Coal Pile Inventory Adjustme	SE	$714	$11	$174	$53	$94	$121	$308	$45	$27	$3
1901000	287449	DTA Federal Detriment of State NOL	SO	-$22,703	-$525	-$6,167	-$1,739	-$2,564	-$3,206	-$9,760	-$1,253	-$642	-$54
1901000	287453	DTA 610.143 WA PRGRM	OTHER	$78	$	$	$	$	$	$	$	$	$
1901000	287473	DTA 705.270 Reg Liab	OTHER	$238	$	$	$	$	$	$	$	$	$
1901000	287474	DTA 705.271 Reg Liab	OTHER	$18	$	$	$	$	$	$	$	$	$
1901000	287475	DTA 705.272 Reg Liab	OTHER	$7	$	$	$	$	$	$	$	$	$
1901000	287476	DTA 705.273 Reg Liab	OTHER	$349	$	$	$	$	$	$	$	$	$
1901000	287477	DTA 705.274 Reg Liab	OTHER	$1	$	$	$	$	$	$	$	$	$
1901000	287478	DTA 705.275 Reg Liab	OTHER	$21	$	$	$	$	$	$	$	$	$
1901000	287479	DTA 105.221 Saf Har	SG	$36,874	$621	$9,505	$2,897	$4,472	$5,677	$15,982	$2,072	$1,204	$121
1901000	287482	DTA 205.025 PMI Fuel Cost Adjustment	SE	$1,695	$26	$412	$125	$224	$288	$730	$107	$64	$6
1901000	287483	DTA 120.105 Willow Wind Account Receivab	WA	$37	$	$	$37	$	$	$	$	$	$
1901000	287499	DTA - PMI Def Tax	SE	$8,324	$130	$2,024	$613	$1,101	$1,414	$3,588	$525	$313	$31
1901000	287681	DTL 920.110 BRIDGER EXTRACTION TAXES PAY	SE	$2,662	$41	$647	$196	$352	$452	$1,147	$168	$100	$10
1901000	287706	DTL 610.100 COAL MINE DEVT PMI	SE	$1,833	$29	$446	$135	$242	$311	$790	$116	$69	$7
1901000	287718	DTL 610.111 PMI Gain/Loss on Assets	SE	-$4	$	-$1	$	-$1	-$1	-$2	$	$	$
1901000	287719	DTL 910.910 PMI Sec. 471 Inv Adj	SE	-$1,013	-$16	-$246	-$75	-$134	-$172	-$436	-$64	-$38	-$4

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Balance (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
1901000	287720	DTL 610.100 PMI DEV'T COST AMORT	SE	-$2,595	-$40	-$631	-$191	-$343	-$441	-$1,119	-$164	-$97	-$10
1901000	287721	DTL 610.115 PMI OVERBURDEN REMOVAL	SE	$209	$3	$51	$15	$28	$36	$90	$13	$8	$1
1901000	287722	DTL 505.510 PMI VAC ACCRUAL	SE	$295	$5	$72	$22	$39	$50	$127	$19	$11	$1
1901000	287723	DTL 205.411 PMI SEC. 263A	SE	$2,871	$45	$698	$212	$380	$488	$1,237	$181	$108	$11
1901000	287726	DTL PMI PP&E	SE	-$32,482	-$506	-$7,898	-$2,393	-$4,297	-$5,516	-$13,999	-$2,049	-$1,220	-$121
1901000	287735	DTL 910.905 PMI COST DEPLETION	SE	-$274	-$4	-$67	-$20	-$36	-$47	-$118	-$17	-$10	-$1
1901000 Total				**$125,981**	**$2,513**	**$31,644**	**$8,838**	**$12,267**	**$15,307**	**$47,246**	**$5,936**	**$3,040**	**$265**
1901090	287374	DTA 100.105 FAS 109 Deferred Tax Liabili	WA	$3,761	$	$	$3,761	$	$	$	$	$	$
1901090 Total				**$3,761**	**$**	**$**	**$3,761**	**$**	**$**	**$**	**$**	**$**	**$**
2811000	287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	-$121,388	-$2,043	-$31,290	-$9,538	-$14,723	-$18,687	-$52,612	-$6,820	-$3,964	-$397
2811000 Total				**-$121,388**	**-$2,043**	**-$31,290**	**-$9,538**	**-$14,723**	**-$18,687**	**-$52,612**	**-$6,820**	**-$3,964**	**-$397**
2820000	287704	DTL 105.143/165 Basis Diff - Intangibles	SO	-$1	$	$	$	$	$	$	$	$	$
2820000 Total				**-$1**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
2821000	287605	DTL PP&E Powertax	DITBAL	-$3,031,108	-$68,312	-$832,740	-$182,562	-$347,598	-$420,489	-$1,299,686	-$170,877	-$72,891	-$8,569
2821000	287608	DTL Safe Harbor Lease Cholla	SG	-$4,962	-$84	-$1,279	-$390	-$602	-$764	-$2,151	-$279	-$162	-$16
2821000	287740	DTL 110.200 TAX PERCENTAGE DEPLETION	SE	$467	$7	$114	$34	$62	$79	$201	$29	$18	$2
2821000	287753	DTL 110.100 BOOK DEPLETION	SE	-$6,538	-$102	-$1,590	-$482	-$865	-$1,110	-$2,818	-$413	-$246	-$24
2821000	287766	DTL 610.100N Amort	SO	$286	$7	$78	$22	$32	$40	$123	$16	$8	$1
2821000	287771	DTL 110.205 SRC tax depletion	SE	$579	$9	$141	$43	$77	$98	$250	$37	$22	$2
2821000	287962	DTL - Fixed Assets - State Modifications	SO	$40,184	$928	$10,916	$3,078	$4,538	$5,674	$17,274	$2,218	$1,136	$95
2821000	287963	DTL - Fixed Assets - State Modif (Fed De	SO	-$14,064	-$325	-$3,821	-$1,077	-$1,588	-$1,986	-$6,046	-$776	-$397	-$33
2821000 Total				**-$3,015,156**	**-$67,870**	**-$828,182**	**-$181,334**	**-$345,944**	**-$418,457**	**-$1,292,852**	**-$170,044**	**-$72,513**	**-$8,543**
2831000	287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	-$381	$	$	$	$	-$381	$	$	-$381	$
2831000	287573	DTL 415.873 Deferred Excess NPC-WA Hydro	WA	-$1,013	$	$	-$1,013	$	$	$	$	$	$
2831000	287575	DTL 425.125 Deferred Coal Cost-Arch	SE	-$24	$	-$6	-$2	-$3	-$4	-$10	-$2	-$1	$
2831000	287576	DTL 415.822 RgAst UT	OTHER	-$2,730	$	$	$	$	$	$	$	$	$
2831000	287577	DTL 415.820 Contra Pensn Reg Asset MMT &	OR	$3,081	$	$3,081	$	$	$	$	$	$	$
2831000	287578	DTL 415.821 Contra Pensn Reg Asset MMT &	WYU	$631	$	$	$	$	$631	$	$	$631	$
2831000	287579	DTL 415.822 Reg Asset _ Pension MMT_UT	UT	-$752	$	$	$	$	$	-$752	$	$	$
2831000	287580	DTL 415.823 Contra Pensn Reg Asset CTG_U	UT	$2,259	$	$	$	$	$	$2,259	$	$	$
2831000	287581	DTL 415.824 Contra Pensn Reg Asset MMT &	CA	$275	$275	$	$	$	$	$	$	$	$
2831000	287582	DTL 415.825 Contra Pensn Reg Asset CTG_W	WA	$773	$	$	$773	$	$	$	$	$	$
2831000	287584	DTL 415.827 Reg Asset - FAS 158 Post - R	OR	-$586	$	-$586	$	$	$	$	$	$	$
2831000	287585	DTL 415.828 Reg Asset - FAS 158 Post - R	WYP	-$117	$	$	$	-$117	-$117	$	$	$	$
2831000	287586	DTL 415.829 Reg Asset - Post - Ret MMT_U	UT	-$740	$	$	$	$	$	-$740	$	$	$
2831000	287588	DTL 415.831 Reg Asset - Post - Ret MMT_C	CA	-$52	-$52	$	$	$	$	$	$	$	$
2831000	287590	DTL 415.840 Reg Asset - Deferred OR Ind	OTHER	-$205	$	$	$	$	$	$	$	$	$
2831000	287591	DTL 415.301 Environmental Clean-up Accrl	WA	$247	$	$	$247	$	$	$	$	$	$
2831000	287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	-$6,106	$	$	$	$	$	$	$	$	$
2831000	287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	-$4,917	$	$	$	$	$	$	$	$	$
2831000	287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	-$185	$	$	$	-$185	-$185	$	$	$	$
2831000	287614	DTL 430.100 Weatherization	SO	-$2,433	-$56	-$661	-$186	-$275	-$344	-$1,046	-$134	-$69	-$6
2831000	287616	DTL Interim provision reg assets/Liabil	OTHER	-$10,812	$	$	$	$	$	$	$	$	$
2831000	287634	DTL 415.300 Environmental Clean-up Accru	SG	-$6,705	-$113	-$1,728	-$527	-$813	-$1,032	-$2,906	-$377	-$219	-$22
2831000	287635	DTL 415.500 Cholla Plt Transact Costs-AP	SGCT	-$2,804	-$47	-$725	-$221	-$341	-$433	-$1,219	-$158	-$92	$
2831000	287639	DTL 415.510 WA Disallowed Colstrip 3-Wri	WA	-$200	$	$	-$200	$	$	$	$	$	$
2831000	287640	DTL 415.680 Deferred Intervener Funding	OR	-$14	$	-$14	$	$	$	$	$	$	$
2831000	287647	DTL 425.100 IDAHO DEFERRED REGULATORY EX	IDU	-$17	$	$	$	$	$	$	-$17	$	$
2831000	287653	DTL 425.250 TGS Buyout	SG	-$53	-$1	-$14	-$4	-$6	-$8	-$23	-$3	-$2	$
2831000	287656	DTL 425.280 Joseph Settlement	SG	-$369	-$6	-$95	-$29	-$45	-$57	-$160	-$21	-$12	-$1
2831000	287661	DTL 425.360 Hermiston Swap	SG	-$1,667	-$28	-$430	-$131	-$202	-$257	-$723	-$94	-$54	-$5
2831000	287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	-$170	$	-$170	$	$	$	$	$	$	$
2831000	287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	-$638	$	$	$	$	$	-$638	$	$	$
2831000	287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	-$72	$	$	$	$	$	$	-$72	$	$
2831000	287669	DTL 210.180 PRE MEM	SO	-$1,432	-$33	-$389	-$110	-$162	-$202	-$615	-$79	-$40	-$3
2831000	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	-$4,344	-$94	-$1,138	-$325	-$491	-$616	-$1,923	-$238	-$125	-$11
2831000	287685	DTL 425.380 Idaho Customer Balancing Acc	IDU	-$1,019	$	$	$	$	$	$	-$1,019	$	$
2831000	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	-$7,560	-$175	-$2,054	-$579	-$854	-$1,068	-$3,250	-$417	-$214	-$18
2831000	287728	DTL 415.800 GRID WST	SG	$429	$7	$111	$34	$52	$66	$186	$24	$14	$1
2831000	287737	DTL 415.803 RTO Grid West N/R-W/O-WA	WA	-$9	$	$	-$9	$	$	$	$	$	$
2831000	287747	DTL 705.240 CA Energy Program	CA	-$96	-$96	$	$	$	$	$	$	$	$
2831000	287750	DTL 425.310 Hydro Relicensing Obligation	OTHER	-$10,227	$	$	$	$	$	$	$	$	$
2831000	287760	DTL 415.896 WA - Chehalis Plant Rev Req	WA	-$5,693	$	$	-$5,693	$	$	$	$	$	$
2831000	287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	SE	-$1,354	-$21	-$329	-$100	-$179	-$230	-$584	-$85	-$51	-$5
2831000	287772	DTL 505.800 State Tax Ded on Fed TR	OTHER	$	$	$	$	$	$	$	$	$	$
2831000	287779	DTL 415.850 Unrec Plt	SG	-$736	-$12	-$190	-$58	-$89	-$113	-$319	-$41	-$24	-$2

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Balance (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
2831000	287781	DTL 415.870 Def CA	OTHER	-$725	$	$	$	$	$	$	$	$	$
2831000	287783	DTL 415.880 Def Ut	UT	$6	$	$	$	$	$	$6	$	$	$
2831000	287784	DTL 415.900 OR SB RE	OTHER	-$416	$	$	$	$	$	$	$	$	$
2831000	287787	DTL 415.895 OR _RCAC SEP-DEC 07	OR	-$239	$	-$239	$	$	$	$	$	$	$
2831000	287789	DTL 415.804 RTO GW	OR	$27	$	$27	$	$	$	$	$	$	$
2831000	287792	DTL 505.125 ACCRUED ROYALTIES	SE	-$2	$	$	$	$	$	-$1	$	$	$
2831000	287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	-$467	$	$	$	$	$	$	$	$	$
2831000	287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	-$95	$	$	$	$	$	$	$	$	$
2831000	287862	DTL 415.893 OR MEHC Transition Service C	OTHER	-$1,127	$	$	$	$	$	$	$	$	$
2831000	287864	DTL 415.852 Powerdale Decom Cost Amort-I	IDU	-$116	$	$	$	$	$	$	-$116	$	$
2831000	287865	DTL 415.853 Powerdale Decom Cost Amort-O	OR	-$187	$	-$187	$	$	$	$	$	$	$
2831000	287866	DTL 415.854 Powerdale Decom Cost Amort-W	WA	-$323	$	$	-$323	$	$	$	$	$	$
2831000	287867	DTL 415.856 Powerdale Decom Cost Amort-W	WYU	-$13	$	$	$	$	-$13	$	$	-$13	$
2831000	287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	-$253	$	$	$	-$253	-$253	$	$	$	$
2831000	287869	DTL 415.859 Reg Asset-WY Def Advertising	OTHER	-$20	$	$	$	$	$	$	$	$	$
2831000	287870	DTL 415.865 Reg Asset-UT Major Plant Add	OTHER	-$5,968	$	$	$	$	$	$	$	$	$
2831000	287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	-$86	$	$	$	$	$	$	$	$	$
2831000	287872	DTL 720.841 RA Tax Adj on PR Benefit-CA	OTHER	-$124	$	$	$	$	$	$	$	$	$
2831000	287873	DTL 720.842 RA Tax Adj on PR Benefit-ID	OTHER	-$277	$	$	$	$	$	$	$	$	$
2831000	287874	DTL 720.843 RA Tax Adj on PR Benefit-OR	OTHER	-$1,548	$	$	$	$	$	$	$	$	$
2831000	287875	DTL 720.844 RA Tax Adj on PR Benefit-UT	OTHER	-$1,974	$	$	$	$	$	$	$	$	$
2831000	287877	DTL 720.846 RA Tax Adj on PR Benefit-WY	OTHER	-$755	$	$	$	$	$	$	$	$	$
2831000	287879	DTL 415.898 Deferred Coal Cost Naughton	SE	-$3,134	-$49	-$762	-$231	-$414	-$532	-$1,350	-$198	-$118	-$12
2831000	287880	DTL 415.897 Transition Severance Cost CA	CA	-$85	-$85	$	$	$	$	$	$	$	$
2831000	287881	DTL 415.705 RA # Tax Rev Req Adj-WY	WYU	-$38	$	$	$	$	$	-$38	$	-$38	$
2831000	287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	-$1,338	$	$	$	$	$	$	$	$	$
2831000	287883	DTL 430.116 RA Fed Int Exp (ID)	OTHER	-$113	$	$	$	$	$	$	$	$	$
2831000	287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	-$78	$	$	$	$	$	$	$	$	$
2831000	287944	DTL - REG. ASSET FEDERAL INT EXP	UT	-$821	$	$	$	$	$	-$821	$	$	$
2831000	287947	DTL 415.501 Cholla Plant Transaction Cos	IDU	$82	$	$	$	$	$	$	$82	$	$
2831000	287948	DTL 415.502 Cholla Plant Transaction Cos	OR	$134	$	$134	$	$	$	$	$	$	$
2831000	287949	DTL 415.503 Cholla Plant Transaction Cos	WA	$242	$	$	$242	$	$	$	$	$	$
2831000	287961	DTL Reg Asset Federal Int Exp (WY)	OTHER	-$221	$	$	$	$	$	$	$	$	$
2831000	287990	DTL - PMI Def Tax	SE	-$8,324	-$130	-$2,024	-$613	-$1,101	-$1,414	-$3,588	-$525	-$313	-$31
2831000 Total				**-$96,912**	**-$716**	**-$8,388**	**-$9,058**	**-$5,480**	**-$6,600**	**-$18,217**	**-$3,489**	**-$1,120**	**-$115**
Grand Total				**-$3,103,714**	**-$68,117**	**-$836,217**	**-$187,331**	**-$353,881**	**-$428,437**	**-$1,316,435**	**-$174,418**	**-$74,556**	**-$8,791**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Investment Tax Credit Balance (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
2551000	285602	ACCUM DEF ITC - PPL - 1983	ITC84	-$873	-$29	-$619	-$124	-$96	-$96	$	$	$	$
2551000	285603	ACCUM DEF ITC - PPL - 1984	ITC85	-$874	-$47	-$591	-$117	-$101	-$101	$	$	$	$
2551000	285604	ACCUM DEF ITC - PPL - 1985	ITC85	-$1,153	-$62	-$780	-$154	-$134	-$134	$	$	$	$
2551000	285605	ACCUM DEF ITC - PPL - 1986	ITC86	-$1,110	-$53	-$717	-$146	-$172	-$172	$	$	$	$
2551000	285606	ACCUM DEF ITC - PPL - 1987	ITC88	-$178	-$8	-$109	-$27	-$30	-$30	$	$	$	$
2551000	285607	ACCUM DEF ITC - PPL - 1988	ITC89	-$398	-$19	-$225	-$61	-$82	-$82	$	$	$	$
2551000	285608	JIM BRIDGER RETROFIT ITC - PPL	ITC90	-$273	-$4	-$43	-$11	-$10	-$47	-$128	-$38	-$37	$
2551000 Total				**-$4,858**	**-$223**	**-$3,085**	**-$638**	**-$625**	**-$662**	**-$128**	**-$38**	**-$37**	**$**
Grand Total				**-$4,858**	**-$223**	**-$3,085**	**-$638**	**-$625**	**-$662**	**-$128**	**-$38**	**-$37**	**$**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Customer Advances (Actuals)

Balance as of June 2011
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC
2520000	210550	Payments Received Uncompleted Projects	IDU	-$592	$	$	$	$	$	$	-$592	$	$
2520000	210550	Payments Received Uncompleted Projects	OR	-$7,097	$	-$7,097	$	$	$	$	$	$	$
2520000	210550	Payments Received Uncompleted Projects	SG	-$904	-$15	-$233	-$71	-$110	-$139	-$392	-$51	-$30	-$3
2520000	210550	Payments Received Uncompleted Projects	UT	-$2,766	$	$	$	$	$	-$2,766	$	$	$
2520000	210550	Payments Received Uncompleted Projects	WA	-$4	$	$	-$4	$	$	$	$	$	$
2520000	210550	Payments Received Uncompleted Projects	WYP	-$789	$	$	$	-$789	-$789	$	$	$	$
2520000	210550	Payments Received Uncompleted Projects	WYU	-$411	$	$	$	$	-$411	$	$	-$411	$
2520000	210553	Transmission Payments Received - Capital	SG	-$1,865	-$31	-$481	-$147	-$226	-$287	-$808	-$105	-$61	-$6
2520000	285460	Transm Intercon Deposits - w/3rd Party	SG	-$13,436	-$226	-$3,463	-$1,056	-$1,630	-$2,068	-$5,824	-$755	-$439	-$44
2520000 Total				**-$27,864**	**-$273**	**-$11,274**	**-$1,278**	**-$2,754**	**-$3,694**	**-$9,790**	**-$1,503**	**-$940**	**-$53**
Grand Total				**-$27,864**	**-$273**	**-$11,274**	**-$1,278**	**-$2,754**	**-$3,694**	**-$9,790**	**-$1,503**	**-$940**	**-$53**

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/1103
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Black Cap Solar, LLC Project

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/1104
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of R. Bryce Dalley

PacifiCorp's Property Tax Estimation Procedure

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/1105
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Carbon Steam Plant Depreciation Calcualtions

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	ALLOCATED	REF#
May 2013 In Service							
Adjustment to Plant in Service:							
Transmission Plant - Capital Addition	355	3	380,613,978	SG	25.7772%	98,111,455	Page 3
Adjustment to Depreciation Reserve:							
Transmission Plant - Capital Addition	108TP	3	(3,896,866)	SG	25.7772%	(1,004,501)	Page 3
Adjustment to Depreciation Expense:							
Transmission Plant - Capital Addition	403TP	3	7,194,213	SG	25.7772%	1,854,464	Page 3
Adjustment to O&M Expense:							
Mona to Oquirrh	571	3	150,000	SG	25.7772%	38,666	
Adjustments to Tax:							
Schedule M Adjustment	SCHMDT	3	15,809,183	SG	25.7772%	4,075,158	Page 4
Deferred Income Tax Expense	41010	3	5,999,743	SG	25.7772%	1,546,563	Page 4
ADIT Balance	282	3	(2,858,818)	SG	25.7772%	(736,922)	Page 4

Description of Exhibit:

This exhibit adds the Mona to Oquirrh transmission capital project to rate base, as discussed in detail in the direct testimony of Company witness Mr. Darrell T. Gerrard. The figures above represent the capital investment, depreciation expense, accumulated depreciation, O&M, and tax impacts associated with the segment of the line that will be placed into service in May 2013. The total Oregon-allocated annual revenue requirement associated with this segment of the transmission line is shown on page two.

PacifiCorp
Oregon General Rate Case
Revenue Requirement: Mona to Oquirrh Project

	Mona - Oquirrh Addition (May 2013)			
	Total Company	**Oregon Allocated**	**Price Change**	**Results with Price Change**
Operating Revenues:				
General Business Revenues	-	-	13,082,797	13,082,797
Interdepartmental	-	-		
Special Sales	-	-		
Other Operating Revenues	-	-		
Total Operating Revenues	-	-	13,082,797	13,082,797
Operating Expenses:				
Steam Production	-	-		
Nuclear Production	-	-		
Hydro Production	-	-		
Other Power Supply	-	-		
Embedded Cost Differential	-	-		
Transmission	150,000	38,666		38,666
Distribution	-	-		
Customer Accounting	-	-	67,581	67,581
Customer Service & Info	-	-		
Sales	-	-		
Administrative & General	-	-		
Total O&M Expenses	150,000	38,666	67,581	106,247
Depreciation	7,194,213	1,854,464		1,854,464
Amortization	-	-		
Taxes Other Than Income	-	-	311,371	311,371
Income Taxes - Federal	(10,882,844)	(2,804,754)	4,244,482	1,439,727
Income Taxes - State	(1,478,798)	(381,120)	576,755	195,635
Income Taxes - Def Net	5,999,743	1,546,563		1,546,563
Investment Tax Credit Adj.	-	-		
Misc Revenue & Expense	-	-		
Total Operating Expenses:	982,315	253,818	5,200,188	5,454,006
Operating Rev For Return:	(982,315)	(253,818)	7,882,609	7,628,790
Rate Base:				
Electric Plant In Service	380,613,978	98,111,455		98,111,455
Plant Held for Future Use	-	-		
Misc Deferred Debits	-	-		
Elec Plant Acq Adj	-	-		
Nuclear Fuel	-	-		
Prepayments	-	-		
Fuel Stock	-	-		
Material & Supplies	-	-		
Working Capital	-	(63,327)		(63,327)
Weatherization Loans	-	-		
Misc Rate Base	-	-		
Total Electric Plant:	380,613,978	98,048,128		98,048,128
Rate Base Deductions:				
Accum Prov For Deprec	(3,896,866)	(1,004,501)		(1,004,501)
Accum Prov For Amort	-	-		
Accum Def Income Tax	(2,858,818)	(736,922)		(736,922)
Unamortized ITC	-	-		
Customer Adv For Const	-	-		
Customer Service Deposits	-	-		
Misc Rate Base Deductions	-	-		
Total Rate Base Deductions	(6,755,684)	(1,741,423)		(1,741,423)
Total Rate Base:	373,858,295	96,306,705		96,306,705
Return on Rate Base		-0.26%		7.92%
Return on Equity		-5.30%		10.20%
TAX CALCULATION:				
Operating Revenue	(7,344,213)	(1,893,129)	12,703,845	10,810,715
Other Deductions	-	-		-
Interest (AFUDC)	-	-		-
Interest	9,419,240	2,426,417		2,426,417
Schedule "M" Additions	-	-		-
Schedule "M" Deductions	15,809,183	4,075,158		4,075,158
Income Before Tax	(32,572,636)	(8,394,703)	12,703,845	4,309,141
State Income Taxes	(1,478,798)	(381,120)	576,755	195,635
Oregon/Utah State Tax Credits	-	-	-	-
Total State Income Taxes	(1,478,798)	(381,120)	576,755	195,635
Taxable Income	(31,093,839)	(8,013,584)	12,127,090	4,113,506
Federal Taxes Before Credits	(10,882,844)	(2,804,754)	4,244,482	1,439,727
Renewable Energy Tax Credit	-	-	-	-
Federal Income Taxes	(10,882,844)	(2,804,754)	4,244,482	1,439,727

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

Depreciation Rate (Transmission SG)	1.890%

Mona - Oquirrh Project
In Service: May 2013

	Capital Addition Pieces		Depreciation Pieces (Capital)	
Month	**Addition Per Month**	**Capital Addition Balance**	**Depreciation Expense**	**Depreciation Reserve**
May-13	380,613,978	380,613,978	299,759	(299,759)
Jun-13	-	380,613,978	599,518	(899,277)
Jul-13	-	380,613,978	599,518	(1,498,794)
Aug-13	-	380,613,978	599,518	(2,098,312)
Sep-13	-	380,613,978	599,518	(2,697,830)
Oct-13	-	380,613,978	599,518	(3,297,348)
Nov-13	-	380,613,978	599,518	(3,896,866)
Dec-13	-	380,613,978	599,518	(4,496,383)
Jan-14	-	380,613,978	599,518	(5,095,901)
Feb-14	-	380,613,978	599,518	(5,695,419)
Mar-14	-	380,613,978	599,518	(6,294,937)
Apr-14	-	380,613,978	599,518	(6,894,454)
May-14	-	380,613,978	599,518	(7,493,972)
Total	380,613,978	**380,613,978**	**7,194,213**	**(3,896,866)**
		13 Month Average	Annual Level	13 Month Average
		Ref. Page 1	**Ref. Page 1**	**Ref. Page 1**

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

Mona-Limber-Oquirrh Project - (May 2013 Portion)					
	Tax Depreciation		Book Depreciation		Accumulated
Month	Book-Tax Difference	Deferred Income Tax	Book-Tax Difference	Deferred Income Tax	Deferred Income Tax
01/31/2013	0	0	0	0	0
02/28/2013	0	0	0	0	0
03/31/2013	(4,694,571)	1,781,637	1,798,553	(682,569)	(1,099,068)
04/30/2013	0	0	0	0	(1,099,068)
05/31/2013	0	0	0	0	(1,099,068)
06/30/2013	(4,694,571)	1,781,637	1,798,553	(682,569)	(2,198,136)
07/31/2013	0	0	0	0	(2,198,136)
08/31/2013	0	0	0	0	(2,198,136)
09/30/2013	(4,694,571)	1,781,637	1,798,553	(682,569)	(3,297,204)
10/31/2013	0	0	0	0	(3,297,204)
11/30/2013	0	0	0	0	(3,297,204)
12/31/2013	(4,694,569)	1,781,636	1,798,553	(682,569)	(4,396,271)
01/31/2014	0	0	0	0	(4,396,271)
02/28/2014	0	0	0	0	(4,396,271)
03/31/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(7,098,811)
04/30/2014	0	0	0	0	(7,098,811)
05/31/2014	0	0	0	0	(7,098,811)
06/30/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(9,801,351)
07/31/2014	0	0	0	0	(9,801,351)
08/31/2014	0	0	0	0	(9,801,351)
09/30/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(12,503,891)
10/31/2014	0	0	0	0	(12,503,891)
11/30/2014	0	0	0	0	(12,503,891)
12/31/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(15,206,431)
Book-Tax Differences	**(23,003,395)**	**8,730,019**	**7,194,212**	**(2,730,276)**	
	Ref. Page 1	**Ref. Page 1**	**Ref. Page 1**	**Ref. Page 1**	

Monthly Rollfoward of Accumulated Deferred Income Tax Liability: Internal Revenue Code Regulations				
Month Ended	Beg. Bal	Provision	Accum. Provision	Ending Balance
05/31/2013	(1,099,068)	0	0	(1,099,068)
06/30/2013	(1,099,068)	(1,011,745)	(1,011,745)	(2,110,813)
07/31/2013	(2,110,813)	0	(1,011,745)	(2,110,813)
08/31/2013	(2,110,813)	0	(1,011,745)	(2,110,813)
09/30/2013	(2,110,813)	(734,719)	(1,746,464)	(2,845,532)
10/31/2013	(2,845,532)	0	(1,746,464)	(2,845,532)
11/30/2013	(2,845,532)	0	(1,746,464)	(2,845,532)
12/31/2013	(2,845,532)	(457,693)	(2,204,157)	(3,303,225)
01/31/2014	(3,303,225)	0	(2,204,157)	(3,303,225)
02/28/2014	(3,303,225)	0	(2,204,157)	(3,303,225)
03/31/2014	(3,303,225)	(459,062)	(2,663,219)	(3,762,287)
04/30/2014	(3,762,287)	0	(2,663,219)	(3,762,287)
05/31/2014	(3,762,287)	0	(2,663,219)	(3,762,287)
13-Month Average				**(2,858,818)**
				Ref. Page 1

Monthly Period Ended	06/30/2013 Accrual	09/30/2013 Accrual	12/31/2013 Accrual	03/31/2014 Accrual	Forecast Period
6/1 - 6/30/2013	1	0	0	0	30
07/31/2013	31	0	0	0	31
08/31/2013	31	0	0	0	31
09/30/2013	30	1	0	0	30
10/31/2013	31	31	0	0	31
11/30/2013	30	30	0	0	30
12/31/2013	31	31	1	0	31
01/31/2014	31	31	31	0	31
02/28/2014	28	28	28	0	28
03/31/2014	31	31	31	1	31
04/30/2014	30	30	30	30	30
05/31/2014	31	31	31	31	31
Days In Forecast Per.	**336**	**244**	**152**	**62**	**365**
% Days in Forecast Per.	**92.0548%**	**66.8493%**	**41.6438%**	**16.9863%**	**100.0000%**

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

BOOK BASIS

Description	Cost	AFUDC Debt	AFUDC Equity	AFUDC Total	Total
Land	**0**	0	0	**0**	**0**
Land Rights	**0**	0	0	**0**	**0**
Non-Land	**351,766,345**	10,052,596	18,795,037	**28,847,633**	**380,613,978**
Total	**351,766,345**	10,052,596	18,795,037	**28,847,633**	**380,613,978**

TAX BASIS

Description	Book Basis	Less: AFUDC Debt	Less: AFUDC Equity	Less: AFUDC Total	Cost	Add: Avoided Costs	Tax Basis	Tax Depreciation Method	Tax Depreciation Convention	Tax Depreciation Recovery Period
Land	**0**	0	0	**0**	**0**	**0**	**0**	Non -Depreciable		
Land Rights	**0**	0	0	**0**	**0**	**0**	**0**	Straight-Line	Mid-Month	84-Years
Non-Land	**380,613,978**	(10,052,596)	(18,795,037)	**(28,847,633)**	**351,766,345**	**23,799,297**	**375,565,642**	MACRS	Half-Year	15-Years
Total	**380,613,978**	**(10,052,596)**	**(18,795,037)**	**(28,847,633)**	**351,766,345**	**23,799,297**	**375,565,642**			

Mona-Limber-Oquirrh Project - (May 2013 Portion)

TAX DEPRECIATION
MACRS / 15-Years

Month	Cost	Avoided Costs	Tax Basis
	351,766,345	23,799,297	**375,565,642**
01/31/2013	1,465,693	99,164	**1,564,857**
02/28/2013	1,465,693	99,164	**1,564,857**
03/31/2013	1,465,693	99,164	**1,564,857**
04/30/2013	1,465,693	99,164	**1,564,857**
05/31/2013	1,465,693	99,164	**1,564,857**
06/30/2013	1,465,693	99,164	**1,564,857**
07/31/2013	1,465,693	99,164	**1,564,857**
08/31/2013	1,465,693	99,164	**1,564,857**
09/30/2013	1,465,693	99,164	**1,564,857**
10/31/2013	1,465,693	99,163	**1,564,856**
11/30/2013	1,465,693	99,163	**1,564,856**
12/31/2013	1,465,694	99,163	**1,564,857**
Total 2013	**17,588,317**	**1,189,965**	**18,778,282**
01/31/2014	2,784,817	188,411	**2,973,228**
02/28/2014	2,784,817	188,411	**2,973,228**
03/31/2014	2,784,817	188,411	**2,973,228**
04/30/2014	2,784,817	188,411	**2,973,228**
05/31/2014	2,784,817	188,411	**2,973,228**
06/30/2014	2,784,817	188,411	**2,973,228**
07/31/2014	2,784,817	188,411	**2,973,228**
08/31/2014	2,784,817	188,411	**2,973,228**
09/30/2014	2,784,817	188,411	**2,973,228**
10/31/2014	2,784,817	188,411	**2,973,228**
11/30/2014	2,784,817	188,411	**2,973,228**
12/31/2014	2,784,816	188,412	**2,973,228**
Total 2014	**33,417,803**	**2,260,933**	**35,678,736**

MACRS Depreciation Table: Half-Year Convention

Recovery Year	Recovery Period 15-Year
1	5.00%
2	9.50%
3	8.55%
4	7.70%
5	6.93%
6	6.23%
7	5.90%
8	5.90%
9	5.91%
10	5.90%
11	5.91%
12	5.90%
13	5.91%
14	5.90%
15	5.91%
16	2.95%
	100.00%

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

SG Allocation Factor	25.7772%
Federal Tax Rate	35.0000%
State Tax Rate	4.54%

Capital Structure and Cost			
	%	**Cost**	**Weighted Cost**
Debt	46.900%	5.372%	2.519%
Preferred	0.300%	5.427%	0.016%
Common	52.800%	10.200%	5.386%
			7.921%

Revenue Sensitive Items	
Operating Revenue	100%
Operating Deductions	
Uncollectable Accounts	0.517%
Taxes Other - Franchise Tax	2.300%
Taxes Other - Revenue Tax	0.00%
Taxes Other - Resource Supplier	0.080%
Taxes Other - Gross Receipts	0.00%
Sub-Total	97.103%
State Income Tax @ 4.54%	4.408%
Sub-Total	92.695%
Federal Income Tax @ 35.00%	32.443%
Net Operating Income	60.252%

CONFIDENTIAL
Docket No. UE-246
Exhibit PAC/1107
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Global Insight Escalation Indices

March 2012

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

DIRECT TESTIMONY OF C. CRAIG PAICE

TABLE OF CONTENTS

ATTACHED EXHIBITS

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

A. My name is C. Craig Paice. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. I am currently employed as a Consultant in the Regulation Department.

Qualifications

Q. Please describe your education, business experience, and responsibilities.

A. I received a Bachelor of Science Degree in Business Management from Brigham Young University in 1976. I have also attended various educational, professional, and electric industry seminars during my career with the Company. I have been employed by PacifiCorp since the merger in 1989. Prior to that time, I was employed by Utah Power & Light Company beginning in 1978 holding various positions in the accounting, customer service, and regulatory areas. In my current position, my primary responsibilities are to prepare, present, and explain the results of the Company's cost of service studies to regulators and interested parties in jurisdictions where PacifiCorp provides retail electric service.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures, and the Oregon Marginal Cost Study.

Unbundled Class Revenue Requirements

Q. Please identify Exhibit PAC/1201 and explain what it shows.

A. Exhibit PAC/1201 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services – Billing, Consumer Services – Metering, Consumer Services – Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base assets and expenses were either assigned or allocated to unbundled categories in accordance with OAR 860-038-0200. Traditional revenue requirement methodology, (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Costs and rate base assets are from PacifiCorp's Oregon Results of Operations Report, as filed by Company witness Mr. R. Bryce Dalley. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1201.

Q. Please identify Exhibit PAC/1202 and explain what it shows.

A. Exhibit PAC/1202, Tab 1 is the summary page from PacifiCorp's December 2013

Functionalized Oregon Results of Operations Report ("Functionalized Oregon Results of Operations Report") and is the basis for the unbundled revenue requirement in Exhibit PAC/1201. It separates the results of operations into the unbundled categories identified above.

Q. Please explain how the various expenses and rate base assets in the Functionalized Oregon Results of Operations were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission ("FERC") account is found in Exhibit PAC/1202, Tab 2. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1206.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PAC/1203. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/1204.

A. Exhibit PAC/1204 contains a summary from PacifiCorp's State of Oregon December 2013 Marginal Cost Study ("Marginal Cost Study"). The Marginal Cost Study is described later in my testimony.

Q. Please identify Exhibit PAC/1205 and explain what it shows.

A. Page 1 of Exhibit PAC/1205 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours ("MWh") are shown on line 2. Full long-run marginal costs for each customer class, separated by function, are shown on lines 5 through 11. Lines 15 through 23 show each class' share of total marginal costs for each function as well as each class' share of revenue and MWh. Lines 27 through 36 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier is shown in the total column. The total for each function is then allocated to a particular customer class based on that class' share of total marginal cost for that function. For example, the residential class accounts for 42.23 percent of generation marginal costs and is assigned 42.23 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 38 through 45 compare the total revenue

requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1205.

A. Pages 2 and 3 of Exhibit PAC/1205 provides a reconciliation between Operating Revenues and Target Revenue Requirement as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1201 and 1202. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1205 accounts for all Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

Marginal Cost Study

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/1207. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PAC/1207 contains seven summary tables followed by 15 sections of supporting data.

Q. Is this marginal cost of service study similar to studies the Company has previously filed?

A. Yes. This study is consistent with the cost of service study presented in the Company's filing in Docket UE 217.

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10 and 20-

year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs. A detailed description of marginal cost procedures is included in Exhibit PAC/1207, Tab 1.

Q. Please describe the marginal cost summary tables included in Exhibit PAC/1207, Tab 2.

A. Tables 1 and 2 of Exhibit PAC/1207 summarize the one-, 10-, and 20-year marginal costs on a mills per kWh or dollars per customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12-month period ending December 31, 2013 ("Test Period"). This information is used to calculate annual long-run marginal costs by class shown on Table 4.

Q. Please explain how generation marginal costs are calculated.

A. The marginal generation costs in this study are based on the Company's currently approved Oregon avoided cost calculations. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. The remaining fixed and all variable

costs of the combined cycle turbine are considered energy related. Marginal generation costs are summarized on Table 5 of Exhibit PAC/1207.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures to meet increased load on the transmission system. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 6 of Exhibit PAC/1207.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 7 of Exhibit PAC/1207 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in dollars per kW/year; (2) commitment-related, shown in dollars per customer/year; and (3) billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductor that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation as determined by the Company's Computer Aided Design Operations ("CADOPS") database. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is also included in the marginal cost procedures in Exhibit PAC/1207, Tab 1.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance ("O&M"). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M and meter reading expense. Current typical installed metering costs are determined for each customer load size by analyzing service require-ments, such as single or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense and all the remaining customer accounting and customer service activities. Meter reading expense is based on historical costs and allocated to customer classes based on typical meter reading times. Customer accounting and customer service expense are based on historical expenditures and

are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Q. Does this conclude your direct testimony?

A. Yes.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2013 Forecast

Function			Revenue Requirement
Production		$	738,208,096
Transmission		$	159,416,933
Distribution		$	265,022,949
Ancillary		$	10,667,409
Customer Billing		$	12,299,575
Customer Metering		$	26,194,763
Customer Other		$	18,823,959
Retail Service	a	$	-
Public Purposes	b	$	-
Total State of Oregon		$	1,230,633,684

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

Exhibit PAC/1201
Paice/1

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2013 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
1	Functionalized Situs Revenues @ Earned	7.03%	8.51%	1,182,374,666	713,384,138	149,254,434	252,606,176	10,667,409	12,161,007	25,755,131	18,546,371	-	-	224,465,659	-	28,140,517
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,182,374,666	713,384,138	149,254,434	252,606,176	10,667,409	12,161,007	25,755,131	18,546,371	-	-	224,465,659	-	28,140,517
4																
5	Target Increase in Return	7.92%	10.20%	29,076,883	15,311,128	6,268,111	6,969,803	0	85,467	271,160	171,213			6,969,803	-	-
6																
7	Add															
8	Uncollectible Expense			249,290	128,232	52,496	64,141	0	716	2,271	1,434	-	-	58,373	-	5,768
9	Franchise Tax			1,109,957			1,109,957									1,109,957
10	Other Revenue Based Taxes			38,607	19,859	8,130	9,933	0	111	352	222	-	-	9,040	-	893
11	Inc Taxes - State			2,127,497	1,120,284	458,625	509,966	0	6,253	19,840	12,527	-	-	509,966	-	-
12	Inc Taxes - Federal			15,656,783	8,244,454	3,375,137	3,752,971	0	46,021	146,009	92,192	-	-	3,752,971	-	-
13	Total Increase Needed			48,259,018	24,823,958	10,162,499	12,416,773	0	138,569	439,632	277,588	-	-	11,300,154	-	1,116,619
14																
15	Total Oregon General Business Revenue @	7.92%	10.20%	1,230,633,684	738,208,096	159,416,933	265,022,949	10,667,409	12,299,575	26,194,763	18,823,959	-	-	235,765,813	-	29,257,136
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,230,633,684	738,208,096	159,416,933	265,022,949	10,667,409	12,299,575	26,194,763	18,823,959	-	-	235,765,813	-	29,257,136
18																
19	Rate Base			3,253,958,859	1,713,449,859	701,456,740	779,982,266	0	9,564,560	30,345,161	19,160,273			779,982,266	-	-
					52.657%	21.557%	23.970%	0.000%	0.294%	0.933%	0.589%	0.000%	0.000%	23.970%	0.000%	0.000%

Source:
Total Column : Exhibit PPL 1002
Row 1: Exhibit PPL 1002
Row 8: Uncollectible 0.51657%
Row 9: Franchise Tax @ 2.3000%
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.

Exhibit PAC/1201
Paice/2

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2013 Forecast

	Description of Account Summary:	Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Other
	Operating Revenues								
1	General Business Revenues	1,182,374,666	713,384,138	149,254,434	252,606,176	10,667,409	12,161,007	25,755,131	18,546,371
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	119,935,205	119,935,205	-	-	-	-	-	-
5	Other Operating Revenues	39,568,077	27,594,320	12,855,990	5,469,228	(10,667,409)	3,781,631	219,121	315,195
6	Total Operating Revenues	1,341,877,948	860,913,664	162,110,424	258,075,404	0	15,942,638	25,974,252	18,861,566
8	Operating Expenses:								
9	Steam Production	279,186,078	279,186,078	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	12,991,451	12,991,451	-	-	-	-	-	-
12	Other Power Supply	293,375,043	293,375,043	-	-	-	-	-	-
13	ECD	(5,419,206)	(5,419,206)	-	-	-	-	-	-
14	Transmission	51,375,843	241,232	51,134,611	-	-	-	-	-
15	Distribution	70,646,415	-	-	65,787,806	-	-	4,858,609	-
16	Customer Accounts	35,339,085	4,114,518	760,782	1,211,144	0	11,224,266	11,211,350	6,817,025
17	Customer Service	4,061,969	-	-	1,637,007	-	-	-	2,424,961
18	Sales	-	-	-	-	-	-	-	-
19	Administrative & General	45,484,898	12,634,450	4,017,760	19,386,357	-	1,630,338	2,794,796	5,021,197
21	Total O & M Expenses	787,041,577	597,123,566	55,913,153	88,022,315	0	12,854,604	18,864,755	14,263,184
23	Depreciation	178,458,250	97,389,809	25,154,545	51,857,999	-	549,815	2,688,863	817,221
24	Amortization Expense	13,807,399	7,299,270	1,016,989	1,661,959	-	1,327,780	881,601	1,619,800
25	Taxes Other Than Income	65,230,076	18,510,072	6,762,688	38,900,357	0	218,256	543,195	295,507
26	Income Taxes - Federal	(4,057,709)	(28,536,431)	7,550,500	15,933,365	0	57,585	970,160	(32,889)
27	Income Taxes - State	1,549,528	(1,776,724)	1,025,988	2,165,080	0	7,825	131,829	(4,469)
28	Income Taxes - Def Net	71,514,522	50,858,218	15,630,210	4,453,830	-	254,395	(238,743)	556,613
29	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
30	Misc Revenue & Expense	(346,250)	(371,331)	(240,373)	265,185	-	204	6	60
32	Total Operating Expenses	1,113,197,394	740,496,449	112,813,699	203,260,090	0	15,270,463	23,841,666	17,515,027
34	Operating Revenue for Return	228,680,554	120,417,215	49,296,725	54,815,314	0	672,175	2,132,586	1,346,539
36	Rate Base:								
37	Electric Plant in Service	6,407,404,503	3,070,045,170	1,219,470,027	1,940,195,496	-	35,458,162	93,235,851	48,999,797
38	Plant Held for Future Use	-	-	-	-	-	-	-	-
39	Misc Deferred Debits	22,573,238	15,220,198	5,965,990	606,622	-	98,369	226,991	455,069
40	Elec Plant Acq Adj	11,260,952	11,260,952	-	-	-	-	-	-
41	Nuclear Fuel	-	-	-	-	-	-	-	-
42	Prepayments	7,666,103	3,532,952	523,078	1,550,415	-	332,217	575,633	1,151,807
43	Fuel Stock	50,782,521	50,782,521	-	-	-	-	-	-
44	Material & Supplies	54,123,489	45,631,271	350,959	7,879,352	-	-	261,907	-
45	Working Capital	27,888,103	13,723,779	2,118,312	6,393,785	0	1,019,530	1,720,301	2,912,396
46	Weatherization Loans	(1,210)	-	-	(1,210)	-	-	-	-
47	Miscellaneous Rate Base	-	-	-	-	-	-	-	-
49	Total Electric Plant	6,581,697,699	3,210,196,843	1,228,428,366	1,956,624,461	0	36,908,278	96,020,682	53,519,069
51	Rate Base Deductions:								
52	Accum Prov For Depr	(2,198,381,147)	(977,168,343)	(330,001,934)	(846,892,042)	-	(2,637,104)	(37,928,244)	(3,753,480)
53	Accum Prov For Amort	(140,097,658)	(41,763,573)	(5,853,861)	(29,170,515)	-	(22,667,039)	(14,649,307)	(25,993,362)
54	Accum Def Income Taxes	(960,764,357)	(467,558,675)	(186,689,682)	(290,342,997)	-	(1,507,987)	(11,897,523)	(2,767,493)
55	Unamortized ITC	(1,115,967)	(403,993)	(55,116)	(279,830)	-	(60,799)	(105,276)	(210,953)
56	Customer Adv for Const	(11,392,393)	-	(3,944,241)	(7,189,750)	-	-	(258,401)	-
57	Customer Service Deposits	-	-	-	-	-	-	-	-
58	Misc. Rate Base Deductions	(15,987,319)	(9,852,400)	(426,791)	(2,767,061)	-	(470,791)	(836,769)	(1,633,507)
60	Total Rate Base Deductions	(3,327,738,840)	(1,496,746,984)	(526,971,626)	(1,176,642,195)	-	(27,343,718)	(65,675,521)	(34,358,796)
62	Total Rate Base	3,253,958,859	1,713,449,859	701,456,740	779,982,266	0	9,564,560	30,345,161	19,160,273
64	Return on Rate Base	7.0278%	7.0278%	7.0278%	7.0278%	7.0278%	7.0278%	7.0278%	7.0278%
66	Return on Equity	8.5076%	8.5076%	8.5076%	8.5076%	8.5076%	8.5076%	8.5076%	8.5076%

Docket No. UE-246
Exhibit PAC/1202-2
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Unbundled Results of Operations
Functional Detail

March 2012

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
2010 PROTOCOL												
Sales to Ultimate Customers												
	440	Residential Sales										
				S	580,219,963	729,208,138	149,254,434	252,606,176	10,667,409	12,161,007	25,755,131	18,546,371
		Less Klamath Surcharge Revenue										
			P	S	(15,824,000)	(15,824,000)	-	-	-	-	-	-
					564,395,963	713,384,138	149,254,434	252,606,176	10,667,409	12,161,007	25,755,131	18,546,371
	442	Commercial & Industrial Sales										
				S	612,827,521							
			P	SE	-	-	-	-	-	-	-	-
			PT	SG	-	-	-	-	-	-	-	-
					612,827,521	-	-	-	-	-	-	-
	444	Public Street & Highway Lighting										
				S	5,151,182							
				SO	-							
					5,151,182	-	-	-	-	-	-	-
	445	Other Sales to Public Authority										
				S	-							
					-	-	-	-	-	-	-	-
	448	Interdepartmental										
			D_SPLIT	S	-	-	-	-	-	-	-	-
			GP	SO	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers					**1,182,374,666**	**713,384,138**	**149,254,434**	**252,606,176**	**10,667,409**	**12,161,007**	**25,755,131**	**18,546,371**
	447	Sales for Resale-Non NPC										
			P	S	1,018,526	1,018,526	-	-	-	-	-	-
					1,018,526	1,018,526	-	-	-	-	-	-
	447NPC	Sales for Resale-NPC										
			P	SG	118,916,679	118,916,679	-	-	-	-	-	-
			P	SE	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-
					118,916,679	118,916,679	-	-	-	-	-	-
		Total Sales for Resale			119,935,205	119,935,205	-	-	-	-	-	-
	449	Provision for Rate Refund										
			P	S	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-
Total Sales from Electricity					**1,302,309,871**	**833,319,344**	**149,254,434**	**252,606,176**	**10,667,409**	**12,161,007**	**25,755,131**	**18,546,371**
	450	Forfeited Discounts & Interest										
			C_BILLING	S	3,149,119	-	-	-	-	3,149,119	-	-
			C_BILLING	SO	-	-	-	-	-	-	-	-
					3,149,119	-	-	-	-	3,149,119	-	-
	451	Misc Electric Revenue										
			CSS_SYS	S	1,140,452	-	-	-	-	627,248	205,281	307,922
			GP	SG	-	-	-	-	-	-	-	-
			DSM	SO	313	-	-	313	-	-	-	-
					1,140,764	-	-	313	-	627,248	205,281	307,922
	453	Water Sales										
			P	SG	22,128	22,128	-	-	-	-	-	-
					22,128	22,128	-	-	-	-	-	-
	454	Rent of Electric Property										
			D	S	5,103,258	-	-	5,103,258	-	-	-	-
			T	SG	1,468,652	-	1,468,652	-	-	-	-	-
			GP	SO	951,106	455,713	181,016	288,000	-	5,263	13,840	7,273
					7,523,016	455,713	1,649,668	5,391,258	-	5,263	13,840	7,273
		Oregon Ancillary Services				10,667,409			(10,667,409)			
	456	Other Electric Revenue										
			OTHSGR	S	(81)	(53)	(28)	-	-	-	-	-
			C_BILLING	CN	-	-	-	-	-	-	-	-
			OTHSE	SE	2,648,749	-	2,648,749	-	-	-	-	-
			OTHSO	SO	77,657	-	-	77,657	-	-	-	-
			OTHSGR	SG	25,006,725	16,449,124	8,557,601	-	-	-	-	-
					27,733,050	16,449,070	11,206,322	77,657	-	-	-	-
		Total Other Electric Revenues			**39,568,077**	**27,594,320**	**12,855,990**	**5,469,228**	**(10,667,409)**	**3,781,631**	**219,121**	**315,195**
Total Electric Operating Revenues					**1,341,877,948**	**860,913,664**	**162,110,424**	**258,075,404**	**0**	**15,942,638**	**25,974,252**	**18,861,566**

97	Miscellaneous Revenues										
98	41160	Gain on Sale of Utility Plant - CR									
99		**D**	S	-	-	-	-	-	-	-	-
100		T	SG	-	-	-	-	-	-	-	-
101		G	SO	-	-	-	-	-	-	-	-
102		T	SG	-	-	-	-	-	-	-	-
103		P	SG	-	-	-	-	-	-	-	-
104				-	-	-	-	-	-	-	-
105											
106	41170	Loss on Sale of Utility Plant									
107		**D_SPLIT**	S	-	-	-	-	-	-	-	-
108		T	SG	-	-	-	-	-	-	-	-
109				-	-	-	-	-	-	-	-
110											
111	4118	Gain from Emission Allowances									
112		P	S	-	-	-	-	-	-	-	-
113		P	SE	(300,280)	(300,280)	-	-	-	-	-	-
114				(300,280)	(300,280)	-	-	-	-	-	-
115											
116	41181	Gain from Disposition of NOX Credits									
117		P	SE	-	-	-	-	-	-	-	-
118				-	-	-	-	-	-	-	-
119											
120	4194	Impact Housing Interest Income									
121		P	SG	-	-	-	-	-	-	-	-
122				-	-	-	-	-	-	-	-
123											
124	421	(Gain) / Loss on Sale of Utility Plant									
125		**D**	S	265,014	-	-	265,014	-	-	-	-
126		T	SG	(196,416)	-	(196,416)	-	-	-	-	-
127		T	SG	(44,078)	-	(44,078)	-	-	-	-	-
128		B_Center	CN	264	-	-	-	-	204	-	60
129		PTD	SO	570	274	120	170	-	-	6	-
130		P	SG	(71,325)	(71,325)	-	-	-	-	-	-
131				(45,970)	(71,051)	(240,373)	265,185	-	204	6	60
132											
133	**Total Miscellaneous Revenues**			**(346,250)**	**(371,331)**	**(240,373)**	**265,185**	**-**	**204**	**6**	**60**
134	Miscellaneous Expenses										
135	4311	Interest on Customer Deposits									
136		C_BILLING	S	-	-	-	-	-	-	-	-
137				-	-	-	-	-	-	-	-
138	**Total Miscellaneous Expenses**			-	-	-	-	-	-	-	-
139											
140	**Net Misc Revenue and Expense**			**(346,250)**	**(371,331)**	**(240,373)**	**265,185**	**-**	**204**	**6**	**60**
141											
142	500	Operation Supervision & Engineering									
143		P	SG	4,682,033	4,682,033	-	-	-	-	-	-
144		P	SG	619,526	619,526	-	-	-	-	-	-
145				5,301,559	5,301,559	-	-	-	-	-	-
146											
147	501	Fuel Related-Non NPC									
148		P	SE	4,750,837	4,750,837	-	-	-	-	-	-
149		P	SE	-	-	-	-	-	-	-	-
150		P	SE	-	-	-	-	-	-	-	-
151		P	SE	-	-	-	-	-	-	-	-
152		P	SE	849,923	849,923	-	-	-	-	-	-
153				5,600,760	5,600,760	-	-	-	-	-	-
154											
155	501NPC	Fuel Related-NPC									
156		P	S	-	-	-	-	-	-	-	-
157		P	SE	176,089,025	176,089,025	-	-	-	-	-	-
158		P	SE	-	-	-	-	-	-	-	-
159		P	SE	-	-	-	-	-	-	-	-
160		P	SE	-	-	-	-	-	-	-	-
161		P	SE	13,726,882	13,726,882	-	-	-	-	-	-
162				189,815,907	189,815,907	-	-	-	-	-	-
163											
164		Total Fuel Related		195,416,666	195,416,666	-	-	-	-	-	-
165											
166	502	Steam Expenses									
167		P	SG	8,628,451	8,628,451	-	-	-	-	-	-
168		P	SG	2,136,060	2,136,060	-	-	-	-	-	-
169				10,764,511	10,764,511	-	-	-	-	-	-
170											
171	503	Steam From Other Sources-Non-NPC									
172		P	SE	(829)	(829)	-	-	-	-	-	-
173				(829)	(829)	-	-	-	-	-	-
174											
175	503NPC	Steam From Other Sources-NPC									
176		P	SE	1,017,161	1,017,161	-	-	-	-	-	-
177				1,017,161	1,017,161	-	-	-	-	-	-
178											
179	505	Electric Expenses									
180		P	SG	846,106	846,106	-	-	-	-	-	-
181		P	SG	317,806	317,806	-	-	-	-	-	-
182				1,163,912	1,163,912	-	-	-	-	-	-
183											
184	506	Misc. Steam Expense									
185		P	SG	13,093,679	13,093,679	-	-	-	-	-	-
186		P	SE	-	-	-	-	-	-	-	-
187		P	SG	532,133	532,133	-	-	-	-	-	-
188				13,625,812	13,625,812	-	-	-	-	-	-

190	507	Rents										
191			P	SG	80,043	80,043	-	-	-	-	-	-
192			P	SG	174	174	-	-	-	-	-	-
193					80,217	80,217	-	-	-	-	-	-
194												
195	510	Maint Supervision & Engineering										
196			P	SG	569,897	569,897	-	-	-	-	-	-
197			P	SG	560,582	560,582	-	-	-	-	-	-
198					1,130,479	1,130,479	-	-	-	-	-	-
199												
200												
201												
202	511	Maintenance of Structures										
203			P	SG	6,373,435	6,373,435	-	-	-	-	-	-
204			P	SG	114,308	114,308	-	-	-	-	-	-
205					6,487,743	6,487,743	-	-	-	-	-	-
206												
207	512	Maintenance of Boiler Plant										
208			P	SG	28,086,271	28,086,271	-	-	-	-	-	-
209			P	SG	2,240,092	2,240,092	-	-	-	-	-	-
210					30,326,363	30,326,363	-	-	-	-	-	-
211												
212	513	Maintenance of Electric Plant										
213			P	SG	10,445,225	10,445,225	-	-	-	-	-	-
214			P	SG	173,437	173,437	-	-	-	-	-	-
215					10,618,663	10,618,663	-	-	-	-	-	-
216												
217	514	Maintenance of Misc. Steam Plant										
218			P	SG	2,705,702	2,705,702	-	-	-	-	-	-
219			P	SG	548,119	548,119	-	-	-	-	-	-
220					3,253,821	3,253,821	-	-	-	-	-	-
221												
222	**Total Steam Power Generation**				**279,186,078**	**279,186,078**	**-**	**-**	**-**	**-**	**-**	**-**
223	517	Operation Super & Engineering										
224			P	SG	-	-	-	-	-	-	-	-
225					-	-	-	-	-	-	-	-
226												
227	518	Nuclear Fuel Expense										
228			P	SE	-	-	-	-	-	-	-	-
229												
230					-	-	-	-	-	-	-	-
231												
232	519	Coolants and Water										
233			P	SG	-	-	-	-	-	-	-	-
234					-	-	-	-	-	-	-	-
235												
236	520	Steam Expenses										
237			P	SG	-	-	-	-	-	-	-	-
238					-	-	-	-	-	-	-	-
239												
240												
241												
242	523	Electric Expenses										
243			P	SG	-	-	-	-	-	-	-	-
244					-	-	-	-	-	-	-	-
245												
246	524	Misc. Nuclear Expenses										
247			P	SG	-	-	-	-	-	-	-	-
248					-	-	-	-	-	-	-	-
249												
250	528	Maintenance Super & Engineering										
251			P	SG	-	-	-	-	-	-	-	-
252					-	-	-	-	-	-	-	-
253												
254	529	Maintenance of Structures										
255			P	SG	-	-	-	-	-	-	-	-
256					-	-	-	-	-	-	-	-
257												
258	530	Maintenance of Reactor Plant										
259			P	SG	-	-	-	-	-	-	-	-
260					-	-	-	-	-	-	-	-
261												
262	531	Maintenance of Electric Plant										
263			P	SG	-	-	-	-	-	-	-	-
264					-	-	-	-	-	-	-	-
265												
266	532	Maintenance of Misc Nuclear										
267			P	SG	-	-	-	-	-	-	-	-
268					-	-	-	-	-	-	-	-
269												
270	**Total Nuclear Power Generation**				-	-	-	-	-	-	-	-
271												
272	535	Operation Super & Engineering										
273			P	DGP	-	-	-	-	-	-	-	-
274			P	SG	2,555,228	2,555,228	-	-	-	-	-	-
275			P	SG	(130,272)	(130,272)	-	-	-	-	-	-
276												
277					2,424,956	2,424,956	-	-	-	-	-	-

279	536	Water For Power										
280			P	DGP	-	-	-	-	-	-	-	-
281			P	SG	54,690	54,690	-	-	-	-	-	-
282			P	SG	-	-	-	-	-	-	-	-
283												
284					54,690	54,690	-	-	-	-	-	-
285												
286	537	Hydraulic Expenses										
287			P	DGP	-	-	-	-	-	-	-	-
288			P	SG	1,068,090	1,068,090	-	-	-	-	-	-
289			P	SG	71,651	71,651	-	-	-	-	-	-
290												
291					1,139,741	1,139,741	-	-	-	-	-	-
292												
293	538	Electric Expenses										
294			P	DGP	-	-	-	-	-	-	-	-
295			P	SG	-	-	-	-	-	-	-	-
296			P	SG	-	-	-	-	-	-	-	-
297												
298					-	-	-	-	-	-	-	-
299												
300	539	Misc. Hydro Expenses										
301			P	DGP	-	-	-	-	-	-	-	-
302			P	SG	5,320,560	5,320,560	-	-	-	-	-	-
303			P	SG	1,977,217	1,977,217	-	-	-	-	-	-
304												
305												
306					7,297,777	7,297,777	-	-	-	-	-	-
307												
308	540	Rents (Hydro Generation)										
309			P	DGP	-	-	-	-	-	-	-	-
310			P	SG	45,915	45,915	-	-	-	-	-	-
311			P	SG	273	273	-	-	-	-	-	-
312												
313					46,188	46,188	-	-	-	-	-	-
314												
315	541	Maint Supervision & Engineering										
316			P	DGP	-	-	-	-	-	-	-	-
317			P	SG	452	452	-	-	-	-	-	-
318			P	SG	-	-	-	-	-	-	-	-
319												
320					452	452	-	-	-	-	-	-
321												
322	542	Maintenance of Structures										
323			P	DGP	-	-	-	-	-	-	-	-
324			P	SG	276,199	276,199	-	-	-	-	-	-
325			P	SG	5,817	5,817	-	-	-	-	-	-
326												
327					282,016	282,016	-	-	-	-	-	-
328												
329												
330												
331												
332	543	Maintenance of Dams & Waterways										
333			P	DGP	-	-	-	-	-	-	-	-
334			P	SG	374,071	374,071	-	-	-	-	-	-
335			P	SG	170,491	170,491	-	-	-	-	-	-
336												
337					544,562	544,562	-	-	-	-	-	-
338												
339	544	Maintenance of Electric Plant										
340			P	DGP	-	-	-	-	-	-	-	-
341			P	SG	342,953	342,953	-	-	-	-	-	-
342			P	SG	96,740	96,740	-	-	-	-	-	-
343												
344					439,693	439,693	-	-	-	-	-	-
345												
346	545	Maintenance of Misc. Hydro Plant										
347			P	DGP	-	-	-	-	-	-	-	-
348			P	SG	529,283	529,283	-	-	-	-	-	-
349			P	SG	232,090	232,090	-	-	-	-	-	-
350												
351					761,374	761,374	-	-	-	-	-	-
352												
353	**Total Hydraulic Power Generation**				**12,991,451**	**12,991,451**	-	-	-	-	-	-
354												
355	546	Operation Super & Engineering										
356			P	SG	111,019	111,019	-	-	-	-	-	-
357			P	SG	-	-	-	-	-	-	-	-
358					111,019	111,019	-	-	-	-	-	-

360	547	Fuel-Non-NPC										
361			P	SE	-	-	-	-	-	-	-	-
362			P	SE	-	-	-	-	-	-	-	-
363					-	-	-	-	-	-	-	-
364												
365	547NPC	Fuel-NPC										
366			P	SE	84,865,419	84,865,419	-	-	-	-	-	-
367			P	SE	4,181,415	4,181,415	-	-	-	-	-	-
368					89,046,834	89,046,834	-	-	-	-	-	-
369												
370	548	Generation Expense										
371			P	SG	3,193,112	3,193,112	-	-	-	-	-	-
372			P	SG	321,624	321,624	-	-	-	-	-	-
373					3,514,735	3,514,735	-	-	-	-	-	-
374												
375	549	Miscellaneous Other										
376			P	S	-	-	-	-	-	-	-	-
377			P	SG	5,581,974	5,581,974	-	-	-	-	-	-
378			P	SG	-	-	-	-	-	-	-	-
379					5,581,974	5,581,974	-	-	-	-	-	-
380												
381												
382												
383												
384	550	Maint Supervision & Engineering										
385			P	S	502,584	502,584	-	-	-	-	-	-
386			P	SG	1,072,033	1,072,033	-	-	-	-	-	-
387			P	SG	-	-	-	-	-	-	-	-
388					1,574,617	1,574,617	-	-	-	-	-	-
389												
390	551	Maint Supervision & Engineering										
391			P	SG	-	-	-	-	-	-	-	-
392					-	-	-	-	-	-	-	-
393												
394	552	Maintenance of Structures										
395			P	SG	687,690	687,690	-	-	-	-	-	-
396			P	SG	37,621	37,621	-	-	-	-	-	-
397					725,311	725,311	-	-	-	-	-	-
398												
399	553	Maint of Generation & Electric Plant										
400			P	SG	2,507,974	2,507,974	-	-	-	-	-	-
401			P	SG	138,282	138,282	-	-	-	-	-	-
402					2,646,256	2,646,256	-	-	-	-	-	-
403												
404	554	Maintenance of Misc. Other										
405			P	SG	700,630	700,630	-	-	-	-	-	-
406			P	SG	35,178	35,178	-	-	-	-	-	-
407					735,808	735,808	-	-	-	-	-	-
408												
409	**Total Other Power Generation**				**103,936,555**	**103,936,555**	**-**	**-**	**-**	**-**	**-**	**-**
410												
411												
412	555	Purchased Power-Non NPC										
413			P	S	-	-	-	-	-	-	-	-
414					-	-	-	-	-	-	-	-
415												
416	555NPC	Purchased Power-NPC										
417			P	S	(145,921)	(145,921)	-	-	-	-	-	-
418			P	SG	166,248,421	166,248,421	-	-	-	-	-	-
419			P	SE	9,229,951	9,229,951	-	-	-	-	-	-
420			P	SG	-	-	-	-	-	-	-	-
421			P	DGP	-	-	-	-	-	-	-	-
422					175,332,451	175,332,451	-	-	-	-	-	-
423												
424		Total Purchased Power			175,332,451	175,332,451	-	-	-	-	-	-
425												
426	556	System Control & Load Dispatch										
427			P	SG	327,956	327,956	-	-	-	-	-	-
428												
429					327,956	327,956	-	-	-	-	-	-
430												
431												
432												
433	557	Other Expenses										
434			P	S	(53,813)	(53,813)	-	-	-	-	-	-
435			P	SG	17,975,286	17,975,286	-	-	-	-	-	-
436			P	SGCT	290,280	290,280	-	-	-	-	-	-
437			P	SE	-	-	-	-	-	-	-	-
438			P	SG	-	-	-	-	-	-	-	-
439			P	TROJP	-	-	-	-	-	-	-	-
440												
441		Less Klamath Surcharge Expense										
442			P	SG	(4,433,671)	(4,433,671)	-	-	-	-	-	-
443												
444					13,778,081	13,778,081	-	-	-	-	-	-
445												
446	**Total Other Power Supply**				**189,438,488**	**189,438,488**	**-**	**-**	**-**	**-**	**-**	**-**
447												
448	**TOTAL PRODUCTION EXPENSE**				**585,552,572**	**585,552,572**	**-**	**-**	**-**	**-**	**-**	**-**
449												
450		Embedded Cost Differentials										
451		Company Owned Hydr	P	DGP	-	-	-	-	-	-	-	-
452		Company Owned Hydr	P	SG	-	-	-	-	-	-	-	-
453		Mid-C Contract	P	MC	-	-	-	-	-	-	-	-
454		Mid-C Contract	P	SG	-	-	-	-	-	-	-	-
455		Existing QF Contracts	P	S	-	-	-	-	-	-	-	-
456		Existing QF Contracts	P	SG	-	-	-	-	-	-	-	-
457												
458					-	-	-	-	-	-	-	-

460		Hydro Endowment Fixed Dollar Proposal											
461		Klamath Surcharge Sit	P	S	(5,690,345)	(5,690,345)	-	-	-	-	-	-	
462		ECD Hydro	P	S	2,699,880	2,699,880	-	-	-	-	-	-	
463		Mid-C Contract	P	MC	(6,434,648)	(6,434,648)	-	-	-	-	-	-	
464		Mid-C Contract	P	SG	4,005,906	4,005,906	-	-	-	-	-	-	
465		Klamath Dam Remova	P	S	11,390,329	11,390,329	-	-	-	-	-	-	
466													
467		Less Klamath Surcharge Expense											
468			P	SG	(11,390,329)	(11,390,329)	-	-	-	-	-	-	
469													
470					(5,419,206)	(5,419,206)	-	-	-	-	-	-	
471													
472	560	Operation Supervision & Engineering											
473			T	SG	1,613,851	-	1,613,851	-	-	-	-	-	
474													
475					1,613,851	-	1,613,851	-	-	-	-	-	
476													
477	561	Load Dispatching											
478			T	SG	2,896,600	-	2,896,600	-	-	-	-	-	
479													
480					2,896,600	-	2,896,600	-	-	-	-	-	
481	562	Station Expense											
482			T	SG	764,408	-	764,408	-	-	-	-	-	
483													
484					764,408	-	764,408	-	-	-	-	-	
485													
486	563	Overhead Line Expense											
487			T	SG	31,511	-	31,511	-	-	-	-	-	
488													
489					31,511	-	31,511	-	-	-	-	-	
490													
491	564	Underground Line Expense											
492			T	SG	-	-	-	-	-	-	-	-	
493													
494					-	-	-	-	-	-	-	-	
495													
496	565	Transmission of Electricity by Others-Non NPC											
497			T	SG	-	-	-	-	-	-	-	-	
498			T	SE	-	-	-	-	-	-	-	-	
499					-	-	-	-	-	-	-	-	
500													
501	565NPC	Transmission of Electricity by Others-NPC											
502			T	SG	33,157,810	-	33,157,810	-	-	-	-	-	
503			T	SE	704,946	-	704,946	-	-	-	-	-	
504					33,862,757	-	33,862,757	-	-	-	-	-	
505													
506		Total Transmission of Electricity by Others			33,862,757	-	33,862,757	-	-	-	-	-	
507													
508	566	Misc. Transmission Expense											
509			T	SG	923,703	-	923,703	-	-	-	-	-	
510													
511					923,703	-	923,703	-	-	-	-	-	
512													
513	567	Rents - Transmission											
514			T	SG	502,599	-	502,599	-	-	-	-	-	
515													
516					502,599	-	502,599	-	-	-	-	-	
517													
518	568	Maint Supervision & Engineering											
519			T	SG	612,618	-	612,618	-	-	-	-	-	
520													
521					612,618	-	612,618	-	-	-	-	-	
522													
523	569	Maintenance of Structures											
524			T	SG	1,296,719	-	1,296,719	-	-	-	-	-	
525													
526					1,296,719	-	1,296,719	-	-	-	-	-	
527													
528	570	Maintenance of Station Equipment											
529			STEP_UP	SG	3,007,720	241,232	2,766,487	-	-	-	-	-	
530													
531					3,007,720	241,232	2,766,487	-	-	-	-	-	
532													
533	571	Maintenance of Overhead Lines											
534			T	SG	5,751,924	-	5,751,924	-	-	-	-	-	
535													
536					5,751,924	-	5,751,924	-	-	-	-	-	
537													
538	572	Maintenance of Underground Lines											
539			T	SG	37,956	-	37,956	-	-	-	-	-	
540													
541					37,956	-	37,956	-	-	-	-	-	
542													
543	573	Maint of Misc. Transmission Plant											
544			T	SG	73,478	-	73,478	-	-	-	-	-	
545													
546					73,478	-	73,478	-	-	-	-	-	
547													
548	**TOTAL TRANSMISSION EXPENSE**				**51,375,843**	**241,232**	**51,134,611**	**-**	**-**	**-**	**-**	**-**	

550	580	Operation Supervision & Engineering										
551			D_SPLIT	S	(22)	-	-	(21)	-	-	(1)	-
552			D_SPLIT	SNPD	3,867,843	-	-	3,733,655	-	-	134,188	-
553					3,867,822	-	-	3,733,634	-	-	134,188	-
554												
555	581	Load Dispatching										
556			D	S	0	-	-	0	-	-	-	-
557			D	SNPD	3,846,258	-	-	3,846,258	-	-	-	-
558					3,846,258	-	-	3,846,258	-	-	-	-
559												
560	582	Station Expense										
561			D	S	1,151,914	-	-	1,151,914	-	-	-	-
562			D	SNPD	9,410	-	-	9,410	-	-	-	-
563					1,161,324	-	-	1,161,324	-	-	-	-
564												
565	583	Overhead Line Expenses										
566			D	S	3,085,147	-	-	3,085,147	-	-	-	-
567			D	SNPD	8,449	-	-	8,449	-	-	-	-
568					3,093,596	-	-	3,093,596	-	-	-	-
569												
570	584	Underground Line Expense										
571			D	S	-	-	-	-	-	-	-	-
572			D	SNPD	-	-	-	-	-	-	-	-
573					-	-	-	-	-	-	-	-
574												
575	585	Street Lighting & Signal Systems										
576			D	S	-	-	-	-	-	-	-	-
577			D	SNPD	61,676	-	-	61,676	-	-	-	-
578					61,676	-	-	61,676	-	-	-	-
579												
580	586	Meter Expenses										
581			C_Meter	S	2,954,255	-	-	-	-	-	2,954,255	-
582			C_Meter	SNPD	374,677	-	-	-	-	-	374,677	-
583					3,328,932	-	-	-	-	-	3,328,932	-
584												
585	587	Customer Installation Expenses										
586			D	S	4,507,068	-	-	4,507,068	-	-	-	-
587			D	SNPD	-	-	-	-	-	-	-	-
588					4,507,068	-	-	4,507,068	-	-	-	-
589												
590	588	Misc. Distribution Expenses										
591			D	S	285,912	-	-	285,912	-	-	-	-
592			D	SNPD	1,141,461	-	-	1,141,461	-	-	-	-
593					1,427,373	-	-	1,427,373	-	-	-	-
594												
595	908	Rents										
596			D	S	1,830,943	-	-	1,830,943	-	-	-	-
597			D	SNPD	18,381	-	-	18,381	-	-	-	-
598					1,849,324	-	-	1,849,324	-	-	-	-
599												
600	590	Maint Supervision & Engineering										
601			D_SPLIT	S	332,395	-	-	320,863	-	-	11,532	-
602			D_SPLIT	SNPD	1,104,621	-	-	1,066,298	-	-	38,323	-
603					1,437,016	-	-	1,387,161	-	-	49,855	-
604												
605	591	Maintenance of Structures										
606			D	S	516,721	-	-	516,721	-	-	-	-
607			D	SNPD	23,490	-	-	23,490	-	-	-	-
608					540,210	-	-	540,210	-	-	-	-
609												
610	592	Maintenance of Station Equipment										
611			D	S	5,031,020	-	-	5,031,020	-	-	-	-
612			D	SNPD	405,322	-	-	405,322	-	-	-	-
613					5,436,343	-	-	5,436,343	-	-	-	-
614	593	Maintenance of Overhead Lines										
615			D	S	30,523,061	-	-	30,523,061	-	-	-	-
616			D	SNPD	267,358	-	-	267,358	-	-	-	-
617					30,790,419	-	-	30,790,419	-	-	-	-
618												
619	594	Maintenance of Underground Lines										
620			D	S	6,102,548	-	-	6,102,548	-	-	-	-
621			D	SNPD	58	-	-	58	-	-	-	-
622					6,102,606	-	-	6,102,606	-	-	-	-
623												
624	595	Maintenance of Line Transformers										
625			D	S	-	-	-	-	-	-	-	-
626			D	SNPD	242,727	-	-	242,727	-	-	-	-
627					242,727	-	-	242,727	-	-	-	-
628												
629	596	Maint of Street Lighting & Signal Sys.										
630			D	S	1,223,327	-	-	1,223,327	-	-	-	-
631			D	SNPD	-	-	-	-	-	-	-	-
632					1,223,327	-	-	1,223,327	-	-	-	-
633												
634	597	Maintenance of Meters										
635			C_Meter	S	1,062,137	-	-	-	-	-	1,062,137	-
636			C_Meter	SNPD	283,498	-	-	-	-	-	283,498	-
637					1,345,635	-	-	-	-	-	1,345,635	-
638												
639	599	Maint of Misc. Distribution Plant										
640			D	S	479,343	-	-	479,343	-	-	-	-
641			D	SNPD	(94,582)	-	-	(94,582)	-	-	-	-
642					384,760	-	-	384,760	-	-	-	-
643												
644	**TOTAL DISTRIBUTION EXPENSE**				**70,646,415**	**-**	**-**	**65,787,806**	**-**	**-**	**4,858,609**	**-**

646	901	Supervision										
647			CUST901	S	1,054	-	-	-	-	495	273	286
648			CUST901	CN	801,419	-	-	-	-	376,555	207,668	217,196
649					802,473	-	-	-	-	377,051	207,941	217,481
650												
651	902	Meter Reading Expense										
652			C_Meter	S	10,203,950	-	-	-	-	-	10,203,950	-
653			C_Meter	CN	673,921	-	-	-	-	-	673,921	-
654					10,877,871	-	-	-	-	-	10,877,871	-
655												
656	903	Customer Receipts & Collections										
657			CUST903	S	2,318,208	-	-	-	-	1,450,323	-	867,885
658			CUST903	CN	14,900,482	-	-	-	-	9,322,074	-	5,578,408
659					17,218,690	-	-	-	-	10,772,397	-	6,446,294
660												
661	904	Uncollectible Accounts										
662			REVREQ	S	6,250,186	4,036,065	746,276	1,188,051	0	73,392	119,573	86,829
663			P	SG	-	-	-	-	-	-	-	-
664			REVREQ	CN	121,491	78,453	14,506	23,093	0	1,427	2,324	1,688
665					6,371,676	4,114,518	760,782	1,211,144	0	74,819	121,897	88,517
666												
667	905	Misc. Customer Accounts Expense										
668			CUST905	S	11,087	-	-	-	-	-	590	10,497
669			CUST905	CN	57,288	-	-	-	-	-	3,051	54,237
670					68,375	-	-	-	-	-	3,642	64,733
671												
672	**TOTAL CUSTOMER ACCOUNTS EXPENSE**				**35,339,085**	**4,114,518**	**760,782**	**1,211,144**	**0**	**11,224,266**	**11,211,350**	**6,817,025**
668												
669	907	Supervision										
670			C_Service	S	-	-	-	-	-	-	-	-
671			C_Service	CN	85,093	-	-	-	-	-	-	85,093
672					85,093	-	-	-	-	-	-	85,093
673												
674	908	Customer Assistance										
675			DSM	S	1,637,007	-	-	1,637,007	-	-	-	-
676			C_Service	CN	760,894	-	-	-	-	-	-	760,894
677												
678												
679					2,397,902	-	-	1,637,007	-	-	-	760,894
680												
681	909	Informational & Instructional Adv										
682			C_Service	S	226,726	-	-	-	-	-	-	226,726
683			C_Service	CN	1,280,175	-	-	-	-	-	-	1,280,175
684					1,506,902	-	-	-	-	-	-	1,506,902
685												
686	910	Misc. Customer Service										
687			C_Service	S	-	-	-	-	-	-	-	-
688			C_Service	CN	72,073	-	-	-	-	-	-	72,073
689												
690					72,073	-	-	-	-	-	-	72,073
691												
692	**TOTAL CUSTOMER SERVICE EXPENSE**				**4,061,969**	**-**	**-**	**1,637,007**	**-**	**-**	**-**	**2,424,961**
693												
694	911	Supervision										
695			P	S	-	-	-	-	-	-	-	-
696			P	CN	-	-	-	-	-	-	-	-
697					-	-	-	-	-	-	-	-
698												
699	912	Demonstration & Selling Expense										
700			P	S	-	-	-	-	-	-	-	-
701			P	CN	-	-	-	-	-	-	-	-
702					-	-	-	-	-	-	-	-
703												
704	913	Advertising Expense										
705			P	S	-	-	-	-	-	-	-	-
706			P	CN	-	-	-	-	-	-	-	-
707					-	-	-	-	-	-	-	-
708												
709	916	Misc. Sales Expense										
710			P	S	-	-	-	-	-	-	-	-
711			P	CN	-	-	-	-	-	-	-	-
712					-	-	-	-	-	-	-	-
713												
714	**TOTAL SALES EXPENSE**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

716	**Total Customer Service Exp Including Sales**			**4,061,969**	**-**	**-**	**1,637,007**	**-**	**-**		**2,424,961**
717	920	Administrative & General Salaries									
718		LABOR	S	(821,591)	(297,425)	(40,578)	(206,015)	-	(44,761)	(77,506)	(155,307)
719		LABOR	CN	-	-	-	-	-	-	-	-
720		LABOR	SO	21,443,096	7,762,644	1,059,052	5,376,883	-	1,168,234	2,022,853	4,053,430
721				20,621,505	7,465,219	1,018,474	5,170,868	-	1,123,473	1,945,348	3,898,123
722											
723	921	Office Supplies & expenses									
724		LABOR	S	318,745	115,389	15,742	79,926	-	17,365	30,069	60,253
725		LABOR	CN	-	-	-	-	-	-	-	-
726		LABOR	SO	2,511,034	909,023	124,017	629,645	-	136,803	236,881	474,666
727				2,829,778	1,024,412	139,760	709,570	-	154,168	266,950	534,919
728											
729	922	Office Supplies & expenses									
730		LABOR	S	-	-	-	-	-	-	-	-
731		LABOR	CN	-	-	-	-	-	-	-	-
732		LABOR	SO	(9,470,482)	(3,428,422)	(467,737)	(2,374,735)	-	(515,958)	(893,406)	(1,790,224)
733				(9,470,482)	(3,428,422)	(467,737)	(2,374,735)	-	(515,958)	(893,406)	(1,790,224)
734											
735	923	Outside Services									
736		LABOR	S	13,721	4,967	678	3,441	-	748	1,294	2,594
737		LABOR	CN	-	-	-	-	-	-	-	-
738		LABOR	SO	4,037,223	1,461,521	199,394	1,012,339	-	219,951	380,855	763,164
739				4,050,944	1,466,488	200,072	1,015,779	-	220,698	382,149	765,758
740											
741	924	Property Insurance									
742		DPW	S	5,265,799	-	-	5,103,434	-	-	162,365	-
743		PT	SG	-	-	-	-	-	-	-	-
744		GP	SO	2,648,151	1,268,836	504,001	801,874	-	14,655	38,534	20,251
745				7,913,950	1,268,836	504,001	5,905,308	-	14,655	200,899	20,251
746											
747	925	Injuries & Damages									
748		DPW	S	248,469	-	-	240,808	-	-	7,661	-
749		LABOR	SO	1,905,285	689,735	94,100	477,752	-	103,801	179,737	360,160
750				2,153,754	689,735	94,100	718,561	-	103,801	187,398	360,160
751											
752	926	Employee Pensions & Benefits									
753		LABOR	S	-	-	-	-	-	-	-	-
754		LABOR	CN	-	-	-	-	-	-	-	-
755		LABOR	SO	-	-	-	-	-	-	-	-
756				-	-	-	-	-	-	-	-
757											
758	927	Franchise Requirements									
759		DSM	S	-	-	-	-	-	-	-	-
760		DSM	SG	-	-	-	-	-	-	-	-
761				-	-	-	-	-	-	-	-
762											
763	928	Regulatory Commission Expense									
764		D	S	3,255,051	-	-	3,255,051	-	-	-	-
765		C_SERVICE	CN	-	-	-	-	-	-	-	-
766		D	SO	505,978	-	-	505,978	-	-	-	-
767		FERC	SG	452,419	243,080	209,339	-	-	-	-	-
768				4,213,448	243,080	209,339	3,761,029	-	-	-	-
769											
770	929	Duplicate Charges									
771		LABOR	S	-	-	-	-	-	-	-	-
772		LABOR	SO	(2,101,657)	(760,824)	(103,799)	(526,993)	-	(114,500)	(198,262)	(397,280)
773				(2,101,657)	(760,824)	(103,799)	(526,993)	-	(114,500)	(198,262)	(397,280)
774											
775	930	Misc General Expenses									
776		LABOR	S	2,031,324	735,362	100,325	509,357	-	110,668	191,627	383,985
777		C_SERVICE	CN	-	-	-	-	-	-	-	-
778		LABOR	SO	3,887,765	1,407,415	192,013	974,862	-	211,808	366,756	734,912
779				5,919,090	2,142,778	292,338	1,484,219	-	322,476	558,383	1,118,897
780											
781	931	Rents									
782		LABOR	S	1,140,243	412,781	56,315	285,917	-	62,121	107,566	215,542
783		LABOR	SO	1,560,853	565,047	77,089	391,386	-	85,036	147,244	295,051
784				2,701,096	977,827	133,404	677,303	-	147,157	254,810	510,593
785											
786	935	Maintenance of General Plant									
787		G	S	92,331	21,445	27,724	39,487	-	2,420	1,256	-
788		B_Center	CN	-	-	-	-	-	-	-	-
789		G	SO	6,561,140	1,523,877	1,970,082	2,805,961	-	171,948	89,271	-
790				6,653,471	1,545,322	1,997,806	2,845,448	-	174,368	90,527	-
791											
792	**TOTAL ADMINISTRATIVE & GEN EXPENSE**			**45,484,898**	**12,634,450**	**4,017,760**	**19,386,357**	**-**	**1,630,338**	**2,794,796**	**5,021,197**
793											
794											
795	**TOTAL O&M EXPENSE**			**787,041,577**	**597,123,566**	**55,913,153**	**88,022,315**	**0**	**12,854,604**	**18,864,755**	**14,263,184**
796	403SP	Steam Depreciation									
797		P	SG	7,755,568	7,755,568	-	-	-	-	-	-
798		P	SG	7,861,550	7,861,550	-	-	-	-	-	-
799		P	SG	41,513,012	41,513,012	-	-	-	-	-	-
800		P	SG	2,984,431	2,984,431	-	-	-	-	-	-
801				60,114,561	60,114,561	-	-	-	-	-	-
802											
803	403NP	Nuclear Depreciation									
804		P	SG	-	-	-	-	-	-	-	-
805				-	-	-	-	-	-	-	-

807	403HP	Hydro Depreciation											
808		Pre-Merger Pacific	P	SG	1,594,324	1,594,324	-	-	-	-	-	-	
809		Pre-Merger Utah	P	SG	240,059	240,059	-	-	-	-	-	-	
810		Post-Merger Pacific	P	SG	3,701,915	3,701,915	-	-	-	-	-	-	
811		Post-Merger Utah	P	SG	1,189,881	1,189,881	-	-	-	-	-	-	
812					6,726,179	6,726,179	-	-	-	-	-	-	
813													
814	403OP	Other Production Depreciation											
815			P	S	-	-	-	-	-	-	-	-	
816			P	SG	(854)	(854)	-	-	-	-	-	-	
817			P	SG	26,976,907	26,976,907	-	-	-	-	-	-	
818			P	SG	694,120	694,120	-	-	-	-	-	-	
819			P	SG	-	-	-	-	-	-	-	-	
820					27,670,174	27,670,174	-	-	-	-	-	-	
821													
822	403TP	Transmission Depreciation											
823			T_Split	S	-	-	-	-	-	-	-	-	
824			T_Split	SG	2,780,912	75,465	2,705,447	-	-	-	-	-	
825			T_Split	SG	3,195,980	86,729	3,109,252	-	-	-	-	-	
826			T_Split	SG	17,064,925	463,087	16,601,838	-	-	-	-	-	
827					23,041,818	625,281	22,416,537	-	-	-	-	-	
828													
829													
830													
831	403	Distribution Depreciation											
832	360	Land & Land Rights	D	S	90,290	-	-	90,290	-	-	-	-	
833	361	Structures	D	S	322,906	-	-	322,906	-	-	-	-	
834	362	Station Equipment	D	S	4,669,271	-	-	4,669,271	-	-	-	-	
835	363	Storage Battery Equipr	D	S	-	-	-	-	-	-	-	-	
836	364	Poles & Towers	D	S	12,952,836	-	-	12,952,836	-	-	-	-	
837	365	OH Conductors	D	S	7,171,056	-	-	7,171,056	-	-	-	-	
838	366	UG Conduit	D	S	2,278,280	-	-	2,278,280	-	-	-	-	
839	367	UG Conductor	D	S	4,033,197	-	-	4,033,197	-	-	-	-	
840	368	Line Trans	D	S	11,530,553	-	-	11,530,553	-	-	-	-	
841	369	Services	D	S	4,737,331	-	-	4,737,331	-	-	-	-	
842	370	Meters	C_Meter	S	2,248,801	-	-	-	-	-	2,248,801	-	
843	371	Inst Cust Prem	D	S	121,754	-	-	121,754	-	-	-	-	
844	372	Leased Property	D	S	-	-	-	-	-	-	-	-	
845	373	Street Lighting	D	S	691,685	-	-	691,685	-	-	-	-	
846					50,847,961	-	-	48,599,160	-	-	2,248,801	-	
847													
848	403GP	General Depreciation											
849			TD	S	4,019,896	-	1,627,102	2,309,779	-	-	83,014	-	
850			G-DGP	SG	28,380	19,732	8,648	-	-	-	-	-	
851			G-DGU	SG	35,739	24,848	10,891	-	-	-	-	-	
852			P	SE	4,104	4,104	-	-	-	-	-	-	
853			B_Center	CN	445,373	-	-	-	-	343,613	-	101,761	
854			G-SG	SG	1,711,540	807,104	904,436	-	-	-	-	-	
855			LABOR	SO	3,784,864	1,370,164	186,930	949,059	-	206,202	357,048	715,460	
856			P	SG	1,631	1,631	-	-	-	-	-	-	
857			P	SG	26,031	26,031	-	-	-	-	-	-	
858					10,057,558	2,253,614	2,738,007	3,258,839	-	549,815	440,063	817,221	
859													
860	403GV0	General Vehicles											
861			G-SG	SG	-	-	-	-	-	-	-	-	
862					-	-	-	-	-	-	-	-	
863													
864	403MP	Mining Depreciation											
865			P	SE	-	-	-	-	-	-	-	-	
866					-	-	-	-	-	-	-	-	
867													
868	403EP	Experimental Plant Depreciation											
869			P	SG	-	-	-	-	-	-	-	-	
870			P	SG	-	-	-	-	-	-	-	-	
871					-	-	-	-	-	-	-	-	
872	4031	ARO Depreciation											
873			P	S	-	-	-	-	-	-	-	-	
874					-	-	-	-	-	-	-	-	
875													
876													
877	**TOTAL DEPRECIATION EXPENSE**				**178,458,250**	**97,389,809**	**25,154,545**	**51,857,999**	**-**	**549,815**	**2,688,863**	**817,221**	
878													
879	404GP	Amort of LT Plant - Capital Lease Gen											
880			TD	S	248,068	-	100,408	142,536	-	-	5,123	-	
881			I-SG	SG	-	-	-	-	-	-	-	-	
882			LABOR	SO	342,077	123,836	16,895	85,776	-	18,637	32,270	64,664	
883			I-DGU	SG	-	-	-	-	-	-	-	-	
884			B_Center	CN	80,268	-	-	-	-	61,928	-	18,340	
885			I-DGP	SG	-	-	-	-	-	-	-	-	
886					670,413	123,836	117,303	228,313	-	80,565	37,393	83,004	
887													
888	404SP	Amort of LT Plant - Cap Lease Steam											
889			P	SG	-	-	-	-	-	-	-	-	
890			P	SG	-	-	-	-	-	-	-	-	
891					-	-	-	-	-	-	-	-	

893	404IP	Amort of LT Plant - Intangible Plant									
894			TD	S	8,962	-	3,628	5,150	-	-	185	-
895			P	SE	81,802	81,802	-	-	-	-	-	-
896			I-SG	SG	1,370,809	1,171,490	199,319	-	-	-	-	-
897			LABOR	SO	5,696,867	2,062,330	281,362	1,428,496	-	310,369	537,419	1,076,890
898			CSS_SYS	CN	1,703,357	-	-	-	-	936,846	306,604	459,906
899			I-SG	SG	2,778,846	2,374,795	404,051	-	-	-	-	-
900			I-SG	SG	77,891	66,566	11,326	-	-	-	-	-
901			I-DGP	SG	-	-	-	-	-	-	-	-
902			I-SG	SG	-	-	-	-	-	-	-	-
903			I-SG	SG	-	-	-	-	-	-	-	-
904			I-DGU	SG	4,163	4,163	-	-	-	-	-	-
905					11,722,699	5,761,147	899,685	1,433,646	-	1,247,215	844,208	1,536,796
906												
907	404MP	Amort of LT Plant - Mining Plant										
908			P	SE	-	-	-	-	-	-	-	-
909					-	-	-	-	-	-	-	-
910												
911	404OP	Amort of LT Plant - Other Plant										
912			P	SG	-	-	-	-	-	-	-	-
913					-	-	-	-	-	-	-	-
914												
915												
916	404HP	Amortization of Other Electric Plant										
917		Pre-Merger Pacific	P	SG	64,189	64,189	-	-	-	-	-	-
918		Pre-Merger Utah	P	SG	11,479	11,479	-	-	-	-	-	-
919		Post-Merger Plant	P	SG	-	-	-	-	-	-	-	-
920					75,668	75,668	-	-	-	-	-	-
921												
922	**Total Amortization of Limited Term Plant**				12,468,780	5,960,651	1,016,989	1,661,959	-	1,327,780	881,601	1,619,800
923												
924												
925	405	Amortization of Other Electric Plant										
926			GP	S	-	-	-	-	-	-	-	-
927												
928					-	-	-	-	-	-	-	-
929												
930	406	Amortization of Plant Acquisition Adj										
931			P	S	-	-	-	-	-	-	-	-
932			P	SG	-	-	-	-	-	-	-	-
933			P	SG	-	-	-	-	-	-	-	-
934			P	SG	1,338,619	1,338,619	-	-	-	-	-	-
935			P	SO	-	-	-	-	-	-	-	-
936					1,338,619	1,338,619	-	-	-	-	-	-
937	407	Amort of Prop Losses, Unrec Plant, etc										
938			D_SPLIT	S	-	-	-	-	-	-	-	-
939			GP	SO	-	-	-	-	-	-	-	-
940			P	SG	(0)	(0)	-	-	-	-	-	-
941			P	SE	-	-	-	-	-	-	-	-
942			P	SG	-	-	-	-	-	-	-	-
943			P	TROJP	(0)	(0)	-	-	-	-	-	-
944					(0)	(0)	-	-	-	-	-	-
945												
946	**TOTAL AMORTIZATION EXPENSE**				**13,807,399**	**7,299,270**	**1,016,989**	**1,661,959**	**-**	**1,327,780**	**881,601**	**1,619,800**
947												
948	408	Taxes Other Than Income										
949			D	S	28,140,517	-	-	28,140,517	-	-	-	-
950			GP	GPS	33,892,921	16,239,461	6,450,568	10,262,953	-	187,561	493,185	259,192
951			REVREQ	SO	2,614,058	1,688,031	312,120	496,887	0	30,695	50,010	36,315
952			P	SE	201,150	201,150	-	-	-	-	-	-
953			P	SG	381,430	381,430	-	-	-	-	-	-
954			DSM	OPRV-ID	-	-	-	-	-	-	-	-
955			GP	EXCTAX	-	-	-	-	-	-	-	-
956			GP	SG	-	-	-	-	-	-	-	-
957												
958												
959												
960					65,230,076	18,510,072	6,762,688	38,900,357	0	218,256	543,195	295,507
961												
962												
963	41140	Deferred Investment Tax Credit - Fed										
964			PTD	DGU	-	-	-	-	-	-	-	-
965												
966					-	-	-	-	-	-	-	-
967												
968	41141	Deferred Investment Tax Credit - Idaho										
969			PTD	DGU	-	-	-	-	-	-	-	-
970												
971					-	-	-	-	-	-	-	-
972												
973	TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-
974												
975												
976	427	Interest on Long-Term Debt										
977			NP	S	81,982,452	41,326,706	17,803,437	21,440,605	-	204,588	819,201	387,917
978			NP	SNP	-	-	-	-	-	-	-	-
979					81,982,452	41,326,706	17,803,437	21,440,605	-	204,588	819,201	387,917
980												
981	428	Amortization of Debt Disc & Exp										
982			NP	SNP	-	-	-	-	-	-	-	-
983					-	-	-	-	-	-	-	-
984												
985	429	Amortization of Premium on Debt										
986			NP	SNP	-	-	-	-	-	-	-	-
987					-	-	-	-	-	-	-	-

989	431	Other Interest Expense									
990			NUTIL	OTH	-	-	-	-	-	-	-	-
991			GP	SO	-	-	-	-	-	-	-	-
992			NP	SNP	-	-	-	-	-	-	-	-
993					-	-	-	-	-	-	-	-
994												
995	432	AFUDC - Borrowed										
996			NP	SNP	-	-	-	-	-	-	-	-
997					-	-	-	-	-	-	-	-
998												
999		Total Electric Interest Deductions for Tax			81,982,452	41,326,706	17,803,437	21,440,605	-	204,588	819,201	387,917
1000												
1001		Non-Utility Portion of Interest										
1002			427 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1003			428 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1004			429 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1005			431 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1006												
1007		Total Non-utility Interest			-	-	-	-	-	-	-	-
1008												
1009		Total Interest Deductions for Tax			81,982,452	41,326,706	17,803,437	21,440,605	-	204,588	819,201	387,917
1010												
1011												
1012	419	Interest & Dividends										
1013			GP	S	-	-	-	-	-	-	-	-
1014			GP	SNP	(14,012,032)	(6,713,728)	(2,666,798)	(4,242,916)	-	(77,542)	(203,893)	(107,155)
1015		Total Operating Deductions for Tax			(14,012,032)	(6,713,728)	(2,666,798)	(4,242,916)	-	(77,542)	(203,893)	(107,155)
1016												
1017												
1018	41010	Deferred Income Tax - Federal-DR										
1019			GP	S	20,423	9,785	3,887	6,184	-	113	297	156
1020			P	SCHMDEXP	-	-	-	-	-	-	-	-
1021			PT	SG	8,074	5,614	2,460	-	-	-	-	-
1022			LABOR	SO	(4,225)	(1,530)	(209)	(1,059)	-	(230)	(399)	(799)
1023			NP	SNP	8,497,948	4,283,748	1,845,428	2,222,441	-	21,207	84,915	40,210
1024			P	SE	274,745	274,745	-	-	-	-	-	-
1025			PT	SG	11,726,499	8,153,135	3,573,363	-	-	-	-	-
1026			GP	GPS	5,749,293	2,754,718	1,094,217	1,740,916	-	31,816	83,660	43,967
1027			TAXDEPR	TAXDEPR	131,700,357	77,761,913	23,816,041	28,253,503	-	513,302	617,100	738,497
1028			C_BILLING	BADDEBT	-	-	-	-	-	-	-	-
1029			CSS_SYS	CN	0	-	-	-	-	0	0	0
1030			IBT	IBT	-	-	-	-	-	-	-	-
1031			D	SNPD	-	-	-	-	-	-	-	-
1032					157,973,114	93,242,129	30,335,188	32,221,985	-	566,208	785,573	822,031
1033												
1034												
1035												
1036	41110	Deferred Income Tax - Federal-CR										
1037			GP	S	(1,773,344)	(849,680)	(337,506)	(536,978)	-	(9,814)	(25,804)	(13,561)
1038			P	SE	-	-	-	-	-	-	-	-
1039			C_BILLING	BADDEBT	-	-	-	-	-	-	-	-
1040			NP	SNP	(7,240,251)	(3,649,753)	(1,572,304)	(1,893,519)	-	(18,068)	(72,347)	(34,259)
1041			PT	SG	(4,032,267)	(2,803,532)	(1,228,735)	-	-	-	-	-
1042			D_SPLIT	CIAC	(5,183,797)	-	-	(5,003,954)	-	-	(179,843)	-
1043			LABOR	SO	(1,151,118)	(416,718)	(56,853)	(288,644)	-	(62,714)	(108,592)	(217,598)
1044			D	SNPD	-	-	-	-	-	-	-	-
1045			CSS_SYS	CN	-	-	-	-	-	-	-	-
1046			P	SGCT	(110,164)	(110,164)	-	-	-	-	-	-
1047			BOOKDEPR	SCHMDEXP	(66,836,000)	(34,422,413)	(11,509,580)	(20,045,059)	-	(221,218)	(637,730)	-
1048			P	TROJD	-	-	-	-	-	-	-	-
1049			IBT	IBT	-	-	-	-	-	-	-	-
1050			P	SG	-	-	-	-	-	-	-	-
1051			P	SG	-	-	-	-	-	-	-	-
1052			P	SG	-	-	-	-	-	-	-	-
1053			P	SG	(131,650)	(131,650)	-	-	-	-	-	-
1054			P	SG	-	-	-	-	-	-	-	-
1055					(86,458,591)	(42,383,911)	(14,704,978)	(27,768,154)	-	(311,813)	(1,024,317)	(265,418)
1056												
1057		TOTAL DEFERRED INCOME TAXES			71,514,522	50,858,218	15,630,210	4,453,830	-	254,395	(238,743)	556,613
1058	SCHMAF	Additions - Flow Through										
1059			SCHMAF	S	-	-	-	-	-	-	-	-
1060			SCHMAF	SNP	-	-	-	-	-	-	-	-
1061			SCHMAF	SO	-	-	-	-	-	-	-	-
1062			SCHMAF	SE	-	-	-	-	-	-	-	-
1063			P	TROJP	-	-	-	-	-	-	-	-
1064			SCHMAF	SG	-	-	-	-	-	-	-	-
1065					-	-	-	-	-	-	-	-
1066												
1067	SCHMAP	Additions - Permanent										
1068			P	S	-	-	-	-	-	-	-	-
1069			P	SE	3,890	3,890	-	-	-	-	-	-
1070			PTD	SNP	-	-	-	-	-	-	-	-
1071			SCHMAP-SO	SO	(679,689)	(252,937)	(41,826)	(171,093)	-	(34,417)	(59,999)	(119,417)
1072			SCHMAP	SG	-	-	-	-	-	-	-	-
1073			BOOKDEPR	SCHMDEXP	(66,275)	(34,134)	(11,413)	(19,877)	-	(219)	(632)	-
1074					(742,075)	(283,181)	(53,239)	(190,970)	-	(34,636)	(60,631)	(119,417)

SCHMAT	Additions - Temporary										
		SCHMAT-SITUS	S	(36,000)	(19,658)	(1,465)	(7,193)	-	(474)	(973)	(6,237)
		SCHMAT-SG	SG	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	13,659,185	-	-	13,185,302	-	-	473,883	-
		SCHMAT-SNP	SNP	19,077,894	9,645,320	4,223,328	5,043,343	-	3,181	161,341	1,381
		P	TROJD	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-
		SCHMAT-SE	SE	-	-	-	-	-	-	-	-
		SCHMAT-SG	SG	10,606,153	10,342,809	263,344	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-
		SCHMAT-SO	SO	3,033,169	1,380,790	489,048	787,690	-	57,901	116,840	200,900
		SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-
		P	SGCT	290,280	290,280	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	176,111,302	90,702,256	30,327,476	52,818,263	-	582,904	1,680,403	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				222,741,982	112,341,796	35,301,731	71,827,404	-	643,513	2,431,495	196,043
TOTAL SCHEDULE - M ADDITIONS				221,999,907	112,058,615	35,248,492	71,636,434	-	608,877	2,370,864	76,626
SCHMDF	Deductions - Flow Through										
		SCHMDF	S	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent										
		SCHMDP	S	-	-	-	-	-	-	-	-
		P	SE	116,216	116,216	-	-	-	-	-	-
		SCHMDP	SNP	99,824	38,048	5,085	24,396	-	5,206	9,028	18,062
		SCHMDP	IBT	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	(1,113,764)	(403,195)	(55,008)	(279,278)	-	(60,679)	(105,068)	(210,537)
				(897,724)	(248,931)	(49,923)	(254,882)	-	(55,473)	(96,040)	(192,475)
SCHMDT	Deductions - Temporary										
		SCHMDT-SITUS	S	53,813	44,549	470	2,488	-	485	846	4,975
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	22,391,894	11,319,329	4,961,145	5,922,981	-	-	188,439	-
		SCHMDT	CN	0	0	0	0	-	0	0	0
		SCHMDT-SG	SG	21,276	21,276	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-
		P	SE	723,945	723,945	-	-	-	-	-	-
		SCHMDT-SG	SG	30,899,050	30,899,050	-	-	-	-	-	-
		SCHMDT-GPS	GPS	15,149,254	7,659,648	3,352,058	4,003,445	-	3,931	128,466	1,706
		SCHMDT-SO	SO	(11,134)	(4,959)	(2,034)	(3,999)	-	(26)	(83)	(33)
		TAXDEPR	TAXDEPR	347,027,370	204,900,828	62,754,714	74,447,322	-	1,352,539	1,626,045	1,945,922
		SCHMDT-SNP	SNPD	-	-	-	-	-	-	-	-
				416,255,469	255,563,666	71,066,353	84,372,237	-	1,356,929	1,943,713	1,952,570
TOTAL SCHEDULE - M DEDUCTIONS				415,357,745	255,314,735	71,016,431	84,117,355	-	1,301,456	1,847,673	1,760,095
TOTAL SCHEDULE - M ADJUSTMENTS				(193,357,838)	(143,256,120)	(35,767,939)	(12,480,921)	-	(692,580)	523,191	(1,683,469)
40911	State Income Taxes										
		IBT	S	1,650,682	(1,675,570)	1,025,988	2,165,080	0	7,825	131,829	(4,469)
		IBT	IBT	-	-	-	-	-	-	-	-
	Renewable Energy Credits	P	SG	(101,154)	(101,154)	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				1,549,528	(1,776,724)	1,025,988	2,165,080	0	7,825	131,829	(4,469)
Calculation of Taxable Income:											
	Operating Revenues			1,341,877,948	860,913,664	162,110,424	258,075,404	0	15,942,638	25,974,252	18,861,566
	Operating Deductions:										
	O & M Expenses			787,041,577	597,123,566	55,913,153	88,022,315	0	12,854,604	18,864,755	14,263,184
	Depreciation Expense			178,458,250	97,389,809	25,154,545	51,857,999	-	549,815	2,688,863	817,221
	Amortization Expense			13,807,399	7,299,270	1,016,989	1,661,959	-	1,327,780	881,601	1,619,800
	Taxes Other Than Income			65,230,076	18,510,072	6,762,688	38,900,357	0	218,256	543,195	295,507
	Interest & Dividends (AFUDC-Equity)			(14,012,032)	(6,713,728)	(2,666,798)	(4,242,916)	-	(77,542)	(203,893)	(107,155)
	Misc Revenue & Expense			(346,250)	(371,331)	(240,373)	265,185	-	204	6	60
	Total Operating Deductions			1,030,179,020	713,237,657	85,940,203	176,464,898	0	14,873,117	22,774,528	16,888,617
	Other Deductions:										
	Interest Deductions			81,982,452	41,326,706	17,803,437	21,440,605	-	204,588	819,201	387,917
	Interest on PCRBS			-	-	-	-	-	-	-	-
	Schedule M Adjustments			(193,357,838)	(143,256,120)	(35,767,939)	(12,480,921)	-	(692,580)	523,191	(1,683,469)
	Income Before State Taxes			36,358,638	(36,906,819)	22,598,846	47,688,979	0	172,354	2,903,714	(98,436)
	State Income Taxes			1,549,528	(1,776,724)	1,025,988	2,165,080	0	7,825	131,829	(4,469)
Total Taxable Income				34,809,110	(35,130,095)	21,572,858	45,523,900	0	164,529	2,771,886	(93,967)
Tax Rate				35%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
Federal Income Tax - Calculated				12,183,188	(12,295,533)	7,550,500	15,933,365	0	57,585	970,160	(32,889)
Adjustments to Calculated Tax:											
40910	PMI	P	SE	(3,890)	(3,890)	-	-	-	-	-	-
40910	Renewable Energy Credits	P	SG	(16,237,007)	(16,237,007)	-	-	-	-	-	-
40910		P	SO	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-
Federal Income Tax				(4,057,709)	(28,536,431)	7,550,500	15,933,365	0	57,585	970,160	(32,889)
TOTAL OPERATING EXPENSES				**1,113,197,394**	**740,496,449**	**112,813,699**	**203,260,090**	**0**	**15,270,463**	**23,841,666**	**17,515,027**
310	Land and Land Rights										

1177			P	SG	8,970,049	8,970,049	-	-	-	-	-	-
1178			P	SG	14,513,424	14,513,424	-	-	-	-	-	-
1179			P	S	-	-	-	-	-	-	-	-
1180			P	SG	636,372	636,372	-	-	-	-	-	-
1181					24,719,996	24,719,996	-	-	-	-	-	-
1182												
1183	311	Structures and Improvements										
1184			P	SG	60,211,631	60,211,631	-	-	-	-	-	-
1185			P	SG	83,733,863	83,733,863	-	-	-	-	-	-
1186			P	SG	78,972,610	78,972,610	-	-	-	-	-	-
1187			P	SG	15,140,906	15,140,906	-	-	-	-	-	-
1188					238,059,010	238,059,010	-	-	-	-	-	-
1189												
1190	312	Boiler Plant Equipment										
1191			P	SG	156,018,697	156,018,697	-	-	-	-	-	-
1192			P	SG	145,667,975	145,667,975	-	-	-	-	-	-
1193			P	SG	738,374,307	738,374,307	-	-	-	-	-	-
1194			P	SG	78,680,677	78,680,677	-	-	-	-	-	-
1195					1,118,741,656	1,118,741,656	-	-	-	-	-	-
1196												
1197	314	Turbogenerator Units										
1198			P	SG	32,746,820	32,746,820	-	-	-	-	-	-
1199			P	SG	37,032,078	37,032,078	-	-	-	-	-	-
1200			P	SG	150,467,435	150,467,435	-	-	-	-	-	-
1201			P	SG	16,429,445	16,429,445	-	-	-	-	-	-
1202					236,675,778	236,675,778	-	-	-	-	-	-
1203												
1204	315	Accessory Electric Equipment										
1205			P	SG	22,407,794	22,407,794	-	-	-	-	-	-
1206			P	SG	35,432,140	35,432,140	-	-	-	-	-	-
1207			P	SG	32,618,606	32,618,606	-	-	-	-	-	-
1208			P	SG	17,179,832	17,179,832	-	-	-	-	-	-
1209					107,638,372	107,638,372	-	-	-	-	-	-
1210												
1211												
1212												
1213	316	Misc Power Plant Equipment										
1214			P	SG	1,215,564	1,215,564	-	-	-	-	-	-
1215			P	SG	1,310,819	1,310,819	-	-	-	-	-	-
1216			P	SG	5,031,098	5,031,098	-	-	-	-	-	-
1217			P	SG	1,040,505	1,040,505	-	-	-	-	-	-
1218					8,597,986	8,597,986	-	-	-	-	-	-
1219												
1220	317	Steam Plant ARO										
1221			P	S	-	-	-	-	-	-	-	-
1222					-	-	-	-	-	-	-	-
1223												
1224	SP	Unclassified Steam Plant - Account 300										
1225			P	SG	1,345,840	1,345,840	-	-	-	-	-	-
1226					1,345,840	1,345,840	-	-	-	-	-	-
1227												
1228												
1229	**Total Steam Production Plant**				**1,735,778,637**	**1,735,778,637**	-	-	-	-	-	-
1230												
1231	320	Land and Land Rights										
1232			P	SG	-	-	-	-	-	-	-	-
1233			P	SG	-	-	-	-	-	-	-	-
1234					-	-	-	-	-	-	-	-
1235												
1236	321	Structures and Improvements										
1237			P	SG	-	-	-	-	-	-	-	-
1238			P	SG	-	-	-	-	-	-	-	-
1239					-	-	-	-	-	-	-	-
1240												
1241	322	Reactor Plant Equipment										
1242			P	SG	-	-	-	-	-	-	-	-
1243			P	SG	-	-	-	-	-	-	-	-
1244					-	-	-	-	-	-	-	-
1245												
1246	323	Turbogenerator Units										
1247			P	SG	-	-	-	-	-	-	-	-
1248			P	SG	-	-	-	-	-	-	-	-
1249					-	-	-	-	-	-	-	-
1250												
1251	324	Land and Land Rights										
1252			P	SG	-	-	-	-	-	-	-	-
1253			P	SG	-	-	-	-	-	-	-	-
1254					-	-	-	-	-	-	-	-
1255												
1256	325	Misc. Power Plant Equipment										
1257			P	SG	-	-	-	-	-	-	-	-
1258			P	SG	-	-	-	-	-	-	-	-
1259					-	-	-	-	-	-	-	-
1260												
1261												
1262	NP	Unclassified Nuclear Plant - Acct 300										
1263			P	SG	-	-	-	-	-	-	-	-
1264					-	-	-	-	-	-	-	-
1265												
1266												
1267	**Total Nuclear Production Plant**				-	-	-	-	-	-	-	-

330	Land and Land Rights											
	Pre-Merger Pacific	P	SG	2,716,355	2,716,355	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	1,358,308	1,358,308	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	2,467,187	2,467,187	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	173,448	173,448	-	-	-	-	-	-	
				6,715,298	6,715,298	-	-	-	-	-	-	
331	Structures and Improvements											
	Pre-Merger Pacific	P	SG	5,361,491	5,361,491	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	1,359,623	1,359,623	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	20,717,003	20,717,003	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	2,125,454	2,125,454	-	-	-	-	-	-	
				29,563,571	29,563,571	-	-	-	-	-	-	
332	Reservoirs, Dams & Waterways											
	Pre-Merger Pacific	P	SG	37,745,800	37,745,800	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	4,642,981	4,642,981	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	87,622,372	87,622,372	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	18,577,198	18,577,198	-	-	-	-	-	-	
				148,588,350	148,588,350	-	-	-	-	-	-	
333	Water Wheel, Turbines, & Generators											
	Pre-Merger Pacific	P	SG	8,051,368	8,051,368	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	2,216,074	2,216,074	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	11,654,008	11,654,008	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	7,852,104	7,852,104	-	-	-	-	-	-	
				29,773,554	29,773,554	-	-	-	-	-	-	
334	Accessory Electric Equipment											
	Pre-Merger Pacific	P	SG	1,119,249	1,119,249	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	934,902	934,902	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	11,608,735	11,608,735	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	1,894,229	1,894,229	-	-	-	-	-	-	
				15,557,116	15,557,116	-	-	-	-	-	-	
335	Misc. Power Plant Equipment											
	Pre-Merger Pacific	P	SG	295,358	295,358	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	41,587	41,587	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	255,765	255,765	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	3,243	3,243	-	-	-	-	-	-	
				595,953	595,953	-	-	-	-	-	-	
336	Roads, Railroads & Bridges											
	Pre-Merger Pacific	P	SG	1,194,055	1,194,055	-	-	-	-	-	-	
	Pre-Merger Utah	P	SG	212,104	212,104	-	-	-	-	-	-	
	Post-Merger Pacific	P	SG	2,666,519	2,666,519	-	-	-	-	-	-	
	Post-Merger Utah	P	SG	173,801	173,801	-	-	-	-	-	-	
				4,246,479	4,246,479	-	-	-	-	-	-	
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				**235,040,321**	**235,040,321**	**-**	**-**	**-**	**-**	**-**	**-**	
340	Land and Land Rights											
		P	S	75,000	75,000	-	-	-	-	-	-	
		P	SG	7,452,870	7,452,870	-	-	-	-	-	-	
		P	SG	-	-	-	-	-	-	-	-	
		P	SG	-	-	-	-	-	-	-	-	
				7,527,870	7,527,870	-	-	-	-	-	-	
341	Structures and Improvements											
		P	SG	40,154,943	40,154,943	-	-	-	-	-	-	
		P	SG	42,149	42,149	-	-	-	-	-	-	
		P	SG	1,093,030	1,093,030	-	-	-	-	-	-	
				41,290,121	41,290,121	-	-	-	-	-	-	
342	Fuel Holders, Producers & Accessories											
		P	SG	2,171,603	2,171,603	-	-	-	-	-	-	
		P	SG	31,278	31,278	-	-	-	-	-	-	
		P	SG	588,783	588,783	-	-	-	-	-	-	
				2,791,664	2,791,664	-	-	-	-	-	-	
343	Prime Movers											
		P	S	-	-	-	-	-	-	-	-	
		P	SG	(125,178)	(125,178)	-	-	-	-	-	-	
		P	SG	580,736,588	580,736,588	-	-	-	-	-	-	
		P	SG	14,377,256	14,377,256	-	-	-	-	-	-	
				594,988,666	594,988,666	-	-	-	-	-	-	
344	Generators											
		P	S	-	-	-	-	-	-	-	-	
		P	SG	-	-	-	-	-	-	-	-	
		P	SG	85,645,208	85,645,208	-	-	-	-	-	-	
		P	SG	4,091,774	4,091,774	-	-	-	-	-	-	
				89,736,982	89,736,982	-	-	-	-	-	-	

345	Accessory Electric Plant											
		P	SG	59,876,360	59,876,360	-	-	-	-	-	-	
		P	SG	40,363	40,363	-	-	-	-	-	-	
		P	SG	752,602	752,602	-	-	-	-	-	-	
				60,669,326	60,669,326	-	-	-	-	-	-	
346	Misc. Power Plant Equipment											
		P	SG	3,015,925	3,015,925	-	-	-	-	-	-	
		P	SG	3,045	3,045	-	-	-	-	-	-	
				3,018,971	3,018,971	-	-	-	-	-	-	
347	Other Production ARO											
		P	S	-	-	-	-	-	-	-	-	
				-	-	-	-	-	-	-	-	
OP	Unclassified Other Prod Plant-Acct 300											
		P	S	-	-	-	-	-	-	-	-	
		P	SG	-	-	-	-	-	-	-	-	
				-	-	-	-	-	-	-	-	
Total Other Production Plant				**800,023,598**	**800,023,598**	**-**	**-**	**-**	**-**	**-**	**-**	
Experimental Plant												
103	Experimental Plant											
		P	SG	-	-	-	-	-	-	-	-	
Total Experimental Plant				-	-	-	-	-	-	-	-	
TOTAL PRODUCTION PLANT				**2,770,842,557**	**2,770,842,557**	**-**	**-**	**-**	**-**	**-**	**-**	
350	Land and Land Rights											
		T	SG	5,443,164	-	5,443,164	-	-	-	-	-	
		T	SG	12,498,866	-	12,498,866	-	-	-	-	-	
		T	SG	30,277,730	-	30,277,730	-	-	-	-	-	
				48,219,760	-	48,219,760	-	-	-	-	-	
352	Structures and Improvements											
		T	S	-	-	-	-	-	-	-	-	
		T	SG	1,917,051	-	1,917,051	-	-	-	-	-	
		T	SG	4,680,778	-	4,680,778	-	-	-	-	-	
		T	SG	28,734,179	-	28,734,179	-	-	-	-	-	
				35,332,008	-	35,332,008	-	-	-	-	-	
353	Station Equipment											
		STEP_UP	SG	32,163,321	2,579,640	29,583,682	-	-	-	-	-	
		STEP_UP	SG	47,180,219	3,784,061	43,396,158	-	-	-	-	-	
		STEP_UP	SG	331,545,531	26,591,410	304,954,121	-	-	-	-	-	
				410,889,071	32,955,111	377,933,960	-	-	-	-	-	
354	Towers and Fixtures											
		T	SG	40,067,116	-	40,067,116	-	-	-	-	-	
		T	SG	34,360,128	-	34,360,128	-	-	-	-	-	
		T	SG	171,084,298	-	171,084,298	-	-	-	-	-	
				245,511,541	-	245,511,541	-	-	-	-	-	
355	Poles and Fixtures											
		T	S	-	-	-	-	-	-	-	-	
		T	SG	15,190,517	-	15,190,517	-	-	-	-	-	
		T	SG	28,713,299	-	28,713,299	-	-	-	-	-	
		T	SG	183,448,835	-	183,448,835	-	-	-	-	-	
				227,352,651	-	227,352,651	-	-	-	-	-	
356	Clearing and Grading											
		T	SG	47,820,404	-	47,820,404	-	-	-	-	-	
		T	SG	40,643,437	-	40,643,437	-	-	-	-	-	
		T	SG	139,267,859	-	139,267,859	-	-	-	-	-	
				227,731,700	-	227,731,700	-	-	-	-	-	
357	Underground Conduit											
		T	SG	1,642	-	1,642	-	-	-	-	-	
		T	SG	23,625	-	23,625	-	-	-	-	-	
		T	SG	814,927	-	814,927	-	-	-	-	-	
				840,194	-	840,194	-	-	-	-	-	
358	Underground Conductors											
		T	SG	-	-	-	-	-	-	-	-	
		T	SG	280,340	-	280,340	-	-	-	-	-	
		T	SG	1,646,527	-	1,646,527	-	-	-	-	-	
				1,926,867	-	1,926,867	-	-	-	-	-	
359	Roads and Trails											
		T	SG	480,237	-	480,237	-	-	-	-	-	
		T	SG	113,552	-	113,552	-	-	-	-	-	
		T	SG	2,396,027	-	2,396,027	-	-	-	-	-	
				2,989,816	-	2,989,816	-	-	-	-	-	
TP	Unclassified Trans Plant - Acct 300											
		T	SG	13,613,732	-	13,613,732	-	-	-	-	-	
				13,613,732	-	13,613,732	-	-	-	-	-	
TS0	Unclassified Trans Sub Plant - Acct 300											
		T	SG	-	-	-	-	-	-	-	-	
				-	-	-	-	-	-	-	-	
TOTAL TRANSMISSION PLANT				**1,214,407,339**	**32,955,111**	**1,181,452,228**	**-**	**-**	**-**	**-**	**-**	

1462			D	S	13,257,962	-	-	13,257,962	-	-	-	-
1463					13,257,962	-	-	13,257,962	-	-	-	-
1464												
1465	361	Structures and Improvements										
1466			D	S	20,534,828	-	-	20,534,828	-	-	-	-
1467					20,534,828	-	-	20,534,828	-	-	-	-
1468												
1469	362	Station Equipment										
1470			D	S	210,485,397	-	-	210,485,397	-	-	-	-
1471					210,485,397	-	-	210,485,397	-	-	-	-
1472												
1473	363	Storage Battery Equipment										
1474			D	S	-	-	-	-	-	-	-	-
1475					-	-	-	-	-	-	-	-
1476												
1477	364	Poles, Towers & Fixtures										
1478			D	S	333,267,914	-	-	333,267,914	-	-	-	-
1479					333,267,914	-	-	333,267,914	-	-	-	-
1480												
1481	365	Overhead Conductors										
1482			D	S	238,618,730	-	-	238,618,730	-	-	-	-
1483					238,618,730	-	-	238,618,730	-	-	-	-
1484												
1485	366	Underground Conduit										
1486			D	S	86,537,680	-	-	86,537,680	-	-	-	-
1487					86,537,680	-	-	86,537,680	-	-	-	-
1488												
1489												
1490												
1491												
1492	367	Underground Conductors										
1493			D	S	162,476,403	-	-	162,476,403	-	-	-	-
1494					162,476,403	-	-	162,476,403	-	-	-	-
1495												
1496	368	Line Transformers										
1497			D	S	400,087,161	-	-	400,087,161	-	-	-	-
1498					400,087,161	-	-	400,087,161	-	-	-	-
1499												
1500	369	Services										
1501			D	S	228,599,776	-	-	228,599,776	-	-	-	-
1502					228,599,776	-	-	228,599,776	-	-	-	-
1503												
1504	370	Meters										
1505			C_Meter	S	61,958,530	-	-	-	-	-	61,958,530	-
1506					61,958,530	-	-	-	-	-	61,958,530	-
1507												
1508	371	Installations on Customers' Premises										
1509			D	S	2,568,397	-	-	2,568,397	-	-	-	-
1510					2,568,397	-	-	2,568,397	-	-	-	-
1511												
1512	372	Leased Property										
1513			D	S	-	-	-	-	-	-	-	-
1514					-	-	-	-	-	-	-	-
1515												
1516	373	Street Lights										
1517			D	S	22,646,805	-	-	22,646,805	-	-	-	-
1518					22,646,805	-	-	22,646,805	-	-	-	-
1519												
1520	DP	Unclassified Dist Plant - Acct 300										
1521			D	S	4,850,420	-	-	4,850,420	-	-	-	-
1522					4,850,420	-	-	4,850,420	-	-	-	-
1523												
1524	DS0	Unclassified Dist Sub Plant - Acct 300										
1525			D	S	-	-	-	-	-	-	-	-
1526					-	-	-	-	-	-	-	-
1527												
1528												
1529	**TOTAL DISTRIBUTION PLANT**				**1,785,890,003**	**-**	**-**	**1,723,931,473**	**-**	**-**	**61,958,530**	**-**
1530												
1531	389	Land and Land Rights										
1532			D_SPLIT	S	3,046,462	-	-	2,940,770	-	-	105,692	-
1533			B_Center	CN	331,362	-	-	-	-	255,651	-	75,711
1534			G-DGU	SG	86	60	26	-	-	-	-	-
1535			G-SG	SG	316	149	167	-	-	-	-	-
1536			LABOR	SO	1,520,343	550,381	75,088	381,228	-	82,829	143,423	287,393
1537					4,898,568	550,590	75,281	3,321,997	-	338,480	249,115	363,104
1538												
1539	390	Structures and Improvements										
1540			D_SPLIT	S	33,831,192	-	-	32,657,475	-	-	1,173,718	-
1541			G-DGP	SG	91,851	63,862	27,989	-	-	-	-	-
1542			G-DGU	SG	422,241	293,573	128,668	-	-	-	-	-
1543			B_Center	CN	3,615,446	-	-	-	-	2,789,375	-	826,072
1544			G-SG	SG	1,376,909	649,304	727,606	-	-	-	-	-
1545			LABOR	SO	28,235,668	10,221,632	1,394,530	7,080,129	-	1,538,297	2,663,637	5,337,444
1546					67,573,309	11,228,371	2,278,793	39,737,604	-	4,327,672	3,837,354	6,163,515
1547												
1548	391	Office Furniture & Equipment										
1549			D_SPLIT	S	3,251,346	-	-	3,138,546	-	-	112,800	-
1550			G-DGP	SG	-	-	-	-	-	-	-	-
1551			G-DGU	SG	1,365	949	416	-	-	-	-	-
1552			B_Center	CN	2,442,069	-	-	-	-	1,884,095	-	557,974
1553			G-SG	SG	1,186,746	559,629	627,117	-	-	-	-	-
1554			P	SE	16,541	16,541	-	-	-	-	-	-
1555			LABOR	SO	14,884,788	5,388,462	735,144	3,732,379	-	810,933	1,404,170	2,813,700
1556			P	SG	23,131	23,131	-	-	-	-	-	-
1557			P	SG	-	-	-	-	-	-	-	-
1558					21,805,985	5,988,712	1,362,677	6,870,925	-	2,695,028	1,516,970	3,371,674

1560	392	Transportation Equipment									
1561			D_SPLIT	S	21,181,722	-	-	20,446,857	-	-	734,865	-
1562			LABOR	SO	1,980,242	716,870	97,802	496,548	-	107,885	186,808	374,329
1563			G-SG	SG	4,450,770	2,098,832	2,351,938	-	-	-	-	-
1564			B_Center	CN	-	-	-	-	-	-	-	-
1565			G-DGU	SG	200,837	139,637	61,200	-	-	-	-	-
1566			P	SE	98,263	98,263	-	-	-	-	-	-
1567			G-DGP	SG	31,006	21,558	9,448	-	-	-	-	-
1568			P	SG	88,669	88,669	-	-	-	-	-	-
1569			P	SG	11,511	11,511	-	-	-	-	-	-
1570					28,043,021	3,175,340	2,520,389	20,943,405	-	107,885	921,673	374,329
1571												
1572	393	Stores Equipment										
1573			D_SPLIT	S	2,672,691	-	-	2,579,966	-	-	92,725	-
1574			G-DGP	SG	17,980	12,501	5,479	-	-	-	-	-
1575			G-DGU	SG	69,153	48,080	21,073	-	-	-	-	-
1576			LABOR	SO	88,264	31,953	4,359	22,132	-	4,809	8,326	16,685
1577			G-SG	SG	1,063,915	501,706	562,209	-	-	-	-	-
1578			P	SG	13,912	13,912	-	-	-	-	-	-
1579					3,925,915	608,152	593,119	2,602,099	-	4,809	101,051	16,685
1580												
1581	394	Tools, Shop & Garage Equipment										
1582			D_SPLIT	S	10,248,972	-	-	9,893,401	-	-	355,571	-
1583			G-DGP	SG	345,179	239,994	105,185	-	-	-	-	-
1584			G-SG	SG	5,387,639	2,540,628	2,847,012	-	-	-	-	-
1585			LABOR	SO	1,032,741	373,864	51,006	258,961	-	56,264	97,424	195,221
1586			P	SE	1,728	1,728	-	-	-	-	-	-
1587			G-SG	SG	234,007	110,350	123,657	-	-	-	-	-
1588			P	SG	437,475	437,475	-	-	-	-	-	-
1589			P	SG	23,177	23,177	-	-	-	-	-	-
1590					17,710,918	3,727,215	3,126,860	10,152,362	-	56,264	452,996	195,221
1591												
1592	395	Laboratory Equipment										
1593			D_SPLIT	S	9,316,206	-	-	8,992,995	-	-	323,211	-
1594			G-DGP	SG	391	272	119	-	-	-	-	-
1595			G-DGU	SG	1,384	963	422	-	-	-	-	-
1596			LABOR	SO	1,549,899	561,081	76,548	388,639	-	84,439	146,211	292,980
1597			P	SE	1,846	1,846	-	-	-	-	-	-
1598			G-SG	SG	1,629,693	768,508	861,185	-	-	-	-	-
1599			P	SG	65,216	65,216	-	-	-	-	-	-
1600			P	SG	3,614	3,614	-	-	-	-	-	-
1601					12,568,251	1,401,501	938,274	9,381,634	-	84,439	469,422	292,980
1602												
1603	396	Power Operated Equipment										
1604			D_SPLIT	S	29,310,166	-	-	28,293,298	-	-	1,016,868	-
1605			G-DGP	SG	217,845	151,462	66,383	-	-	-	-	-
1606			G-SG	SG	8,039,263	3,791,044	4,248,220	-	-	-	-	-
1607			LABOR	SO	308,980	111,854	15,260	77,477	-	16,833	29,148	58,407
1608			G-DGU	SG	421,252	292,885	128,366	-	-	-	-	-
1609			P	SE	10,949	10,949	-	-	-	-	-	-
1610			P	SG	-	-	-	-	-	-	-	-
1611			P	SG	257,730	257,730	-	-	-	-	-	-
1612					38,566,184	4,615,924	4,458,229	28,370,775	-	16,833	1,046,016	58,407
1613	397	Communication Equipment										
1614			D_SPLIT	S	57,049,520	-	-	55,070,280	-	-	1,979,240	-
1615			G-DGP	SG	143,926	100,068	43,858	-	-	-	-	-
1616			G-DGU	SG	88,544	61,562	26,982	-	-	-	-	-
1617			LABOR	SO	12,471,396	4,514,787	615,949	3,127,218	-	679,450	1,176,500	2,357,492
1618			B_Center	CN	69,781	-	-	-	-	53,837	-	15,944
1619			G-SG	SG	27,829,767	13,123,574	14,706,194	-	-	-	-	-
1620			P	SE	7,547	7,547	-	-	-	-	-	-
1621			G-SG	SG	20,797	9,807	10,990	-	-	-	-	-
1622			G-SG	SG	(2,594)	(1,223)	(1,371)	-	-	-	-	-
1623					97,678,684	17,816,122	15,402,602	58,197,498	-	733,287	3,155,740	2,373,436
1624												
1625	398	Misc. Equipment										
1626			D_SPLIT	S	670,085	-	-	646,837	-	-	23,247	-
1627			G-DGP	SG	-	-	-	-	-	-	-	-
1628			G-DGU	SG	-	-	-	-	-	-	-	-
1629			B_Center	CN	62,495	-	-	-	-	48,216	-	14,279
1630			LABOR	SO	794,358	287,567	39,233	199,186	-	43,277	74,936	150,159
1631			P	SE	405	405	-	-	-	-	-	-
1632			G-SG	SG	492,498	232,245	260,253	-	-	-	-	-
1633			P	SG	-	-	-	-	-	-	-	-
1634					2,019,842	520,218	299,485	846,024	-	91,493	98,184	164,438
1635												
1636	399	Coal Mine										
1637			P	SE	118,723,886	118,723,886	-	-	-	-	-	-
1638	MP	Unckassified Mine Plant	P	SE	-	-	-	-	-	-	-	-
1639					118,723,886	118,723,886	-	-	-	-	-	-
1640												
1641	399L	WIDCO Capital Lease										
1642			P	SE	-	-	-	-	-	-	-	-
1643												
1644												
1645		Remove Capital Leases			-	-	-	-	-	-	-	-
1646					-	-	-	-	-	-	-	-
1647												
1648	1011390	General Capital Leases										
1649			D_SPLIT	S	5,882,166	-	-	5,678,094	-	-	204,072	-
1650			P	SG	8,698,478	8,698,478	-	-	-	-	-	-
1651			LABOR	SO	3,440,188	1,245,387	169,907	862,632	-	187,424	324,533	650,306
1652					18,020,833	9,943,865	169,907	6,540,726	-	187,424	528,605	650,306
1653												
1654		Remove Capital Leases			(18,020,833)	(9,943,865)	(169,907)	(6,540,726)	-	(187,424)	(528,605)	(650,306)
1655					-	-	-	-	-	-	-	-

1657	1011346	General Gas Line Capital Leases										
1658			P	SG	-	-	-	-	-	-	-	-
1659					-	-	-	-	-	-	-	-
1660												
1661		Remove Capital Leases			-	-	-	-	-	-	-	-
1662					-	-	-	-	-	-	-	-
1663												
1664	GP	Unclassified Gen Plant - Acct 300										
1665			D_SPLIT	S	-	-	-	-	-	-	-	-
1666			LABOR	SO	420,728	152,308	20,779	105,498	-	22,922	39,690	79,531
1667			B_Center	CN	-	-	-	-	-	-	-	-
1668			G-SG	SG	(13,796)	(6,506)	(7,291)	-	-	-	-	-
1669			G-DGP	SG	-	-	-	-	-	-	-	-
1670			G-DGU	SG	-	-	-	-	-	-	-	-
1671					406,932	145,802	13,489	105,498	-	22,922	39,690	79,531
1672												
1673	399G	Unclassified Gen Plant - Acct 300										
1674			D_SPLIT	S	-	-	-	-	-	-	-	-
1675			LABOR	SO	-	-	-	-	-	-	-	-
1676			G-SG	SG	-	-	-	-	-	-	-	-
1677			G-DGP	SG	-	-	-	-	-	-	-	-
1678			G-DGU	SG	-	-	-	-	-	-	-	-
1679					-	-	-	-	-	-	-	-
1680												
1681	**TOTAL GENERAL PLANT**				**413,921,494**	**168,501,832**	**31,069,197**	**180,529,821**	**-**	**8,479,112**	**11,888,210**	**13,453,321**
1682												
1683	301	Organization										
1684			D_SPLIT	S	-	-	-	-	-	-	-	-
1685			LABOR	SO	-	-	-	-	-	-	-	-
1686			I-SG	SG	-	-	-	-	-	-	-	-
1687					-	-	-	-	-	-	-	-
1688	302	Franchise & Consent										
1689			D_SPLIT	S	-	-	-	-	-	-	-	-
1690			I-SG	SG	1,109,640	948,295	161,344	-	-	-	-	-
1691			I-DGP	SG	43,699,705	43,699,705	-	-	-	-	-	-
1692			I-DGU	SG	2,333,228	2,333,228	-	-	-	-	-	-
1693			I-DGP	SG	-	-	-	-	-	-	-	-
1694			I-DGU	SG	154,919	154,919	-	-	-	-	-	-
1695					47,297,491	47,136,147	161,344	-	-	-	-	-
1696												
1697	303	Miscellaneous Intangible Plant										
1698			D_SPLIT	S	1,320,629	-	-	1,274,812	-	-	45,817	-
1699			LABOR	SG	33,796,386	12,234,675	1,669,168	8,474,486	-	1,841,249	3,188,212	6,388,597
1700			LABOR	SO	103,628,219	37,514,590	5,118,089	25,984,905	-	5,645,732	9,775,859	19,589,045
1701			P	SE	860,259	860,259	-	-	-	-	-	-
1702			CSS_SYS	CN	35,440,125	-	-	-	-	19,492,069	6,379,223	9,568,834
1703			I-DGP	SG	-	-	-	-	-	-	-	-
1704			I-DGP	SG	-	-	-	-	-	-	-	-
1705					175,045,618	50,609,524	6,787,257	35,734,202	-	26,979,049	19,389,111	35,546,475
1706	303	Less Non-Utility Plant										
1707			I-SITUS	S	-	-	-	-	-	-	-	-
1708					175,045,618	50,609,524	6,787,257	35,734,202	-	26,979,049	19,389,111	35,546,475
1709	IP	Unclassified Intangible Plant - Acct 300										
1710			D_SPLIT	S	-	-	-	-	-	-	-	-
1711			I-SG	SG	-	-	-	-	-	-	-	-
1712			I-DGU	SG	-	-	-	-	-	-	-	-
1713			LABOR	SO	-	-	-	-	-	-	-	-
1714					-	-	-	-	-	-	-	-
1715												
1716	**TOTAL INTANGIBLE PLANT**				**222,343,110**	**97,745,671**	**6,948,601**	**35,734,202**	**-**	**26,979,049**	**19,389,111**	**35,546,475**
1717												
1718	**TOTAL ELECTRIC PLANT IN SERVICE**				**6,407,404,503**	**3,070,045,170**	**1,219,470,027**	**1,940,195,496**	**-**	**35,458,162**	**93,235,851**	**48,999,797**
1719												
1720	105	Plant Held For Future Use										
1721			D_SPLIT	S	-	-	-	-	-	-	-	-
1722			P	SG	-	-	-	-	-	-	-	-
1723			T	SG	-	-	-	-	-	-	-	-
1724			P	SG	-	-	-	-	-	-	-	-
1725			P	SE	-	-	-	-	-	-	-	-
1726			G	SG	-	-	-	-	-	-	-	-
1727												
1728												
1729					-	-	-	-	-	-	-	-
1730												
1731	114	Electric Plant Acquisition Adjustments										
1732			P	S	-	-	-	-	-	-	-	-
1733			P	SG	37,277,580	37,277,580	-	-	-	-	-	-
1734			P	SG	3,753,337	3,753,337	-	-	-	-	-	-
1735					41,030,917	41,030,917	-	-	-	-	-	-
1736												
1737	115	Accum Provision for Asset Acquisition Adjustments										
1738			P	S	-	-	-	-	-	-	-	-
1739			P	SG	(26,362,499)	(26,362,499)	-	-	-	-	-	-
1740			P	SG	(3,407,467)	(3,407,467)	-	-	-	-	-	-
1741					(29,769,966)	(29,769,966)	-	-	-	-	-	-
1742												
1743	120	Nuclear Fuel										
1744			P	SE	-	-	-	-	-	-	-	-
1745					-	-	-	-	-	-	-	-
1746												
1747	124	Weatherization										
1748			DSM	S	0	-	-	0	-	-	-	-
1749			DSM	SO	(1,210)	-	-	(1,210)	-	-	-	-
1750					(1,210)	-	-	(1,210)	-	-	-	-

1752	182W	Weatherization											
1753			DSM	S	-	-	-	-	-	-	-	-	
1754			DSM	SG	-	-	-	-	-	-	-	-	
1755			DSM	SG	-	-	-	-	-	-	-	-	
1756			DSM	SO	-	-	-	-	-	-	-	-	
1757					-	-	-	-	-	-	-	-	
1758													
1759	186W	Weatherization											
1760			DSM	S	-	-	-	-	-	-	-	-	
1761			DSM	CN	-	-	-	-	-	-	-	-	
1762			DSM	CNP	-	-	-	-	-	-	-	-	
1763			DSM	SG	-	-	-	-	-	-	-	-	
1764			DSM	SO	-	-	-	-	-	-	-	-	
1765					-	-	-	-	-	-	-	-	
1766													
1767		Total Weatherization			(1,210)	-	-	(1,210)	-	-	-	-	
1768													
1769	151	Fuel Stock											
1770			P	DEU	-	-	-	-	-	-	-	-	
1771			P	SE	50,628,609	50,628,609	-	-	-	-	-	-	
1772			P	SE	-	-	-	-	-	-	-	-	
1773			P	SE	1,622,602	1,622,602	-	-	-	-	-	-	
1774					52,251,211	52,251,211	-	-	-	-	-	-	
1775													
1776	152	Fuel Stock - Undistributed											
1777			P	SE	-	-	-	-	-	-	-	-	
1778					-	-	-	-	-	-	-	-	
1779													
1780	25316	DG&T Working Capital Deposit											
1781			P	SE	(830,793)	(830,793)	-	-	-	-	-	-	
1782					(830,793)	(830,793)	-	-	-	-	-	-	
1783													
1784	25317	DG&T Working Capital Deposit											
1785			P	SE	(637,897)	(637,897)	-	-	-	-	-	-	
1786					(637,897)	(637,897)	-	-	-	-	-	-	
1787													
1788	25319	Provo Working Capital Deposit											
1789			P	SE	-	-	-	-	-	-	-	-	
1790					-	-	-	-	-	-	-	-	
1791													
1792		Total Fuel Stock			50,782,521	50,782,521	-	-	-	-	-	-	
1793	154	Materials and Supplies											
1794			MSS	S	27,856,546	23,485,729	180,633	4,055,384	-	-	134,799	-	
1795			MSS	SG	1,212,407	1,022,175	7,862	176,503	-	-	5,867	-	
1796			MSS	SE	1,497,500	1,262,536	9,710	218,008	-	-	7,246	-	
1797			MSS	SO	14,077	11,868	91	2,049	-	-	68	-	
1798			MSS	SG	22,482,876	18,955,212	145,788	3,273,080	-	-	108,796	-	
1799			MSS	SG	(479)	(404)	(3)	(70)	-	-	(2)	-	
1800			MSS	SNPD	(666,740)	(562,126)	(4,323)	(97,065)	-	-	(3,226)	-	
1801			MSS	SG	-	-	-	-	-	-	-	-	
1802			MSS	SG	-	-	-	-	-	-	-	-	
1803			MSS	SG	-	-	-	-	-	-	-	-	
1804			MSS	SG	-	-	-	-	-	-	-	-	
1805			MSS	SG	1,797,674	1,515,611	11,657	261,707	-	-	8,699	-	
1806			MSS	SG	-	-	-	-	-	-	-	-	
1807					54,193,860	45,690,601	351,415	7,889,597	-	-	262,247	-	
1808													
1809	163	Stores Expense Undistributed											
1810			MSS	SO	-	-	-	-	-	-	-	-	
1811													
1812					-	-	-	-	-	-	-	-	
1813													
1814	25318	Provo Working Capital Deposit											
1815			MSS	SG	(70,372)	(59,330)	(456)	(10,245)	-	-	(341)	-	
1816													
1817					(70,372)	(59,330)	(456)	(10,245)	-	-	(341)	-	
1818													
1819		Total Materials & Supplies			54,123,489	45,631,271	350,959	7,879,352	-	-	261,907	-	
1820													
1821	165	Prepayments											
1822			LABOR	S	2,209,516	799,870	109,126	554,039	-	120,376	208,437	417,669	
1823			GP	GPS	77,023	36,905	14,659	23,323	-	426	1,121	589	
1824			PT	SG	681,391	473,753	207,637	-	-	-	-	-	
1825			P	SE	817,620	817,620	-	-	-	-	-	-	
1826			LABOR	SO	3,880,554	1,404,805	191,656	973,054	-	211,415	366,075	733,549	
1827					7,666,103	3,532,952	523,078	1,550,415	-	332,217	575,633	1,151,807	
1828													
1829	182M	Misc Regulatory Assets											
1830			DDS2	S	(219,737)	(190,496)	(2,630)	4,383	-	(32,479)	421	1,064	
1831			DEFSG	SG	-	-	-	-	-	-	-	-	
1832			P	SGCT	1,185,308	1,185,308	-	-	-	-	-	-	
1833			DEFSG	SG	-	-	-	-	-	-	-	-	
1834			P	SE	-	-	-	-	-	-	-	-	
1835			P	SG	-	-	-	-	-	-	-	-	
1836			LABOR	SO	2,401,738	869,456	118,619	602,239	-	130,848	226,570	454,005	
1837					3,367,309	1,864,269	115,989	606,622	-	98,369	226,991	455,069	
1838													
1839	186M	Misc Deferred Debits											
1840			LABOR	S	-	-	-	-	-	-	-	-	
1841			P	SG	-	-	-	-	-	-	-	-	
1842			P	SG	-	-	-	-	-	-	-	-	
1843			DEFSG	SG	16,011,908	10,161,908	5,850,000	-	-	-	-	-	
1844			LABOR	SO	-	-	-	-	-	-	-	-	
1845			P	SE	3,194,021	3,194,021	-	-	-	-	-	-	
1846			P	SG	-	-	-	-	-	-	-	-	
1847			GP	EXCTAX	-	-	-	-	-	-	-	-	
1848					19,205,929	13,355,929	5,850,000	-	-	-	-	-	

1850	Working Capital											
1851	CWC	Cash Working Capital										
1852			CWC	S	17,417,166	12,096,101	1,433,724	2,918,084	0	264,365	412,697	292,195
1853			CWC	SO	-	-	-	-	-	-	-	-
1854			CWC	SE	-	-	-	-	-	-	-	-
1855					17,417,166	12,096,101	1,433,724	2,918,084	0	264,365	412,697	292,195
1856												
1857	OWC	Other Working Capital										
1858	131	Cash	GP	SNP	-	-	-	-	-	-	-	-
1859	135	Working Funds	GP	SG	-	-	-	-	-	-	-	-
1860	141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-
1861	143	Other Accounts Receivat	LABOR	SO	15,146,146	5,483,076	748,052	3,797,915	-	825,172	1,428,825	2,863,105
1862	232	Accounts Payable	LABOR	S	-	-	-	-	-	-	-	-
1863	232	Accounts Payable	LABOR	SO	(1,284,992)	(465,182)	(63,464)	(322,213)	-	(70,007)	(121,221)	(242,905)
1864	232	Accounts Payable	P	SE	(872,486)	(872,486)	-	-	-	-	-	-
1865	232	Accounts Payable	P	SG	(44,373)	(44,373)	-	-	-	-	-	-
1866	2533	Other Deferred Credits -	P	S	-	-	-	-	-	-	-	-
1867	2533	Other Deferred Credits -	P	SE	(1,643,260)	(1,643,260)	-	-	-	-	-	-
1868	230	Asset Retirement Obligat	P	SE	(611,750)	(611,750)	-	-	-	-	-	-
1869	230	Asset Retirement Obligat	P	S	-	-	-	-	-	-	-	-
1870	254105	ARO Regulatory Liability	P	S	-	-	-	-	-	-	-	-
1871	254105	ARO Regulatory Liability	P	SE	(218,347)	(218,347)	-	-	-	-	-	-
1872	2533	Cholla Reclamation	P	SE	-	-	-	-	-	-	-	-
1873					10,470,937	1,627,678	684,588	3,475,701	-	755,165	1,307,604	2,620,201
1874												
1875	Total Working Capital				27,888,103	13,723,779	2,118,312	6,393,785	0	1,019,530	1,720,301	2,912,396
1876	Miscellaneous Rate Base											
1877	18221	Unrec Plant & Reg Study Costs										
1878			P	S	-	-	-	-	-	-	-	-
1879												
1880					-	-	-	-	-	-	-	-
1881												
1882	18222	Nuclear Plant - Trojan										
1883			P	S	-	-	-	-	-	-	-	-
1884			P	TROJP	-	-	-	-	-	-	-	-
1885			P	TROJD	-	-	-	-	-	-	-	-
1886					-	-	-	-	-	-	-	-
1887												
1888												
1889												
1890	1869	Misc Deferred Debits-Trojan										
1891			P	S	-	-	-	-	-	-	-	-
1892			P	SG	-	-	-	-	-	-	-	-
1893					-	-	-	-	-	-	-	-
1894												
1895	TOTAL MISCELLANEOUS RATE BASE				-	-	-	-	-	-	-	-
1896												
1897	**TOTAL RATE BASE ADDITIONS**				**174,293,196**	**140,151,673**	**8,958,339**	**16,428,965**	**0**	**1,450,117**	**2,784,831**	**4,519,272**
1898	235	Customer Service Deposits										
1899			C_BILLING	S	-	-	-	-	-	-	-	-
1900			C_BILLING	CN	-	-	-	-	-	-	-	-
1901					-	-	-	-	-	-	-	-
1902												
1903	2281	Prov for Property Insuran	LABOR	SO	-	-	-	-	-	-	-	-
1904	2282	Prov for Injuries & Dama	LABOR	SO	(1,761,649)	(637,737)	(87,006)	(441,736)	-	(95,976)	(166,187)	(333,008)
1905	2283	Prov for Pensions and Be	LABOR	SO	(6,879,785)	(2,490,560)	(339,785)	(1,725,115)	-	(374,815)	(649,011)	(1,300,499)
1906	2283	Prov for Pensions and Be	LABOR	SO	-	-	-	-	-	-	-	-
1907	254	Reg Liabilities - Insuranc	LABOR	SE	-	-	-	-	-	-	-	-
1908					(8,641,434)	(3,128,297)	(426,791)	(2,166,850)	-	(470,791)	(815,197)	(1,633,507)
1909												
1910	22844	Accum Hydro Relicensing Obligation										
1911			P	S	-	-	-	-	-	-	-	-
1912			P	SG	-	-	-	-	-	-	-	-
1913					-	-	-	-	-	-	-	-
1914												
1915	22841	Chehalis Rate Base	P	SG	(386,657)	(386,657)	-	-	-	-	-	-
1916	230	Asset Retirement Obligat	P	TROJP	(424,449)	(424,449)	-	-	-	-	-	-
1917	254105	ARO Regulatory Liability	P	TROJP	(885,130)	(885,130)	-	-	-	-	-	-
1918	254		P	S	(1,313,427)	(1,313,427)	-	-	-	-	-	-
1919					(3,009,663)	(3,009,663)	-	-	-	-	-	-
1920												
1921	252	Customer Advances for Construction										
1922			D_SPLIT	S	(7,448,152)	-	-	(7,189,750)	-	-	(258,401)	-
1923			T	SE	-	-	-	-	-	-	-	-
1924			T	SG	(3,944,241)	-	(3,944,241)	-	-	-	-	-
1925			D_SPLIT	SO	-	-	-	-	-	-	-	-
1926			B_Center	CN	-	-	-	-	-	-	-	-
1927					(11,392,393)	-	(3,944,241)	(7,189,750)	-	-	(258,401)	-
1928												
1929	25398	SO2 Emissions										
1930			P	SE	(201,735)	(201,735)	-	-	-	-	-	-
1931					(201,735)	(201,735)	-	-	-	-	-	-
1932												
1933	25399	Other Deferred Credits										
1934			D_SPLIT	S	(621,782)	-	-	(600,211)	-	-	(21,572)	-
1935			LABOR	SO	-	-	-	-	-	-	-	-
1936			P	SG	(2,287,849)	(2,287,849)	-	-	-	-	-	-
1937			P	SE	(1,224,855)	(1,224,855)	-	-	-	-	-	-
1938					(4,134,487)	(3,512,705)	-	(600,211)	-	-	(21,572)	-

1940	190	Accumulated Deferred Income Taxes									
1941		D_SPLIT	S	2,194,422	-	-	2,118,290	-	-	76,132	-
1942		CSS_SYS	CN	8,496	-	-	-	-	4,673	1,529	2,294
1943		LABOR	SO	22,589,916	8,177,806	1,115,692	5,664,450	-	1,230,713	2,131,040	4,270,216
1944		P	GPS	-	-	-	-	-	-	-	-
1945		IBT	IBT	-	-	-	-	-	-	-	-
1946		P	SG	-	-	-	-	-	-	-	-
1947		P	SG	-	-	-	-	-	-	-	-
1948		C_BILLING	BADDEBT	2,573,821	-	-	-	-	2,573,821	-	-
1949		P	TROJD	-	-	-	-	-	-	-	-
1950		P	SG	1,900,548	1,900,548	-	-	-	-	-	-
1951		P	SE	(3,398,954)	(3,398,954)	-	-	-	-	-	-
1952		LABOR	SNP	-	-	-	-	-	-	-	-
1953		D_SPLIT	SNPD	217,032	-	-	209,503	-	-	7,530	-
1954		P	SG	-	-	-	-	-	-	-	-
1955				26,085,282	6,679,399	1,115,692	7,992,243	-	3,809,207	2,216,230	4,272,510
1956											
1957	281	Accumulated Deferred Income Taxes									
1958		P	S	-	-	-	-	-	-	-	-
1959		PT	SG	-	-	-	-	-	-	-	-
1960		T	SG	-	-	-	-	-	-	-	-
1961				-	-	-	-	-	-	-	-
1962											
1963	282	Accumulated Deferred Income Taxes									
1964		GP	S	(985,558,965)	(472,220,934)	(187,573,551)	(298,432,394)	-	(5,454,020)	(14,341,131)	(7,536,935)
1965		CSS_SYS	CN	-	-	-	-	-	-	-	-
1966		P	SG	-	-	-	-	-	-	-	-
1967		ACCMDIT	DITBAL	1	0	0	0	-	0	0	-
1968		P	SG	-	-	-	-	-	-	-	-
1969		P	SG-P	-	-	-	-	-	-	-	-
1970		P	SG	-	-	-	-	-	-	-	-
1971		P	SG-U	-	-	-	-	-	-	-	-
1972		LABOR	SO	6,366,560	2,304,767	314,438	1,596,423	-	346,854	600,595	1,203,483
1973		P	SG	-	-	-	-	-	-	-	-
1974		P	SE	(1,236,019)	(1,236,019)	-	-	-	-	-	-
1975		P	SG	3,793,149	3,793,149	-	-	-	-	-	-
1976				(976,635,274)	(467,359,037)	(187,259,114)	(296,835,971)	-	(5,107,165)	(13,740,536)	(6,333,451)
1977											
1978	283	Accumulated Deferred Income Taxes									
1979		GP	S	(339,034)	(162,445)	(64,526)	(102,661)	-	(1,876)	(4,933)	(2,593)
1980		P	SG	(501,671)	(501,671)	-	-	-	-	-	-
1981		P	SE	(3,682,412)	(3,682,412)	-	-	-	-	-	-
1982		LABOR	SO	(2,697,991)	(976,703)	(133,251)	(676,525)	-	(146,988)	(254,517)	(510,007)
1983		GP	GPS	(1,581,368)	(757,697)	(300,969)	(478,847)	-	(8,751)	(23,011)	(12,093)
1984		LABOR	SNP	(962,053)	(348,274)	(47,515)	(241,236)	-	(52,413)	(90,756)	(181,859)
1985		P	TROJD	-	-	-	-	-	-	-	-
1986		P	SG	-	-	-	-	-	-	-	-
1987		P	SGCT	(449,836)	(449,836)	-	-	-	-	-	-
1988		IBT	IBT	-	-	-	-	-	-	-	-
1989				(10,214,365)	(6,879,038)	(546,261)	(1,499,268)	-	(210,029)	(373,218)	(706,551)
1990											
1991	TOTAL ACCUMULATED DEF INCOME TAX			(960,764,357)	(467,558,675)	(186,689,682)	(290,342,997)	-	(1,507,987)	(11,897,523)	(2,767,493)
1992	255	Accumulated Investment Tax Credit									
1993		LABOR	S	-	-	-	-	-	-	-	-
1994		LABOR	ITC84	-	-	-	-	-	-	-	-
1995		LABOR	ITC85	(452,636)	(163,859)	(22,355)	(113,499)	-	(24,660)	(42,700)	(85,563)
1996		LABOR	ITC86	(398,357)	(144,210)	(19,674)	(99,888)	-	(21,703)	(37,579)	(75,302)
1997		LABOR	ITC88	(72,551)	(26,264)	(3,583)	(18,192)	-	(3,953)	(6,844)	(13,715)
1998		LABOR	ITC89	(158,131)	(57,245)	(7,810)	(39,652)	-	(8,615)	(14,917)	(29,892)
1999		LABOR	ITC90	(34,292)	(12,414)	(1,694)	(8,599)	-	(1,868)	(3,235)	(6,482)
2000		LABOR	DGU	-	-	-	-	-	-	-	-
2001				(1,115,967)	(403,993)	(55,116)	(279,830)	-	(60,799)	(105,276)	(210,953)
2002											
2003	**TOTAL RATE BASE DEDUCTIONS**			**(989,260,035)**	**(477,815,068)**	**(191,115,831)**	**(300,579,638)**	**-**	**(2,039,576)**	**(13,097,970)**	**(4,611,953)**
2004											
2005											
2006											
2007	108SP	Steam Prod Plant Accumulated Depr									
2008		P	S	-	-	-	-	-	-	-	-
2009		P	SG	(201,076,174)	(201,076,174)	-	-	-	-	-	-
2010		P	SG	(226,447,590)	(226,447,590)	-	-	-	-	-	-
2011		P	SG	(239,284,636)	(239,284,636)	-	-	-	-	-	-
2012		P	SG	(43,262,989)	(43,262,989)	-	-	-	-	-	-
2013				(710,071,390)	(710,071,390)	-	-	-	-	-	-
2014											
2015	108NP	Nuclear Prod Plant Accumulated Depr									
2016		P	SG	-	-	-	-	-	-	-	-
2017		P	SG	-	-	-	-	-	-	-	-
2018		P	SG	-	-	-	-	-	-	-	-
2019				-	-	-	-	-	-	-	-
2020											
2021											
2022	108HP	Hydraulic Prod Plant Accum Depr									
2023		P	S	-	-	-	-	-	-	-	-
2024		Pre-Merger Pacific	P	SG	(41,770,076)	(41,770,076)	-	-	-	-	-
2025		Pre-Merger Utah	P	SG	(7,397,276)	(7,397,276)	-	-	-	-	-
2026		Post-Merger Pacific	P	SG	(14,063,682)	(14,063,682)	-	-	-	-	-
2027		Post-Merger Utah	P	SG	(5,622,119)	(5,622,119)	-	-	-	-	-
2028					(68,853,153)	(68,853,153)	-	-	-	-	-
2029											
2030	108OP	Other Production Plant - Accum Depr									
2031		P	S	-	-	-	-	-	-	-	-
2032		P	SG	(94,531)	(94,531)	-	-	-	-	-	-
2033		P	SG	-	-	-	-	-	-	-	-
2034		P	SG	(130,578,704)	(130,578,704)	-	-	-	-	-	-
2035		P	SG	(6,325,905)	(6,325,905)	-	-	-	-	-	-
2036				(136,999,140)	(136,999,140)	-	-	-	-	-	-

2038	108EP	Experimental Plant - Accum Depr									
2039		P	SG	-	-	-	-	-	-	-	-
2040		P	SG	-	-	-	-	-	-	-	-
2041				-	-	-	-	-	-	-	-
2042											
2043	**TOTAL PRODUCTION PLANT DEPRECIATION**			**(915,923,682)**	**(915,923,682)**	**-**	**-**	**-**	**-**	**-**	**-**
2044											
2045	108TP	Transmission Plant Accumulated Depr									
2046		T_Split	S	-	-	-	-	-	-	-	-
2047		T_Split	SG	(97,501,915)	(2,645,888)	(94,856,026)	-	-	-	-	-
2048		T_Split	SG	(106,027,750)	(2,877,252)	(103,150,498)	-	-	-	-	-
2049		T_Split	SG	(126,411,807)	(3,430,410)	(122,981,397)	-	-	-	-	-
2050	**TOTAL TRANS PLANT ACCUM DEPR**			**(329,941,471)**	**(8,953,551)**	**(320,987,921)**	**-**	**-**	**-**	**-**	**-**
2051	108360	Land and Land Rights									
2052		D	S	(2,950,952)	-	-	(2,950,952)	-	-	-	-
2053				(2,950,952)	-	-	(2,950,952)	-	-	-	-
2054											
2055	108361	Structures and Improvements									
2056		D	S	(4,456,786)	-	-	(4,456,786)	-	-	-	-
2057				(4,456,786)	-	-	(4,456,786)	-	-	-	-
2058											
2059	108362	Station Equipment									
2060		D	S	(66,995,304)	-	-	(66,995,304)	-	-	-	-
2061				(66,995,304)	-	-	(66,995,304)	-	-	-	-
2062											
2063	108363	Storage Battery Equipment									
2064		D	S	-	-	-	-	-	-	-	-
2065				-	-	-	-	-	-	-	-
2066											
2067	108364	Poles, Towers & Fixtures									
2068		D	S	(219,733,317)	-	-	(219,733,317)	-	-	-	-
2069				(219,733,317)	-	-	(219,733,317)	-	-	-	-
2070											
2071	108365	Overhead Conductors									
2072		D	S	(134,233,080)	-	-	(134,233,080)	-	-	-	-
2073				(134,233,080)	-	-	(134,233,080)	-	-	-	-
2074											
2075	108366	Underground Conduit									
2076		D	S	(39,177,324)	-	-	(39,177,324)	-	-	-	-
2077				(39,177,324)	-	-	(39,177,324)	-	-	-	-
2078											
2079	108367	Underground Conductors									
2080		D	S	(66,937,995)	-	-	(66,937,995)	-	-	-	-
2081				(66,937,995)	-	-	(66,937,995)	-	-	-	-
2082											
2083	108368	Line Transformers									
2084		D	S	(180,069,664)	-	-	(180,069,664)	-	-	-	-
2085				(180,069,664)	-	-	(180,069,664)	-	-	-	-
2086											
2087	108369	Services									
2088		D	S	(74,117,855)	-	-	(74,117,855)	-	-	-	-
2089				(74,117,855)	-	-	(74,117,855)	-	-	-	-
2090											
2091	108370	Meters									
2092		C_Meter	S	(34,794,049)	-	-	-	-	-	(34,794,049)	-
2093				(34,794,049)	-	-	-	-	-	(34,794,049)	-
2094											
2095											
2096											
2097	108371	Installations on Customers' Premises									
2098		D	S	(2,588,428)	-	-	(2,588,428)	-	-	-	-
2099				(2,588,428)	-	-	(2,588,428)	-	-	-	-
2100											
2101	108372	Leased Property									
2102		D	S	-	-	-	-	-	-	-	-
2103				-	-	-	-	-	-	-	-
2104											
2105	108373	Street Lights									
2106		D	S	(9,240,924)	-	-	(9,240,924)	-	-	-	-
2107				(9,240,924)	-	-	(9,240,924)	-	-	-	-
2108											
2109	108D00	Unclassified Dist Plant - Acct 300									
2110		D_SPLIT	S	-	-	-	-	-	-	-	-
2111				-	-	-	-	-	-	-	-
2112											
2113	108DS	Unclassified Dist Sub Plant - Acct 300									
2114		D_SPLIT	S	-	-	-	-	-	-	-	-
2115				-	-	-	-	-	-	-	-
2116											
2117	108DP	Unclassified Dist Sub Plant - Acct 300									
2118		D_SPLIT	S	(224,187)	-	-	(216,409)	-	-	(7,778)	-
2119				(224,187)	-	-	(216,409)	-	-	(7,778)	-
2120											
2121											
2122	**TOTAL DISTRIBUTION PLANT DEPR**			**(835,519,865)**	**-**	**-**	**(800,718,038)**	**-**	**-**	**(34,801,827)**	**-**
2123											
2124	108GP	General Plant Accumulated Depr									
2125		D_SPLIT	S	(43,367,585)	-	-	(41,863,018)	-	-	(1,504,567)	-
2126		G-DGP	SG	(540,619)	(375,879)	(164,740)	-	-	-	-	-
2127		G-DGU	SG	(765,345)	(532,125)	(233,220)	-	-	-	-	-
2128		G-SG	SG	(14,255,037)	(6,722,191)	(7,532,845)	-	-	-	-	-
2129		B_Center	CN	(2,204,046)	-	-	-	-	(1,700,457)	-	(503,589)
2130		LABOR	SO	(17,192,285)	(6,223,802)	(849,109)	(4,310,987)	-	(936,647)	(1,621,849)	(3,249,891)
2131		P	SE	(68,527)	(68,527)	-	-	-	-	-	-
2132		G-SG	SG	(11,893)	(5,609)	(6,285)	-	-	-	-	-
2133		G-SG	SG	(431,111)	(203,297)	(227,813)	-	-	-	-	-
2134				(78,836,448)	(14,131,430)	(9,014,013)	(46,174,004)	-	(2,637,104)	(3,126,417)	(3,753,480)

2136											
2137	108MP	Mining Plant Accumulated Depr.									
2138			P	S	-	-	-	-	-	-	-	-
2139			P	SE	(38,159,679)	(38,159,679)	-	-	-	-	-	-
2140					(38,159,679)	(38,159,679)	-	-	-	-	-	-
2141	108MP	Less Centralia Situs Depreciation									
2142			P	S	-	-	-	-	-	-	-	-
2143					(38,159,679)	(38,159,679)	-	-	-	-	-	-
2144											
2145	1081390	Accum Depr - Capital Lease									
2146			LABOR	SO	-	-	-	-	-	-	-	-
2147					-	-	-	-	-	-	-	-
2148											
2149		Remove Capital Leases			-	-	-	-	-	-	-	-
2150					-	-	-	-	-	-	-	-
2151											
2152	1081399	Accum Depr - Capital Lease									
2153			P	S	-	-	-	-	-	-	-	-
2154			P	SE	-	-	-	-	-	-	-	-
2155					-	-	-	-	-	-	-	-
2156											
2157		Remove Capital Leases			-	-	-	-	-	-	-	-
2158					-	-	-	-	-	-	-	-
2159											
2160											
2161	**TOTAL GENERAL PLANT ACCUM DEPR**				**(116,996,128)**	**(52,291,109)**	**(9,014,013)**	**(46,174,004)**	**-**	**(2,637,104)**	**(3,126,417)**	**(3,753,480)**
2162												
2163	**TOTAL ACCUM DEPR - PLANT IN SERVICE**				**(2,198,381,147)**	**(977,168,343)**	**(330,001,934)**	**(846,892,042)**	**-**	**(2,637,104)**	**(37,928,244)**	**(3,753,480)**
2164	111SP	Accum Prov for Amort-Steam										
2165			P	SG	-	-	-	-	-	-	-	-
2166			P	SG	-	-	-	-	-	-	-	-
2167					-	-	-	-	-	-	-	-
2168												
2169												
2170	111GP	Accum Prov for Amort-General										
2171			D_SPLIT	S	(6,890,301)	-	-	(6,651,253)	-	-	(239,048)	-
2172			CSS_SYS	CN	(960,540)	-	-	-	-	(528,297)	(172,897)	(259,346)
2173			I-SG	SG	-	-	-	-	-	-	-	-
2174			LABOR	SO	(3,588,443)	(1,299,057)	(177,229)	(899,806)	-	(195,501)	(338,519)	(678,330)
2175			P	SE	-	-	-	-	-	-	-	-
2176					(11,439,284)	(1,299,057)	(177,229)	(7,551,059)	-	(723,798)	(750,464)	(937,676)
2177												
2178												
2179	111HP	Accum Prov for Amort-Hydro										
2180		Pre-Merger Pacific	P	SG	-	-	-	-	-	-	-	-
2181		Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
2182		Post-Merger Pacific	P	SG	(158,376)	(158,376)	-	-	-	-	-	-
2183		Post-Merger Utah	P	SG	(135,860)	(135,860)	-	-	-	-	-	-
2184					(294,236)	(294,236)	-	-	-	-	-	-
2185												
2186												
2187	111IP	Accum Prov for Amort-Intangible Plant										
2188			D_SPLIT	S	466,390	-	-	450,209	-	-	16,181	-
2189			LABOR	SG	-	-	-	-	-	-	-	-
2190			LABOR	SG	(92,923)	(33,639)	(4,589)	(23,300)	-	(5,062)	(8,766)	(17,565)
2191			P	SE	(448,760)	(448,760)	-	-	-	-	-	-
2192			LABOR	SG	(10,769,954)	(3,898,845)	(531,917)	(2,700,579)	-	(586,754)	(1,015,993)	(2,035,865)
2193			I-SG	SG	(8,154,902)	(6,969,160)	(1,185,743)	-	-	-	-	-
2194			I-SG	SG	(990,090)	(846,128)	(143,961)	-	-	-	-	-
2195			CSS_SYS	CN	(31,178,494)	-	-	-	-	(17,148,172)	(5,612,129)	(8,418,193)
2196			P	SG	-	-	-	-	-	-	-	-
2197			P	SG	(44,102)	(44,102)	-	-	-	-	-	-
2198			LABOR	SO	(77,151,304)	(27,929,647)	(3,810,422)	(19,345,785)	-	(4,203,252)	(7,278,136)	(14,584,062)
2199					(128,364,138)	(40,170,280)	(5,676,632)	(21,619,456)	-	(21,943,241)	(13,898,843)	(25,055,686)
2200	111IP	Less Non-Utility Plant										
2201			NUTIL	OTH	-	-	-	-	-	-	-	-
2202					(128,364,138)	(40,170,280)	(5,676,632)	(21,619,456)	-	(21,943,241)	(13,898,843)	(25,055,686)
2203												
2204	111390	Accum Amtr - Capital Lease										
2205			LABOR	S	(2,003,233)	(725,193)	(98,938)	(502,313)	-	(109,137)	(188,977)	(378,675)
2206			P	SG	(1,131,827)	(1,131,827)	-	-	-	-	-	-
2207			LABOR	SO	286,860	103,847	14,168	71,931	-	15,628	27,061	54,226
2208					(2,848,199)	(1,753,173)	(84,770)	(430,383)	-	(93,509)	(161,916)	(324,449)
2209												
2210		Remove Capital Lease Amtr			2,848,199	1,753,173	84,770	430,383	-	93,509	161,916	324,449
2211												
2212	**TOTAL ACCUM PROV FOR AMORTIZATION**				**(140,097,658)**	**(41,763,573)**	**(5,853,861)**	**(29,170,515)**	**-**	**(22,667,039)**	**(14,649,307)**	**(25,993,362)**

Docket No. UE-246
Exhibit PAC/1203
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

CY 2011 Ancillary Services Revenue

March 2012

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
CY 2011 Ancillary Services Revenue
12 Months Ended December 31, 2013 Forecast

Line	Item	Notes	Thermal Resource	Hydro Resource	Other Resource	Firm Purchases	Total Resources
1	System Resources CY 2013 (MWh)	(Note 1)	52,664,461	3,932,477	3,152,594	12,791,246	72,540,778
2	Plant allocated to Oregon based on JAM dollars	(Note 2)	25.78%	25.78%	25.78%	25.78%	
3	Oregon share of Resource Providing Service by type (MWh)	(Line 1 x Line 2)	13,575,400	1,013,681	812,706	3,297,219	18,699,005
4	Resource type % of total		72.60%	5.42%	4.35%	17.63%	100.00%
5	Oregon Retail Load, Including Losses, by resource type	(Line 4 x Line 5 Total)	10,602,610	791,701	634,736	2,575,182	14,604,230
6	FERC Tariff Ancillary Service Charges						
	Regulation and Frequency Response Service						
7	Billing Determinant (Load Energy MWh)		NA	NA	NA	NA	14,604,230
8	Charge ($/MWh)		NA	NA	NA	NA	0.1600
9	Total Cost	(Line 8 x Line 9)	NA	NA	NA	NA	$2,336,677
	Operating Reservice - Spinning Reserve Service						
10	Billing Determinant (Generated Energy in MWh)		10,602,610	791,701	634,736	2,575,182	14,604,230
11	Charge ($/MWh)		0.3730	0.2660	NA	NA	
12	Total Cost	(Line 11 x Line 12)	$3,954,774	$210,593			$4,165,366
	Operating Reservice - Supplemental Reserve Service						
13	Billing Determinant (Generated Energy in MWh)		10,602,610	791,701	634,736	2,575,182	14,604,230
14	Charge ($/MWh)		0.3730	0.2660	NA	NA	
15	Total Cost	(Line 14 x Line 15)	$3,954,774	$210,593			$4,165,366
16	Oregon Annual Ancillary Service Revenue ($ x thousands)	Line 10 + Line 13 + Line 16)					$10,667,409

Note 1 - Source :Net Power Cost Analysis

Note 2 - CY 2013 JAM Model

Total Electric Plant in Service by Plant Type ($ x Millions)		Thermal	Hydro	Other	Total
Oregon		1,735.8	235.0	800.0	2,770.8
System		6,733.8	911.8	3,103.4	10,749.0
Percent of System		25.78%	25.78%	25.78%	25.78%

Acount 555 Purchased Power - SG	Dollars
Oregon	166,248,421
System	644,944,800
Percent of System	25.78%

Production Plant	TOTAL	OTHER	OREGON
Total Steam Production Plant	6,733,786,706	4,998,008,069	1,735,778,637
Total Hydraulic Plant	911,816,379	676,776,058	235,040,321
Total Other Production Plant	3,103,398,847	2,303,375,249	800,023,598
TOTAL PRODUCTION PLANT	10,749,001,932	7,978,159,376	2,770,842,557

Docket No. UE-246
Exhibit PAC/1204
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Oregon Marginal Cost of Service Summary

March 2012

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2013 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 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) Trans (trn)	(R) Irrg Sch 41 (sec)	(S) Sch 51,53,54 Streetlighting (sec)
	Demand Related Marginal Cost																			
1	Generation	$179,482	$79,840	$8,289	$6,997	$15	$6,748	$9,706	$12,592	$256	$2,707	$13,547	$1,227	$7,632	$6,204	$690	$13,197	$7,558	$2,277	
2	Transmission	$256,597	$114,142	$11,851	$10,004	$22	$9,647	$13,876	$18,002	$366	$3,870	$19,368	$1,755	$10,911	$8,870	$986	$18,866	$10,805	$3,256	
3	Distribution																			
4	Poles	$68,953	$40,154	$4,352	$3,490	$10	$2,436	$3,535	$4,737	$84	$736	$3,629	$331	$1,665	$1,371	$11	$176	$0	$2,235	
5	Conductor	$88,330	$50,290	$5,231	$4,194	$11	$3,192	$4,632	$6,207	$111	$1,075	$5,301	$484	$2,664	$2,193	$23	$335	$0	$2,387	
6	Substations	$75,664	$37,495	$3,407	$2,732	$8	$2,704	$3,924	$5,259	$94	$1,150	$5,672	$517	$3,288	$2,708	$302	$5,565	$0	$839	
7	Subtotal: Pole, Cond, Subs	$232,948	$127,940	$12,990	$10,416	$29	$8,332	$12,091	$16,203	$289	$2,960	$14,603	$1,332	$7,618	$6,272	$336	$6,076	$0	$5,461	
8	Transformers	$15,020	$10,216	$584	$421	$0	$519	$616	$806	$0	$159	$793	$0	$464	$0	$48	$0	$0	$394	
9	Distribution subtotal	$247,967	$138,156	$13,574	$10,837	$29	$8,851	$12,707	$17,009	$289	$3,119	$15,396	$1,332	$8,082	$6,272	$384	$6,076	$0	$5,855	
10																				
11	Total Demand Related	$684,046	$332,138	$33,714	$27,838	$66	$25,246	$36,289	$47,603	$911	$9,696	$48,311	$4,314	$26,625	$21,346	$2,060	$38,139	$18,363	$11,388	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$862,436	$360,160	$39,333	$33,528	$86	$28,471	$43,193	$59,560	$1,218	$13,348	$67,628	$5,793	$37,683	$32,187	$3,531	$70,849	$50,408	$14,027	$1,432
16	Transmission Energy Related	$49,374	$20,619	$2,252	$1,919	$5	$1,630	$2,473	$3,410	$70	$764	$3,872	$332	$2,157	$1,843	$202	$4,056	$2,886	$803	$82
17	Total Energy	$911,809	$380,779	$41,584	$35,447	$91	$30,101	$45,666	$62,969	$1,288	$14,112	$71,500	$6,124	$39,840	$34,030	$3,734	$74,905	$53,293	$14,830	$1,514
18																				
19	Customer Related Marginal Cost																			
20	Poles	$54,784	$40,478	$7,233	$1,153	$6	$291	$231	$134	$3	$7	$20	$1	$1	$1	$0	$0	$0	$2,151	$3,074
21	Conductor	$25,452	$19,888	$3,553	$567	$3	$143	$114	$66	$1	$4	$10	$1	$1	$0	$0	$0	$0	$1,056	$44
22	Transformers	$95,126	$63,435	$11,945	$2,748	$0	$3,432	$3,065	$1,912	$0	$255	$650	$0	$131	$0	$3	$0	$0	$7,476	$75
23	Service Drops	$62,508	$47,215	$8,248	$2,764	$0	$1,167	$962	$1,082	$0	$115	$571	$0	$376	$0	$7	$0	$0	$0	$0
24	Meters	$12,405	$8,876	$1,265	$352	$79	$145	$123	$447	$86	$48	$124	$84	$31	$104	$1	$50	$311	$276	$2
25	Meter Reading	$9,797	$7,498	$1,442	$230	$1	$167	$133	$77	$2	$14	$36	$3	$18	$11	$0	$5	$1	$154	$2
26	Billing & Collections	$19,571	$16,564	$2,131	$340	$2	$154	$122	$71	$2	$8	$20	$2	$14	$8	$0	$4	$1	$103	$25
27	Uncollectables	$5,185	$4,566	$133	$21	$0	$89	$71	$41	$1	$29	$75	$7	$69	$41	$1	$19	$4	$18	$0
28	Customer Service / Other	$6,058	$5,073	$677	$108	$1	$55	$43	$25	$1	$4	$11	$1	$7	$4	$0	$2	$0	$38	$7
29	Total Commitment & Billing Rel.	$290,886	$213,593	$36,627	$8,284	$91	$5,645	$4,864	$3,855	$96	$485	$1,516	$100	$649	$169	$12	$80	$317	$11,273	$3,230
30																				
31	Total Revenue @ Full MC																			
32	Generation	$1,041,918	$440,000	$47,622	$40,525	$101	$35,219	$52,899	$72,152	$1,474	$16,055	$81,175	$7,020	$45,315	$38,391	$4,221	$84,046	$57,966	$16,304	$1,432
33	Transmission	$305,971	$134,761	$14,103	$11,923	$27	$11,277	$16,349	$21,412	$436	$4,634	$23,240	$2,087	$13,068	$10,713	$1,188	$22,922	$13,691	$4,059	$82
34	Distribution	$485,837	$309,172	$44,553	$18,070	$37	$13,885	$17,079	$20,202	$294	$3,500	$16,647	$1,334	$8,591	$6,273	$394	$6,076	$0	$16,538	$3,193
35	Customer - Billing	$19,571	$16,564	$2,131	$340	$2	$154	$122	$71	$2	$8	$20	$2	$14	$8	$0	$4	$1	$103	$25
36	Customer - Metering	$22,202	$16,375	$2,707	$582	$80	$313	$256	$524	$88	$63	$160	$88	$50	$115	$1	$55	$312	$431	$4
37	Customer - Other	$6,058	$5,073	$677	$108	$1	$55	$43	$25	$1	$4	$11	$1	$7	$4	$0	$2	$0	$38	$7
38	Revenue (less Uncollectables)	$1,881,557	$921,945	$111,792	$71,548	$248	$60,903	$86,748	$114,386	$2,294	$24,264	$121,253	$10,531	$67,045	$55,505	$5,805	$113,105	$71,969	$37,474	$4,744
39																				
40	Customer - Uncollectables	$5,185	$4,566	$133	$21	$0	$89	$71	$41	$1	$29	$75	$7	$69	$41	$1	$19	$4	$18	$0
41	Total Revenue	$1,886,742	$926,510	$111,925	$71,569	$248	$60,992	$86,819	$114,427	$2,295	$24,293	$121,328	$10,538	$67,114	$55,545	$5,806	$113,124	$71,973	$37,491	$4,744

Exhibit PAC/1204
Paice/1

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2013 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C)	(D) General Service Sch 28	(E)	(F) General Service Sch 30	(G)	(H)	(I) Large Power Service Sch 48T	(J)	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54	Street Lighting Sch 51	Sch 53	Sch 54	
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)			(sec)	(sec)	(sec)	
1	**Total Operating Revenues**	$1,172,659	$564,491	$119,925	$144	$159,882	$1,384	$91,384	$6,735	$45,205	$107,902	$47,976	$24,939.978	$2,690	$1,965	$621	$104	
2	**MWh**	13,020,247	5,400,866	1,092,595	1,331	1,967,805	18,795	1,214,303	89,386	618,043	1,589,947	795,520	210,342	$21,313	10,626	9,548	1,139	
3																		
4	**Functionalized 20 Year Full Marginal Costs - Class $**																	
5	Generation	$1,041,918	$440,000	$88,146	$101	$160,270	$1,474	$97,231	$7,020	$49,537	$122,438	$57,966	$16,304	$1,432	$714	$639	$79	0.0672
6	Transmission	$305,971	$134,761	$26,026	$27	$49,037	$436	$27,874	$2,087	$14,256	$33,635	$13,691	$4,059	$82	$41	$37	$5	0.0038
7	Distribution	$485,839	$309,172	$62,623	$37	$51,166	$294	$20,147	$1,334	$8,985	$12,349	$0	$16,538	$3,195	$3,058	$91	$46	0.1499
8	Customer - Billing	$19,571	$16,564	$2,471	$2	$347	$2	$27	$2	$14	$12	$1	$103	$25	$14	$8	$3	0.0012
9	Customer - Metering	$22,200	$16,375	$3,289	$80	$1,093	$88	$223	$88	$51	$170	$312	$431	$2	$0	$0	$2	0.0001
10	Customer - Other	$6,058	$5,073	$785	$1	$123	$1	$16	$1	$7	$6	$0	$38	$7	$4	$2	$1	0.0003
11	Total	$1,881,557	$921,945	$183,340	$248	$262,037	$2,294	$145,517	$10,531	$72,850	$168,609	$71,969	$37,474	$4,744	$3,830	777	137	0.2226
12																		
13	**Functional Revenue Requirement Allocation Factors**																	
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**																	
15	Generation	100.00%	42.23%	8.46%	0.01%	15.38%	0.14%	9.33%	0.67%	4.75%	11.75%	5.56%	1.56%	0.14%	0.07%	0.06%	0.01%	
16	Transmission	100.00%	44.04%	8.51%	0.01%	16.03%	0.14%	9.11%	0.68%	4.66%	10.99%	4.47%	1.33%	0.03%	0.01%	0.01%	0.00%	
17	Distribution	100.00%	63.64%	12.89%	0.01%	10.53%	0.06%	4.15%	0.27%	1.85%	2.54%	0.00%	3.40%	0.66%	0.63%	0.02%	0.01%	
18	Ancillary Service	100.00%	42.23%	8.46%	0.01%	15.38%	0.14%	9.33%	0.67%	4.75%	11.75%	5.56%	1.56%	0.14%	0.07%	0.06%	0.01%	
19	Customer - Billing	100.00%	84.64%	12.63%	0.01%	1.78%	0.01%	0.14%	0.01%	0.07%	0.06%	0.00%	0.53%	0.13%	0.07%	0.04%	0.02%	
20	Customer - Metering	100.00%	73.76%	14.81%	0.36%	4.92%	0.40%	1.00%	0.39%	0.23%	0.76%	1.40%	1.94%	0.01%	0.00%	0.00%	0.01%	
21	Customer - Other	100.00%	83.74%	12.96%	0.01%	2.03%	0.01%	0.26%	0.02%	0.11%	0.09%	0.01%	0.63%	0.12%	0.07%	0.04%	0.02%	
22	Embedded DSM - (MWh)	100.00%	41.48%	8.39%	0.01%	15.11%	0.14%	9.33%	0.69%	4.75%	12.21%	6.11%	1.62%	0.16%	0.08%	0.07%	0.01%	
23	Regulatory & Franchise	100.00%	48.14%	10.23%	0.01%	13.63%	0.12%	7.79%	0.57%	3.85%	9.20%	4.09%	2.13%	0.23%	0.17%	0.05%	0.01%	
24																		
25																		
26	**Functionalized Class Revenue Requirement - (Target)**																	
27	Generation	$730,938	$308,674	$61,837	$71	$112,435	$1,034	$68,210	$4,925	$34,751	$85,894	$40,665	$11,438	$1,004	$501	$448	$56	0.0471
28	Transmission	$158,120	$69,642	$13,450	$14	$25,342	$225	$14,405	$1,078	$7,367	$17,382	$7,075	$2,098	$42	$21	$19	$2	0.0020
29	Distribution	$233,847	$148,813	$30,142	$18	$24,628	$141	$9,697	$642	$4,325	$5,944	$0	$7,960	$1,538	$1,472	$44	$22	0.0722
30	Ancillary Services	$10,581	$4,468	$895	$1	$1,628	$15	$987	$71	$503	$1,243	$589	$166	$15	$7	$6	$1	0.0007
31	Customer - Billing	$13,474	$11,404	$1,701	$1	$239	$1	$19	$1	$10	$8	$1	$71	$17	$9	$6	$2	0.0008
32	Customer - Metering	$25,472	$18,788	$3,773	$92	$1,254	$101	$256	$101	$58	$195	$358	$494	$3	$0	$0	$3	0.0001
33	Customer - Other	$17,907	$14,996	$2,321	$1	$363	$2	$47	$3	$20	$17	$1	$113	$22	$12	$7	$3	0.0010
34	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-
35	Regulatory & Franchise T	$28,989	$13,955	$2,965	$4	$3,952	$34	$2,259	$166	$1,118	$2,667	$1,186	$617	$67	$49	$15	$3	0.0031
36	Total	$1,219,327	$590,738	$117,085	$202	$169,840	$1,554	$95,880	$6,988	$48,152	$113,350	$49,874	$22,956	$2,707	$2,071	$545	$91	0.1270
37																		
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	96.17%	95.56%	102.43%	71.19%	94.14%	89.09%	95.31%	96.38%	93.88%	95.19%	96.20%	108.64%	99.36%	94.90%	113.93%	113.61%	
39	(Line 1 / Line 36)																	
40																		
41	**Increase or (Decrease)**	$46,667	$26,247	($2,841)	$58	$9,958	$169	$4,496	$253	$2,946	$5,448	$1,897	($1,984)	$17	$106	($76)	($12)	
42	(Line 36 - Line 1)																	
43																		
44																		
45	**Percent Increase (Decrease)**	3.98%	4.65%	-2.37%	40.47%	6.23%	12.24%	4.92%	3.76%	6.52%	5.05%	3.95%	-7.95%	0.64%	5.38%	-12.22%	-11.98%	
46	(Line 41 / Line 1)																	
		3.98%	4.65%	-2.32%		6.28%		4.84%		5.12%			-7.95%	0.64%				

Exhibit PAC/1205
Paice/1

Docket No. UE-246
Exhibit PAC/1206
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functionalized Results of Operations

March 2012

PacifiCorp
12 Months Ended June 2011
FUNCTIONAL FACTORS

Function	Description	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
B_Center	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	77.1516%	0.0000%	22.8484%	0.0000%	100.0000%
BOOKDEPR	Book Depreciation	51.5028%	17.2206%	29.9914%	0.0000%	0.3310%	0.9542%	0.0000%	0.0000%	100.0000%
C_BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100.0000%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%	100.0000%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%	100.0000%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	46.9861%	25.9126%	27.1014%	0.0000%	100.0000%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	62.5622%	0.0000%	37.4378%	0.0000%	100.0000%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	5.3259%	94.6741%	0.0000%	100.0000%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDS2	Deferred Debits - Situs	86.6926%	1.1969%	-1.9946%	0.0000%	14.7807%	-0.1914%	-0.4843%	0.0000%	100.0000%
DDS6	Deferred Debits - Situs	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DDSO2	Deferred Debits - System Overhead	11.1769%	3.7256%	85.0975%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDSO6	Deferred Debits - System Overhead	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DEFSG	Deferred Debit - System Generation	63.4647%	36.5353%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DSM	Demand Side Management	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	96.9166%	0.0000%	0.0000%	3.0834%	0.0000%	0.0000%	100.0000%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
FERC	FERC Fees	53.7289%	46.2711%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G	General Plant	23.2258%	30.0265%	42.7664%	0.0000%	2.6207%	1.3606%	0.0000%	0.0000%	100.0000%
G-SG	General Plant - SG Factor	47.1566%	52.8434%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SITUS	General Plant - SITUS Factor	0.0000%	25.8489%	71.8647%	0.0000%	0.0000%	2.2864%	0.0000%	0.0000%	100.0000%
I	Intangible Plant	55.5738%	14.8544%	13.6863%	0.0000%	8.1169%	3.6746%	4.0940%	0.0000%	100.0000%
I-DGP	Intangible Plant - DGP Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-DGU	Intangible Plant - DGU Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SG	Intangible Plant - SG Factor	85.4598%	14.5402%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SITUS	Intangible Plant - SITUS Factor	2.7484%	47.0180%	48.6847%	0.0000%	0.0000%	1.5489%	0.0000%	0.0000%	100.0000%
LABOR	Oregon Direct Labor Expense	36.2011%	4.9389%	25.0751%	0.0000%	5.4481%	9.4336%	18.9032%	0.0000%	100.0000%
MSS	Materials & Supplies	84.3096%	0.6484%	14.5581%	0.0000%	0.0000%	0.4839%	0.0000%	0.0000%	100.0000%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHDGP	Other Revenues - DGP Factor	65.7788%	34.2212%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHDGU	Other Revenues - DGU Factor	65.7788%	34.2212%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSE	Other Revenues - SE Factor	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSG	Other Revenues - SG Factor	65.7788%	34.2212%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSGR	Other Revenues - Rolled-In SG Factor	65.7788%	34.2212%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSITUS	Other Revenues - SITUS	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSO	Other Revenues - SO Factor	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMA	Schedule M Additions	52.1393%	17.8149%	26.7765%	0.0000%	0.6357%	1.2760%	1.3576%	0.0000%	100.0000%
SCHMAF	Schedule M Additions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAP	Schedule M Additions - Permanent	37.9740%	6.1301%	24.8869%	0.0000%	4.9906%	8.7025%	17.3159%	0.0000%	100.0000%
SCHMAP-SO	Schedule M Additions - Permanent-SO	37.2136%	6.1537%	25.1722%	0.0000%	5.0637%	8.8273%	17.5694%	0.0000%	100.0000%
SCHMAT	Schedule M Additions - Temporary	52.3817%	18.0149%	26.8088%	0.0000%	0.5611%	1.1490%	1.0845%	0.0000%	100.0000%
SCHMAT-SG	Schedule M Additions - Temporary-SG	97.5171%	2.4829%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SE	Schedule M Additions - Temporary-SE	99.9659%	0.0026%	0.0134%	0.0000%	0.0029%	0.0050%	0.0101%	0.0000%	100.0000%
SCHMAT-SITUS	Schedule M Additions - Temporary-SITUS	54.6049%	4.0702%	19.9816%	0.0000%	1.3155%	2.7015%	17.3263%	0.0000%	100.0000%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	50.5576%	22.1373%	26.4355%	0.0000%	0.0167%	0.8457%	0.0072%	0.0000%	100.0000%
SCHMAT-SO	Schedule M Additions - Temporary-SO	45.5230%	16.1233%	25.9692%	0.0000%	1.9089%	3.8521%	6.6234%	0.0000%	100.0000%
SCHMD	Schedule M Deductions	59.4229%	17.0658%	20.3437%	0.0000%	0.4020%	0.5261%	2.2395%	0.0000%	100.0000%
SCHMDF	Schedule M Deductions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDP	Schedule M Deductions - Permanent	38.1147%	5.0939%	24.4391%	0.0000%	5.2148%	9.0436%	18.0939%	0.0000%	100.0000%
SCHMDP-SO	Schedule M Deductions - Permanent- SO	36.2011%	4.9389%	25.0751%	0.0000%	5.4481%	9.4336%	18.9032%	0.0000%	100.0000%
SCHMDT	Schedule M Deductions - Temporary	59.5656%	17.1459%	20.3163%	0.0000%	0.3698%	0.4691%	2.1334%	0.0000%	100.0000%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	50.5612%	22.1269%	26.4267%	0.0000%	0.0259%	0.8480%	0.0113%	0.0000%	100.0000%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDT-SITUS	Schedule M Deductions - Temporary-SITUS	82.7842%	0.8738%	4.6242%	0.0000%	0.9003%	1.5730%	9.2444%	0.0000%	100.0000%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	50.5510%	22.1560%	26.4515%	0.0000%	0.0000%	0.8415%	0.0000%	0.0000%	100.0000%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	44.5373%	18.2713%	35.9206%	0.0000%	0.2299%	0.7433%	0.2974%	0.0000%	100.0000%
STEP_UP	Step-up Transformers	8.0204%	91.9796%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
TAXDEPR	Tax Depreciation	59.0446%	18.0835%	21.4529%	0.0000%	0.3897%	0.4686%	0.5607%	0.0000%	100.0000%

Exhibit PAC/1206
Paice/1

TOTAL FUNCFAC

PacifiCorp
12 Months Ended June 2011
FERC FORM 1 Funtionalization Factors

Factor	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
PLANT	21,263,673	10,749,002	4,711,177	5,624,550			178,944	0	0
UNCLASSIFIED PLANT	0							0	0
TOTAL PLANT	21,263,673	10,749,002	4,711,177	5,624,550	0	0	178,944	0	0
PLANT %									
P	100.0000%	100.0000%							
T	100.0000%		100.0000%						
CUST						100.0000%			
DPW	100.0000%			96.9166%			3.0834%		
PTD	100.0000%	50.5510%	22.1560%	26.4515%			0.8415%	0.0000%	0.0000%
PT	100.0000%	69.5270%	30.4730%						
TD	100.0000%		44.8057%	53.4924%			1.7019%		

Source: Jun 2011 Results of Operations

Material & Supplies	110,731,982	93,357,638	718,031	16,120,474			535,839	0	0
Material & Supplies %	100.0000%	84.3096%	0.6484%	14.5581%	0.0000%	0.0000%	0.4839%	0.0000%	0.0000%

Source: Ferc Form 1 (2010) - pg. 227

	Meter Percent of Total Distribution	
Account 370	178,944	3.22%
Total Distribution	5,562,398	100.00%

Source: Jun 2011 Results of Operations

FERC (mWh)	28,449,800	15,285,755	13,164,045	0	0	0	0	0	0
FERC %	100.0000%	53.7289%	46.2711%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Source: 2010 FERC reporting requirment No. 582

Exhibit PAC/1206
Paice/2

PacifiCorp
12 Months Ended June 2011
Depreciation Expense

Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
CUST	1,706	-	-	-	-	1,706	-	-	-
DPW	143,309	-	-	138,890	-	-	4,419	-	-
G-DGP	358	181	79	95	-	-	3	-	-
G-DGU	801	557	244	-	-	-	-	-	-
G-SG	5,696	-	2,552	3,047	-	-	97	-	-
G-SITUS	12,138	-	3,138	8,723	-	-	278	-	-
P	257,395	257,395	-	-	-	-	-	-	-
PTD	14,632	7,397	3,242	3,870	-	-	123	-	-
T	79,528	-	79,528	-	-	-	-	-	-
Book Depreciation	515,564	265,530	88,783	154,625	-	1,706	4,919	-	-
BookDepr Factor	**100.00%**	**51.5028%**	**17.2206%**	**29.9914%**	**0.0000%**	**0.3310%**	**0.9542%**	**0.0000%**	**0.0000%**
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.9166%	0.0000%	0.0000%	3.0834%	0.0000%	0.0000%
G-DGP	100.0000%	50.5510%	22.1560%	26.4515%	0.0000%	0.0000%	0.8415%	0.0000%	0.0000%
G-DGU	100.0000%	69.5270%	30.4730%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
G-SG	100.0000%	0.0000%	44.8057%	53.4924%	0.0000%	0.0000%	1.7019%	0.0000%	0.0000%
G-SITUS	100.0000%	0.0000%	25.8489%	71.8647%	0.0000%	0.0000%	2.2864%	0.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	50.5510%	22.1560%	26.4515%	0.0000%	0.0000%	0.8415%	0.0000%	0.0000%
TD	100.0000%	0.0000%	44.8057%	53.4924%	0.0000%	0.0000%	1.7019%	0.0000%	0.0000%
G	100.0000%	23.2258%	30.0265%	42.7664%	0.0000%	2.6207%	1.3606%	0.0000%	0.0000%

Exhibit PAC/1206
Paice/3

PacifiCorp
CSS System Allocation Factor
Business Center Allocation Factor
12 Months Ended June 2011

Description	Total	Production	Transmission	Distribution	Retail	Ancillary	C_Billing	C_Metering	C_Service
Customer Service System (CSS)									
CSS_SYS	100.0000%						55.0000%	18.0000%	27.0000%

The size is based on the lines of code; regardless of type of code.
Some Additional Code related to general use and system maintenance is assumed to be shared by all functions.

Business Center Expenses									
Wasatch Business Center -									
2011	11,229,426						11,220,734		8,692
2011 Support	1,369,887						684,943		684,943
Portland Business Center -									
2011	21,103,203						15,238,634		5,864,569
2011 Support	4,207,045						2,103,523		2,103,523
Total	$ 37,909,561						$ 29,247,833		$ 8,661,728
B_CENTER	100.0000%						77.1516%		22.8484%

Exhibit PAC/1206
Paice/4

PacifiCorp
Summary of Ferc Accounts 901 - 910 by Funtional Groups

Line No.	Description	FERC Account	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1	Supervision	901	2,627,337					1,234,483	680,810	712,044
2	Meter Reading	902	22,883,023					-	22,883,023	-
3	Cust. Records & Coll. Exp.	903	56,512,714					35,355,614	-	21,157,100
4	Misc. Customer Acct. Exp.	905	196,637					-	10,473	186,164
5	Supervision	907	279,527					-	-	279,527
6	Customer Assistance Exp.	908	103,832,699					-	-	103,832,699
7	Information & Instructional Exp.	909	4,705,212					-	-	4,705,212
8	Misc. cust. Serv. & Inform. Exp.	910	232,845					-	-	232,845
9		Total	191,269,995							
10										
11	Uncollectible Accounts	904	12,989,486							
12	Grand Total		204,259,480							

Account	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
CUST901	100.0000%					46.9861%	25.9126%	27.1014%
CUST903	100.0000%					62.5622%	-	37.4378%
CUST905	100.0000%					-	5.3259%	94.6741%

Exhibit PAC/1206
Paice/5

PacifiCorp
12 Months Ended June 2011
Deferred Debits / Reg Assets

	Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
RA-SE	182M	SE	P	0	0	0	0	0	0	0	0
RA-SG	182M	SG	P	0	0	0	0	0	0	0	0
RA-SGCT	182M	SGCT	P	6,828	6,828	0	0	0	0	0	0
RA-SG-P	182M	SG-P	P	0	0	0	0	0	0	0	0
RA-SO	182M	SO	DMSC	5,547	0	0	5,547	0	0	0	0
RA-SO	182M	SO	DPW	0	0	0	0	0	0	0	0
RA-SO	182M	SO	ESD	3,294	988	329	1,976	0	0	0	0
RA-SO	182M	SO	P	0	0	0	0	0	0	0	0
RA-SO	182M	SO	TD	0	0	0	0	0	0	0	0
RA-TROJD	182M	TROJD	P	0	0	0	0	0	0	0	0
RA-TROJP	182M	TROJP	P	0	0	0	0	0	0	0	0
RA-OTHER	182M	OTHER	DMSC	5,453	0	0	5,453	0	0	0	0
RA-OTHER	182M	OTHER	CUST	1,579	0	0	0	0	1,579	0	0
RA-OTHER	182M	OTHER	LABOR	14,218	5,147	702	3,565	0	775	1,341	2,688
RA-OTHER	182M	OTHER	P	51,178	51,178	0	0	0	0	0	0
RA-OTHER	182M	OTHER	PT	10,922	0	10,922	0	0	0	0	0
RA-OTHER	182M	OTHER	PTD	14,703	7,432	3,257	3,889	0	0	124	0
RA-OTHER	182M	OTHER	TD	664	0	298	355	0	0	11	0
RA-SITUS	182M	SITUS	CUST	3,168	0	0	0	0	3,168	0	0
RA-SITUS	182M	SITUS	DMSC	-623	0	0	-623	0	0	0	0
RA-SITUS	182M	SITUS	LABOR	-544	-197	-27	-136	0	-30	-51	-103
RA-SITUS	182M	SITUS	P	17,963	17,963	0	0	0	0	0	0
RA-SITUS	182M	SITUS	PTD	1,268	641	281	335	0	0	11	0
	Total-SO			8,841	988	329	7,524	-	-	-	-
	Total SITUS			21,233	18,407	254	(424)	-	3,138	(41)	(103)
	Total RA			135,618	89,980	15,762	20,363	-	5,492	1,436	2,585
	DDSO2 FACTOR			**100.00%**	**11.1769%**	**3.7256%**	**85.0975%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	DDS2 FACTOR			**100.00%**	**86.6926%**	**1.1969%**	**-1.9946%**	**0.0000%**	**14.7807%**	**-0.1914%**	**-0.4843%**
DD-SE	186M	SE	P	13,137	13,137	0	0	0	0	0	0
DD-SG	186M	SG	P	31,278	31,278	0	0	0	0	0	0
DD-SG	186M	SG	T	18,006	0	18,006	0	0	0	0	0
DD-SO	186M	SO	DMSC	0	0	0	0	0	0	0	0
DD-OTHER	186M	OTHER	DMSC	2,384	0	0	2,384	0	0	0	0
DD-OTHER	186M	OTHER	T	11,366	0	11,366	0	0	0	0	0
	Total SITUS			-	-	-	-	-	-	-	-
	Total SG			49,283	31,278	18,006	-	-	-	-	-
	Total-SO			-	-	-	-	-	-	-	-
	Total-DD			76,170	44,414	29,372	2,384	-			-
	DEFSG FACTOR			**100.00%**	**63.4647%**	**36.5353%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**

Exhibit PAC/1206
Paice/6

PacifiCorp
12 Months Ended June 2011
Deferred Debits / Reg Assets

Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Major Adjustment										
1998 Early Retirement		LABOR	-	0	0	0	0	0	0	0
1999 Early Retirement		LABOR	-	0	0	0	0	0	0	0
Transition Planning		PTD	-	0	0	0	0	0	0	0
Environmental Clean-up		ESD	-	0	0	0	0	0	0	0
Y2K		PTD	-	0	0	0	0	0	0	0
Subtotal Major Adjustments			-	-	-	-	-	-	-	-
Total 186M SO			-	-	-	-	-	-	-	-
Total 182 &186			211,788	134,395	45,135	22,746	-	5,492	1,436	2,585

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
DMSC	100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.9166%	0.0000%	0.0000%	3.0834%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD	100.0000%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP	100.0000%	50.6936%	21.7495%	26.1054%	0.0000%	0.3625%	0.9317%	0.1573%
LABOR	100.0000%	36.2011%	4.9389%	25.0751%	0.0000%	5.4481%	9.4336%	18.9032%
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	50.5510%	22.1560%	26.4515%	0.0000%	0.0000%	0.8415%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR	100.0000%	59.0446%	18.0835%	21.4529%	0.0000%	0.3897%	0.4686%	0.5607%
TD	100.0000%	0.0000%	44.8057%	53.4924%	0.0000%	0.0000%	1.7019%	0.0000%

PacifiCorp
12 Months Ended June 2011
General Plant

Description		Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Business Centers		CN	CUST	24,826	0	0	0	0	24,826	0	0
		SE	P	660	660	0	0	0	0	0	0
		SG	P	96,342	96,342	0	0	0	0	0	0
		SG	T	107,960	0	107,960	0	0	0	0	0
		SG	TD	0	0	0	0	0	0	0	0
General Plant		SO	DPW	0	0	0	0	0	0	0	0
		SO	PTD	243,358	123,020	53,918	64,372	0	0	2,048	0
		SO	TD	0	0	0	0	0	0	0	0
		SO	P	0	0	0	0	0	0	0	0
	SSGCH	SG	P	0	0	0	0	0	0	0	0
	SSGCT	SG	DPW	0	0	0	0	0	0	0	0
	SSGCT	SG	P	0	0	0	0	0	0	0	0
		SITUS	DPW	200,616	0	0	194,431	0	0	6,186	0
		SITUS	P	0	0	0	0	0	0	0	0
		SITUS	TD	273,554	0	122,568	146,330	0	0	4,655	0
Total-CUST				24,826	0	0	0	0	24,826	0	0
Total-TD				273,554	0	122,568	146,330	0	0	4,655	0
Total-PTD				243,358	123,020	53,918	64,372	0	0	2,048	0
Total-DPW				200,616	0	0	194,431	0	0	6,186	0
Total-SSGCH				0	0	0	0	0	0	0	0
Total-SSGCT				0	0	0	0	0	0	0	0
Total-G-SG				204,302	96,342	107,960	0	0	0	0	0
Total-UT				660	660	0	0	0	0	0	0
Total-G-Situs				474,170	0	122,568	340,761	0	0	10,841	0
Total-SO				243,358	123,020	53,918	64,372	0	0	2,048	0
Total-General Plant				947,316	220,022	284,446	405,133	0	24,826	12,889	0
G-SG Factor				**100.00%**	**47.1566%**	**52.8434%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
UT Factor				**100.00%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
G-SITUS Factor				**100.00%**	**0.0000%**	**25.8489%**	**71.8647%**	**0.0000%**	**0.0000%**	**2.2864%**	**0.0000%**
SO Factor				**100.00%**	**50.5510%**	**22.1560%**	**26.4515%**	**0.0000%**	**0.0000%**	**0.8415%**	**0.0000%**
G Allocator				**100.00%**	**23.2258%**	**30.0265%**	**42.7664%**	**0.0000%**	**2.6207%**	**1.3606%**	**0.0000%**
Total Gen. Plant				947,316							
Mining			acct 399 from JAM	488,304	660	660	0	0	0	0	0
Total			P	1,435,620							

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	44.81%	53.49%	0.00%	0.00%	1.70%	0.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
DPW	100.00%	0.00%	0.00%	96.92%	0.00%	0.00%	3.08%	0.00%
PTD	100.00%	50.55%	22.16%	26.45%	0.00%	0.00%	0.84%	0.00%
GP	100.00%	50.69%	21.75%	26.11%	0.00%	0.36%	0.93%	0.16%

Exhibit PAC/1206
Paice/8

PacifiCorp
12 Months Ended June 2011
Intangible Plant
(In 000's)

Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
CN	CSS_SYS	111,921	0	0	0	0	61,556	20,146	30,219
CN	CUST	4,511	0	0	0	0	2,481	812	1,218
CN	C_METER	2,665	0	0	0	0	0	2,665	0
CN	C_SERVICE	1,981	0	0	0	0	0	0	1,981
SE	P	3,654	3,654	0	0	0	0	0	0
SG	P	94,169	94,169	0	0	0	0	0	0
SG	PTD	-	0	0	0	0	0	0	0
SG	T	47,228	0	47,228	0	0	0	0	0
SG	P	173,622	173,622	0	0	0	0	0	0
SG	P	9,790	9,790	0	0	0	0	0	0
SO	CUST	2,680	0	0	0	0	1,474	482	724
SO	C_METER	2,908	0	0	0	0	0	2,908	0
SO	C_BILLING	2,179	0	0	0	0	2,179	0	0
SO	DPW	24,000	0	0	23,260	0	0	740	0
SO	P	29,195	29,195	0	0	0	0	0	0
SO	PTD	302,242	152,786	66,965	79,947	0	0	2,544	0
SO	TD	12,686	0	5,684	6,786	0	0	216	0
SO	LABOR	-	0	0	0	0	0	0	0
SITUS	PTD	463	234	102	122	0	0	4	0
SITUS	T	531	0	531	0	0	0	0	0
SITUS	TD	7,514	0	3,367	4,020	0	0	128	0
Total-DGP		-	-	-	-	-	-	-	-
Total-DGU		-	-	-	-	-	-	-	-
Total-SG		324,810	277,582	47,228	-	-	-	-	-
Total-SITUS		8,508	234	4,000	4,142	-	-	132	-
Total-Intangible		833,938	463,451	123,877	114,135	-	67,690	30,644	34,141
I-SG FACTOR		**100.00%**	**85.4598%**	**14.5402%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
I-Situs FACTOR		**100.00%**	**2.7484%**	**47.0180%**	**48.6847%**	**0.0000%**	**0.0000%**	**1.5489%**	**0.0000%**
I FACTOR		**100.00%**	**55.5738%**	**14.8544%**	**13.6863%**	**0.0000%**	**8.1169%**	**3.6746%**	**4.0940%**

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	44.81%	53.49%	0.00%	0.00%	1.70%	0.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
C_BILLING	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
C_METER	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
C_SERVICE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
DPW	100.00%	0.00%	0.00%	96.92%	0.00%	0.00%	3.08%	0.00%
PTD	100.00%	50.55%	22.16%	26.45%	0.00%	0.00%	0.84%	0.00%
LABOR	100.00%	36.20%	4.94%	25.08%	0.00%	5.45%	9.43%	18.90%

Exhibit PAC/1206
Ralse/9

PacifiCorp
Oregon Labor Costs
12 Months Ended June 2011

Ferc Account	Funct.	FERC Form 1	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
500-554, 913,916	P	50,662,543	50,662,543	-	-	-	-	-	-
560-569, 571-573	T	5,040,487	-	5,040,487	-	-	-	-	-
580,590	D_Split	1,349,997	-	-	1,308,372	-	-	41,626	-
581,585,587-589,591,596,598, 599	D	33,898,000	-	-	33,898,000	-	-	-	-
586,597,902	C_Meter	13,034,325	-	-	-	-	-	13,034,325	-
901	CUST901	646,957	-	-	-	-	303,979	167,643	175,334
903	CUST903	11,740,786	-	-	-	-	7,345,297	-	4,395,488
905	CUST905	28,203	-	-	-	-	-	1,502	26,701
907,908	C_Service	21,838,361	-	-	-	-	-	-	21,838,361
909,910	C_Service	104,879	-	-	-	-	-	-	104,879
570	Step_Up	2,059,043	165,144	1,893,899	-	-	-	-	-
	Total Labor	140,403,579	50,827,687	6,934,385	35,206,372	-	7,649,277	13,245,095	26,540,763
	LABOR	**100.0000%**	**36.2011%**	**4.9389%**	**25.0751%**	**-**	**5.4481%**	**9.4336%**	**18.9032%**

Functional Allocation Factor		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
C_METER	100.0000%	-	-	-	-	-	100.000%	-
C_Service	100.0000%	-	-	-	-	-	-	100.000%
CUST901	100.0000%	-	-	-	-	46.986%	25.913%	27.101%
CUST903	100.0000%	-	-	-	-	62.562%	-	37.438%
CUST905	100.0000%	-	-	-	-	-	5.326%	94.674%
D	100.0000%	-	-	100.000%	-	-	-	-
D_SPLIT	100.0000%	-	-	96.917%	-	-	3.083%	-
P	100.0000%	100.000%	-	-	-	-	-	-
STEP_UP	100.0000%	8.0204%	91.9796%	-	-	-	-	-
T	100.0000%	-	100.0000%	-	-	-	-	-
1	2	3	4	5	6	7	8	9

Exhibit PAC/1206
Paice/10

PacifiCorp
12 Months Ended June 2011
Schedule M

ADDITIONS

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
SCHMAP-OTHER	SCHMAP	OTHER	P	29	29	-	-	-	-	-	-
SCHMAP-SCHMDEXP	SCHMAP	SCHMDEXP	LABOR	(536)	(194)	(26)	(134)	-	(29)	(51)	(101)
SCHMAP-SE	SCHMAP	SE	P	130	130	-	-	-	-	-	-
SCHMAP-SO	SCHMAP	SO	LABOR	13,204	4,780	652	3,311	-	719	1,246	2,496
SCHMAP-SO	SCHMAP	SO	PTD	1,002	507	222	265	-	-	8	-
	Total-SO			14,207	5,287	874	3,576	-	719	1,254	2,496
	Total SCHMAP			13,830	5,252	848	3,442	-	690	1,204	2,395
	SCHMAP-SO			**100.00%**	**37.2136%**	**6.1537%**	**25.1722%**	**0.0000%**	**5.0637%**	**8.8273%**	**17.5694%**
	SCHMAP FACTOR			**100.00%**	**37.9740%**	**6.1301%**	**24.8869%**	**0.0000%**	**4.9906%**	**8.7025%**	**17.3159%**
SCHMAT-CIAC	SCHMAT	CIAC	DPW	27,829	-	-	26,971	-	-	858	-
SCHMAT-BADDEBT	SCHMAT	BADDEBT	CUST	1,315	-	-	-	-	1,315	-	-
SCHMAT-SCHMDEXP	SCHMAT	SCHMDEXP	GP	568,694	288,292	123,688	148,460	-	2,062	5,298	895
SCHMAT-SE	SCHMAT	SE	LABOR	17	6	1	4	-	1	2	3
SCHMAT-SE	SCHMAT	SE	P	32,744	32,744	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	P	16,463	16,463	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	T	419	-	419	-	-	-	-	-
SCHMAT-SGCT	SCHMAT	SGCT	P	1,122	1,122	-	-	-	-	-	-
SCHMAT-SNP	SCHMAT	SNP	GP	2,331	1,182	507	609	-	8	22	4
SCHMAT-SNP	SCHMAT	SNP	PTD	48,346	24,440	10,712	12,788	-	-	407	-
SCHMAT-SNPD	SCHMAT	SNPD	DPW	9,587	-	-	9,292	-	-	296	-
SCHMAT-OTHER	SCHMAT	OTHER	DMSC	1,150	-	-	-	-	-	-	1,150
SCHMAT-OTHER	SCHMAT	OTHER	GP	795	403	173	208	-	3	7	1
SCHMAT-OTHER	SCHMAT	OTHER	P	20,091	20,091	-	-	-	-	-	-
SCHMAT-OTHER	SCHMAT	OTHER	PTD	8,675	4,385	1,922	2,295	-	-	73	-
SCHMAT-SO	SCHMAT	SO	LABOR	15,866	5,744	784	3,978	-	864	1,497	2,999
SCHMAT-SO	SCHMAT	SO	PTD	29,415	14,870	6,517	7,781	-	-	248	-
SCHMAT-TROJD	SCHMAT	TROJD	P	1,902	1,902	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	DMSC	2,742	-	-	-	-	-	-	2,742
SCHMAT-SITUS	SCHMAT	SITUS	DPW	2,868	-	-	2,779	-	-	88	-
SCHMAT-SITUS	SCHMAT	SITUS	ESD	58	17	6	35	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	GP	643	326	140	168	-	2	6	1
SCHMAT-SITUS	SCHMAT	SITUS	LABOR	5,131	1,857	253	1,287	-	280	484	970
SCHMAT-SITUS	SCHMAT	SITUS	P	9,475	9,475	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	PTD	49	25	11	13	-	-	0	-
SCHMAT-SITUS	SCHMAT	SITUS	T	462	-	462	-	-	-	-	-
	Total-SG			16,882	16,463	419	-	-	-	-	-
	Total-SE			32,762	32,751	1	4	-	1	2	3
	Total-SNP			50,678	25,621	11,219	13,397	-	8	429	4
	Total-SITUS			21,427	11,700	872	4,282	-	282	579	3,713
	Total SO			45,281	20,613	7,301	11,759	-	864	1,744	2,999
	Total-SCHMAT			808,193	423,345	145,595	216,667	-	4,535	9,286	8,765
	SCHMAT-SG			**100.00%**	**97.5171%**	**2.4829%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMAT-SE			**100.00%**	**99.9659%**	**0.0026%**	**0.0134%**	**0.0000%**	**0.0029%**	**0.0050%**	**0.0101%**
	SCHMAT-SNP			**100.00%**	**50.5576%**	**22.1373%**	**26.4355%**	**0.0000%**	**0.0167%**	**0.8457%**	**0.0072%**
	SCHMAT-SITUS			**100.00%**	**54.6049%**	**4.0702%**	**19.9816%**	**0.0000%**	**1.3155%**	**2.7015%**	**17.3263%**
	SCHMAT-SO			**100.00%**	**45.5230%**	**16.1233%**	**25.9692%**	**0.0000%**	**1.9089%**	**3.8521%**	**6.6234%**
	SCHMAT FACTOR			**100.00%**	**52.3817%**	**18.0149%**	**26.8088%**	**0.0000%**	**0.5611%**	**1.1490%**	**1.0845%**
SCHMAF-DGP	SCHMAF	DGP	P	-	-	-	-	-	-	-	-
SCHMAF-TROJP	SCHMAF	TROJP	P	-	-	-	-	-	-	-	-
	Total-SCHMAF			-	-	-	-	-	-	-	-
	SCHMAF FACTOR			**0.00%**							
	Total-SCHMA			822,022	428,597	146,443	220,109	-	5,225	10,489	11,160
	SCHMA FACTOR			**100.00%**	**52.1393%**	**17.8149%**	**26.7765%**	**0.0000%**	**0.6357%**	**1.2760%**	**1.3576%**

PacifiCorp
12 Months Ended June 2011
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
						DEDUCTIONS					
SCHMDP-SCHMDEXP	SCHMDP	SCHMDEXP	LABOR	109	40	5	27	-	6	10	21
SCHMDP-SE	SCHMDP	SE	P	574	574	-	-	-	-	-	-
SCHMDP-SG	SCHMDP	SG	P	-	-	-	-	-	-	-	-
SCHMDP-SNP	SCHMDP	SNP	PTD	361	183	80	96	-	-	3	-
SCHMDP-SO	SCHMDP	SO	LABOR	20,812	7,534	1,028	5,219	-	1,134	1,963	3,934
SCHMDP-SO	SCHMDP	SO	PTD	-	-	-	-	-	-	-	-
	Total-SO			20,812	7,534	1,028	5,219	-	1,134	1,963	3,934
	Total-SCHMDP			21,857	8,331	1,113	5,342	-	1,140	1,977	3,955
	SCHMDP-SO			**100.00%**	**36.2011%**	**4.9389%**	**25.0751%**	**0.0000%**	**5.4481%**	**9.4336%**	**18.9032%**
	SCHMDP FACTOR			**100.00%**	**38.1147%**	**5.0939%**	**24.4391%**	**0.0000%**	**5.2148%**	**9.0436%**	**18.0939%**
SCHMDT-BADDEBT	SCHMDT	BADDEBT	CUST	-	-	-	-	-	-	-	-
SCHMDT-CN	SCHMDT	CN	CUST	48	-	-	-	-	48	-	-
SCHMDT-DGP	SCHMDT	DGP	P	-	-	-	-	-	-	-	-
SCHMDT-GPS	SCHMDT	GPS	GP	4,908	2,488	1,067	1,281	-	18	46	8
SCHMDT-GPS	SCHMDT	GPS	PTD	63,651	32,176	14,103	16,837	-	-	536	-
SCHMDT-OTHER	SCHMDT	OTHER	CUST	604	-	-	-	-	604	-	-
SCHMDT-OTHER	SCHMDT	OTHER	DMSC	52,131	-	-	-	-	-	-	52,131
SCHMDT-OTHER	SCHMDT	OTHER	DPW	386	-	-	374	-	-	12	-
SCHMDT-OTHER	SCHMDT	OTHER	LABOR	2,969	1,075	147	745	-	162	280	561
SCHMDT-OTHER	SCHMDT	OTHER	P	42,312	42,312	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	PT	15,725	10,933	4,792	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	TD	1,230	-	551	658	-	-	21	-
SCHMDT-SE	SCHMDT	SE	P	48,399	48,399	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	GP	-	-	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	P	62,164	62,164	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	T	-	-	-	-	-	-	-	-
SCHMDT-SNP	SCHMDT	SNP	PTD	88,835	44,907	19,682	23,498	-	-	748	-
SCHMDT-SNPD	SCHMDT	SNPD	DPW	-	-	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	ESD	6,710	2,013	671	4,026	-	-	-	-
SCHMDT-SO	SCHMDT	SO	GP	10,615	5,381	2,309	2,771	-	38	99	17
SCHMDT-SO	SCHMDT	SO	LABOR	279	101	14	70	-	15	26	53
SCHMDT-SO	SCHMDT	SO	P	-	-	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	PTD	5,740	2,902	1,272	1,518	-	-	48	-
SCHMDT-SSGCH	SCHMDT	SSGCH	P	-	-	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	TAXDEPR	-	-	-	-	-	-	-	-
SCHMDT-TAXDEPR	SCHMDT	TAXDEPR	TAXDEPR	2,847,400	1,681,235	514,910	610,849	-	11,098	13,342	15,967
SCHMDT-TROJD	SCHMDT	TROJD	P	-	-	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	DMSC	591	-	-	-	-	-	-	591
SCHMDT-SITUS	SCHMDT	SITUS	DPW	41	-	-	40	-	-	1	-
SCHMDT-SITUS	SCHMDT	SITUS	GP	26	13	6	7	-	0	0	0
SCHMDT-SITUS	SCHMDT	SITUS	LABOR	1,593	577	79	399	-	87	150	301
SCHMDT-SITUS	SCHMDT	SITUS	P	7,399	7,399	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	PTD	-	-	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	T	-	-	-	-	-	-	-	-
	Total-GPS			68,559	34,664	15,170	18,118	-	18	581	8
	Total-SG			62,164	62,164	-	-	-	-	-	-
	Total-SNP			88,835	44,907	19,682	23,498	-	-	748	-
	Total-SNPD			-	-	-	-	-	-	-	-
	Total SO			23,344	10,397	4,265	8,385	-	54	174	69
	Total-SITUS			9,650	7,989	84	446	-	87	152	892
	Total SCHMDT			3,263,754	1,944,074	559,601	663,073	-	12,070	15,309	69,628
	SCHMDT-GPS			**100.00%**	**50.5612%**	**22.1269%**	**26.4267%**	**0.0000%**	**0.0259%**	**0.8480%**	**0.0113%**
	SCHMDT-SG			**100.00%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMDT-SNP			**100.00%**	**50.5510%**	**22.1560%**	**26.4515%**	**0.0000%**	**0.0000%**	**0.8415%**	**0.0000%**
	SCHMDT-SNPD			**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMDT-SO			**100.00%**	**44.5373%**	**18.2713%**	**35.9206%**	**0.0000%**	**0.2299%**	**0.7433%**	**0.2974%**
	SCHMDT-SITUS			**100.00%**	**82.7842%**	**0.8738%**	**4.6242%**	**0.0000%**	**0.9003%**	**1.5730%**	**9.2444%**
	SCHMDT FACTOR			**100.00%**	**59.5656%**	**17.1459%**	**20.3163%**	**0.0000%**	**0.3698%**	**0.4691%**	**2.1334%**

Exhibit PAC/1206
Paice/12

PacifiCorp
12 Months Ended June 2011
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
SCHMDF-DGP	SCHMDF	DGP	P	-	-	-	-	-	-	-	-
	Total-SCHMDF			-	-	-	-		-		-
	SCHMDF FACTOR			**0.00%**							
	Total-SCHMD			3,285,610	1,952,404	560,714	668,414	-	13,209	17,286	73,582
	SCHMD FACTOR			**100.00%**	**59.4229%**	**17.0658%**	**20.3437%**	**0.0000%**	**0.4020%**	**0.5261%**	**2.2395%**
	Net SCHM										

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
DMSC	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	100.00%	0.0000%	0.0000%	96.9166%	0.0000%	0.0000%	3.0834%	0.0000%
CUST	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD	100.00%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP	100.00%	50.6936%	21.7495%	26.1054%	0.0000%	0.3625%	0.9317%	0.1573%
LABOR	100.00%	36.2011%	4.9389%	25.0751%	0.0000%	5.4481%	9.4336%	18.9032%
P	100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT	100.00%	69.5270%	30.4730%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD	100.00%	50.5510%	22.1560%	26.4515%	0.0000%	0.0000%	0.8415%	0.0000%
T	100.00%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR	100.00%	59.0446%	18.0835%	21.4529%	0.0000%	0.3897%	0.4686%	0.5607%
TD	100.00%	0.0000%	44.8057%	53.4924%	0.0000%	0.0000%	1.7019%	0.0000%

Exhibit PAC/1206
Paice/13

PacifiCorp
12 Months Ended June 2011
Step-up Transformer Factor

Asset Class 35340 = GSU and Assoc Equip

Class	Description	Acq.value	Accum.dep.	Book Value
35300	Station Equipment	298,501,892.48	-32,680,427.13	265,821,465.35
35301	Transformers	273,147,821.47	-70,730,291.09	202,417,530.38
35303	Static Var Unit	45,862,848.78	-3,932,728.31	41,930,120.47
35305	Synchronous Condens.	5,727,108.08	-2,264,275.73	3,462,832.35
35307	Regulators	1,164,942.93	-394,956.89	769,986.04
35309	Circuit Breakers	157,572,199.01	-30,891,643.44	126,680,555.57
35311	Capacitor Bank	59,320,602.79	-9,243,561.21	50,077,041.58
35313	Metal Clad Switchgr.	5,396,785.17	-745,877.36	4,650,907.81
35315	Switching Equipment	74,068,092.77	-17,936,560.58	56,131,532.19
35317	Structures & Foundn.	196,284,961.55	-30,993,524.15	165,291,437.40
35319	Relay & Control Eqp.	140,275,720.23	-23,760,618.53	116,515,101.70
35321	Storage Battery Eqp.	6,728,747.59	-953,709.29	5,775,038.30
35323	Auxiliary Power Eqp.	2,923,193.81	-483,045.34	2,440,148.47
35325	Grounding System	25,529,989.45	-3,471,229.84	22,058,759.61
35327	Bus,Wire,Cable&Insul	142,518,994.20	-27,571,287.50	114,947,706.70
35329	Station Lighting	2,114,087.70	-468,841.06	1,645,246.64
35331	Mobile Substation	4,085,372.42	-543,679.59	3,541,692.83
35333	Mobile Circuit Swtcr	227,698.97	-63,786.61	163,912.36
35337	Crane Or Hoist	850.74	-595.72	255.02
35339	Fire Protection Sys.	91,267.57	-23,620.78	67,646.79
35340	GSU and Assoc Equip	128,604,674.02	-24,034,106.77	104,570,567.25
35341	Supervsry Cont Equip	21,986,694.13	-8,211,480.52	13,775,213.61
35342	Sprvsry Cntl Eqp 353	745,899.80	-174,655.30	571,244.50
35343	Dispatch Comp. Sys.	24,674.82	-17,782.90	6,891.92
35344	Dsptch Comp Sys(353)	18,339.61	-4,880.54	13,459.07
35345	Dispatch Hardware	952,146.51	-562,673.60	389,472.91
35347	Dsptch Strg Btry Eqp	8,490.14	-5,700.00	2,790.14
35348	Dsptch Strg Btry 353	59,785.18	-16,048.62	43,736.56
35349	Dispatch Time Stdrd	15,974.97	-8,157.65	7,817.32
35350	Dsptch Time Std(353)	44,875.51	-14,083.32	30,792.19
	PacifiCorp	1,594,004,732.40	(290,203,829.37)	1,303,800,903.03
		$	Percent	
35340	Step-up Transformers included in Acct 353	104,570,567.25	8.020440%	Production
	Acct 353 other than step-up transformers	1,199,230,335.78	91.979560%	Transmission
35300-35399	Account 353 Station Equipment	1,303,800,903.03	100.000000%	

Exhibit PAC/1206
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PacifiCorp
12 Months Ended June 2011
Tax Depreciation

	Total	Production	Transmission	Distribution	General	Mining
Total	1,349,984,079	742,247,565	237,942,444	260,930,957	98,474,771	10,388,342

Conversion to COS Functions	**Total**	**Production**	**Transmission**	**Distribution**	**Ancillary**	**C Billing**	**C Metering**	**C Service**	**DSM**
Percent of GenPlant in Functions (%'s developed in JAM Dec 2011 - use "Total Plant" variable)	100.0000%	45.1450%	6.2778%	29.1235%	0.0000%	5.3431%	6.4235%	7.6872%	0.0000%
Allocation of GenPlant to Functions	98,474,771	44,456,424	6,182,002	28,679,339	-	5,261,562	6,325,540	7,569,904	-
Assignment of Mining to Prod Function	10,388,342	10,388,342							
Adjusted Totals	1,349,984,079	797,092,331	244,124,446	289,610,296	-	5,261,562	6,325,540	7,569,904	-
TAXDEPR FACTOR	**100.0000%**	**59.0446%**	**18.0835%**	**21.4529%**	**0.0000%**	**0.3897%**	**0.4686%**	**0.5607%**	**0.0000%**

Exhibit PAC/1206
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12 Months Ended June 2011
Gross Plant
(In 000's)

Description	Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
Production Plant		P	10,749,002	10,749,002	0	0	0	0	0	0	0
Transmission Plant		T	4,711,177	0	4,711,177	0	0	0	0	0	0
Distribution Plant		DPW	5,803,494	0	0	5,624,550	0	0	178,944	0	0
Mining	SE	P	488,304	488,304	0	0	0	0	0	0	0
General Plant				0	0	0	0	0	0	0	0
Business Centers	CN	B_Center	24,826	0	0	0	0	19,154	0	5,672	0
Utah Mine	SE	P	660	660	0	0	0	0	0	0	0
	SG	P	96,342	96,342	0	0	0	0	0	0	0
	SG	T	107,960	0	107,960	0	0	0	0	0	0
	SO	DPW	0	0	0	0	0	0	0	0	0
	SG	P	0	0	0	0	0	0	0	0	0
	SG	DPW	0	0	0	0	0	0	0	0	0
	SG	P	0	0	0	0	0	0	0	0	0
General Plant	SITUS	DPW	200,616	0	0	194,431	0	0	6,186	0	0
General Plant	SITUS	P	0	0	0	0	0	0	0	0	0
General Plant	SITUS	TD	273,554	0	122,568	146,330	0	0	4,655	0	0
Total General Plant			703,959	97,002	230,528	340,761	0				0
Intangible Plant											
	CN	CSS_SYS	111,921	0	0	0	0	61,556	20,146	30,219	0
	SE	P	3,654	3,654	0	0	0	0	0	0	0
	SG	P	94,169	94,169	0	0	0	0	0	0	0
	SG	PTD	0	0	0	0	0	0	0	0	0
	SG	T	47,228	0	47,228	0	0	0	0	0	0
	SG	P	173,622	173,622	0	0	0	0	0	0	0
	SG	P	9,790	9,790	0	0	0	0	0	0	0
	SO	CUST	2,680	0	0	0	0	1,474	482	724	0
	SO	C_METER	2,908	0	0	0	0	0	2,908	0	0
	SO	C_BILLING	2,179	0	0	0	0	2,179	0	0	0
	SO	DPW	24,000	0	0	23,260	0	0	740	0	0
	SO	P	29,195	29,195	0	0	0	0	0	0	0
	SO	PTD	302,242	152,786	66,965	79,947	0	0	2,544	0	0
	SO	TD	12,686	0	5,684	6,786	0	0	216	0	0
	SO	LABOR	0	0	0	0	0	0	0	0	0
Total Intangible Plant			816,274	463,217	119,877	109,993	0				0
Total Gross Plant			23,272,209	11,797,525	5,061,581	6,075,304	0	84,363	216,821	36,615	0
GP Factor			**100.0000%**	**50.6936%**	**21.7495%**	**26.1054%**	**0.0000%**	**0.3625%**	**0.9317%**	**0.1573%**	**0.0000%**

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TD	100.0000%	0.0000%	44.8057%	53.4924%	0.0000%	0.0000%	1.7019%	0.0000%	0.0000%
B_Center	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	77.1516%	0.0000%	22.8484%	0.0000%
CSS_SYS	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%
C_BILLING	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
C_METER	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
C_SERVICE	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.9166%	0.0000%	0.0000%	3.0834%	0.0000%	0.0000%
PTD	100.0000%	50.5510%	22.1560%	26.4515%	0.0000%	0.0000%	0.8415%	0.0000%	0.0000%
LABOR	100.0000%	36.2011%	4.9389%	25.0751%	0.0000%	5.4481%	9.4336%	18.9032%	0.0000%

Exhibit PAC/1206
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PacifiCorp
12 Months Ended June 2011
Account 456

Main Account	Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
456	SO	DMSC	0	0	0	0	0	0	0	0	0
456	SE	P	0	0	0	0	0	0	0	0	0
456	SE	T	10,745	0	10,745	0	0	0	0	0	0
456	SG	P	117,830	117,830	0	0	0	0	0	0	0
456	SG	T	61,301	0	61,301	0	0	0	0	0	0
456	SO	DMSC	293	0	0	293	0	0	0	0	0
456	SITUS	DMSC	94,223	0	0	94,223	0	0	0	0	0
456	SITUS	P	0	0	0	0	0	0	0	0	0
Total Situs Revenues			94,223	0	0	94,223	0	0	0	0	0
Total CN Revenues			0	0	0	0	0	0	0	0	0
Total SE Revenues			10,745	0	10,745	0	0	0	0	0	0
Total SG Revenues			179,130	117,830	61,301	0	0	0	0	0	0
Total SO Revenues			293	0	0	293	0	0	0	0	0
Total Operation			284,392	117,830	72,046	94,516	0	0	0	0	0
OTHSITUS			**100.0000%**	**0.0000%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
CN Factor			**0.0000%**								
OTHSE			**100.0000%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
OTHSG			**100.0000%**	**65.7788%**	**34.2212%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
OTHSO			**100.0000%**	**0.0000%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
Total Operation Factor			**100.0000%**	**41.4322%**	**25.3333%**	**33.2345%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	44.81%	53.49%	0.00%	0.00%	1.70%	0.00%	0.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
DPW	100.00%	0.00%	0.00%	96.92%	0.00%	0.00%	3.08%	0.00%	0.00%
PTD	100.00%	50.55%	22.16%	26.45%	0.00%	0.00%	0.84%	0.00%	0.00%
DMSC	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Exhibit PAC/1206
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Docket No. UE-246
Exhibit PAC/1207
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

December 2013 Marginal Cost Study for the State of Oregon

March 2012

Exhibit PAC/1207
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PacifiCorp
Oregon Marginal Cost Study
December 2013

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Exhibit PAC/1207
Tab 1. Procedures

PacifiCorp
Marginal Cost Study & Circuit Model Procedures

INTRODUCTION

Customer class marginal costs are developed to illustrate the resources required to produce one additional unit of electricity or add one additional customer to the system. One, five, ten and twenty years marginal costs are calculated because the Company believes the Commission should have information about the Company's marginal costs over different time periods. Twenty-year (or long run) marginal costs, however, are the primary time frame used in setting retail tariff prices.

The one-year marginal costs include only changes in operating costs, while ten- and twenty-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. There are no short-run demand-related generation, transmission or distribution costs. Long-run costs include ten or twenty years of generation costs, transmission and distribution costs.

One, ten and twenty-year marginal costs are summarized by customer class and load size group and shown in mills/kilowatt-hour (kWh). Marginal commitment costs and billing expenses, which are sometimes referred to as customer costs, are shown in dollars per customer per year. Costs are shown for both the one-year and the long-run time periods.

Unit costs are adjusted to 2013 values and are shown by generation, transmission, and distribution functional categories and by demand, energy, and commitment and billing costing classifications. Also included are energy usage, peak demand, and number of customers by customer class for the 12 month period ending December 2013.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Summary of Marginal Costs Demand & Energy in Mills/kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Summary of Marginal Costs Commitment and Billing in $ / Customer / Month" (Sheet 'Table 2'). Unit costs and billing information are shown on "20 Year Costing Inputs and Customer Data Marginal Unit Costs" (Sheet 'Table 3').

MARGINAL GENERATION COSTS

The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations. The analysis recognizes that baseload generation produces the dual products of capacity and energy. The new resource costs are based on the fixed and variable cost of a Combined Cycle Combustion Turbine (CCCT), which operates as a baseload unit. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy and are added to the variable production cost of the CCCT to determine total avoided energy cost. Energy and capacity costs are present valued, summed and an

annual charge applied to the total. The marginal generation cost calculation is shown within the study on sheet "Summary of Marginal Generation Costs In Nominal Dollars" (Sheet 'Table 5').

MARGINAL TRANSMISSION COSTS

The calculation of transmission costs are based on a five-year (2013-2017) analysis of forecasted expenditures to meet increased load on the transmission system. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand.

Unlike growth-related system support and local transmission investments, the Company's investment in bulk power lines is classified both to demand and energy in the same proportions as twenty-year marginal costs of generation resources. Bulk transmission costs are classified this way because they are thought to be an integral part of the generation system. The Company's investments in high voltage bulk transmission lines are being made to move both energy and capacity. It is usually not possible to site a thermal plant close to the customers the plant is intended to serve. Instead, bulk power lines are constructed to transmit the energy being generated, along with the accompanying capacity.

Each year's growth-related transmission investments are adjusted to 2013 dollars and the five years are totaled. The total transmission investment is divided by the forecasted growth in system demand over the 5-year period to determine the marginal investment per kilowatt (kW). An annual charge for including an A&G expense loading factor and a transmission O&M loading factor are added to the per kW investment to arrive at long-run transmission marginal cost.

The marginal transmission calculation including the split between demand and energy can be seen within the marginal cost study on page "Marginal Transmission Investment and O&M Expenses" (Sheet 'Transm1'). A summarized version of this page is "Marginal Cost of Transmission Investment and Associated Expenses" (Sheet 'Table 6').

MARGINAL DISTRIBUTION COSTS

Distribution costs are classified into three components: Demand-related, shown in dollars per kW/year, commitment-related, shown in dollars per customer/year, and billing-related, shown in dollars per customer/year. Commitment costs consist of the costs of transformers, poles, and conductor that are not determined by the level of demand customers place on the system. Demand-related costs are the additional costs of larger transformers, substations, poles, and conductors with sufficient capacity to serve the level of demand a customer class places on the system. Billing costs are the costs of meters, service drops, and customer accounting functions.

A summary of distribution marginal costs showing these three components are on page "Marginal Distribution & Billing Costs By Load Size 2013 Dollars" (Sheet 'Table 7').

Marginal line transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of the statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Line transformer regression results are shown on page "Calculation of Escalation Factors for Transformers (Regression weighted by number of transformer banks)" (Sheet 'XFMR 3'). Transformer demand costs are shown on page "Transformer Demand Costs" (Sheet 'XFMR 2') and commitment costs are shown on page "Transformer Commitment Costs by Customer Load Class" (Sheet 'XFMR 1').

Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model (Sheets 'PC4' through 'PC14'). The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics for the state of Oregon. The model determines the cost of the circuit by using current cost estimates to construct one mile of distribution facilities using each of the Company's single and three phase wire sizes. The results are segregated into commitment related and demand related costs for each customer class. A more detailed description of the circuit model is included as an appendix to this narrative.

Marginal poles and wire costs are shown on page "Hypothetical Circuit Study Results Annual Demand and Commitment Costs" (Sheet 'PC 1').

Marginal substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2011 - 2015. As part of the capital budgeting process the company determines which substations are approaching their maximum design loading. When load can no longer be shifted to adjacent substations, an upgrade, either greater capacity at the substation or a new substation, is required. The capital investment in common year dollars is totaled across all projects and across the budget-planning horizon to produce total substation investment. The substation investment is divided by the associated incremental substation capacity to get dollars / kW. The dollars per kW is adjusted to an annual value by applying a real levelized carrying charge. Substation marginal costs are classified entirely to demand, and are allocated to customer classes based on the distribution peak load for each class.

Page "Substation Investment" (Sheet 'Dist Sub 2') shows the detail of the substation calculation. "Distribution Substation Costs / kW 2013 Dollars" (Sheet 'Dist Sub 1') shows the annualized cost in $/kW.

The marginal cost of services includes the costs of new service drop investment plus associated O&M expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase

service and voltage level. Incremental service drop O&M is based on the average of ten years of historical expenditures.

The metering category includes the marginal cost of metering equipment with associated O&M expense. Average meter investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M expense is based on historical expenditures.

The billing customer service/other category includes the costs of billing, payment processing, debt recovery, meter reading expenses and all remaining customer accounting and customer service activities. Customer accounting and customer service expense are based on the most recent five years of expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

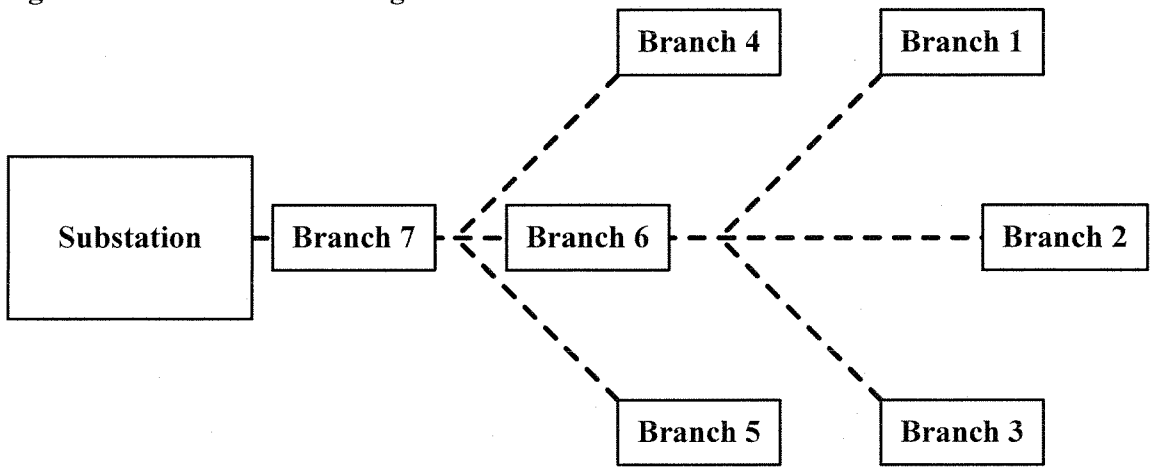
Meter and Service investment calculations for residential and Schedules 23/28/30 are located on pages "Weighted Average Installed Meter Costs Residential & Schedules 23/28/30" (Sheet 'Meters 1') and "Weighted Average Installed Service Drop Costs Residential & Schedules 23/28/30" (Sheet 'Services 1'). The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense by Schedule" (Sheet 'Cust Exp Sum'). These calculations are brought together on "Marginal Distribution & Billing Costs By Load Size 2013 Dollars" (Sheet 'Table 7') to calculate Metering, Billing and Customer Service Related Costs ($/Customer/Yr).

PacifiCorp
Distribution Circuit Model
PacifiCorp Distribution Circuit Model

General Overview

The PacifiCorp Distribution Circuit Model is an Excel workbook that calculates the cost of building a hypothetical circuit (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical circuit is used rather than a sampling of actual existing circuits. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution circuits, makes the selection of any single, or small number of typical circuits impractical. The fundamental concept of the hypothetical circuit is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Circuit Model Diagram



The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the circuit. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite circuit using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the circuit between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data

Listed below are the basic statistics that we use to calculate the composite circuit for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size

3. Overhead and Underground Line Miles
4. Number of Poles
5. Number of Circuits -- distribution line points of origin radiating from a substation.
6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate

The model determines the cost of the circuit by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average of 26.25 poles per mile to the state average poles per mile. For example, Oregon has an average of 25.79 poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR	$ 25,488	0.982	$ 25,029	$ 12,296	$ 37,325
3 Phase - 1/0 ACSR 1\0 ACSR	$ 41,960	0.982	$ 41,205	$ 27,019	$ 68,224
3 Phase - 447 AAC & 4\0 AAC	$ 46,635	0.982	$ 45,796	$ 44,841	$ 90,637
3 Phase -795 AAC & 477 AAC	$ 52,608	0.982	$ 51,661	$ 99,267	$ 150,928

	State Specific Account 364 Pole Statistics				Adjustment
State	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	56,409	12,494,494	2,366	23.84	0.908
Idaho	101,402	23,142,034	4,383	23.14	0.881
Oregon	370,656	75,887,077	14,373	25.79	0.982
Utah	358,198	60,670,523	11,491	31.17	1.187
Washington	99,105	18,892,136	3,578	27.70	1.055
Wyoming	155,134	38,383,830	7,270	21.34	0.813
Total	1,140,904	229,470,094	43,460	26.25	1.000

Customer Placement

One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The circuit model takes distance into account by assigning customers to the different branches of the circuit based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel.

Figure 3 shows the Customer Distribution on the Hypothetical Circuit Branch for Oregon.

Figure 3 Customer Distribution

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
18	Res - Schedule 4 (sec)	0.86%	0.86%	0.86%	3.66%	3.66%	3.66%	86.44%	100.00%
19	GS - Schedule 23 - 0-15 kW (sec)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
20	GS - Schedule 23 - 15+ kW (sec)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
21	GS - Schedule 23 - Primary (pri)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
22	GS - Schedule 28 - 0-50 kW (sec)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
23	GS - Schedule 28 - 51-100 kW (sec)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
24	GS - Schedule 28 - > 101kW (sec)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
25	GS - Schedule 28 - Primary (pri)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
26	GS - Schedule 30 - 0-300 kW (sec)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
27	GS - Schedule 30 - 301+ kW (sec)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
28	GS - Schedule 30 - Primary (pri)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
29	Irrigation - Sch 41	2.57%	2.57%	2.57%	12.31%	12.31%	12.31%	55.35%	100.00%
30	LPS - Schedule 48T - 1 - 4 MW (sec)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
31	LPS - Schedule 48T - 1 - 4 MW (pri)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
32	LPS - Schedule 48T - > 4 MW (sec)		Large Customers are on dedicated circuits and are not included here						
33	LPS - Schedule 48T - > 4 MW (pri)		Large Customers are on dedicated circuits and are not included here						

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by circuit branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution circuits in the state to determine the average length of the composite circuit (line miles / number of circuits) and the number of customers on the circuit (customers / circuits). Figure 4 shows the average number of customers located on each of the seven circuit branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	7.78	7.78	7.78	33.23	33.23	33.23	784.30	907.31
2	GS 0-15 kW (sec) (23)	1.62	1.62	1.62	4.91	4.91	4.91	106.47	126.06
3	GS >15 kW (sec) (23)	0.26	0.26	0.26	0.78	0.78	0.78	16.98	20.11
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.09
5	GS < 50 kW (sec) (28)	0.07	0.07	0.07	0.18	0.18	0.18	7.67	8.43
6	GS 51-100 kW (sec) (28)	0.05	0.05	0.05	0.15	0.15	0.15	6.09	6.69
7	GS > 100 kW (sec) (28)	0.03	0.03	0.03	0.08	0.08	0.08	3.54	3.89
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.41	0.43
10	GS >300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	1.04	1.09
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
12	Irrigation	0.41	0.41	0.41	1.95	1.95	1.95	8.76	15.83
13	Large GS 1 - 4 MW (sec)	-	-	-	0.00	0.00	0.00	0.20	0.21
14	Large GS 1 - 4 MW (pri)	-	-	-	0.00	0.00	0.00	0.12	0.12
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	10.23	10.23	10.23	41.31	41.31	41.31	935.84	1,090.47

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the circuit, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the circuit becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the circuit. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the circuit. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the circuit kW loading on each of the circuit branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Circuit kW Load by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Circuit kW Loads								
1	Residential	16.3	16.3	16.3	69.4	69.4	69.4	1,638.5	1,895.6
2	GS 0-15 kW (sec) (23)	2.2	2.2	2.2	6.7	6.7	6.7	145.5	172.2
3	GS >15 kW (sec) (23)	1.8	1.8	1.8	5.4	5.4	5.4	116.7	138.1
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4
5	GS < 50 kW (sec) (28)	1.1	1.1	1.1	3.0	3.0	3.0	124.4	136.7
6	GS 51-100 kW (sec) (28)	1.6	1.6	1.6	4.3	4.3	4.3	180.6	198.4
7	GS > 100 kW (sec) (28)	2.1	2.1	2.1	5.8	5.8	5.8	242.0	265.9
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)	0.2	0.2	0.2	0.7	0.7	0.7	55.3	58.1
10	GS >300 kW (sec) (30)	1.2	1.2	1.2	3.5	3.5	3.5	272.7	286.8
11	GS (pri) (30)	0.1	0.1	0.1	0.3	0.3	0.3	25.6	26.9
12	Irrigation	1.1	1.1	1.1	5.2	5.2	5.2	23.5	42.4
13	Large GS 1 - 4 MW (sec)	-	-	-	2.8	2.8	2.8	157.8	166.2
14	Large GS 1 - 4 MW (pri)	-	-	-	2.4	2.4	2.4	133.7	140.9
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	27.8	27.8	27.8	109.7	109.7	109.7	3,121.1	3,533.4

Circuit Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per circuit (total line miles / total number of circuits) and dividing it by the number of branches per circuit (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 35% single phase, the circuit branch length is split between single and three-phase. The total

branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors, as shown in figure 6.
Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related. Branches 6 and 7 are 100% three-phase and are considered all demand. Figure 6 shows the circuit costs per mile, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

Figure 6 – Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR	$ 25,488	0.982	$ 25,029	$ 12,296	$ 37,325
3 Phase - 1/0 ACSR 1\0 ACSR	$ 41,960	0.982	$ 41,205	$ 27,019	$ 68,224
3 Phase - 447 AAC & 4\0 AAC	$ 46,635	0.982	$ 45,796	$ 44,841	$ 90,637
3 Phase -795 AAC & 477 AAC	$ 52,608	0.982	$ 51,661	$ 99,267	$ 150,928

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSR	3 Phase - 1/0 ACSR 1\0 ACSR	Total	
Poles	$ 46,274	$ 141,475	$ 187,749	
Conductors	$ 22,733	$ 92,769	$ 115,502	
Total	$ 69,006	$ 234,244	$ 303,250	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 241,904		$ 272,887	
Conductors	$ 236,862		$ 524,354	
Total	$ 478,766		$ 797,241	

Miles per Branch	5.28
Single Phase Miles Per Branch	1.85
Three Phase Miles Per Branch	3.43

Customer Circuit Costs
After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical circuit model branch cost sheet, as shown in figure 7. Figure 7 includes the total cost per circuit branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

Figure 7 – Oregon Hypothetical Circuit Model Branch Costs

Conductors Type	(A) Total Cost Poles	(B) Total Cost Conductor	(C) Commitment Cost Poles	(D) Commitment Cost Conductor	(E) Demand Cost Poles	(F) Demand Cost Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total segment	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 2						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 3						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 4						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 5						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 241,904	$ 236,862	NA	NA	$ 241,904	$ 236,862
Total Segments	$ 241,904	$ 236,862	$ -	$ -	$ 241,904	$ 236,862
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 272,887	$ 524,354	NA	NA	$ 272,887	$ 524,354
Total segment	$ 272,887	$ 524,354	$ -	$ -	$ 272,887	$ 524,354

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the circuit branches. Customer classes that locate on all branches share cost responsibility for all branches of the circuit including the trunk. Large industrial customers, who locate on the trunk of the circuit, share cost responsibility for only the trunk. Cost responsibility is determined by calculating the percentage of demand, or percentage of customers, by class that share a particular branch of the circuit. The total branch costs are then multiplied by the share percentage, and the branch costs are totaled by class. To calculate the total branch cost, the applicable cost of branches 6 and 7 are assigned to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class and divided by circuit kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles Demand Calculations, Branch 6 & 7 Cost Assignment

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.39%	14.39%	14.39%	NA	NA	56.83%	NA	100.00%	
2	Branch 6 Cost	$ 34,812	$ 34,812	$ 34,812	NA	NA	$ 137,468	NA	$ 241,904	**$ / kW**
3	% Demand	0.79%	0.79%	0.79%	3.10%	3.10%	3.10%	88.33%	100.00%	
4	Branch 7 Cost	$ 2,145	$ 2,145	$ 2,145	$ 8,469	$ 8,469	$ 8,469	$ 241,045	$ 272,887	
5	Branch Demand Cost	$ 55,538	$ 55,538	$ 55,538	$ 55,538	$ 55,538	NA	NA		Average
6	Total	$ 92,495	$ 92,495	$ 92,495	$ 64,007	$ 64,007	$ 145,937	$ 241,045	$ 792,481	$ 224.28
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 54,136	$ 54,136	$ 54,136	$ 40,517	$ 40,517	$ 92,378	$ 126,546	$ 462,366	$ 243.92
11	GS 0-15 kW (sec) (23)	$ 7,379	$ 7,379	$ 7,379	$ 3,915	$ 3,915	$ 8,927	$ 11,235	$ 50,128	$ 291.03
12	GS >15 kW (sec) (23)	$ 5,917	$ 5,917	$ 5,917	$ 3,140	$ 3,140	$ 7,158	$ 9,009	$ 40,197	$ 291.03
13	GS (pri) (23)	$ 17	$ 17	$ 17	$ 9	$ 9	$ 20	$ 26	$ 114	$ 291.03
14	GS < 50 kW (sec) (28)	$ 3,661	$ 3,661	$ 3,661	$ 1,743	$ 1,743	$ 3,973	$ 9,611	$ 28,052	$ 205.21
15	GS 51-100 kW (sec) (28)	$ 5,313	$ 5,313	$ 5,313	$ 2,529	$ 2,529	$ 5,766	$ 13,947	$ 40,710	$ 205.21
16	GS > 100 kW (sec) (28)	$ 7,120	$ 7,120	$ 7,120	$ 3,389	$ 3,389	$ 7,727	$ 18,691	$ 54,556	$ 205.21
17	GS (pri) (28)	$ 131	$ 131	$ 131	$ 62	$ 62	$ 142	$ 344	$ 1,003	$ 205.21
18	GS 0-300 kW (sec) (30)	$ 812	$ 812	$ 812	$ 412	$ 412	$ 940	$ 4,268	$ 8,468	$ 145.71
19	GS >300 kW (sec) (30)	$ 4,005	$ 4,005	$ 4,005	$ 2,035	$ 2,035	$ 4,640	$ 21,060	$ 41,784	$ 145.71
20	GS (pri) (30)	$ 376	$ 376	$ 376	$ 191	$ 191	$ 435	$ 1,976	$ 3,921	$ 145.71
21	Irrigation	$ 3,630	$ 3,630	$ 3,630	$ 3,048	$ 3,048	$ 6,949	$ 1,813	$ 25,748	$ 607.11
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,633	$ 1,633	$ 3,724	$ 12,190	$ 19,181	$ 115.39
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,384	$ 1,384	$ 3,156	$ 10,329	$ 16,253	$ 115.39
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 92,495	$ 92,495	$ 92,495	$ 64,007	$ 64,007	$ 145,937	$ 241,045	$ 792,481	

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon 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	14.21%	14.21%	14.21%	NA	NA	57.38%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	$ Per
3	% customer	0.94%	0.94%	0.94%	3.79%	3.79%	3.79%	85.82%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ 132,211	NA	NA		average
6	Total	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ -	$ -	$ 661,054	$ 606.21
7										
8									Total	$ Per
9									Commitment	Customer
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 100,563	$ 100,563	$ 100,563	$ 106,328	$ 106,328	$ -	$ -	$ 514,344	$ 566.89
12	GS 0-15 kW (sec) (23)	$ 20,957	$ 20,957	$ 20,957	$ 15,711	$ 15,711	$ -	$ -	$ 94,294	$ 748.00
13	GS >15 kW (sec) (23)	$ 3,343	$ 3,343	$ 3,343	$ 2,506	$ 2,506	$ -	$ -	$ 15,041	$ 748.00
14	GS (pri) (23)	$ 15	$ 15	$ 15	$ 11	$ 11	$ -	$ -	$ 68	$ 748.00
15	GS < 50 kW (sec) (28)	$ 876	$ 876	$ 876	$ 589	$ 589	$ -	$ -	$ 3,807	$ 451.59
16	GS 51-100 kW (sec) (28)	$ 695	$ 695	$ 695	$ 467	$ 467	$ -	$ -	$ 3,019	$ 451.59
17	GS > 100 kW (sec) (28)	$ 404	$ 404	$ 404	$ 272	$ 272	$ -	$ -	$ 1,755	$ 451.59
18	GS (pri) (28)	$ 11	$ 11	$ 11	$ 7	$ 7	$ -	$ -	$ 47	$ 451.59
19	GS 0-300 kW (sec) (30)	$ 23	$ 23	$ 23	$ 17	$ 17	$ -	$ -	$ 103	$ 240.41
20	GS >300 kW (sec) (30)	$ 59	$ 59	$ 59	$ 42	$ 42	$ -	$ -	$ 262	$ 240.41
21	GS (pri) (30)	$ 6	$ 6	$ 6	$ 4	$ 4	$ -	$ -	$ 25	$ 240.41
22	Irrigation	$ 5,259	$ 5,259	$ 5,259	$ 6,239	$ 6,239	$ -	$ -	$ 28,253	$ 1,784.51
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 11	$ 11	$ -	$ -	$ 23	$ 107.75
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 7	$ 7	$ -	$ -	$ 13	$ 107.75
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ -	$ -	$ 661,054	

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a circuit in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated circuit for their exclusive use. Since they have a dedicated circuit, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated circuit. Dividing the total cost of a 2/3 of a mile circuit by the customer's kW gets the customers demand cost in dollars per kW. Table 10 shows this calculation for Oregon.

Table 10 – Oregon Dedicated Circuit 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	$ 51,661	$ 99,267	$ 51,661	$ 99,267
2	Average Trunk Length	0.67 miles		0.67 miles	
3	Total Construction Cost	$ 34,613	$ 66,509	$ 34,613	$ 66,509
4	Customer Peak Demand	4,846 kW		3,997 kW	
5	Demand Cost $/kW	$7.14	$13.73	$8.66	$16.64

Summary

The final step in the circuit model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the $/customer and $/circuit kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

Table 11 – Oregon Summary of Results

	(A)	(B)	(C)	(D)	(E)	(F)		
	Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Residential	$ 566.89	$ 278.49	$ 243.92	$ 305.51	907.3	1,895.55	$ 462,366	$ 579,111
GS 0-15 kW (sec) (23)	$ 748.00	$ 367.47	$ 291.03	$ 349.70	126.1	172.24	$ 50,128	$ 60,234
GS >15 kW (sec) (23)	$ 748.00	$ 367.47	$ 291.03	$ 349.70	20.1	138.12	$ 40,197	$ 48,301
GS (pri) (23)	$ 748.00	$ 367.47	$ 291.03	$ 349.70	0.1	0.39	$ 114	$ 137
GS < 50 kW (sec) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	8.4	136.70	$ 28,052	$ 36,753
GS 51-100 kW (sec) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	6.7	198.38	$ 40,710	$ 53,336
GS > 100 kW (sec) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	3.9	265.85	$ 54,556	$ 71,478
GS (pri) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	0.1	4.89	$ 1,003	$ 1,314
GS 0-300 kW (sec) (30)	$ 240.41	$ 118.11	$ 145.71	$ 212.87	0.4	58.11	$ 8,468	$ 12,371
GS >300 kW (sec) (30)	$ 240.41	$ 118.11	$ 145.71	$ 212.87	1.1	286.76	$ 41,784	$ 61,042
GS (pri) (30)	$ 240.41	$ 118.11	$ 145.71	$ 212.87	0.1	26.91	$ 3,921	$ 5,728
Irrigation	$ 1,784.51	$ 876.67	$ 607.11	$ 648.00	15.8	42.41	$ 25,748	$ 27,482
Large GS 1 - 4 MW (sec)	$ 107.75	$ 52.93	$ 115.39	$ 184.58	0.2	166.23	$ 19,181	$ 30,684
Large GS 1 - 4 MW (pri)	$ 107.75	$ 52.93	$ 115.39	$ 184.58	0.1	140.86	$ 16,253	$ 26,001
Total -	$ 606.21	$ 297.81	$ 224.28	$ 286.97	1,090.5	3,533.4	$ 792,481	$ 1,013,970
Large GS + 4 MW (sec)	$ -	$ -	$ 8.66	$ 16.64	-	3,997.43	$ 34,613	$ 66,509
Large GS + 4 MW (pri)	$ -	$ -	$ 7.14	$ 13.73	-	4,845.82	$ 34,613	$ 66,509
							$ 861,707	$ 1,146,988

	Commitment	Demand	Total
Poles	$ 661,054	$ 861,707	$ 1,522,761
Conductor	$ 324,753	$ 1,146,988	$ 1,471,741
Total	$ 985,807	$ 2,008,695	$ 2,994,501

Exhibit PAC/1207
Tab 2. Summaries

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2013 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)	65.45	71.31	70.50	65.45	132.81	132.00
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	65.45	71.31	70.50	65.45	128.47	127.66
5	15+ kW	(sec)	65.45	71.31	70.50	65.45	126.68	125.87
6	Primary	(pri)	63.86	69.12	68.52	63.86	118.71	117.84
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	65.45	71.31	70.50	65.45	130.44	129.63
10	51-100 kW	(sec)	65.45	71.31	70.50	65.45	127.33	126.53
11	> 101kW	(sec)	65.45	71.31	70.50	65.45	124.61	123.80
12	Primary	(pri)	63.58	69.27	68.52	63.58	117.74	117.01
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	65.45	71.31	70.50	65.45	119.74	118.94
16	301+ kW	(sec)	65.45	71.31	70.50	65.45	118.95	118.14
17	Primary	(pri)	63.60	69.29	68.52	63.60	117.56	116.77
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	65.45	71.31	70.50	65.45	118.42	117.62
21	1 - 4 MW	(pri)	63.60	69.30	68.52	63.60	112.28	111.49
22	> 4 MW	(sec)	65.45	71.30	70.50	65.45	110.22	109.40
23	> 4 MW	(pri)	63.60	69.30	68.52	63.60	104.18	103.40
24								
25	Trans	(trn)	62.19	67.75	66.99	62.19	90.84	90.07
26								
27								
28	Schedule 41- Irrigation	(sec)	65.45	71.31	70.50	65.45	125.45	124.64

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) 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'
(C) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2013 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 2013 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.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2013 Dollars

Line	Description		(A) 1 Year 1&3 Phase	(B) 10 & 20 Year 1&3 Phase
1	Res - Schedule 4	(sec)	$15.61	$37.12
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	17.83	47.01
5	15+ kW	(sec)	30.70	66.66
6	Primary	(pri)	143.23	157.08
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	34.20	108.57
10	51-100 kW	(sec)	35.28	117.97
11	> 101kW	(sec)	72.72	160.88
12	Primary	(pri)	146.56	154.91
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	85.31	188.40
16	301+ kW	(sec)	127.01	230.08
17	Primary	(pri)	159.18	163.63
18				
19	Total			
20	1 - 4 MW	(sec)	400.97	504.69
21	1 - 4 MW	(pri)	221.88	223.88
22	> 4 MW	(sec)	400.97	502.69
23	> 4 MW	(pri)	221.88	221.88
24	Trans	(trn)	4,401.97	4,401.97
25				
26				
27	Schedule 41- Irrigation	(sec)	11.14	121.18
28	Schedule 41- Irrigation	(sec)	11.14	121.18

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.

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 2013 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) > 101kW (sec)	(H) Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) 301+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trans (trn)	(Q) Irrigation Sch 41 (sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	873	91	77	0	74	106	138	3	30	148	14	83	70	8	148	88	25
2		Distribution	995	90	73	0	72	104	140	3	31	151	14	87	74	8	152	0	22
3		Transformer	3,144	179	129	2	160	190	248	13	49	244	21	143	119	15	241	157	121
4																			
5	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
6																			
7	Peak MW @ Generator	System	970	101	85	0	82	118	153	3	33	165	15	93	75	8	160	92	28
8		Distribution	1,105	100	81	0	80	116	155	3	34	167	15	97	80	9	164	N/A	25
9		Transformer	3,492	199	144	N/A	177	210	276	N/A	54	271	N/A	158	N/A	17	N/A	N/A	135
10																			
11	Energy																		
12	Energy - Annual MWh	@ Meter	5,400,866	589,821	502,774	1,331	426,951	647,714	893,140	18,795	200,164	1,014,139	89,386	565,086	496,681	52,957	1,093,266	795,520	210,342
13	Energy Loss Factor		1.1001	1.1001	1.1001	1.0690	1.1001	1.1001	1.1001	1.0690	1.1001	1.1001	1.0690	1.1001	1.0690	1.1001	1.0690	1.0453	1.1001
14	Energy - Annual MWh	@ Generator	5,941,277	648,838	553,082	1,423	469,671	712,525	982,508	20,093	220,193	1,115,613	95,557	621,629	530,972	58,256	1,168,746	831,533	231,389
15																			
16	Customer																		
17	Annual Customers		479,457	64,929	10,357	48	4,332	3,436	1,997	52	215	549	51	107	63	2	30	6	8,090
18	Average Customers																		3,154
19																			
20	Unit Costs																		
21																			
22	Generation	$ / System Peak kW	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35
23	Transmission	$ / System Peak kW	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73
24	Poles, Cond., Subst.	$ / Dist. kW	$115.76	$129.35	$129.35	$129.35	$104.54	$104.54	$104.54	$104.54	$87.34	$87.34	$87.34	$78.60	$78.60	$37.70	$37.04	$0.00	$220.85
25	Transformers	$ / Xfmr kW	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$0.00	$2.93	$0.00	$2.93	$0.00	$0.00	$2.93
26																			
27	Energy - @ Generator																		
28	Generation	$ / kWh	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062
29	Transmission	$ / kWh	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347
30																			
31	Poles	$ / Cust / Year	$84.42	$111.40	$111.40	$111.40	$67.26	$67.26	$67.26	$67.26	$35.81	$35.81	$35.81	$16.05	$16.05	$0.00	$0.00	$0.00	$265.78
32	Conductor	$ / Cust / Year	$41.48	$54.73	$54.73	$54.73	$33.04	$33.04	$33.04	$33.04	$17.60	$17.60	$17.60	$7.89	$7.89	$0.00	$0.00	$0.00	$130.56
33	Transformers	$ / Cust / Year	$132.30	$183.96	$265.37	$0.00	$792.15	$892.07	$957.54	$0.00	$1,183.68	$1,183.48	$0.00	$1,220.71	$0.00	$1,220.71	$0.00	$0.00	$924.08
34	Service Drop	$ / Cust / Year	$98.48	$127.03	$266.93	$0.00	269.46	280.04	541.36	-	539.40	1,039.69	-	$3,509.42	$0.00	$3,509.42	$0.00	$0.00	$0.00
35	Meters	$ / Cust / Year	$18.51	$19.48	$33.97	$1,651.28	33.51	35.90	223.94	1,651.28	225.47	225.50	1,651.28	$290.85	$1,651.28	$290.85	$1,651.28	$51,812	$34.18
36	Meter Reading	$ / Cust / Year	$15.64	$22.21	$22.21	$22.21	38.63	38.63	38.63	38.63	66.31	66.31	66.31	172.81	$172.81	$172.81	$172.81	$172.81	$48.95
37	Billing & Collections	$ / Cust / Year	$34.55	$32.82	$32.82	$32.82	35.58	35.58	35.58	35.58	35.58	35.58	35.58	131.63	$131.63	$131.63	$131.63	$131.63	$32.82
38	Uncollectables	$ / Cust / Year	$9.52	$2.05	$2.05	$2.05	20.59	20.59	20.59	20.59	136.23	136.23	136.23	645.55	$645.55	$645.55	$645.55	$645.55	$5.60
39	Customer Service / Other	$ / Cust / Year	$10.58	$10.43	$10.43	$10.43	12.58	12.58	12.58	12.58	20.75	20.75	20.75	61.34	$61.34	$61.34	$61.34	$61.34	$12.16
40	Total Commitment & Billing	$ / Cust / Year	$445.49	$564.11	$799.91	$1,884.92	$1,302.81	$1,415.69	$1,930.53	$1,858.97	$2,260.83	$2,760.95	$1,963.56	$6,056.25	$2,686.55	$6,032.31	$2,662.61	$52,824	$1,454.13

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) `Customer Loads12 Months Ended December 2013'
Lines 5 & 13 Tab 16.1 (Losses:) `Energy Loss Factors'
Lines 12 & 17 Tab 17.2 (Cust Data 2:) `Customers and MWh's12 Months Ended December 2013 - Normalized'
Line 22 Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 23 Tab 5.1 (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 4.1 (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'

Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2013 Dollars
(Dollars in 000's)

Line	Description	(A) Total	(B) Residential (sec)	General Service - Schedule 23 (C) 0-15 kW (sec)	(D) 15+ kW (sec)	(E) Primary (pri)	General Power - Schedule 28 (F) 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	General Power - Schedule 30 (J) 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	Large Power Service - Schedule 48T (M) 1 - 4 MW (sec)	(N) 1 - 4 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) Trans (trn)	(R) Irrg Sch 41 (sec)	(S) Sch 51,53,54 Streetlighting (sec)
	Demand Related Marginal Cost																			
1	Generation	$179,482	$79,840	$8,289	$6,997	$15	$6,748	$9,706	$12,592	$256	$2,707	$13,547	$1,227	$7,632	$6,204	$690	$13,197	$7,558	$2,277	
2	Transmission	$256,597	$114,142	$11,851	$10,004	$22	$9,647	$13,876	$18,002	$366	$3,870	$19,368	$1,755	$10,911	$8,870	$986	$18,866	$10,805	$3,256	
3	Distribution																			
4	Poles	$68,953	$40,154	$4,352	$3,490	$10	$2,436	$3,535	$4,737	$84	$736	$3,629	$331	$1,665	$1,371	$11	$176	$0	$2,235	
5	Conductor	$88,330	$50,290	$5,231	$4,194	$11	$3,192	$4,632	$6,207	$111	$1,075	$5,301	$484	$2,664	$2,193	$23	$335	$0	$2,387	
6	Substations	$75,664	$37,495	$3,407	$2,732	$8	$2,704	$3,924	$5,259	$94	$1,150	$5,672	$517	$3,288	$2,708	$302	$5,565	$0	$839	
7	Subtotal: Pole, Cond, Subs	$232,948	$127,940	$12,990	$10,416	$29	$8,332	$12,091	$16,203	$289	$2,960	$14,603	$1,332	$7,618	$6,272	$336	$6,076	$0	$5,461	
8	Transformers	$15,020	$10,216	$584	$421	$0	$519	$616	$806	$0	$159	$793	$0	$464	$0	$48	$0	$0	$394	
9	Distribution subtotal	$247,967	$138,156	$13,574	$10,837	$29	$8,851	$12,707	$17,009	$289	$3,119	$15,396	$1,332	$8,082	$6,272	$384	$6,076	$0	$5,855	
10																				
11	Total Demand Related	$684,046	$332,138	$33,714	$27,838	$66	$25,246	$36,289	$47,603	$911	$9,696	$48,311	$4,314	$26,625	$21,346	$2,060	$38,139	$18,363	$11,388	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$862,436	$360,160	$39,333	$33,528	$86	$28,471	$43,193	$59,560	$1,218	$13,348	$67,628	$5,793	$37,683	$32,187	$3,531	$70,849	$50,408	$14,027	$1,432
16	Transmission Energy Related	$49,374	$20,619	$2,252	$1,919	$5	$1,630	$2,473	$3,410	$70	$764	$3,872	$332	$2,157	$1,843	$202	$4,056	$2,886	$803	$82
17	Total Energy	$911,809	$380,779	$41,584	$35,447	$91	$30,101	$45,666	$62,969	$1,288	$14,112	$71,500	$6,124	$39,840	$34,030	$3,734	$74,905	$53,293	$14,830	$1,514
18																				
19	Customer Related Marginal Cost																			
20	Poles	$54,784	$40,478	$7,233	$1,153	$6	$291	$231	$134	$3	$7	$20	$1	$1	$1	$0	$0	$0	$2,151	$3,074
21	Conductor	$25,452	$19,888	$3,553	$567	$3	$143	$114	$66	$1	$4	$10	$1	$1	$0	$0	$0	$0	$1,056	$44
22	Transformers	$95,126	$63,435	$11,945	$2,748	$0	$3,432	$3,065	$1,912	$0	$255	$650	$0	$131	$0	$3	$0	$0	$7,476	$75
23	Service Drops	$62,508	$47,215	$8,248	$2,764	$0	$1,167	$962	$1,082	$0	$115	$571	$0	$376	$0	$7	$0	$0	$0	
24	Meters	$12,405	$8,876	$1,265	$352	$79	$145	$123	$447	$86	$48	$124	$84	$31	$104	$1	$50	$311	$276	$2
25	Meter Reading	$9,797	$7,498	$1,442	$230	$1	$167	$133	$77	$2	$14	$36	$3	$18	$11	$0	$5	$1	$154	$2
26	Billing & Collections	$19,571	$16,564	$2,131	$340	$2	$154	$122	$71	$2	$8	$20	$2	$14	$8	$0	$4	$1	$103	$25
27	Uncollectables	$5,185	$4,566	$133	$21	$0	$89	$71	$41	$1	$29	$75	$7	$69	$41	$1	$19	$4	$18	$0
28	Customer Service / Other	$6,058	$5,073	$677	$108	$1	$55	$43	$25	$1	$4	$11	$1	$7	$4	$0	$2	$0	$38	$7
29	Total Commitment & Billing Rel.	$290,886	$213,593	$36,627	$8,284	$91	$5,645	$4,864	$3,855	$96	$485	$1,516	$100	$649	$169	$12	$80	$317	$11,273	$3,230
30																				
31	Total Revenue @ Full MC																			
32	Generation	$1,041,918	$440,000	$47,622	$40,525	$101	$35,219	$52,899	$72,152	$1,474	$16,055	$81,175	$7,020	$45,315	$38,391	$4,221	$84,046	$57,966	$16,304	$1,432
33	Transmission	$305,971	$134,761	$14,103	$11,923	$27	$11,277	$16,349	$21,412	$436	$4,634	$23,240	$2,087	$13,068	$10,713	$1,188	$22,922	$13,691	$4,059	$82
34	Distribution	$485,837	$309,172	$44,553	$18,070	$37	$13,885	$17,079	$20,202	$294	$3,500	$16,647	$1,334	$8,591	$6,273	$394	$6,076	$0	$16,538	$3,193
35	Customer - Billing	$19,571	$16,564	$2,131	$340	$2	$154	$122	$71	$2	$8	$20	$2	$14	$8	$0	$4	$1	$103	$25
36	Customer - Metering	$22,202	$16,375	$2,707	$582	$80	$313	$256	$524	$88	$63	$160	$88	$50	$115	$1	$55	$312	$431	$4
37	Customer - Other	$6,058	$5,073	$677	$108	$1	$55	$43	$25	$1	$4	$11	$1	$7	$4	$0	$2	$0	$38	$7
38	Revenue (less Uncollectables)	$1,881,557	$921,945	$111,792	$71,548	$248	$60,903	$86,748	$114,386	$2,294	$24,264	$121,253	$10,531	$67,045	$55,505	$5,805	$113,105	$71,969	$37,474	$4,744
39																				
40	Customer - Uncollectables	$5,185	$4,566	$133	$21	$0	$89	$71	$41	$1	$29	$75	$7	$69	$41	$1	$19	$4	$18	$0
41	Total Revenue	$1,886,742	$926,510	$111,925	$71,569	$248	$60,992	$86,819	$114,427	$2,295	$24,293	$121,328	$10,538	$67,114	$55,545	$5,806	$113,124	$71,973	$37,491	$4,744

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 + .4066) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 9) x (Table 7, Row 7) x (1 + .4066) (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

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)
2013			77.74	59.50	18.24	$82.31
2014			79.62	61.04	18.58	$83.80
2015			81.62	62.72	18.90	$85.28
2016			83.87	64.63	19.24	$86.79
2017			86.05	66.47	19.58	$88.34
2018			88.67	68.74	19.93	$89.90
2019			87.65	67.37	20.28	$91.50
2020			88.50	67.86	20.64	$93.11
2021			93.29	72.29	21.00	$94.76
2022			98.39	77.01	21.38	$96.44
2023			93.26	71.50	21.76	$98.16
2024			90.29	68.15	22.14	$99.90
2025			94.70	72.16	22.54	$101.67
2026			96.55	73.61	22.94	$103.47
2027			96.82	73.48	23.34	$105.30
2028			100.41	76.65	23.76	$107.17
2029			104.36	80.18	24.18	$109.07
2030			107.82	83.21	24.61	$111.01
2031			109.79	84.75	25.04	$112.97
2032			111.71	86.22	25.49	$114.98
2013	**1 year -**					
|	Sum of PV Costs	@ 7.92%	77.74	59.50	18.24	$82.31
2013 - 2017	**5 year -**					
|	Sum of PV Costs	@ 7.92%	351.76	270.33	81.43	$367.35
|	Annual Cost	@ 22.41%	78.83	60.58	18.25	$82.32
2013 - 2022	**10 years -**					
|	Sum of PV Costs	@ 7.92%	619.97	477.80	142.17	$641.36
|	Annual Cost	@ 12.84%	79.60	61.35	18.25	$82.35
2013 - 2032	**20 years -**					
|	Sum of PV Costs	@ 7.92%	956.06	734.80	221.26	$998.18
|	Annual Cost	@ 8.25%	78.87	60.62	18.25	$82.35

Footnotes:
(B) Tab 4.1 (Energy:) `Marginal Generation Energy Costs'
(C) Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 3.1 (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 - (2013 to 2017 in $000's)	$1,004,694
2		
3	System Growth MW's from 2013 to 2017	791 MW
4		
5	Marginal Investment (growth invest / kW)	$1,270.11 / kW
6		
7	Annualized Investment x 8.39%	106.56 / kW
8	Admin. & General Factor x 1.41%	17.91
9	Annual O&M Expenses x 1.395%	17.72 / kW
10	Annualized Marginal Cost	$142.19 / kW
11		
12	Marginal Cost of Demand-Related Transmission	$117.73 / kW
13		
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	$24.47 / kW
15	Marginal Cost of Energy-Related Transmission	$0.00347 / kWh
16	$24.47 / (8760 x 80.49% LF))	

Sources:
Tab 5.2 (Transm2:) `2013-2017 Forecasted Transmission'
Tab 5.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'

Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
2013 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) > 101kW (sec)	(H) Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) 301+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trans (trn)	(Q) Irrg Sch 41 (sec)
	Demand Related Costs ($/kW)																		
1	Poles		25.83	30.81	30.81	30.81	21.73	21.73	21.73	21.73	15.43	15.43	15.43	12.22	12.22	0.92	0.76	NA	64.28
2	Conductors		32.35	37.03	37.03	37.03	$28.47	28.47	28.47	28.47	22.54	22.54	22.54	19.54	19.54	1.76	1.45	NA	68.61
3	Substation		24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	NA	24.12
4	Dist. O&M @ of Total Investment	40.66%	33.46	37.39	37.39	37.39	30.22	30.22	30.22	30.22	25.25	25.25	25.25	22.72	22.72	10.90	10.71	NA	63.84
5	Total $/ Dist. kW		$115.76	$129.35	$129.35	$129.35	$104.54	$104.54	$104.54	$104.54	$87.34	$87.34	$87.34	$78.60	$78.60	$37.70	$37.04	-	$220.85
6																			
7	Transformers		2.08	2.08	2.08	NA	2.08	2.08	2.08	NA	2.08	2.08	NA	2.08	NA	2.08	NA	NA	2.08
8	Dist. O&M @ of Total Investment	40.66%	0.85	0.85	0.85	NA	0.85	0.85	0.85	NA	0.85	0.85	NA	0.85	NA	0.85	NA	NA	0.85
9	Total $/ Transformer kW		$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$0.00	$2.93	$0.00	$2.93	$0.00	$0.00	$2.93
10																			
11																			
12	Commitment Related Costs ($/Customer)																		
13	Poles		60.02	79.20	79.20	79.20	47.82	47.82	47.82	47.82	25.46	25.46	25.46	11.41	11.41	-	-	NA	188.95
14	Conductors		29.49	38.91	38.91	38.91	23.49	23.49	23.49	23.49	12.51	12.51	12.51	5.61	5.61	-	-	NA	92.82
15	Transformers		94.06	130.78	188.66	NA	563.16	634.20	680.75	NA	841.52	841.37	NA	867.84	NA	867.84	NA	NA	656.96
16	Dist. O&M @ of Total Investment	40.66%	74.64	101.20	124.73	48.02	257.98	286.86	305.79	28.99	357.60	357.54	15.44	359.79	6.92	352.87	-	NA	381.69
17	Total Commitment Related		$258.21	$350.09	$431.50	$166.13	$892.45	$992.37	$1,057.85	$100.30	$1,237.09	$1,236.88	$53.41	$1,244.65	$23.94	$1,220.71	$0.00	$0.00	$1,320.42
18																			
19	Billing Related Costs ($/Customer/Yr)																		
20	Service Drop		70.01	90.31	189.77	NA	191.57	199.09	384.87	NA	383.48	739.15	NA	$2,494.97	NA	$2,494.97	NA	NA	NA
21	Service Drop O&M @	40.66%	28.47	36.72	77.16	NA	77.89	80.95	156.49	NA	155.92	300.54	NA	1,014.45	NA	1,014.45	NA	NA	NA
22	Meter		11.69	12.30	21.45	$1,042.67	21.16	22.67	141.40	1,042.67	142.37	142.39	1,042.67	$183.65	$1,042.67	$183.65	$1,042.67	$32,716.00	21.58
23	Meter O&M at	58.37%	6.82	7.18	12.52	608.61	12.35	13.23	82.54	608.61	83.10	83.11	608.61	107.20	608.61	107.20	608.61	19,096.33	12.60
24	Meter Reading		15.64	22.21	22.21	22.21	38.63	38.63	38.63	38.63	$66.31	$66.31	$66.31	172.81	172.81	172.81	172.81	172.81	48.95
25	Billing & Collections		34.55	32.82	32.82	32.82	35.58	35.58	35.58	35.58	$35.58	$35.58	$35.58	131.63	131.63	131.63	131.63	131.63	32.82
26	Uncollectables		9.52	2.05	2.05	2.05	20.59	20.59	20.59	20.59	$136.23	$136.23	$136.23	645.55	645.55	645.55	645.55	645.55	5.60
27	Customer Service / Other		10.58	10.43	10.43	10.43	12.58	12.58	12.58	12.58	20.75	20.75	20.75	61.34	61.34	61.34	61.34	61.34	12.16
28	Total Billing Related		$187.28	$214.02	$368.41	$1,718.79	$410.35	$423.32	$872.68	$1,758.66	$1,023.74	$1,524.06	$1,910.15	$4,811.60	$2,662.61	$4,811.60	$2,662.61	$52,823.66	$133.71
29																			
30																			
31	Monthly Billing Related (Line 28 / 12)		$15.61	$17.83	$30.70	$143.23	$34.20	$35.28	$72.72	$146.56	$85.31	$127.01	$159.18	$400.97	$221.88	$400.97	$221.88	$4,401.97	$11.14
32																			
33	Total Distribution (Comm & Billing Costs)		$445.49	$564.11	$799.91	$1,884.92	$1,302.81	$1,415.69	$1,930.53	$1,858.96	$2,260.83	$2,760.95	$1,963.56	$6,056.25	$2,686.55	$6,032.31	$2,662.61	$52,823.66	$1,454.13
34	Line 17 + Line 28																		
35	Monthly Commitment & Bill (Line 33 / 12)		$37.12	$47.01	$66.66	$157.08	$108.57	$117.97	$160.88	$154.91	$188.40	$230.08	$163.63	$504.69	$223.88	$502.69	$221.88	$4,401.97	$121.18

Sources: Lines

Line 1 - 2 Tab 7.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 3 Tab 6.1 (Dist Sub 1:) `Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 40.66%
Tab 9.1 (Dist OM:) `Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 40.66% Factor)
Line 7 Tab 8.2 (XFMR 2:) `Transformer Demand Costs'
Line 13 - 14 Tab 7.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 15 Tab 8.1 (XFMR 1:) `Transformer Commitment Costs'
Line 20 Tab 10.1 (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 58.37% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) `Summary of Customer Accounting Expense By Schedule'

Billing Costs

PacifiCorp
Oregon Marginal Cost Study
Total 20 Year Demand Costs Divided by Billing kW
December 2013 Dollars
(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 Service - 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)
	Demand Related Marginal Cost																		
1	Generation -	$179,482	$79,840	$8,289	$6,997	$15	$6,748	$9,706	$12,592	$256	$2,707	$13,547	$1,227	$7,632	$6,204	$690	$13,197	$7,558	$2,277
2	Transmission -	$256,597	$114,142	$11,851	$10,004	$22	$9,647	$13,876	$18,002	$366	$3,870	$19,368	$1,755	$10,911	$8,870	$986	$18,866	$10,805	$3,256
3																			
4	Distribution -																		
5	Poles, Wire, Sub	$232,948	$127,940	$12,990	$10,416	$29	$8,332	$12,091	$16,203	$289	$2,960	$14,603	$1,332	$7,618	$6,272	$336	$6,076	$0	$5,461
6	Transformers	$15,020	$10,216	$584	$421	$0	$519	$616	$806	$0	$159	$793	$0	$464	$0	$48	$0	$0	$394
7	Distribution Subtotal	$247,967	$138,156	$13,574	$10,837	$29	$8,851	$12,707	$17,009	$289	$3,119	$15,396	$1,332	$8,082	$6,272	$384	$6,076	$0	$5,855
8																			
9	Total Demand Related	$684,046	$332,138	$33,714	$27,838	$66	$25,246	$36,289	$47,603	$911	$9,696	$48,311	$4,314	$26,625	$21,346	$2,060	$38,139	$18,363	$11,388
10																			
11	Average Billing kW	6,856,010	4,692,804	256,390	184,997	1,836	159,606	189,511	248,109	12,855	48,730	244,088	21,045	142,690	119,309	14,919	240,966	156,904	121,252
12																			
13	Generation -		$17.01	$32.33	$37.82	$8.17	$42.28	$51.22	$50.75	$19.92	$55.55	$55.50	$58.30	53.49	52.00	46.25	54.77	48.17	18.78
14	Transmission -		$24.32	$46.22	$54.08	$11.98	$60.44	$73.22	$72.56	$28.47	$79.42	$79.35	$83.39	76.47	74.34	66.09	78.29	68.86	26.85
15																			
16	Distribution -																		
17	Poles, Wire, Sub		$27.26	$50.67	$56.31	$15.61	$52.20	$63.80	$65.31	$22.52	$60.74	$59.83	$63.28	53.39	52.57	22.54	25.21	0.00	45.04
18	Transformers		$2.18	$2.28	$2.27	$0.00	$3.25	$3.25	$3.25	$0.00	$3.26	$3.25	$0.00	3.25	0.00	3.21	0.00	0.00	3.25
19	Distribution subtotal		$29.44	$52.94	$58.58	$15.61	$55.45	$67.05	$68.56	$22.52	$64.00	$63.08	$63.28	56.64	52.57	25.74	25.21	0.00	48.29
20																			
21																			
22																			
23																			
24	Total Demand Related		$70.78	$131.49	$150.48	$35.76	$158.18	$191.49	$191.87	$70.90	$198.97	$197.93	$204.97	$186.59	$178.91	$138.08	$158.27	$117.03	$93.92
25																			
26	Monthly Demand Costs		$5.90	$10.96	$12.54	$2.98	$13.18	$15.96	$15.99	$5.91	$16.58	$16.49	$17.08	$15.55	$14.91	$11.51	$13.19	$9.75	$7.83

Full MC %

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage @ Meter
December 2013 Dollars

Line	Description		(A) Marginal Cost (000)s	(B) Mills / kWh	(C) % of Total
	Demand Related Marginal Cost -				
1	Generation		$179,482	13.78	9.5%
2	Transmission		256,597	19.71	13.6%
3	Dist. Poles, Cond., Subst.		232,948	17.89	12.3%
4	Dist. Transformers		15,020	1.15	0.8%
5	Total Demand Related		$684,046	52.53	36.3%
6					
7	Energy Related Marginal Cost -				
8					
9	Generation		$862,436	66.24	45.7%
10	Transmission		49,374	3.79	2.6%
11	Total Energy Related		$911,809	70.03	48.3%
12					
13	Commitment & Billing -				
14	Commitment		175,362	13.47	9.3%
15	Billing		115,524	8.87	6.1%
16	Total Commitment & Billing		$290,886	22.34	15.4%
17					
18					
19	TOTAL MARGINAL COST		$1,886,742	144.90	100.0%
20					
21					
22	Note: Total MWh =	13,020,402			

PacifiCorp
Oregon Marginal Cost Study
10 Year Run Costing Inputs and Customer Data
Marginal Unit Costs
December 2013 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) General Service - Schedule 23 15+ kW (sec)	(D) General Service - Schedule 23 (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) General Service - Schedule 28 51-100 kW (sec)	(G) General Service - Schedule 28 > 101kW (sec)	(H) General Service - Schedule 28 Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) General Service - Schedule 30 301+ kW (sec)	(K) General Service - Schedule 30 Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) Large Power Service - Schedule 48T 1 - 4 MW (pri)	(N) Large Power Service - Schedule 48T > 4 MW (sec)	(O) Large Power Service - Schedule 48T > 4 MW (pri)	(P) Large Power Service - Schedule 48T (trn)	(Q) Irrg Sch 41 (sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	873	91	77	0	74	106	138	3	30	148	14	83	70	8	148	88	25
2		Distribution	995	90	73	0	72	104	140	3	31	151	14	87	74	8	152	0	22
3		Transformer	3,144	179	129	2	160	190	248	13	49	244	21	143	119	15	241	157	121
4	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
5	Peak MW @ Generator	System	970	101	85	0	82	118	153	3	33	165	15	93	75	8	160	92	28
6		Distribution	1,105	100	81	0	80	116	155	3	34	167	15	97	80	9	164	-	25
7		Transformer	3,492	199	144	N/A	177	210	276	N/A	54	271	N/A	158	N/A	17	N/A	N/A	135
8																			
9																			
10	Energy																		
11	Energy - Annual MWh	@ Meter	5,400,866	589,821	502,774	1,331	426,951	647,714	893,140	18,795	200,164	1,014,139	89,386	565,086	496,681	52,957	1,093,266	795,520	210,342
12	Energy Loss Factor		1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.06904	1.10006	1.06904	1.10006	1.06904	1.04527	1.10006
13	Energy - Annual MWh	@ Generator	5,941,277	648,838	553,082	1,423	469,671	712,525	982,508	20,093	220,193	1,115,613	95,557	621,629	530,972	58,256	1,168,746	831,533	231,389
14																			
15																			
16	Customer																		
17	Annual Customers		479,457	64,929	10,357	48	4,332	3,436	1,997	52	215	549	51	107	63	2	30	6	8,090
18	Average Customers																		3,154
19																			
20	Unit Costs																		
21																			
22	Generation	$ / System Peak kW	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35	$82.35
23	Transmission	$ / System Peak kW	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73
24	Poles, Cond., Subst.	$ / Dist. kW	$115.76	$129.35	$129.35	$129.35	$104.54	$104.54	$104.54	$104.54	$87.34	$87.34	$87.34	$78.60	$78.60	$37.70	$37.04	$0.00	$220.85
25	Transformers	$ / Xfmr kW	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$0.00	$2.93	$0.00	$2.93	$0.00	$0.00	$2.93
26																			
27																			
28	Energy @ Generator	$ / kWh	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482	$0.06482
29																			
30																			
31	Commitment & Billing	$ / Cust. / Year	$445.49	$564.11	$799.91	1,884.92	$1,302.81	$1,415.69	$1,930.53	$1,858.96	$2,260.83	$2,760.95	$1,963.56	6,056.25	$2,686.55	$6,032.31	$2,662.61	$52,823.66	1,454.13

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost By Load Class
December 2013 Dollars
(Dollars in 000's)

Line		(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) General Service - Schedule 23 15+ kW (sec)	(E) General Service - Schedule 23 (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) General Service - Schedule 28 51-100 kW (sec)	(H) General Service - Schedule 28 > 101kW (sec)	(I) General Service - Schedule 28 Primary (pri)	(J) General Service - Schedule 30 0-300 kW (sec)	(K) General Service - Schedule 30 301+ kW (sec)	(L) General Service - Schedule 30 Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) Large Power Service - Schedule 48T 1 - 4 MW (pri)	(O) Large Power Service - Schedule 48T > 4 MW (sec)	(P) Large Power Service - Schedule 48T > 4 MW (pri)	(Q) Large Power Service - Schedule 48T (trn)	(R) Irrg Sch 41 (sec)
	Demand Related Marginal Cost																		
1	Generation -	$179,482	$79,840	$8,289	$6,997	$15	$6,748	$9,706	$12,592	$256	$2,707	$13,547	$1,227	$7,632	$6,204	$690	$13,197	$7,558	$2,277
2	Transmission -	$256,597	$114,142	$11,851	$10,004	$22	$9,647	$13,876	$18,002	$366	$3,870	$19,368	$1,755	$10,911	$8,870	$986	$18,866	$10,805	$3,256
3																			
4	Distribution -																		
5	Poles, Conductor, Substations	$232,947	$127,937	$12,990	$10,417	$29	$8,332	$12,091	$16,204	$289	$2,959	$14,603	$1,332	$7,618	$6,273	$336	$6,076	$0	$5,461
6	Transformers	$15,040	$10,231	$584	$421	$0	$519	$617	$807	$0	$159	$794	$0	$464	$0	$49	$0	$0	$395
7	Distribution subtotal	$247,987	$138,168	$13,574	$10,838	$29	$8,851	$12,708	$17,011	$289	$3,118	$15,397	$1,332	$8,082	$6,273	$385	$6,076	$0	$5,856
8																			
9	Total Demand Related	$684,066	$332,150	$33,714	$27,839	$66	$25,246	$36,290	$47,605	$911	$9,695	$48,312	$4,314	$26,625	$21,347	$2,061	$38,139	$18,363	$11,389
10	(Lines 1+2+7)																		
11																			
12																			
13	Energy Related Marginal Cost																		
14																			
15	Total Energy Related	$920,664	$385,116	$42,058	$35,851	$92	$30,444	$46,186	$63,687	$1,302	$14,273	$72,315	$6,194	$40,294	$34,418	$3,776	$75,759	$53,900	$14,999
16																			
17																			
18	Customer Related Marginal Cost																		
19																			
20	Commitment & Billing Rel.	$287,656	$213,593	$36,627	$8,285	$90	$5,644	$4,864	$3,855	$97	$486	$1,516	$100	$648	$169	$12	$80	$317	$11,273
21																			
22																			
23	Total Revenue @ Full MC	$1,892,386	$930,859	$112,399	$71,975	$248	$61,334	$87,340	$115,147	$2,310	$24,454	$122,143	$10,608	$67,567	$55,934	$5,849	$113,978	$72,580	$37,661

5 Year MC

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs by Load Class
December 2013 Dollars
(Dollars in 000's)

Line		(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) General Service - 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 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) (trn)	(R) Irrg Sch 41 (sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	873	91	77	0	74	106	138	3	30	148	14	83	70	8	148	88	25
2	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
3	Peak MW @ Generator	System	970	101	85	0	82	118	153	3	33	165	15	93	75	8	160	92	28
4																			
5	Energy																		
6	Energy - Annual MWh @ Meter	12,998,934	5,400,866	589,821	502,774	1,331	426,951	647,714	893,140	18,795	200,164	1,014,139	89,386	565,086	496,681	52,957	1,093,266	795,520	210,342
7	Energy Loss Factor		1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.06904	1.10006	1.06904	1.10006	1.06904	1.04527	1.10006
8	Energy - Annual MWh @ Generator	14,203,303	5,941,277	648,838	553,082	1,423	469,671	712,525	982,508	20,093	220,193	1,115,613	95,557	621,629	530,972	58,256	1,168,746	831,533	231,389
9																			
10	Customer																		
11	Average Customers	573,721	479,457	64,929	10,357	48	4,332	3,436	1,997	52	215	549	51	107	63	2	30	6	8,090
12																			3,154
13	Unit Costs																		
14																			
15	Generation - $ / System Peak kW		$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32	$82.32
16	Energy @ Generator $ / kWh		$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058	$0.06058
17	Billing Related Costs		$187.28	$214.02	$368.41	$1,718.79	$410.35	423.32	$872.68	$1,758.66	$1,023.74	$1,524.06	$1,910.15	$4,811.60	$2,662.61	$4,811.60	$2,662.61	$52,823.66	$34.18
18																			$99.53
19	Marginal Costs $000																		
20																			
21	Total Demand Related	$179,420	$79,811	$8,286	$6,995	$15	$6,745	$9,703	$12,588	$256	$2,706	$13,542	$1,227	$7,629	$6,202	$690	$13,192	$7,555	$2,277
22																			
23	Total Energy Related	$860,437	$359,923	$39,307	$33,506	$86	$28,453	$43,165	$59,520	$1,217	$13,339	$67,584	$5,789	$37,658	$32,166	$3,529	$70,803	$50,374	$14,018
24																			
25	Billing Related Costs	$115,489	$89,793	$13,896	$3,816	$83	$1,778	$1,455	$1,743	$91	$220	$837	$97	$515	$168	$10	$80	$317	$590
26																			
27	Total Revenue @ Full MC	$1,155,346	$529,527	$61,489	$44,317	$184	$36,976	$54,323	$73,851	$1,564	$16,265	$81,963	$7,113	$45,802	$38,536	$4,229	$84,075	$58,246	$16,885

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs by Load Class
December 2013 Dollars
(Dollars in 000's)

Line		(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) General Service - 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 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) (trn)	(R) Irrg Sch 41 (sec)
	Billing Units																		
	Energy																		
1	Energy - Annual MWh @ Meter	12,998,934	5,400,866	589,821	502,774	1,331	426,951	647,714	893,140	18,795	200,164	1,014,139	89,386	565,086	496,681	52,957	1,093,266	795,520	210,342
2	Energy Loss Factor		1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.06904	1.10006	1.06904	1.10006	1.06904	1.04527	1.10006
3	Energy - Annual MWh @ Generator	14,203,303	5,941,277	648,838	553,082	1,423	469,671	712,525	982,508	20,093	220,193	1,115,613	95,557	621,629	530,972	58,256	1,168,746	831,533	231,389
4																			
5	Customer																		
6	Average Customers	573,721	479,457	64,929	10,357	48	4,332	3,436	1,997	52	215	549	51	107	63	2	30	6	8,090
7																			3,154
8	Unit Costs																		
9																			
10	Energy @ Generator $ / kWh		$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950	$0.05950
11																			
12	Billing Related Costs		$187.28	$214.02	$368.41	1,718.79	$410.35	423.32	$872.68	$1,758.66	$1,023.74	$1,524.06	$1,910.15	$4,811.60	$2,662.61	$4,811.60	$2,662.61	$52,823.66	$34.18
13																			$99.53
14																			
15	Marginal Costs $000																		
16																			
17	Total Energy Related	$845,040	$353,482	$38,603	$32,906	$85	$27,944	$42,392	$58,455	$1,195	$13,101	$66,375	$5,685	$36,984	$31,591	$3,466	$69,536	$49,473	$13,767
18																			
19	Billing Related Costs	$115,489	$89,793	$13,896	$3,816	$83	$1,778	$1,455	$1,743	$91	$220	$837	$97	$515	$168	$10	$80	$317	$590
20																			
21																			
22	Total Revenue @ Full MC	$960,529	$443,275	$52,499	$36,722	$168	$29,722	$43,847	$60,198	$1,286	$13,321	$67,212	$5,782	$37,499	$31,759	$3,476	$69,616	$49,790	$14,357

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 @ 7.92%	(C) PV of Capacity $/kW (A) x (B)	(D) Capacity Mills/kWh (A) / 0.515 / 8,760	(E) PV of Capacity Mills/kWh (B) * (D)
2013	$82.31	1.0000	82.31	18.24	18.24
2014	$83.80	0.9266	77.65	18.58	17.22
2015	$85.28	0.8586	73.22	18.90	16.23
2016	$86.79	0.7956	69.05	19.24	15.31
2017	$88.34	0.7372	65.12	19.58	14.43
2018	$89.90	0.6831	61.41	19.93	13.61
2019	$91.50	0.6330	57.92	20.28	12.84
2020	$93.11	0.5865	54.61	20.64	12.11
2021	$94.76	0.5435	51.50	21.00	11.41
2022	$96.44	0.5036	48.57	21.38	10.77
2023	$98.16	0.4666	45.80	21.76	10.15
2024	$99.90	0.4324	43.20	22.14	9.57
2025	$101.67	0.4007	40.74	22.54	9.03
2026	$103.47	0.3713	38.42	22.94	8.52
2027	$105.30	0.3440	36.22	23.34	8.03
2028	$107.17	0.3188	34.17	23.76	7.57
2029	$109.07	0.2954	32.22	24.18	7.14
2030	$111.01	0.2737	30.38	24.61	6.74
2031	$112.97	0.2536	28.65	25.04	6.35
2032	$114.98	0.2350	27.02	25.49	5.99

			$/kW		mills / kWh
2013	1 Year -	Sum of PV Costs @ 7.92%	82.31		18.24
2013 - 2017	5 Year -	Short Run -			
		Sum of PV Costs @ 7.92%	$367.35		$81.43
		Annual Cost of Capacity @ 22.41%	82.32		18.25
2013 - 2022	10 Years -	Medium Run -			
		Sum of PV Costs @ 7.92%	$641.36		142.17
		Annual Cost of Capacity @ 12.84%	82.35		18.25
2013 - 2032	20 Years -	Long Run -			
		Sum of PV Costs @ 7.92%	$998.18		221.26
		Annual Cost of Capacity @ 8.25%	82.35		18.25

Footnote:

Column A: Total Cost of Simple Cycle: Table 8, Page 1, column (f)

Energy

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

Calendar Year (12 Mo Ended Dec)	(A) SCCT Fixed Costs ($/kW-yr) (1)	(B) SCCT Fixed Costs ($/kW-mo) (2)	(C) CCCT Fixed Costs ($/kW-yr) (3)	(D) CCCT Fixed Costs ($/kW-mo) (4)	(E) Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	(F) Capitalized Energy Cost 51.5% CF ($/MWh) (6)	(G) Purchase Cost ($/MWh) (7)	(H) Updated Gas Price ($/MMBtu) (8)	(I) CCCT Energy Costs 7,150 Btu/kWh ($/MWh) (9)	(J) Variable Avoided Energy Cost ($/MWh) (7) + (9) =(10)	(K) Capitalized Energy Cost 51.5% CF ($/MWh) (6)=(11)	(L) Total Avoided Energy Cost ($/MWh) (10) + (11) =(12)	(M) Present Value Factors (13) @ 7.92%	(N) Present Value of Energy (14) (12)*(13)
2013	82.31	6.86	129.44	10.79	3.93	10.45	0.00	6.86	49.05	49.05	10.45	59.50	1.0000	59.50
2014	83.80	6.98	131.75	10.98	4.00	10.63	0.00	7.05	50.41	50.41	10.63	61.04	0.9266	56.56
2015	85.28	7.11	134.06	11.17	4.07	10.81	0.00	7.26	51.91	51.91	10.81	62.72	0.8586	53.85
2016	86.79	7.23	136.44	11.37	4.14	11.01	0.00	7.50	53.63	53.63	11.01	64.63	0.7956	51.42
2017	88.34	7.36	138.86	11.57	4.21	11.20	0.00	7.73	55.27	55.27	11.20	66.47	0.7372	49.00
2018	89.90	7.49	141.32	11.78	4.29	11.40	0.00	8.02	57.34	57.34	11.40	68.74	0.6831	46.96
2019	91.50	7.63	143.83	11.99	4.36	11.60	0.00	7.80	55.77	55.77	11.60	67.37	0.6330	42.65
2020	93.11	7.76	146.38	12.20	4.44	11.81	0.00	7.84	56.06	56.06	11.81	67.86	0.5865	39.80
2021	94.76	7.90	148.97	12.41	4.52	12.02	0.00	8.43	60.27	60.27	12.02	72.29	0.5435	39.29
2022	96.44	8.04	151.61	12.63	4.60	12.23	0.00	9.06	64.78	64.78	12.23	77.01	0.5036	38.78
2023	98.16	8.18	154.29	12.86	4.68	12.44	0.00	8.26	59.06	59.06	12.44	71.50	0.4666	33.36
2024	99.90	8.33	157.03	13.09	4.76	12.66	0.00	7.76	55.48	55.48	12.66	68.15	0.4324	29.47
2025	101.67	8.47	159.81	13.32	4.85	12.89	0.00	8.29	59.27	59.27	12.89	72.16	0.4007	28.92
2026	103.47	8.62	162.65	13.55	4.93	13.12	0.00	8.46	60.49	60.49	13.12	73.61	0.3713	27.33
2027	105.30	8.78	165.53	13.79	5.02	13.35	0.00	8.41	60.13	60.13	13.35	73.48	0.3440	25.28
2028	107.17	8.93	168.46	14.04	5.11	13.59	0.00	8.82	63.06	63.06	13.59	76.65	0.3188	24.44
2029	109.07	9.09	171.46	14.29	5.20	13.83	0.00	9.28	66.35	66.35	13.83	80.18	0.2954	23.69
2030	111.01	9.25	174.49	14.54	5.29	14.07	0.00	9.67	69.14	69.14	14.07	83.21	0.2737	22.78
2031	112.97	9.41	177.58	14.80	5.38	14.32	0.00	9.85	70.43	70.43	14.32	84.75	0.2536	21.49
2032	114.98	9.58	180.74	15.06	5.48	14.58	0.00	10.02	71.64	71.64	14.58	86.22	0.2350	20.26

				Mills / kWh
2013	1 Year -	Sum of PV Costs		59.50
2013 - 2017	5 Year -	Short Run -		
		Sum of PV Costs	@ 7.92% =	270.33
		Annual Cost of Energy	@ 22.41% =	60.58
2013 - 2022	10 Years -	Medium Run -		
		Sum of PV Costs	@ 7.92% =	477.80
		Annual Cost of Energy	@ 12.84% =	61.35
2013 - 2032	20 Years -	Long Run -		
		Sum of PV Costs	@ 7.92% =	734.80
		Annual Cost of Energy	@ 8.25% =	60.62

Footnote:

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 (b)
Column I: Heat Rate for Combined Cycle: 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)
2013	82.31	129.44	6.86	82.31	129.44	6.86
2014	83.80	131.75	7.05	83.80	131.75	7.05
2015	85.28	134.06	7.26	85.28	134.06	7.26
2016	86.79	136.44	7.50	86.79	136.44	7.50
2017	88.34	138.86	7.73	88.34	138.86	7.73
2018	89.90	141.32	8.02	89.90	141.32	8.02
2019	91.50	143.83	7.80	91.50	143.83	7.80
2020	93.11	146.38	7.84	93.11	146.38	7.84
2021	94.76	148.97	8.43	94.76	148.97	8.43
2022	96.44	151.61	9.06	96.44	151.61	9.06
2023	98.16	154.29	8.26	98.16	154.29	8.26
2024	99.90	157.03	7.76	99.90	157.03	7.76
2025	101.67	159.81	8.29	101.67	159.81	8.29
2026	103.47	162.65	8.46	103.47	162.65	8.46
2027	105.30	165.53	8.41	105.30	165.53	8.41
2028	107.17	168.46	8.82	107.17	168.46	8.82
2029	109.07	171.46	9.28	109.07	171.46	9.28
2030	111.01	174.49	9.67	111.01	174.49	9.67
2031	112.97	177.58	9.85	112.97	177.58	9.85
2032	114.98	180.74	10.02	114.98	180.74	10.02

CCCT Capacity Factor	51.5%
CCCT Heat Rate (Btu/kWh)	7,150

Source:

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%

Exhibit PAC/1207
Tab 5. Transmission

Transm1

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
2013 Dollars

Line	Item	(A) Total (B) + (C)	(B) Demand Related	(C) Energy Related	
1	2013 Forecasted	248,015	193,915	54,100	
2	2014 Forecasted	259,680	200,732	58,948	
3	2015 Forecasted	178,072	152,807	25,265	
4	2016 Forecasted	142,156	132,379	9,777	
5	2017 Forecasted	176,771	151,975	24,796	
6					
7	Growth Related Investments - (2013 to 2017 in $000's)	$1,004,694	$831,808	$172,886	
8					
9	System Growth MW's from 2013-2017	791			MW
10					
11	Marginal Investment (7) / (9)	$1,270.11	$1,051.55	$218.56	/kW
12					
13	Annualized Investment (11) x 8.39%	$106.56	$88.23	$18.34	/kW
14	Admin. & General Factor (11) x 1.41%	$17.91	$14.83	$3.08	/kW
15	Annual O&M Expenses (11) x 1.395%	$17.72	$14.67	$3.05	/kW
16					
17	Annualized Marginal Cost Sum (13) to (15)	$142.19	$117.73	$24.47	/kW
18					
19	Marginal Cost of Energy-Related Transmission			$0.00347	/kWh
20	$24.47 / 8760 hours / 80.49% Load Factor))				

Footnote:

Lines 1-7	Tab 5.2 (Transm2:) `2013-2017 Forecasted Transmission'
Line 9	Peak Load Forecast Detail, Dec. 16, 2009 - Forecasting Dept.
Line 13	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 8.39% factor)
Line 14	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 1.41% factor)
Line 15	Tab 5.3 (Tran_OM:) `Transmission O & M Expenses' (for 1.395% factor)
Line 20	See Tab "TransLF"

Transm2

PacifiCorp
Oregon Marginal Cost Study
2013-2017 Forecasted Transmission
December 2013 Dollars(in 000's)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Forecast				Total
Line	Description	2013	2014	2015	2016	2017	
1	Bulk Power Lines (grid)	69,164	75,361	32,300	12,500	31,700	
2	price adjustment factor	1.018	1.018	1.018	1.018	1.018	
3	Adjusted Bulk Power Lines (grid)	70,388	76,695	32,872	12,721	32,261	224,937
4							
5	Growth Related Major Projects (local)	174,538	179,802	142,675	127,184	141,997	
6	price adjustment factor	1.018	1.018	1.018	1.018	1.018	
7	Adjusted Growth Related Major Projects (local)	177,627	182,985	145,200	129,435	144,510	779,757
8							
9	Bulk Power Lines - Demand Related	16,288	17,747	7,607	2,944	7,465	
10	Line (3) x Demand Factor 23.14%						
11							
12	Bulk Power Lines - Energy Related	54,100	58,948	25,265	9,777	24,796	172,886
13	Line (3) - Line (9)						
14							
15	Total Growth Demand Related	193,915	200,732	152,807	132,379	151,975	831,808
16	Line (7) + Line (9)						
17							
18	$ Demand Related	$193,915	$200,732	$152,807	$132,379	$151,975	$831,808
19	$ Energy Related	$54,100	$58,948	$25,265	$9,777	$24,796	$172,886
20							
21	Total Marginal Transmission Investment	$248,015	$259,680	$178,072	$142,156	$176,771	$1,004,694

Footnotes:

Line 1 & 5 Bulk power line & growth related projects data provided in 2011 dollars for each year
Line 10 Demand Portion of Transmission = 18.25 / (18.25+60.62) = 23.14%

Index		Escalation Factor
2012	2013	2012 - 2013
1.0170	1.0350	1.0177

Tran_OM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

Line	Description	(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	(F) 2006	(G) 2007	(H) 2008	(I) 2009	(J) 2010	
1	Transmission O&M Exp.	123,213	102,419	105,962	105,324	115,283	136,930	154,195	174,010	172,875	195,628	
2	Wheeling	94,737	76,949	77,497	76,944	83,360	94,111	106,592	121,167	117,161	136,855	
3	Net Transmission O&M Line (1) - (2)	28,476	25,469	28,465	28,379	31,922	42,820	47,603	52,843	55,713	58,774	
4	Transmission Plant	2,232,246	2,299,173	2,396,665	2,487,677	2,578,317	2,688,839	2,874,659	3,054,529	3,342,914	4,339,114	
5	Tran. O&M Loading Line (3) / (4)	1.276%	1.108%	1.188%	1.141%	1.238%	1.593%	1.656%	1.730%	1.667%	1.355%	1.395%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(2) page 321, line 96

Exhibit PAC/1207
Tab 6. Dist. Substation

Dist Sub 1

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2013 Dollars

Line		
1	Incremental Substation Cost - $ / kW	$235.77
2		
3	Annual Distribution Carrying Charge	10.23%
4		
5	Substation Marginal Cost - $ / kW	$24.12 / 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)
2011	Riddle	OR	25.0	$4,360	$174
2012	Canyonville	OR	25.0	$3,572	$143
2011	Humbug Creek	OR	9.4	$2,020	$215
2011	Bend Plant	OR	12.5	$3,121	$250
2011	Alderwood	OR	20.0	$2,349	$117
2011	Deschutes	OR	12.5	$2,117	$169
2012	Gold Hill	OR	2.0	$100	$50
2012	Dodge Bridge	OR	12.5	$1,754	$140
2012	Knott	OR	10.0	$6,810	$681
2013	Independence	OR	10.0	$2,811	$281
2013	Dorris	CA	9.4	$2,500	$266
2013	Jefferson	OR	7.5	$900	$120
2013	China Hat	OR	25.0	$2,900	$116
2013	Red Blanket	OR	2.0	$1,000	$500
2013	Selah	WA	25.0	$6,000	$240
2013	Hunters Circle	OR	12.5	$4,100	$328
2014	River Road	WA	25.0	$2,500	$100
2014	Tangent	OR	25.0	$7,000	$280
2014	Winston	OR	5.0	$900	$180
2014	Henley	OR	19.0	$6,600	$347
2014	Lassen	CA	12.5	$8,040	$643
2015	Vine Street	OR	10.0	$3,500	$350
2015	Vilas Road	OR	25.0	$2,800	$112
2015	Punkin Center	WA	15.6	$2,600	$167
2015	Winchester	OR	5.0	$2,200	$440
			362.4	**$82,554**	

Index		Escalation Factor
2011	2013	2011 - 2013
1.0000	1.0350	1.0350

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Circuit Study Results
Annual Demand and Commitment Costs
December 2013 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 10.23%	(B) x 10.23%			(E) x 10.23%	(F) x 10.23%
1	Res - Schedule 4	(sec)	$252.46	$316.20	$25.83	$32.35	$586.73	$288.24	$60.02	$29.49
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$301.22	$361.94	$30.81	$37.03	$774.18	$380.33	$79.20	$38.91
5	15+ kW	(sec)	$301.22	$361.94	$30.81	$37.03	$774.18	$380.33	$79.20	$38.91
6	Primary	(pri)	$301.22	$361.94	$30.81	$37.03	$774.18	$380.33	$79.20	$38.91
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$212.40	$278.27	$21.73	$28.47	$467.40	$229.62	$47.82	$23.49
10	51-100 kW	(sec)	$212.40	$278.27	$21.73	$28.47	$467.40	$229.62	$47.82	$23.49
11	> 101kW	(sec)	$212.40	$278.27	$21.73	$28.47	$467.40	$229.62	$47.82	$23.49
12	Primary	(pri)	$212.40	$278.27	$21.73	$28.47	$467.40	$229.62	$47.82	$23.49
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$150.81	$220.32	$15.43	$22.54	$248.83	$122.24	$25.46	$12.51
16	301+ kW	(sec)	$150.81	$220.32	$15.43	$22.54	$248.83	$122.24	$25.46	$12.51
17	Primary	(pri)	$150.81	$220.32	$15.43	$22.54	$248.83	$122.24	$25.46	$12.51
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$119.42	$191.04	$12.22	$19.54	$111.52	$54.79	$11.41	$5.61
21	1 - 4 MW	(pri)	$119.42	$191.04	$12.22	$19.54	$111.52	$54.79	$11.41	$5.61
22	> 4 MW	(sec)	$8.96	$17.22	$0.92	$1.76	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$7.39	$14.21	$0.76	$1.45	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$628.35	$670.68	$64.28	$68.61	$1,846.97	$907.35	$188.95	$92.82

Footnotes:
**$ / kW are in terms of Distribution kW.

PC 2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Three Phase Costs as Demand

Line	(A) Demand Poles Cost	(B) Demand Conductor Cost	(C) Commitment Poles Cost	(D) Commitment Conductor Cost	(E) 2013 Demand Poles Cost	(F) 2013 Demand Conductor Cost	(G) 2013 Commitment Poles Cost	(H) 2013 Commitment Conductor Cost
					(D) x 1.0350	(C) x 1.0350	(B) x 1.0350	(A) x 1.0350
1	Res - Schedule 4							
2	$243.92	$305.51	$566.89	$278.49	$252.46	$316.20	$586.73	$288.24
3								
4	GS - Schedule 23							
5	$291.03	$349.70	$748.00	$367.47	$301.22	$361.94	$774.18	$380.33
6	$291.03	$349.70	$748.00	$367.47	$301.22	$361.94	$774.18	$380.33
7	$291.03	$349.70	$748.00	$367.47	$301.22	$361.94	$774.18	$380.33
8								
9	GS - Schedule 28							
10	$205.21	$268.86	$451.59	$221.85	$212.40	$278.27	$467.40	$229.62
11	$205.21	$268.86	$451.59	$221.85	$212.40	$278.27	$467.40	$229.62
12	$205.21	$268.86	$451.59	$221.85	$212.40	$278.27	$467.40	$229.62
13	$205.21	$268.86	$451.59	$221.85	$212.40	$278.27	$467.40	$229.62
14	$205.21	$268.86	$451.59	$221.85	$212.40	$278.27	$467.40	$229.62
15								
16	GS - Schedule 30							
17	$145.71	$212.87	$240.41	$118.11	$150.81	$220.32	$248.83	$122.24
18	$145.71	$212.87	$240.41	$118.11	$150.81	$220.32	$248.83	$122.24
19	$145.71	$212.87	$240.41	$118.11	$150.81	$220.32	$248.83	$122.24
20								
21	LPS - Schedule 48T							
22	$115.39	$184.58	$107.75	$52.93	$119.42	$191.04	$111.52	$54.79
23	$115.39	$184.58	$107.75	$52.93	$119.42	$191.04	$111.52	$54.79
24	$8.66	$16.64	$0.00	$0.00	$8.96	$17.22	$0.00	$0.00
25	$7.14	$13.73	$0.00	$0.00	$7.39	$14.21	$0.00	$0.00
26								
27	Irrigation - Schedule 41							
28	$607.11	$648.00	$1,784.51	$876.67	$628.35	$670.68	$1,846.97	$907.35
29								

Index		Escalation Factor
2011	2013	2011 - 2013
1.0000	1.0350	1.0350

Footnotes:
Escalation Factors: Cost Trends of Electric Utility Construction, Table A14
Pole and conductor costs from Distribution Circuit Model.

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line	Class		(A) Annual MWh	(B) Number of Customers	(C) Average MWh per Customer (A) / (B)	(D) Distribution Peak MW	(E) Average kW per customer (D)/(B) * 1,000	(F) Percent Single Phase
1	Res - Schedule 4	(sec)	5,544,795	476,340	11.64	995	2.09	100.00%
2	GS - Schedule 23 - 0-15 kW	(sec)	607,536	66,182	9.18	90	1.37	82.27%
3	GS - Schedule 23 - 15+ kW	(sec)	517,875	10,557	49.06	73	6.87	45.54%
4	GS - Schedule 23 - Primary	(pri)	1,348	48	28.29	0	4.33	-
5	GS - Schedule 28 - 0-50 kW	(sec)	434,840	4,426	98.25	72	16.22	29.72%
6	GS - Schedule 28 - 51-100 kW	(sec)	659,683	3,510	187.93	104	29.67	13.44%
7	GS - Schedule 28 - > 101kW	(sec)	909,643	2,040	445.87	140	68.41	2.77%
8	GS - Schedule 28 - Primary	(pri)	18,807	54	345.86	3	47.17	-
9	GS - Schedule 30 - 0-300 kW	(sec)	202,409	224	903.97	31	136.26	0.15%
10	GS - Schedule 30 - 301+ kW	(sec)	1,025,511	573	1,790.94	151	262.91	0.18%
11	GS - Schedule 30 - Primary	(pri)	90,988	54	1,695.78	14	263.30	-
12	Irrigation - Sch 41	(sec)	200,049	8,312	24.07	22	2.68	15.13%
13	LPS - Schedule 48T - 1 - 4 MW	(sec)	549,225	112	4,924.19	87	782.45	-
14	LPS - Schedule 48T - 1 - 4 MW	(pri)	474,189	65	7,306.46	74	1,139.48	-
15	LPS - Schedule 48T - > 4 MW	(sec)	51,470	2	25,628.41	8	3,997.43	-
16	LPS - Schedule 48T - > 4 MW	(pri)	1,043,759	31	33,276.06	152	4,845.82	-
17	Total -		12,332,129	572,529		2,015		

Customer Distribution on the Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
18	Res - Schedule 4 (sec)	0.86%	0.86%	0.86%	3.66%	3.66%	3.66%	86.44%	100.00%
19	GS - Schedule 23 - 0-15 kW (sec)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
20	GS - Schedule 23 - 15+ kW (sec)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
21	GS - Schedule 23 - Primary (pri)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
22	GS - Schedule 28 - 0-50 kW (sec)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
23	GS - Schedule 28 - 51-100 kW (sec)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
24	GS - Schedule 28 - > 101kW (sec)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
25	GS - Schedule 28 - Primary (pri)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
26	GS - Schedule 30 - 0-300 kW (sec)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
27	GS - Schedule 30 - 301+ kW (sec)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
28	GS - Schedule 30 - Primary (pri)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
29	Irrigation - Sch 41	2.57%	2.57%	2.57%	12.31%	12.31%	12.31%	55.35%	100.00%
30	LPS - Schedule 48T - 1 - 4 MW (sec)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
31	LPS - Schedule 48T - 1 - 4 MW (pri)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
32	LPS - Schedule 48T - > 4 MW (sec)		Large Customers are on dedicated circuits and are not included here						
33	LPS - Schedule 48T - > 4 MW (pri)		Large Customers are on dedicated circuits and are not included here						

34	System property records & engineering information			
35	Number of pole feet in Oregon	75,887,077	Poles per mile	25.79
36	Number of pole miles in Oregon	14,373	Customers per mile	29.49
37	Number of trench feet in Oregon	26,609,821	MWh per customer	21.54
38	Number of trench miles in Oregon	5,040	MWh per circuit	23,490
39	Total miles in Oregon	19,412	Branches per circuit	7
40			Distance per circuit	36.98
41	Number of circuits in Oregon	525	Distance per branch	5.28
42	Number of poles in Oregon	370,656		
43				
44	12 kV circuit 12 miles long has approx. 3 miles of single phase.			
45	which is approx. 25 percent of circuit distance.			
46	9.24 = 25 percent of typical Oregon circuit			
47				
48	5 divide by outer branches			
49	1.849 distance of single phase on outer branch			
50	35.00% equals percentage of single phase outer branch Segments			
51				

PacifiCorp

Oregon Circuit Model Study

Customer Distribution on the Hypothetical Circuit Branch

Class		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	0.86%	0.86%	0.86%	3.66%	3.66%	3.66%	86.44%	100.00%
2	GS 0-15 kW (sec) (23)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
3	GS >15 kW (sec) (23)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
4	GS (pri) (23)	1.29%	1.29%	1.29%	3.89%	3.89%	3.89%	84.46%	100.00%
5	GS < 50 kW (sec) (28)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
6	GS 51-100 kW (sec) (28)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
7	GS > 100 kW (sec) (28)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
8	GS (pri) (28)	0.80%	0.80%	0.80%	2.18%	2.18%	2.18%	91.04%	100.00%
9	GS 0-300 kW (sec) (30)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
10	GS >300 kW (sec) (30)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
11	GS (pri) (30)	0.42%	0.42%	0.42%	1.22%	1.22%	1.22%	95.09%	100.00%
12	Irrigation	2.57%	2.57%	2.57%	12.31%	12.31%	12.31%	55.35%	100.00%
13	Large GS 1 - 4 MW (sec)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
14	Large GS 1 - 4 MW (pri)	-	-	-	1.68%	1.68%	1.68%	94.95%	100.00%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-

Except where customers own their own transformers.

PacifiCorp
Oregon Circuit Model Study
Average Customers by Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	7.78	7.78	7.78	33.23	33.23	33.23	784.30	907.31
2	GS 0-15 kW (sec) (23)	1.62	1.62	1.62	4.91	4.91	4.91	106.47	126.06
3	GS >15 kW (sec) (23)	0.26	0.26	0.26	0.78	0.78	0.78	16.98	20.11
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.09
5	GS < 50 kW (sec) (28)	0.07	0.07	0.07	0.18	0.18	0.18	7.67	8.43
6	GS 51-100 kW (sec) (28)	0.05	0.05	0.05	0.15	0.15	0.15	6.09	6.69
7	GS > 100 kW (sec) (28)	0.03	0.03	0.03	0.08	0.08	0.08	3.54	3.89
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.41	0.43
10	GS >300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	1.04	1.09
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
12	Irrigation	0.41	0.41	0.41	1.95	1.95	1.95	8.76	15.83
13	Large GS 1 - 4 MW (sec)	-	-	-	0.00	0.00	0.00	0.20	0.21
14	Large GS 1 - 4 MW (pri)	-	-	-	0.00	0.00	0.00	0.12	0.12
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	10.23	10.23	10.23	41.31	41.31	41.31	935.84	1,090.47

Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 7.3
Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 4) Tab 7.4
Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.
For Example 7.78 is 476,340 Residential Customers X .857% customers on Branch 1 divided by 525 circuits.

	Percent of Customers								
1	Residential	76.06%	76.06%	76.06%	80.42%	80.42%	80.42%	83.81%	83.20%
2	GS 0-15 kW (sec) (23)	15.85%	15.85%	15.85%	11.88%	11.88%	11.88%	11.38%	11.56%
3	GS >15 kW (sec) (23)	2.53%	2.53%	2.53%	1.90%	1.90%	1.90%	1.81%	1.84%
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)	0.66%	0.66%	0.66%	0.45%	0.45%	0.45%	0.82%	0.77%
6	GS 51-100 kW (sec) (28)	0.53%	0.53%	0.53%	0.35%	0.35%	0.35%	0.65%	0.61%
7	GS > 100 kW (sec) (28)	0.31%	0.31%	0.31%	0.21%	0.21%	0.21%	0.38%	0.36%
8	GS (pri) (28)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
9	GS 0-300 kW (sec) (30)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.04%	0.04%
10	GS >300 kW (sec) (30)	0.04%	0.04%	0.04%	0.03%	0.03%	0.03%	0.11%	0.10%
11	GS (pri) (30)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
12	Irrigation	3.98%	3.98%	3.98%	4.72%	4.72%	4.72%	0.94%	1.45%
13	Large GS 1 - 4 MW (sec)	-	-	-	0.01%	0.01%	0.01%	0.02%	0.02%
14	Large GS 1 - 4 MW (pri)	-	-	-	0.01%	0.01%	0.01%	0.01%	0.01%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

	Sum of Branch Customers								
18	1,2,3,6	10.2	10.2	10.2			41.3		72.0
19	1,2,3,4,5,6,7	10.2	10.2	10.2	41.3	41.3	41.3	935.8	1,090.5
20									
21	1,2,3,6	14.2%	14.2%	14.2%			57.4%		100.0%
22	1,2,3,4,5,6,7	0.9%	0.9%	0.9%	3.8%	3.8%	3.8%	85.8%	100.0%

PacifiCorp
Oregon Circuit Model Study
Circuit kW Load by Branch

Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
	1	2	3	4	5	6	7	Total
Circuit kW Loads								
1 Residential	16.3	16.3	16.3	69.4	69.4	69.4	1,638.5	1,895.6
2 GS 0-15 kW (sec) (23)	2.2	2.2	2.2	6.7	6.7	6.7	145.5	172.2
3 GS >15 kW (sec) (23)	1.8	1.8	1.8	5.4	5.4	5.4	116.7	138.1
4 GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4
5 GS < 50 kW (sec) (28)	1.1	1.1	1.1	3.0	3.0	3.0	124.4	136.7
6 GS 51-100 kW (sec) (28)	1.6	1.6	1.6	4.3	4.3	4.3	180.6	198.4
7 GS > 100 kW (sec) (28)	2.1	2.1	2.1	5.8	5.8	5.8	242.0	265.9
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)	0.2	0.2	0.2	0.7	0.7	0.7	55.3	58.1
10 GS >300 kW (sec) (30)	1.2	1.2	1.2	3.5	3.5	3.5	272.7	286.8
11 GS (pri) (30)	0.1	0.1	0.1	0.3	0.3	0.3	25.6	26.9
12 Irrigation	1.1	1.1	1.1	5.2	5.2	5.2	23.5	42.4
13 Large GS 1 - 4 MW (sec)	-	-	-	2.8	2.8	2.8	157.8	166.2
14 Large GS 1 - 4 MW (pri)	-	-	-	2.4	2.4	2.4	133.7	140.9
15 Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16 Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17 Total	27.8	27.8	27.8	109.7	109.7	109.7	3,121.1	3,533.4

Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 7.3
Source - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Customers multiplied by circuit kW per customer.
For Example 16.3 is 7.78 Residential Customers multiplied by 2.09 average Dist. kW per Customer.

Percent of Branch Load

1	Residential	58.53%	58.53%	58.53%	63.30%	63.30%	63.30%	52.50%	53.65%
2	GS 0-15 kW (sec) (23)	7.98%	7.98%	7.98%	6.12%	6.12%	6.12%	4.66%	4.87%
3	GS >15 kW (sec) (23)	6.40%	6.40%	6.40%	4.91%	4.91%	4.91%	3.74%	3.91%
4	GS (pri) (23)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	3.96%	3.96%	3.96%	2.72%	2.72%	2.72%	3.99%	3.87%
6	GS 51-100 kW (sec) (28)	5.74%	5.74%	5.74%	3.95%	3.95%	3.95%	5.79%	5.61%
7	GS > 100 kW (sec) (28)	7.70%	7.70%	7.70%	5.29%	5.29%	5.29%	7.75%	7.52%
8	GS (pri) (28)	0.14%	0.14%	0.14%	0.10%	0.10%	0.10%	0.14%	0.14%
9	GS 0-300 kW (sec) (30)	0.88%	0.88%	0.88%	0.64%	0.64%	0.64%	1.77%	1.64%
10	GS >300 kW (sec) (30)	4.33%	4.33%	4.33%	3.18%	3.18%	3.18%	8.74%	8.12%
11	GS (pri) (30)	0.41%	0.41%	0.41%	0.30%	0.30%	0.30%	0.82%	0.76%
12	Irrigation	3.92%	3.92%	3.92%	4.76%	4.76%	4.76%	0.75%	1.20%
13	Large GS 1 - 4 MW (sec)	-	-	-	2.55%	2.55%	2.55%	5.06%	4.70%
14	Large GS 1 - 4 MW (pri)	-	-	-	2.16%	2.16%	2.16%	4.29%	3.99%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	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	27.8	27.8	27.8			109.7		193.0
1,2,3,4,5,6,7	27.8	27.8	27.8	109.7	109.7	109.7	3,121.1	3,533.4

1,2,3,6	14.4%	14.4%	14.4%			56.8%		100.0%
1,2,3,4,5,6,7	0.8%	0.8%	0.8%	3.1%	3.1%	3.1%	88.3%	100.0%

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile			Account 365 Conductor Cost per Mile	Total Line Construction Cost
	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost		
1 Phase -1/0 ACSR	$ 25,488	0.982	$ 25,029	$ 12,296	$ 37,325
3 Phase - 1/0 ACSR 1\0 ACSR	$ 41,960	0.982	$ 41,205	$ 27,019	$ 68,224
3 Phase - 447 AAC & 4\0 AAC	$ 46,635	0.982	$ 45,796	$ 44,841	$ 90,637
3 Phase -795 AAC & 477 AAC	$ 52,608	0.982	$ 51,661	$ 99,267	$ 150,928

	State Specific Account 364 Pole Statistics				Adjustment
State	**Poles**	**Pole Feet**	**Pole Miles**	**Poles / Mile**	**Factor**
California	56,409	12,494,494	2,366	23.84	0.908
Idaho	101,402	23,142,034	4,383	23.14	0.881
Oregon	370,656	75,887,077	14,373	25.79	0.982
Utah	358,198	60,670,523	11,491	31.17	1.187
Washington	99,105	18,892,136	3,578	27.70	1.055
Wyoming	155,134	38,383,830	7,270	21.34	0.813
Total	1,140,904	229,470,094	43,460	26.25	1.000

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSR	3 Phase - 1/0 ACSR 1\0 ACSR	Total	
Poles	$ 46,274	$ 141,475	$ 187,749	
Conductors	$ 22,733	$ 92,769	$ 115,502	
Total	$ 69,006	$ 234,244	$ 303,250	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 241,904		$ 272,887	
Conductors	$ 236,862		$ 524,354	
Total	$ 478,766		$ 797,241	

Miles per Branch	5.28
Single Phase Miles Per Branch	1.85
Three Phase Miles Per Branch	3.43

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	$ 46,274	$ 46,274	$ -	$ 22,733	$ 22,733	$ -
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 85,937	$ 55,538	$ 92,769	$ 42,218	$ 50,551
Total Branches 1,2,3,4,5	$ 187,749	$ 132,211	$ 55,538	$ 115,502	$ 64,951	$ 50,551
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 241,904	N/A	$ 241,904	$ 236,862	N/A	$ 236,862
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 272,887	N/A	$ 272,887	$ 524,354	N/A	$ 524,354
Total All Branches	$ 1,453,535	$ 661,054	$ 792,481	$ 1,338,723	$ 324,753	$ 1,013,970

PacifiCorp
Oregon Circuit Model Study
Calculation of Hypothetical Circuit Model Branch Cost

Conductors Type	(A) Total Cost Poles	(B) Total Cost Conductor	(C) Commitment Cost Poles	(D) Commitment Cost Conductor	(E) Demand Cost Poles	(F) Demand Cost Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total segment	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 2						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 3						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 4						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 5						
1 Phase -1/0 ACSR	$ 46,274	$ 22,733	$ 46,274	$ 22,733	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 141,475	$ 92,769	$ 85,937	$ 42,218	$ 55,538	$ 50,551
Total Segments	$ 187,749	$ 115,502	$ 132,211	$ 64,951	$ 55,538	$ 50,551
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 241,904	$ 236,862	NA	NA	$ 241,904	$ 236,862
Total Segments	$ 241,904	$ 236,862	$ -	$ -	$ 241,904	$ 236,862
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 272,887	$ 524,354	NA	NA	$ 272,887	$ 524,354
Total segment	$ 272,887	$ 524,354	$ -	$ -	$ 272,887	$ 524,354
	$2,792,258	**$1,453,535**	**$1,338,723**	**$661,054**	**$324,753**	**$792,481**	**$1,013,970**

Source - 'System-wide Pole and Conductor Costs' (PC 7) Tab 7.7

PacifiCorp
Oregon Circuit Model Study
Poles Demand Calculations
Branch 6 & 7 Cost Assignment

Poles		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.39%	14.39%	14.39%	NA	NA	56.83%	NA	100.00%	
2	Branch 6 Cost	$ 34,812	$ 34,812	$ 34,812	NA	NA	$ 137,468	NA	$ 241,904	**$ / kW**
3	% Demand	0.79%	0.79%	0.79%	3.10%	3.10%	3.10%	88.33%	100.00%	
4	Branch 7 Cost	$ 2,145	$ 2,145	$ 2,145	$ 8,469	$ 8,469	$ 8,469	$ 241,045	$ 272,887	
5	Branch Demand Cost	$ 55,538	$ 55,538	$ 55,538	$ 55,538	$ 55,538	NA	NA		Average
6	Total	$ 92,495	$ 92,495	$ 92,495	$ 64,007	$ 64,007	$ 145,937	$ 241,045	$ 792,481	$ 224.28
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 54,136	$ 54,136	$ 54,136	$ 40,517	$ 40,517	$ 92,378	$ 126,546	$ 462,366	$ 243.92
11	GS 0-15 kW (sec) (23)	$ 7,379	$ 7,379	$ 7,379	$ 3,915	$ 3,915	$ 8,927	$ 11,235	$ 50,128	$ 291.03
12	GS >15 kW (sec) (23)	$ 5,917	$ 5,917	$ 5,917	$ 3,140	$ 3,140	$ 7,158	$ 9,009	$ 40,197	$ 291.03
13	GS (pri) (23)	$ 17	$ 17	$ 17	$ 9	$ 9	$ 20	$ 26	$ 114	$ 291.03
14	GS < 50 kW (sec) (28)	$ 3,661	$ 3,661	$ 3,661	$ 1,743	$ 1,743	$ 3,973	$ 9,611	$ 28,052	$ 205.21
15	GS 51-100 kW (sec) (28)	$ 5,313	$ 5,313	$ 5,313	$ 2,529	$ 2,529	$ 5,766	$ 13,947	$ 40,710	$ 205.21
16	GS > 100 kW (sec) (28)	$ 7,120	$ 7,120	$ 7,120	$ 3,389	$ 3,389	$ 7,727	$ 18,691	$ 54,556	$ 205.21
17	GS (pri) (28)	$ 131	$ 131	$ 131	$ 62	$ 62	$ 142	$ 344	$ 1,003	$ 205.21
18	GS 0-300 kW (sec) (30)	$ 812	$ 812	$ 812	$ 412	$ 412	$ 940	$ 4,268	$ 8,468	$ 145.71
19	GS >300 kW (sec) (30)	$ 4,005	$ 4,005	$ 4,005	$ 2,035	$ 2,035	$ 4,640	$ 21,060	$ 41,784	$ 145.71
20	GS (pri) (30)	$ 376	$ 376	$ 376	$ 191	$ 191	$ 435	$ 1,976	$ 3,921	$ 145.71
21	Irrigation	$ 3,630	$ 3,630	$ 3,630	$ 3,048	$ 3,048	$ 6,949	$ 1,813	$ 25,748	$ 607.11
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,633	$ 1,633	$ 3,724	$ 12,190	$ 19,181	$ 115.39
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,384	$ 1,384	$ 3,156	$ 10,329	$ 16,253	$ 115.39
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 92,495	$ 92,495	$ 92,495	$ 64,007	$ 64,007	$ 145,937	$ 241,045	$ 792,481	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6) Tab 7.6
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $241,904
Line 1 X $241,904
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $272,887
Line 3 X $272,887
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6) Tab 7.6

PacifiCorp
Oregon Circuit Model Study
Conductor Demand Calculations
Branch 6 & 7 Cost Assignment

	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.39%	14.39%	14.39%	NA	NA	56.83%	NA	100.00%	
2	Branch 6 Cost	$ 34,086	$ 34,086	$ 34,086	NA	NA	$ 134,602	NA	$ 236,862	**$ / kW**
3	% Demand	0.79%	0.79%	0.79%	3.10%	3.10%	3.10%	88.33%	100.00%	
4	Branch 7 Cost	$ 4,121	$ 4,121	$ 4,121	$ 16,274	$ 16,274	$ 16,274	$ 463,169	$ 524,354	
5	Branch Demand Cost	$ 50,551	$ 50,551	$ 50,551	$ 50,551	$ 50,551	NA	NA		average
6	Total	$ 88,759	$ 88,759	$ 88,759	$ 66,825	$ 66,825	$ 150,876	$ 463,169	$ 1,013,970	$ 286.97
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 51,949	$ 51,949	$ 51,949	$ 42,300	$ 42,300	$ 95,504	$ 243,158	$ 579,111	$ 305.51
11	GS 0-15 kW (sec) (23)	$ 7,080	$ 7,080	$ 7,080	$ 4,088	$ 4,088	$ 9,229	$ 21,588	$ 60,234	$ 349.70
12	GS >15 kW (sec) (23)	$ 5,678	$ 5,678	$ 5,678	$ 3,278	$ 3,278	$ 7,401	$ 17,311	$ 48,301	$ 349.70
13	GS (pri) (23)	$ 16	$ 16	$ 16	$ 9	$ 9	$ 21	$ 49	$ 137	$ 349.70
14	GS < 50 kW (sec) (28)	$ 3,513	$ 3,513	$ 3,513	$ 1,819	$ 1,819	$ 4,108	$ 18,467	$ 36,753	$ 268.86
15	GS 51-100 kW (sec) (28)	$ 5,098	$ 5,098	$ 5,098	$ 2,640	$ 2,640	$ 5,961	$ 26,800	$ 53,336	$ 268.86
16	GS > 100 kW (sec) (28)	$ 6,832	$ 6,832	$ 6,832	$ 3,538	$ 3,538	$ 7,989	$ 35,915	$ 71,478	$ 268.86
17	GS (pri) (28)	$ 126	$ 126	$ 126	$ 65	$ 65	$ 147	$ 660	$ 1,314	$ 268.86
18	GS 0-300 kW (sec) (30)	$ 779	$ 779	$ 779	$ 431	$ 431	$ 972	$ 8,201	$ 12,371	$ 212.87
19	GS >300 kW (sec) (30)	$ 3,843	$ 3,843	$ 3,843	$ 2,125	$ 2,125	$ 4,797	$ 40,467	$ 61,042	$ 212.87
20	GS (pri) (30)	$ 361	$ 361	$ 361	$ 199	$ 199	$ 450	$ 3,797	$ 5,728	$ 212.87
21	Irrigation	$ 3,483	$ 3,483	$ 3,483	$ 3,182	$ 3,182	$ 7,185	$ 3,484	$ 27,482	$ 648.00
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,705	$ 1,705	$ 3,850	$ 23,423	$ 30,684	$ 184.58
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,445	$ 1,445	$ 3,263	$ 19,848	$ 26,001	$ 184.58
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 88,759	$ 88,759	$ 88,759	$ 66,825	$ 66,825	$ 150,876	$ 463,169	$ 1,013,970	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6) Tab 7.6
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $236,862
Line 1 X $236,862
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $524,354
Line 3 X $524,354
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6) Tab 7.6

PacifiCorp
Oregon Circuit 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	14.21%	14.21%	14.21%	NA	NA	57.38%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per Customer**
3	% customer	0.94%	0.94%	0.94%	3.79%	3.79%	3.79%	85.82%	100.00%	
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ 132,211	NA	NA		average
6	Total	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ -	$ -	$ 661,054	$ 606.21
7										
8									Total	**$ Per**
9									Commitment	**Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 100,563	$ 100,563	$ 100,563	$ 106,328	$ 106,328	$ -	$ -	$ 514,344	$ 566.89
12	GS 0-15 kW (sec) (23)	$ 20,957	$ 20,957	$ 20,957	$ 15,711	$ 15,711	$ -	$ -	$ 94,294	$ 748.00
13	GS >15 kW (sec) (23)	$ 3,343	$ 3,343	$ 3,343	$ 2,506	$ 2,506	$ -	$ -	$ 15,041	$ 748.00
14	GS (pri) (23)	$ 15	$ 15	$ 15	$ 11	$ 11	$ -	$ -	$ 68	$ 748.00
15	GS < 50 kW (sec) (28)	$ 876	$ 876	$ 876	$ 589	$ 589	$ -	$ -	$ 3,807	$ 451.59
16	GS 51-100 kW (sec) (28)	$ 695	$ 695	$ 695	$ 467	$ 467	$ -	$ -	$ 3,019	$ 451.59
17	GS > 100 kW (sec) (28)	$ 404	$ 404	$ 404	$ 272	$ 272	$ -	$ -	$ 1,755	$ 451.59
18	GS (pri) (28)	$ 11	$ 11	$ 11	$ 7	$ 7	$ -	$ -	$ 47	$ 451.59
19	GS 0-300 kW (sec) (30)	$ 23	$ 23	$ 23	$ 17	$ 17	$ -	$ -	$ 103	$ 240.41
20	GS >300 kW (sec) (30)	$ 59	$ 59	$ 59	$ 42	$ 42	$ -	$ -	$ 262	$ 240.41
21	GS (pri) (30)	$ 6	$ 6	$ 6	$ 4	$ 4	$ -	$ -	$ 25	$ 240.41
22	Irrigation	$ 5,259	$ 5,259	$ 5,259	$ 6,239	$ 6,239	$ -	$ -	$ 28,253	$ 1,784.51
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 11	$ 11	$ -	$ -	$ 23	$ 107.75
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 7	$ 7	$ -	$ -	$ 13	$ 107.75
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ 132,211	$ -	$ -	$ 661,054	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5

PacifiCorp
Oregon Circuit Model Study
Conductor Commitment Calculations
Branch 1, 2, 3, 4 & 5 Cost Assignment

Line	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Branch	1	2	3	4	5	6	7		
2	% customer	14.21%	14.21%	14.21%	NA	NA	57.38%	NA	100.00%	
3	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per Customer**
4	% customer	0.94%	0.94%	0.94%	3.79%	3.79%	3.79%	85.82%	100.00%	
5	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
6	Branch Commitment Cost	$ 64,951	$ 64,951	$ 64,951	$ 64,951	$ 64,951	NA	NA		average
7	Total	$ 64,951	$ 64,951	$ 64,951	$ 64,951	$ 64,951	$ -	$ -	$ 324,753	$ 297.81
8										
9									Total Commitment Cost	**$ Per Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7		
11	Residential	$ 49,403	$ 49,403	$ 49,403	$ 52,235	$ 52,235	$ -	$ -	$ 252,680	$ 278.49
12	GS 0-15 kW (sec) (23)	$ 10,296	$ 10,296	$ 10,296	$ 7,718	$ 7,718	$ -	$ -	$ 46,323	$ 367.47
13	GS >15 kW (sec) (23)	$ 1,642	$ 1,642	$ 1,642	$ 1,231	$ 1,231	$ -	$ -	$ 7,389	$ 367.47
14	GS (pri) (23)	$ 7	$ 7	$ 7	$ 6	$ 6	$ -	$ -	$ 33	$ 367.47
15	GS < 50 kW (sec) (28)	$ 430	$ 430	$ 430	$ 289	$ 289	$ -	$ -	$ 1,870	$ 221.85
16	GS 51-100 kW (sec) (28)	$ 341	$ 341	$ 341	$ 230	$ 230	$ -	$ -	$ 1,483	$ 221.85
17	GS > 100 kW (sec) (28)	$ 198	$ 198	$ 198	$ 133	$ 133	$ -	$ -	$ 862	$ 221.85
18	GS (pri) (28)	$ 5	$ 5	$ 5	$ 4	$ 4	$ -	$ -	$ 23	$ 221.85
19	GS 0-300 kW (sec) (30)	$ 11	$ 11	$ 11	$ 8	$ 8	$ -	$ -	$ 50	$ 118.11
20	GS >300 kW (sec) (30)	$ 29	$ 29	$ 29	$ 21	$ 21	$ -	$ -	$ 129	$ 118.11
21	GS (pri) (30)	$ 3	$ 3	$ 3	$ 2	$ 2	$ -	$ -	$ 12	$ 118.11
22	Irrigation	$ 2,583	$ 2,583	$ 2,583	$ 3,065	$ 3,065	$ -	$ -	$ 13,880	$ 876.67
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 6	$ 6	$ -	$ -	$ 11	$ 52.93
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 3	$ 3	$ -	$ -	$ 7	$ 52.93
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 64,951	$ 64,951	$ 64,951	$ 64,951	$ 64,951	$ -	$ -	$ 324,753	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit 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	$ 51,661	$ 99,267	$ 51,661	$ 99,267
2	Average Trunk Length	0.67 miles		0.67 miles	
3	Total Construction Cost	$ 34,613	$ 66,509	$ 34,613	$ 66,509
4	Customer Peak Demand	4,846 kW		3,997 kW	
5	Demand Cost $/kW	$7.14	$13.73	$8.66	$16.64

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 7) Tab 7.7
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 7.3
Line 5 - Line 3 divided by Line 4

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

	(A)	(B)	(C)	(D)	(E)	(F)		
	Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Residential	$ 566.89	$ 278.49	$ 243.92	$ 305.51	907.3	1,895.55	$ 462,366	$ 579,111
GS 0-15 kW (sec) (23)	$ 748.00	$ 367.47	$ 291.03	$ 349.70	126.1	172.24	$ 50,128	$ 60,234
GS >15 kW (sec) (23)	$ 748.00	$ 367.47	$ 291.03	$ 349.70	20.1	138.12	$ 40,197	$ 48,301
GS (pri) (23)	$ 748.00	$ 367.47	$ 291.03	$ 349.70	0.1	0.39	$ 114	$ 137
GS < 50 kW (sec) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	8.4	136.70	$ 28,052	$ 36,753
GS 51-100 kW (sec) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	6.7	198.38	$ 40,710	$ 53,336
GS > 100 kW (sec) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	3.9	265.85	$ 54,556	$ 71,478
GS (pri) (28)	$ 451.59	$ 221.85	$ 205.21	$ 268.86	0.1	4.89	$ 1,003	$ 1,314
GS 0-300 kW (sec) (30)	$ 240.41	$ 118.11	$ 145.71	$ 212.87	0.4	58.11	$ 8,468	$ 12,371
GS >300 kW (sec) (30)	$ 240.41	$ 118.11	$ 145.71	$ 212.87	1.1	286.76	$ 41,784	$ 61,042
GS (pri) (30)	$ 240.41	$ 118.11	$ 145.71	$ 212.87	0.1	26.91	$ 3,921	$ 5,728
Irrigation	$ 1,784.51	$ 876.67	$ 607.11	$ 648.00	15.8	42.41	$ 25,748	$ 27,482
Large GS 1 - 4 MW (sec)	$ 107.75	$ 52.93	$ 115.39	$ 184.58	0.2	166.23	$ 19,181	$ 30,684
Large GS 1 - 4 MW (pri)	$ 107.75	$ 52.93	$ 115.39	$ 184.58	0.1	140.86	$ 16,253	$ 26,001
Total -	$ 606.21	$ 297.81	$ 224.28	$ 286.97	1,090.5	3,533.4	$ 792,481	$ 1,013,970
Large GS + 4 MW (sec)	$ -	$ -	$ 8.66	$ 16.64	-	3,997.43	$ 34,613	$ 66,509
Large GS + 4 MW (pri)	$ -	$ -	$ 7.14	$ 13.73	-	4,845.82	$ 34,613	$ 66,509
							$ 861,707	$ 1,146,988

	Commitment	Demand	Total
Poles	$ 661,054	$ 861,707	$ 1,522,761
Conductor	$ 324,753	$ 1,146,988	$ 1,471,741
Total	$ 985,807	$ 2,008,695	$ 2,994,501

Source : Column (A) - Poles Commitment Calculations' (PC 11) Tab 7.11
Column (B) - Conductor Commitment Calculations' (PC 12) Tab 7.12
Column (C) - Poles Demand Calculations' (PC 9) Tab 7.9
Column (D) - Conductor Demand Calculations' (PC 10) Tab 8.10
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Column (F) - Circuit kW Load by Branch' (PC 6) Tab 7.6

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran. (A) x (B)	(D) # Cust. / Tran.	(E) Transformer $ / Cust. (C) / (D)	(F) Average Customers	(G) Tot. Trans. Commitment $ (E) x (F)
1	Res - Schedule 4	100.00%	344.80	344.80	3.67	$94.06	479,457	$45,097,725
2								
3	GS - Schedule 23							
4	1 Phase	82.27%	344.80	283.67	3.35	$84.61		
5	3 Phase	17.73%	931.63	165.18	3.58	$46.17		
6	0-15 kW	100.00%				$130.78	64,929	$8,491,605
7								
8	1 Phase	45.54%	344.80	157.01	3.35	$46.83		
9	3 Phase	54.46%	931.63	507.40	3.58	$141.83		
10	15+ kW	100.00%				$188.66	10,357	$1,953,976
11								
12	Primary	100.00%	-	-	0.00	0	48	$0
13								
14	GS - Schedule 28							
15	1 Phase	29.72%	344.80	102.48	1.34	$76.25		
16	3 Phase	70.28%	931.63	654.73	1.34	$486.91		
17	0-50 kW	100.00%				$563.16	4,332	$2,439,630.10
18								
19	1 Phase	13.44%	344.80	46.35	1.34	$34.49		
20	3 Phase	86.56%	931.63	806.41	1.34	$599.71		
21	51-100 kW	100.00%				$634.20	3,436	$2,179,113
22								
23	1 Phase	2.77%	344.80	9.56	1.34	$7.11		
24	3 Phase	97.23%	931.63	905.81	1.34	$673.63		
25	> 101kW	100.00%				$680.75	1,997	$1,359,452
26								
27	Primary	100.00%	-	-	0.00	0	52	$0
28								
29	GS - Schedule 30							
30	1 Phase	0.15%	344.80	0.51	1.23	$0.41		
31	3 Phase	99.85%	931.63	930.24	1.11	$841.10		
32	0-300 kW	100.00%				$841.52	215	$180,926
33								
34	1 Phase	0.18%	344.80	0.61	1.23	$0.50		
35	3 Phase	99.82%	931.63	929.99	1.11	$840.88		
36	301+ kW	100.00%				$841.37	549	$461,914
37								
38	Primary	100.00%	-	-	0.00	0	51	$0
39								
40	LPS - Schedule 48T							
41	1 - 4 MW (sec)	100.00%	931.63	931.63	1.07	867.84	107	$92,859
42	1 - 4 MW (pri)	100.00%	-	-	0.00	0	63	$0
43	> 4 MW (sec)	100.00%	931.63	931.63	1.07	867.84	2	$1,736
44	> 4 MW (pri)	100.00%	-	-	0.00	0	30	$0
45	Trans (trn)	100.00%	-	-	0.00	0	6	$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	15.13%	344.80	52.16	1.60	$32.52		
49	3 Phase	84.87%	931.63	790.69	1.27	$624.44		
50	Total	100.00%				$656.96	8,090	$5,314,831

XFMR 2

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Transformer Peak kW's	(C) Tot. Trans. Demand $ (A) x (B)
1	Res - Schedule 4	(sec)	$2.08	3,144,179	$6,539,892
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	$2.08	179,473	$373,304
5	15+ kW	(sec)	$2.08	129,498	$269,356
6	Primary	(pri)	$0.00	0	$0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	$2.08	159,606	$331,980
10	51-100 kW	(sec)	$2.08	189,511	$394,182
11	> 101kW	(sec)	$2.08	248,109	$516,066
12	Primary	(pri)	$0.00	0	$0
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	$2.08	48,730	$101,358
16	301+ kW	(sec)	$2.08	244,088	$507,702
17	Primary	(pri)	$0.00	0	$0
18					
19					
20	LPS - Schedule 48T				
21	1 - 4 MW	(sec)	$2.08	142,690	$296,795
22	1 - 4 MW	(pri)	$0.00	0	$0
23	> 4 MW	(sec)	$2.08	14,919	$31,032
24	> 4 MW	(pri)	$0.00	0	$0
25	Trans	(trn)	$0.00	0	$0
26					
27	Irrigation - Schedule 41 (Average)				
28	Secondary	(sec)	$2.08	121,252	$252,203
29					
30	Totals			4,622,053	$9,613,870

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 0.95	(C) Commitment Related	(D) Indexed to 2013	(E) Annualized $ @ 10.23%
			(A) / 0.95		(B) or (C) x 1.0350	(D) x 10.23%
1	1 Phase $/kW	$18.63	$19.61		$20.30	$2.08
2						
3	3 Phase $/kW	$18.63	$19.61		$20.30	$2.08
4						
5	1 Phase			$3,256.49	$3,370.47	$344.80
6	$/Transformer					
7						
8	3 Phase			$5,542.43		
9	Dummy Variable					
10						
11	3 Phase			$8,798.92	$9,106.89	$931.63
12	$/Transformer					

Index		Escalation Factor
2011	2013	2011 - 2013
1.0000	1.0350	1.0350

Dist OM

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

Line	Description	(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	(F) 2006	(G) 2007	(H) 2008	(I) 2009	(J) 2010
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	48,122,256	48,559,856	48,811,823	71,993,550	67,011,911	68,781,531	71,602,482	73,614,647	71,075,634	69,087,864
2	Less:										
3	585 St Ltg & Signal Systems	-	-	13,067	89,965	45,553	48,057	75,549	64,882	59,174	58,882
4	586 Meter Expense	1,479,307	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057	2,848,811	2,878,301	2,873,361
5	587 Customer Installation Expense	11,531	9,542	90,751	62,896	-	-	3,636,287	3,568,921	4,456,390	4,466,370
6	596 Main. of St Ltg & Signal Systems	609,632	814,491	756,545	885,374	843,436	851,273	945,804	910,118	1,008,869	1,065,645
7	597 Main. of Meters	664,777	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945	1,433,131	1,465,615	1,360,896
8											
9	Total Adjusted Distribution O & M Expense	45,357,009	45,110,206	44,750,901	67,825,184	62,652,513	64,154,665	63,177,840	64,788,784	61,207,285	59,262,711
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	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	1,590,201,846	1,645,851,699	1,694,776,599
15	Less:										
16	370 Meters	56,108,548	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811	59,791,712	60,319,849	60,008,209
17	373 Street Lighting	15,408,466	16,135,274	16,827,066	17,637,977	18,351,472	19,120,699	20,208,050	21,082,794	21,494,031	21,743,089
18											
19	Adjusted Distribution Plant	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	1,509,327,340	1,564,037,819	1,613,025,300
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	3.78%	3.67%	3.53%	5.18%	4.62%	4.59%	4.35%	4.29%	3.91%	3.67%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	4.16%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	10.23%									
31											
32	Annualized Distribution O & M Loading Factor	40.66%									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Exhibit PAC/1207
Tab 10. Cust. Service Drop

Services 1

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(B) % of Customers 1 & 3 Phase (A) / (A,Ttl)	(C) % of Customers 1 Phase (A) / 1Ø	(D) % of Customers 3 Phase (A) / 3Ø	(E) Overhead Service Drop Cost	(F) Underground Service Drop Cost	(G) Overhead %	(H) Underground %	(I) Weighted Service Drop Cost	(J) Weighted Service Drop Cost 1 & 3 Phase (B) x (E)	(K) Weighted Service Drop Cost 1 Phase (C) x (E)	(L) Weighted Service Drop Cost 3 Phase (D) x (E)
1	Res - Schedule 4	476,340	100.00%	100.00%						$684	$684.34	$684.34	
2	Annualized - Line 1 x 10.23%										$70.01	$70.01	
3													
4	GS - Schedule 23												
5	0-15 kW												
6	kW = 0, 1 Phase	48,560	73.37%	89.19%		$881	$710	67.8%	32.2%	$826	$605.88	$736.46	
7	kW = 0, 3 Phase	3,252	4.91%		27.71%	$1,083	$988	67.8%	32.2%	$1,052	$51.70		$291.61
8	kW > 1, 1 Phase	5,887	8.90%	10.81%		$987	$748	67.8%	32.2%	$910	$80.98	$98.44	
9	kW > 1, 3 Phase	8,482	12.82%		72.29%	$1,166	$1,038	67.8%	32.2%	$1,125	$144.20		$813.29
10	Total 0-15 kW	66,182	100.00%	100.00%	100.00%						$882.76	$834.90	$1,104.90
11	Annualized - Line 10 x 10.23%										$90.31	$85.41	$113.03
12													
13	15+ kW												
14	1 Phase	4,807	45.54%	100.00%		$1,780	$1,322	67.8%	32.2%	$1,632	$743.36	$1,632.44	
15	3 Phase	5,750	54.46%		100.00%	$2,107	$1,902	67.8%	32.2%	$2,041	$1,111.72		$2,041.22
16	Total 15+ kW	10,557	100.00%	100.00%	100.00%						$1,855.08	$1,632.44	$2,041.22
17	Annualized - Line 16 x 10.23%										$189.77	$167.00	$208.82
18													
19	Primary												
20	12.47 KV 4-wire Wye	48	100.00%		100.00%					$0		$0.00	$0.00
21	Annualized - (Line 20) x 10.23%									$0.00	$0.00	$0.00	$0.00
22													
23	GS - Schedule 28												
24	0-50 kW												
25	1 Phase	1,315	29.72%	100.00%		$1,780	$1,322	51.0%	49.0%	$1,555	$462.31	$1,555.44	
26	3 Phase	3,110	70.28%		100.00%	$2,107	$1,902	51.0%	49.0%	$2,007	$1,410.35		$2,006.80
27	Total 0-50 kW	4,426	100.00%	100.00%	100.00%						$1,872.66	$1,555.44	$2,006.80
28	Annualized - Line 27 x 10.23%										$191.57	$159.12	$205.30
29													
30	51-100 kW												
31	1 Phase	472	13.44%	100.00%		$1,780	$1,322	51.0%	49.0%	$1,555	$209.07	$1,555.44	
32	3 Phase	3,038	86.56%		100.00%	$2,107	$1,902	51.0%	49.0%	$2,007	$1,737.06		$2,006.80
33	Total 51-100 kW	3,510	100.00%	100.00%	100.00%						$1,946.13	$1,555.44	$2,006.80
34	Annualized - Line 33 x 10.23%										$199.09	$159.12	$205.30
35													
36	> 101kW												
37	1 Phase	57	2.77%	100.00%		$4,080	$4,003	51.0%	49.0%	$4,042	$112.03	$4,042.43	
38	3 Phase	1,984	97.23%		100.00%	$3,767	$3,740	51.0%	49.0%	$3,754	$3,650.17		$3,754.21
39	Total > 101kW	2,040	100.00%	100.00%	100.00%						$3,762.20	$4,042.43	$3,754.21
40	Annualized - Line 39 x 10.23%										$384.87	$413.54	$384.06
41													
42	Primary												
43	12.47 KV 4-wire Wye	54	100.00%		100.00%					$0	$0.00		$0.00
44	Annualized - (Line 43) x 10.23%										$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2011.

Services 2

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
GS - Schedule 30 / LPS - Schedule 48T

Line	Load Class	(A) Customers	(B) % of Customers 1 & 3 Phase (A) / (A,Ttl)	(E) Overhead Service Drop Cost	(F) Underground Service Drop Cost	(G) Overhead %	(H) Underground %	(I) Weighted Service Drop Cost	(J) Weighted Service Drop Cost 1 & 3 Phase (B) x (E)
1	GS - Schedule 30								
2									
3	0-300 kW								
4	1 Phase	0	0.15%	$4,080	$4,003	28.6%	71.4%	$4,025	$5.99
5	3 Phase	224	99.85%	$3,767	$3,740	28.6%	71.4%	$3,748	$3,742.62
6	Total 0-300 kW	224	100.00%						$3,748.61
7	Annualized - Line 6 x 10.23%								$383.48
8									
9	301+ kW								
10	1 Phase	1	0.18%	$7,919	$6,947	28.6%	71.4%	$7,225	$12.69
11	3 Phase	572	99.82%	$7,919	$6,947	28.6%	71.4%	$7,225	$7,212.58
12	Total 301+ kW	573	100.00%						$7,225.27
13	Annualized - Line 12 x 10.23%								$739.15
14									
15	Primary								
16	12.47 KV 4-wire Wye	54	100.00%					$0	$0.00
17	Annualized - Line 16 x 10.23%								$0.00
18									
19	LPS - Schedule 48T								
20	1 - 4 MW (sec)	112	100.00%		$24,389	0.0%	100.0%	$24,389	$24,388.74
21	Annualized - Line 20 x 10.23%								$2,494.97
22									
23	1 - 4 MW (pri)	65	100.00%					$0	$0.00
24	Annualized - Line 23 x 10.23%								$0.00
25									
26	> 4 MW (sec)	2	100.00%		$24,389	0.0%	100.0%	$24,389	$24,388.74
27	Annualized - Line 26 x 10.23%								$2,494.97
28									
29	> 4 MW (pri)	31	100.00%					$0	$0.00
30	Annualized - Line 29 x 10.23%								$0.00
31									
32	Trans (trn)	5	100.00%					$0	$0.00
33	Annualized - Line 32 x 10.23%								$0.00

Footnote:
Columns (E) & (F) - see Tab 10.3 (Services 3:) `Summary of Average Installed Costs Service Drops'

Services 3

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

Line	Load Class	(A) Service Conductor	(B) Cost	(C) Indexed to 2013 (B) x 1.0350	(D) Percent Use	(E) Total Cost per Service
	Residential					
1	OH - small load	#2 Triplex*	$593	$614	33.9%	$208.36
2	OH - all electric	1/0 Triplex	$682	$706	29.2%	$205.78
3	UG - small load	1/0 Triplex	$686	$710	15.5%	$109.78
4	UG - all electric	4/0 Triplex	$723	$748	21.4%	$160.43
5						$684.34
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	$851	$881		
8		UG - 1/0 Triplex	$686	$710		
9						
10						
11	kW = 0, 3 Phase	OH - 1/0 Quadruplex	$1,046	$1,083		
12		UG - 1/0 Quadruplex	$955	$988		
13						
14						
15	kW > 1, 1 Phase	OH - 4/0 Triplex	$954	$987		
16		UG - 4/0 Triplex	$723	$748		
17						
18						
19	kW > 1, 3 Phase	OH - 4/0 Quadruplex	$1,127	$1,166		
20		UG - 4/0 Quadruplex	$1,003	$1,038		
21						
22	16 - 100 kW					
23	1 Phase	OH - 2-4/0 Triplex	$1,720	$1,780		
24		UG - 2-4/0 Triplex	$1,277	$1,322		
25						
26						
27	3 Phase	OH - 2-4/0 Quadruplex	$2,036	$2,107		
28		UG - 2-4/0 Quadruplex	$1,838	$1,902		
29						
30	101 - 300 kW					
31	1 Phase	3-500 & 350N	$3,942	$4,080		
32		3- 750 & 500 N	$3,868	$4,003		
33						
34						
35	3 Phase	OH - 3-4/0 Quadruplex	$3,640	$3,767		
36		4-350 Quad	$3,614	$3,740		
37						
38	301 - 1000 kW					
39	3 Phase	3-750 kcmil Quad.	$7,651	$7,919		
40		4-750 kcmil Quad.	$6,712	$6,947		
41						
42						
43	1000 kW and Over					
44	Secondary Volt(1)	12-1000 kcmil Quad.	$23,564	$24,389		
45						
46						
47	Primary Volt	---	---	---		---

Index 2011	Index 2013	Escalation Factor 2011 - 2013
1.0000	1.0350	1.0350

		Weighted %
Residential Overhead % =	63.1%	
% of Overhead Which Are Small Load=	53.8%	33.9%
% of Overhead Which Are All Electric=	46.2%	29.2%
Residential Underground % =	36.9%	
% of Underground Which Are Small Load=	41.9%	15.5%
% of Underground Which Are All Electric=	58.1%	21.4%
Total OH & UG		100.0%

Exhibit PAC/1207
Tab 11. Cust. Meters
and O&M

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(B) % of Customers 1 & 3 Phase (A) / (A,Ttl)	(C) % of Customers 1 Phase (A) / 1Ø	(D) % of Customers 3 Phase (A) / 3Ø	(E) Metering Cost	(F) Weighted Metering Cost 1 & 3 Phase (B) x (E)	(G) Weighted Metering Cost 1 Phase (C) x (E)	(H) Weighted Metering Cost 3 Phase (D) x (E)
1	Res - Schedule 4	476,340	100.00%	100.00%		$114	$114.22	$114.22	
2	Annualized - (Line 1) x 10.23%						$11.69	$11.68	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	48,560	73.37%	89.19%		$94	$68.70	$83.50	
7	kW = 0, 3 Phase	3,252	4.91%		27.71%	$209	$10.25		$57.82
8	kW > 1, 1 Phase	5,887	8.90%	10.81%		$164	$14.58	$17.72	
9	kW > 1, 3 Phase	8,482	12.82%		72.29%	$209	$26.74		$150.81
10	Total 0-15 kW	66,182	100.00%	100.00%	100.00%		$120.27	$101.22	$208.63
11	Annualized - (Line 10) x 10.23%						$12.30	$10.35	$21.34
12									
13	15+ kW								
14	1 Phase	4,807	45.54%	100.00%		$203	$92.22	$202.52	
15	3 Phase W/O KVAR	4,557	43.17%		79.26%	$209	$90.06		$165.35
16	3 Phase With KVAR	1,193	11.30%		20.74%	$242	$27.36		$50.24
17	Total 15+ kW	10,557	100.00%	100.00%	100.00%		$209.64	$202.52	$215.59
18	Annualized - (Line 17) x 10.23%						$21.45	$20.72	$22.05
19									
20	Primary								
21	12.47 KV 4-wire Wye	48	100.00%		100.00%	$10,192	$10,192.27		$10,192.27
22	Annualized - (Line 21) x 10.23%						$1,042.67	$0.00	$1,042.67
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	2	0.04%	0.14%		$203	$0.08	$0.29	
27	kW = 0, 3 Phase	7	0.15%		0.21%	$209	$0.31		$0.45
28	kW > 1, 1 Phase	1,314	29.68%	99.86%		$203	$60.11	$202.24	
29	kW > 1, 3 Phase	3,104	70.13%		99.79%	$209	$146.31		$208.18
30	Total 0-50 kW	4,426	100.00%	100.00%	100.00%		$206.81	$202.53	$208.63
31	Annualized - (Line 30) x 10.23%						$21.16	$20.72	$21.34
32									
33	51-100 kW								
34	1 Phase	472	13.44%	100.00%		$203	$27.22	$202.52	
35	3 Phase W/O KVAR	1,593	45.39%		52.44%	$209	$94.70		$109.40
36	3 Phase With KVAR	1,445	41.17%		47.56%	$242	$99.72		$115.20
37	Total 51-100 kW	3,510	100.00%	100.00%	100.00%		$221.64	$202.52	$224.60
38	Annualized - (Line 37) x 10.23%						$22.67	$20.72	$22.98
39									
40	> 101kW								
41	1 Phase	57	2.77%	100.00%		$1,032	$28.60	$1,031.95	
42	3 Phase W/O KVAR	789	38.67%		39.77%	$1,392	$538.36		$553.71
43	3 Phase With KVAR	1,195	58.56%		60.23%	$1,392	$815.27		$838.50
44	Total > 101kW	2,040	100.00%	100.00%	100.00%		$1,382.23	$1,031.95	$1,392.21
45	Annualized - (Line 44) x 10.23%						$141.40	$105.57	$142.42
46									
47	Primary								
48	12.47 KV 4-wire Wye	54	100.00%		100.00%	$10,192	$10,192.27		$10,192.27
49	Annualized - (Line 48) x 10.23%						$1,042.67	$0.00	$1,042.67

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2011.

Meters 2

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 (A) / (A,Ttl)	(C) % of Customers 1 Phase (A) / 1Ø	(D) % of Customers 3 Phase (A) / 3Ø	(E) Metering Cost	(F) Weighted Metering Cost 1 & 3 Phase (B) x (E)	(G) Weighted Metering Cost 1 Phase (C) x (E)	(H) Weighted Metering Cost 3 Phase (D) x (E) (F) x 10.23%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	0	0.15%	100.00%		$1,032	$1.54	$1,031.95	
4	3 Phase W/O KVAR	40	17.82%		17.85%	$1,392	$248.14		$248.51
5	3 Phase With KVAR	184	82.03%		82.15%	$1,392	$1,142.00		$1,143.71
6	Total 0-300 kW	224	100.00%	100.00%	100.00%		$1,391.68	$1,031.95	$1,392.22
7	Annualized - (Line 6) x 10.23%						$142.37	$105.57	$142.42
8									
9	301+ kW								
10	1 Phase	1	0.18%	100.00%		$1,193	$2.09	$1,192.74	
11	3 Phase W/O KVAR	78	13.70%		13.72%	$1,392	$190.72		$191.05
12	3 Phase With KVAR	493	86.13%		86.28%	$1,392	$1,199.05		$1,201.16
13	301+ kW	573	100.00%	100.00%	100.00%		$1,391.86	$1,192.74	$1,392.21
14	Annualized - (Line 13) x 10.23%						$142.39	$122.02	$142.42
15									
16	Primary								
17	12.47 KV 4-wire Wye	54	100.00%		100.00%	$10,192	$10,192.27		$10,192.27
18	Annualized - (Line 17) x 10.23%						$1,042.67		$1,042.67
19									
20	LPS - Schedule 48T								
21	1 - 4 MW (sec)	112	100.00%		100.00%	$1,795	$1,795.22		$1,795.22
22	Annualized - (Line 21) x 10.23%						$183.65		$183.65
23									
24	1 - 4 MW (pri)	65	100.00%		100.00%	$10,192	$10,192.27		$10,192.27
25	Annualized - (Line 24) x 10.23%						$1,042.67		$1,042.67
26									
27	> 4 MW (sec)	2	100.00%		100.00%	$1,795	$1,795.22		$1,795.22
28	Annualized - (Line 27) x 10.23%						$183.65		$183.65
29									
30	> 4 MW (pri)	31	100.00%		100.00%	$10,192	$10,192.27		$10,192.27
31	Annualized - (Line 30) x 10.23%						$1,042.67		$1,042.67
32									
33	Trans (trn)	5	100.00%		100.00%	$319,805	$319,804.50		$319,804.50
34	Annualized - (Line 33) x 10.23%						$32,716.00		$32,716.00
35									
36									
37	Irrigation - Schedule 41 (Annual)								
38	0 - 50 kW								
39	kW = 0, 1 Phase	234	2.81%	18.58%		$94	$2.63	$17.40	
40	kW = 0, 3 Phase	1,040	12.51%		14.74%	$209	$26.10		$30.75
41	kW > 1, 1 Phase	1,024	12.32%	81.42%		$164	$20.18	$133.41	
42	kW > 1, 3 Phase	4,016	48.31%		56.93%	$209	$100.80		$118.77
43									
44	51 - 300 kW								
45	1 Phase	-	0.00%	0.00%		$203	$0.00	$0.00	
46	3 Phase W/O KVAR	1,130	13.59%		16.02%	$209	$28.36		$33.42
47	3 Phase With KVAR	814	9.79%		11.54%	$242	$23.72		$27.95
48									
49	> 300 kW								
50	1 Phase	-	0.00%	0.00%		$1,193	$0.00	$0.00	
51	3 Phase W/O KVAR	10	0.12%		0.14%	$1,392	$1.67		$1.97
52	3 Phase With KVAR	45	0.54%		0.64%	$1,392	$7.51		$8.85
53	Total Irrigation	8,312	100.00%	100.00%	100.00%		$210.97	$150.81	$221.71
54							$21.58	$15.43	$22.68
55									
56	Primary	-	100.00%		100.00%	$0	$0.00		$0.00
57							$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2011.

Meters 3

PacifiCorp
Oregon Marginal Cost Study
Incremental 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 10.23%			(F) - (E)	(G) x 10.23%
1	Residential	$114.22	$208.63	$94.41	$9.66	$684.34	$1,047.86	$363.52	$37.19
2									
3	0-15 kW	$93.63	$208.63	$115.00	$11.76	$910.34	$1,125.09	$214.74	$21.97
4									
5	16-100 kW	$202.52	$208.63	$6.11	$0.62	$1,632.44	$2,041.22	$408.78	$41.82
6									
7	101-1000 kW	$1,192.74	$1,392.21	$199.47	$20.41	$4,042.43	$3,754.21	($288.22)	($29.48)
8									
9	1 - 4 MW	N.A.	$1,795.22	N.A.	N.A.	N.A.	$24,388.74	N.A.	N.A.

Meters 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2012 Dollars	(C) Indexed to 2013	(D) Percent Use	(E) Total Installed Cost per Meter
	Residential					
1	Small Load	DM221A	$92.00	$93.63	49.41%	$46.26
2	All Electric)	DM221D	$132.00	$134.34	50.59%	$67.96
3					100.00%	$114.22
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase	DM221A	$92.00	$93.63	100.00%	$93.63
7						
8	kW = 0, 3 Phase	DM241A	$205.00	$208.63	100.00%	$208.63
9						
10	kW > 1, 1 Phase	DM221B	$161.00	$163.85	100.00%	$163.85
11						
12	kW > 1, 3 Phase	DM241A	$205.00	$208.63	100.00%	$208.63
13						
14						
15	15 - 100 kW					
16	1 Phase	DM221C	$199.00	$202.52	100.00%	$202.52
17						
18	3 Phase wo / KVAR	DM241A	$205.00	$208.63	100.00%	$208.63
19						
20	3 Phase with KVAR	DM241B	$238.00	$242.21	100.00%	$242.21
21						
22						
23	100 - 300 kW					
24	1 Phase	DM231ABB	$1,014.00	$1,031.95	100.00%	$1,031.95
25						
26	3 Phase wo / KVAR	DM271AEC	$1,368.00	$1,392.21	100.00%	$1,392.21
27						
28	3 Phase with KVAR	DM271AEC	$1,368.00	$1,392.21	100.00%	$1,392.21
29						
30						
31	300-1000 kW					
32	W/O KVAR, 1 Phase	DM231AFE	$1,172.00	$1,192.74	100.00%	$1,192.74
33						
34	W/O KVAR, 3 Phase	DM271AEC	$1,368.00	$1,392.21	100.00%	$1,392.21
35						
36	W/KVAR, 3 Phase	DM271AEC	$1,368.00	$1,392.21	100.00%	$1,392.21
37						
38						
39	1000 kW and over					
40	Secondary Volt	DM271AEG	$1,764.00	$1,795.22	100.00%	$1,795.22
41						
42	Primary Metering					
43	13.8 KV 3-wire	DM101ACBI	$7,699.00	$7,835.27		$7,835.27
44	12.47 KV 4-wire Wye	DM121DBBI	$10,015.00	$10,192.27		$10,192.27
45	24.9 KV 4-wire Wye	DM121DGBI	$14,126.00	$14,376.03		$14,376.03
46	35 KV 4-wire Wye	DM131DBH	$28,492.00	$28,996.31		$28,996.31

Index		Escalation Factor
2012	2013	2012 - 2013
1.0170	1.0350	1.0177

Meters 5

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

Line	Description	(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	(F) 2006	(G) 2007	(H) 2008	(I) 2009	(J) 2010
	Distribution Meters Expenses										
1	586 Meter Expense	1,479,307	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057	2,848,811	2,878,301	2,873,361
2	597 Main. of Meters	664,777	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945	1,433,131	1,465,615	1,360,896
3											
4	Total Adjusted Distribution Meters Expens	2,144,084	2,625,617	3,200,559	3,130,131	3,470,409	3,727,536	3,767,002	4,281,942	4,343,916	4,234,257
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	56,108,548	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811	59,791,712	60,319,849	60,008,209
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	3.82%	4.60%	5.63%	5.52%	5.97%	6.38%	6.37%	7.16%	7.20%	7.06%
16	Line 3 / Line 4										
17											
18	Average Meter O&M Loading	5.97%									
19	Average of Line 5										
20											
21	Distribution Annual Charge	10.23%									
22											
23	Annualized Meter O&M Loading Factor	58.37%									
24	Line 6 / Line 7										

Exhibit PAC/1207
Tab 12. Street Lighting

Streetlight 1

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Commitment & Billing Related Cost per Customer

Line	Description	100 Watt HPSV	150 Watt HPSV	250 Watt HPSV	400 Watt HPSV	Schedule 53 Customer Owned	Schedule 54 Customer Owned
1	Light Installation Cost - per lamp	$176.72	$195.20	$220.78	$289.56	N. A.	N. A.
2							
3	Distribution Commitment Costs - per customer						
4	Acct. 364 Poles	$79.20	$79.20	$79.20	$79.20	$79.20	$79.20
5	Acct. 365 Conductors	$38.91	$38.91	$38.91	$38.91	$38.91	$38.91
6	Acct. 368 Transformers	N. A.	N. A.	N. A.	N. A.	130.78	188.66
7	Dist O&M at 40.7% of Annual Charge	$48.02	$48.02	$48.02	$48.02	$101.20	$124.73
8	Acct. 370 Meters	N. A.	N. A.	N. A.	N. A.	N. A.	$12.30
9	Meter O&M at 58.37% of Annual Charge	N. A.	N. A.	N. A.	N. A.	N. A.	$7.18
10	Total Commitment Related	$166.13	$166.13	$166.13	$166.13	$350.09	$450.99
11							
12	Billing Costs per Customer	$40.68	$40.68	$40.68	$40.68	$40.68	$62.89
13							
14	Total Marginal Commitment & Billing Cost per Cust.	$206.82	$206.82	$206.82	$206.82	$390.78	$513.88

Sources:
Line 1 "Distribution Cost Development For Street Lighting"
Line 4 `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 5 `Hypothetical Circuit 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

Streetlight 2

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Full Marginal Cost by Schedule

Line	Description	Units	Schedule 51 High Pressure Sodium Vapor				Schedule 53 Customer Owned	Schedule 54 Customer Owned	Total Streetlighting
			9,500 Lumen 100 Watt	16,000 Lumen 150 Watt	27,500 Lumen 250 Watt	50,000 Lumen 400 Watt			
	Energy								
1	Generation Energy $/kWh @ Generator	$/kWh	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	$0.06062	
2	Transmission Energy $/kWh @ Generator	$/kWh	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	$0.00347	
3									
4	Energy @ Meter 2011	kWh	7,440,920	222,364	513,028	2,450,119	9,548,236	1,138,574	
5	Energy @ Meter 2013		7,492,489	223,905	516,584	2,467,100	9,578,780	1,189,338	21,468,196
6	Losses		1.10006	1.10006	1.10006	1.10006	1.10006	1.10006	
7	Energy @ Generator - (5)*(6)	kWh	8,242,187	246,309	568,273	2,713,958	10,537,233	1,308,343	23,616,304
8									
9	Generation Energy Related Marginal Costs - (1)*(7)	$	$499,641	$14,931	$34,449	$164,520	$638,767	$79,312	$1,431,620
10	Transmission Energy Related Marginal Costs - (2)*(7)	$	$28,604	$855	$1,972	$9,419	$36,569	$4,541	$81,959
11									
12	Commitment								
13	Total of Monthly Lamp Billing Units 2013	#	170,285	3,498	4,492	14,018			
14	Number of Lamps 2013 - (13) / 12	#	14,190	292	374	1,168			
15	Light Installation Cost	$/Lamp	$176.72	$195.20	$220.78	$289.56			
16	Light Installation Related		$2,507,697	$56,901	$82,644	$338,249			$2,985,491
17									
18	Average customers - 2013	#	273	37	54	71	260	103	798
19									
20									
21	Acct. 364 Poles		$79.20	$79.20	$79.20	$79.20	$79.20	$79.20	
22	Acct. 365 Conductors		$38.91	$38.91	$38.91	$38.91	$38.91	$38.91	
23	Acct. 368 Transformers		N. A.	N. A.	N. A.	N. A.	$130.78	$188.66	
24	Acct. 370 Meters							$12.30	
25									
26	Acct. 364 Poles with O&M		$30,432	$4,122	$6,016	$7,910	$28,936	$11,474	$88,890
27	Acct. 365 Conductors with O&M		$14,951	$2,025	$2,955	$3,886	$14,216	$5,637	$43,671
28	Acct. 368 Transformers with O&M		N.A.	N.A.	N.A.	N.A.	$47,782	$27,333	$75,115
29	Acct. 370 Meter with O&M		N.A.	N.A.	N.A.	N.A.	N.A.	$2,006	$2,006
30	Total Poles, Conductors, Transfomers		$45,383	$6,147	$8,971	$11,795	$90,934	$46,452	$209,682
31									
32	Total Commitment Marginal Cost		$2,553,080	$63,048	$91,615	$350,044	$90,934	$46,452	$3,195,173
33									
34	Billing / Customer								
35	Billing Related	$/Customer	$31.44	$31.44	$31.44	$31.44	$31.44	$31.44	
36	Meter Reading	$/Customer	-	-	-	-	-	$22.21	
37	Customer Other	$/Customer	$9.25	$9.25	$9.25	$9.25	$9.25	$9.25	
38									
39	Billing Related	$	8,588	1,163	1,698	2,232	8,166	3,238	$25,085
40	Meter Reading	$	-	-	-	-	-	2,287	$2,287
41	Customer Other	$	2,526	342	499	656	2,401	952	$7,377
42	Total Billing Related Marginal Cost		$11,114	$1,505	$2,197	$2,889	$10,567	$6,478	$34,749
43									
44	Total Marginal Cost		$3,092,439	$80,339	$130,233	$526,872	$776,837	$136,782	$4,743,502

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$713,541	$638,767	$79,312	$1,431,620
Transmission	$40,850	$36,569	$4,541	$81,959
Distribution	$3,057,788	$90,934	$46,452	$3,195,173
Customer - Billing	$13,681	8,166	3,238	$25,085
Customer - Metering	-	-	2,287	$2,287
Customer - Other	4,023	2,401	952	$7,377
	$3,829,883	$776,837	$136,782	$4,743,502

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$713.54	$638.77	$79.31	$1,431.62
Transmission	$40.85	$36.57	$4.54	$81.96
Distribution	$3,057.79	$90.93	$46.45	$3,195.17
Customer - Billing	$13.68	$8.17	$3.24	$25.09
Customer - Metering	$0.00	$0.00	$2.29	$2.29
Customer - Other	$4.02	$2.40	$0.95	$7.38

Streetlight 3

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			
			9,500 Lumen 100 Watt	16,000 Lumen 150 Watt	27,500 Lumen 250 Watt	50,000 Lumen 400 Watt
1	Installed Cost Per Unit					
2	Lamp Cost per unit including pole, luminaire,					
3	p.e.control, mast arm and wiring					
4	Without Pole (Functional)		$679.00	$696.00	$868.00	$1,244.00
5	Wood Pole Cost		$770.00	$1,064.00	$1,093.00	$840.00
6	Percent of Wood Pole Utilized		16.67%	20.00%	20.00%	50.00%
7	Adjusted Wood Pole Cost		$128.33	$212.80	$218.60	$420.00
8						
9	Installed Lamp Cost for Analysis	2009 $	$807.33	$908.80	$1,086.60	$1,664.00
10	Index		1.0350	1.0350	1.0350	1.0350
11	Revised Lamp Cost	2011 $	$835.59	$940.61	$1,124.63	$1,722.24
12						
13						
14	Transformer Cost	2009 $	$15.28	$22.33	$39.82	$61.10
15	Index		1.0350	1.0350	1.0350	1.0350
16	Revised Transformer Cost	2011 $	$15.81	$23.11	$41.21	$63.24
17						
18	Total Installed Cost		$851.40	$963.72	$1,165.85	$1,785.48
19						
20	Annual Cost @	10.23%	$87.10	$98.59	$119.27	$182.65
21						
22						
23	Operation & Maintenance					
24	Annual Maintenance Per Unit	2009 $	$86.59	$93.35	$98.08	$103.29
25	Index		1.0350	1.0350	1.0350	1.0350
26		2011 $	$89.62	$96.61	$101.51	$106.90
27						
28						
29	Total Cost per Unit	2011 $	$176.72	$195.20	$220.78	$289.56
30						
31						
32						
33						
34	Assumptions:					
35	Annual Maintenance Per Unit - Percentage of installed cost from 11/99 study.					
36	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.					
37	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.					
38	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.					
39	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.					
40						

Streetlight 4

PacifiCorp
Oregon Marginal Cost Study
Cost of Streetlighting Transformer

Transformer Cost Per Light - 100 Watt			Transformer Cost Per Light - 250 Watt		
Assume Installed Cost* 25 KVA Transformer is		$ 3,264	Assume Installed Cost* 25 KVA Transformer is		$ 3,264
Lamp Line Watts	=	117 watts	Lamp Line Watts	=	305 watts
Transformer Cost = Total Watts/25,000 X Installed Cost			Transformer Cost = Total Watts/25,000 X Installed Cost		
117 / 25000 X $3264 =		$ 15.28	305 / 25000 X $3264 =		$ 39.82
Transformer Cost Per Light - 150 Watt			**Transformer Cost Per Light - 400 Watt**		
Assume Installed Cost* 25 KVA Transformer is		$ 3,264	Assume Installed Cost* 25 KVA Transformer is		$ 3,264
Lamp Line Watts	=	171 watts	Lamp Line Watts	=	468 watts
Transformer Cost = Total Watts/25,000 X Installed Cost			Transformer Cost = Total Watts/25,000 X Installed Cost		
171 / 25000 X $3264 =		$ 22.33	468 / 25000 X $3264 =		$ 61.10

Exhibit PAC/1207
Tab 13. Cust. Acctg.,
Service & Info

Cust Exp Sum

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2013 Dollars

Line	FERC Account	Description	(A) Sch. 4 Residential	(B) Sch. 23 General Service	(C) Sch. 28 General Service	(D) Sch. 30 General Service	(E) Sch. 48T General Service	(F) Sch. 41 Irrigation	(G) Streetlighting	(H) Total
1		Average Number of Customers	479,457	75,334	9,817	815	208	3,154	798	569,582
2										
3		Write-offs By Schedule	4,041,068	136,720	178,895	98,266	118,845	15,627	-	4,589,422
4										
5	901									
6	Supervision	Account 902 + 903 + 904	$28,628,164	$4,299,952	$930,672	$194,068	$197,599	$275,522	$28,954	$34,554,929
7		% of Total 902 + 903 +904	82.85%	12.44%	2.69%	0.56%	0.57%	0.80%	0.08%	100.00%
8		Total 901 $	$1,491,538	$224,029	$48,488	$10,111	$10,295	$14,355	$1,508	$1,800,325
9		Dollars Per Customer	$3.11	$2.97	$4.94	$12.41	$49.50	$4.55	$1.89	$3.16
10	902									
11	Meter Reading Expense	902 Weighting Factor	1.00	1.42	2.47	4.24	11.05	3.13	0.31	
12		Weighted Customers	479,457	106,974	24,248	3,456	2,298	9,870	247	626,551
13		% of Total $	76.52%	17.07%	3.87%	0.55%	0.37%	1.58%	0.04%	100.00%
14		Total 902 $	$7,498,399	$1,673,009	$379,223	$54,043	$35,945	$154,368	$3,868	$9,798,856
15		Dollars Per Customer	$15.64	$22.21	$38.63	$66.31	$172.81	$48.95	$4.85	$17.20
16	903									
17	Cust. Receipts & Collect.	903 Weighting Factor	1.00	0.95	1.03	1.03	3.81	0.95	0.91	
18		Weighted Customers	479,457	71,567	10,112	839	792	2,996	726	566,490
19		% of Total $	84.64%	12.63%	1.78%	0.15%	0.14%	0.53%	0.13%	100.00%
20		Total 903 $	$16,564,052	$2,472,473	$349,328	$29,001	$27,378	$103,498	$25,085	$19,570,815
21		Dollars Per Customer	$34.55	$32.82	$35.58	$35.58	$131.63	$32.82	$31.44	$34.36
22	904									
23	Uncollectibles	Total 904 $	$4,565,713	$154,470	$202,121	$111,024	$134,275	$17,656	$0	$5,185,258
24		% of Write-offs	88.05%	2.98%	3.90%	2.14%	2.59%	0.34%	0.00%	
25		Dollars Per Customer	$9.52	$2.05	$20.59	$136.23	$645.55	$5.60	$0.00	$9.10
26	905									
27	Misc Cust Acct Expense	Account 902 + 903 + 904	$28,628,164	$4,299,952	$930,672	$194,068	$197,599	$275,522	$28,954	$34,554,929
28		% of Total 902 + 903 +904	82.85%	12.44%	2.69%	0.56%	0.57%	0.80%	0.08%	100.00%
29		Total 905 $	$140,574	$21,114	$4,570	$953	$970	$1,353	$142	$169,677
30		Dollars Per Customer	$0.29	$0.28	$0.47	$1.17	$4.66	$0.43	$0.18	$0.30
31	907-910									
32	Supervision, Cust. Assist.	Average Number of customers	479,457	75,334	9,817	815	208	3,154	798	569,582
33	Info & Instructional Exp.,	% of Total	84.18%	13.23%	1.72%	0.14%	0.04%	0.55%	0.14%	100.00%
34	Misc Cust Svc & Info Exp.		$3,440,737	$540,621	$70,450	$5,849	$1,493	$22,631	$5,726	$4,087,506
35		Dollars Per Customer	$7.18	$7.18	$7.18	$7.18	$7.18	$7.18	$7.18	$7.18
36										
37	Total 901 - 910	Total 901 - 910 $	$33,701,013	$5,085,716	$1,054,180	$210,981	$210,357	$313,860	$36,330	$40,612,437
38										
39		Dollars Per Customer	$70.29	$67.51	$107.38	$258.87	$1,011.33	$99.53	$45.53	$71.30

Cust Exp Year

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2013 Dollars

Line	Description	(A) Actual 2006 Dollars	(B) Actual 2007 Dollars	(C) Actual 2008 Dollars	(D) Actual 2009 Dollars	(E) Actual 2010 Dollars	(F) Adjusted 2013 Dollars
							[(A) x 1.1309+ (B) x 1.1112+ (C) x 1.0918+ (D) x 1.0728+ (E) x 1.0541] / 5
	Customer Accounting						
1	901 Supervision	4,869,032	900,404	768,055	788,080	769,087	$1,800,325
2	902 Meter Reading Expense	7,127,052	9,563,375	9,190,112	9,195,750	9,874,311	$9,798,856
3	903 Cust Records & Collection	17,663,200	17,918,701	18,662,255	18,060,493	17,281,809	$19,570,815
4	904 Uncollectible Accounts	5,205,538	3,555,170	6,272,907	4,220,604	4,470,369	$5,185,258
5	905 Misc Cust Acct Expense	417,356	124,686	77,974	87,564	55,759	$169,677
6	Total	35,282,178	32,062,336	34,971,303	32,352,491	32,451,335	$36,524,931
7							
8	Customer Service & Info Expense						
9	907 Supervision	429,900	138,616	77,577	88,905	81,203	$181,175
10	908 Cust Assistance Expense	2,358,698	2,488,601	1,998,956	2,164,154	2,165,667	$2,443,956
11	909 Info & Instructional Expense	996,352	1,248,551	1,236,009	1,706,781	1,433,382	$1,441,120
12	910 Misc Cust Svc & Info Expense	3,238	1,429	19,976	46,577	27,745	$21,255
13	Total	3,788,188	3,877,197	3,332,518	4,006,417	3,707,997	$4,087,506
14							$40,612,437
15	Distribution Expenses						
16	586 Meter Expenses	$2,058,440	$2,206,057	$2,848,811	$2,878,301	$2,873,361	$2,801,249
17	597 Meter Maintenance	$1,669,096	$1,560,945	$1,433,131	$1,465,615	$1,360,896	$1,638,725
18		$3,727,536	$3,767,002	$4,281,942	$4,343,916	$4,234,257	$4,439,974
19							
20							
21	(1) Inflation Adjustment -	1.1309	1.1112	1.0918	1.0728	1.0541	

Source:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Exhibit PAC/1207
Tab 14. A&G Expense
Loading Factor

AG Expenses

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)
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%
2008	$170,044	$18,224,943	0.93%
2009	$162,620	$19,645,569	0.83%
2010	$146,076	$21,775,587	0.67%
10 Year Average A&G to EPIS Loading Factor			1.41%

Footnotes:
(A) FERC Form 1 Page 322-323
(B) FERC Form 1 Page 206-207

Exhibit PAC/1207
Tab 15. Annual Charges

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	1.13%	1.17%
3	Total	NA	NA	NA	3.15%	3.21%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$31.50	$32.10
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	58	50
9						
10	Nominal Interest Rate *	7.92%	7.92%	7.92%	7.92%	7.92%
11						
12	Present Value: Income **	NA	NA	NA	$392.88	$396.27
13	Taxes & Property Taxes per				(PV of $31.50 per year	(PV of $32.10 per year
14	$1,000 of Investment				for 58 years at 7.92%)	for 50 years at 7.92%)
15						
16	Removal Cost Per $1,000 Investment				$204.38	$463.24
17						
18	Present Value: Removal Cost				$2.46	$10.24
19	at End of Useful Life				(PV of $204.38 in	(PV of $463.24 in
20					58 years at 7.92%)	50 years at 7.92%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,395.34	$1,406.51
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.019922	0.041564
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$27.80	$58.46
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,423.14	$1,464.97
30						
31	EOY Annual Charge ***	$82.49	$128.38	$224.12	$83.87	$88.15
32						
33	Annual Economic Carrying	8.25%	12.84%	22.41%	8.39%	8.82%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	1.41%	1.41%
35						
36	Annual Econ Carrying + A&G Loading	8.25%	12.84%	22.41%	9.80%	10.23%

Footnotes:

From Financial Analysis -

** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]

31.50*(1/0.0792-(1/0.0792)/(1+0.0792)^58)
32.10*(1/0.0792-(1/0.0792)/(1+0.0792)^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 = 1.8%
a = expected investment life
r = nominal interest rate

Charge 2

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	7.92%	Income Taxes	
2	Borrowing Rate	7.92%	Transmission	2.02%
3	Inflation	1.77%	Distribution	2.04%
4			Property Taxes	
5	Real Cost of Capital		Transmission	1.13%
6	(1+0.0792)/(1+0.0177)-1 =	6.04%	Distribution	1.17%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: Financial Analysis, Use of Facilities Charges 12/31/10 Basis (prepared 7/21/11)
Inflation Rate, 2009 Avoided Cost, Table 8

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 = 6.04%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.5
	({(A) {yr-1} +(I)) / 100	({J,{yr-1}}-(J)) * 100	(B)	1.0604 ^Year	(C) / (D)	(B)	1.0604 ^58	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000144	1.59%	0.0159	1.060412	0.014958	0.0159	30.028784	0.000528	0.014430	99.9841
2	0.000416	3.17%	0.0317	1.124474	0.028212	0.0317	30.028784	0.001056	0.027156	99.9524
3	0.000671	3.17%	0.0317	1.192407	0.026605	0.0317	30.028784	0.001056	0.025549	99.9207
4	0.000981	4.08%	0.0408	1.264443	0.032289	0.0408	30.028784	0.001360	0.030929	99.8799
5	0.001315	4.69%	0.0469	1.340831	0.034976	0.0469	30.028784	0.001562	0.033414	99.8330
6	0.001629	4.69%	0.0469	1.421833	0.032983	0.0469	30.028784	0.001562	0.031421	99.7861
7	0.002017	6.16%	0.0616	1.507730	0.040870	0.0616	30.028784	0.002052	0.038818	99.7244
8	0.002419	6.79%	0.0679	1.598815	0.042488	0.0679	30.028784	0.002262	0.040226	99.6565
9	0.002797	6.79%	0.0679	1.695404	0.040068	0.0679	30.028784	0.002262	0.037806	99.5886
10	0.003267	8.97%	0.0897	1.797827	0.049907	0.0897	30.028784	0.002988	0.046919	99.4989
11	0.003734	9.52%	0.0952	1.906438	0.049922	0.0952	30.028784	0.003169	0.046752	99.4037
12	0.004173	9.52%	0.0952	2.021610	0.047078	0.0952	30.028784	0.003169	0.043908	99.3085
13	0.004723	12.68%	0.1268	2.143741	0.059162	0.1268	30.028784	0.004224	0.054938	99.1817
14	0.005253	13.03%	0.1303	2.273249	0.057339	0.1303	30.028784	0.004341	0.052998	99.0513
15	0.005750	13.03%	0.1303	2.410582	0.054072	0.1303	30.028784	0.004341	0.049731	98.9210
16	0.006374	17.45%	0.1745	2.556211	0.068258	0.1745	30.028784	0.005811	0.062448	98.7465
17	0.006960	17.45%	0.1745	2.710637	0.064370	0.1745	30.028784	0.005811	0.058559	98.5720
18	0.007526	17.99%	0.1799	2.874393	0.062598	0.1799	30.028784	0.005992	0.056606	98.3921
19	0.008201	22.90%	0.2290	3.048042	0.075119	0.2290	30.028784	0.007625	0.067494	98.1631
20	0.008833	22.90%	0.2290	3.232182	0.070839	0.2290	30.028784	0.007625	0.063214	97.9342
21	0.009459	24.21%	0.2421	3.427446	0.070647	0.2421	30.028784	0.008064	0.062583	97.6920
22	0.010172	29.48%	0.2948	3.634506	0.081119	0.2948	30.028784	0.009818	0.071301	97.3972
23	0.010839	29.48%	0.2948	3.854075	0.076498	0.2948	30.028784	0.009818	0.066679	97.1024
24	0.011512	31.83%	0.3183	4.086909	0.077885	0.3183	30.028784	0.010600	0.067285	96.7841
25	0.012248	37.31%	0.3731	4.333809	0.086091	0.3731	30.028784	0.012425	0.073666	96.4110
26	0.012936	37.31%	0.3731	4.595624	0.081187	0.3731	30.028784	0.012425	0.068762	96.0379
27	0.013640	40.98%	0.4098	4.873257	0.084090	0.4098	30.028784	0.013647	0.070444	95.6281
28	0.014385	46.48%	0.4648	5.167662	0.089949	0.4648	30.028784	0.015479	0.074470	95.1632
29	0.015079	46.48%	0.4648	5.479853	0.084825	0.4648	30.028784	0.015479	0.069345	94.6984
30	0.015797	51.79%	0.5179	5.810903	0.089131	0.5179	30.028784	0.017248	0.071883	94.1805
31	0.016534	57.10%	0.5710	6.161954	0.092671	0.5710	30.028784	0.019016	0.073655	93.6094
32	0.017218	57.10%	0.5710	6.534212	0.087391	0.5710	30.028784	0.019016	0.068375	93.0384
33	0.017933	64.45%	0.6445	6.928960	0.093013	0.6445	30.028784	0.021462	0.071551	92.3939
34	0.018646	69.34%	0.6934	7.347555	0.094378	0.6934	30.028784	0.023093	0.071285	91.7005
35	0.019305	69.34%	0.6934	7.791438	0.089001	0.6934	30.028784	0.023093	0.065909	91.0070
36	0.020000	79.17%	0.7917	8.262137	0.095821	0.7917	30.028784	0.026364	0.069457	90.2153
37	0.020674	83.38%	0.8338	8.761272	0.095168	0.8338	30.028784	0.027766	0.067402	89.3816
38	0.021293	83.38%	0.8338	9.290562	0.089746	0.8338	30.028784	0.027766	0.061980	88.5478
39	0.021951	96.34%	0.9634	9.851827	0.097794	0.9634	30.028784	0.032084	0.065710	87.5843
40	0.022572	99.59%	0.9959	10.446999	0.095325	0.9959	30.028784	0.033164	0.062162	86.5884
41	0.023140	99.59%	0.9959	11.078127	0.089894	0.9959	30.028784	0.033164	0.056731	85.5926
42	0.023742	116.28%	1.1628	11.747383	0.098986	1.1628	30.028784	0.038724	0.060262	84.4298
43	0.024297	118.14%	1.1814	12.457070	0.094836	1.1814	30.028784	0.039342	0.055494	83.2484
44	0.024798	118.14%	1.1814	13.209632	0.089433	1.1814	30.028784	0.039342	0.050092	82.0670
45	0.025328	139.28%	1.3928	14.007657	0.099428	1.3928	30.028784	0.046381	0.053048	80.6742
46	0.025802	139.28%	1.3928	14.853893	0.093764	1.3928	30.028784	0.046381	0.047383	79.2815
47	0.026230	141.63%	1.4163	15.751252	0.089920	1.4163	30.028784	0.047166	0.042753	77.8651
48	0.026663	162.86%	1.6286	16.702822	0.097506	1.6286	30.028784	0.054235	0.043270	76.2365
49	0.027040	162.86%	1.6286	17.711879	0.091951	1.6286	30.028784	0.054235	0.037715	74.6079
50	0.027375	167.95%	1.6795	18.781896	0.089422	1.6795	30.028784	0.055930	0.033492	72.9284
51	0.027693	188.31%	1.8831	19.916555	0.094550	1.8831	30.028784	0.062710	0.031840	71.0453
52	0.027958	188.31%	1.8831	21.119762	0.089163	1.8831	30.028784	0.062710	0.026453	69.1622
53	0.028180	196.04%	1.9604	22.395657	0.087534	1.9604	30.028784	0.065283	0.022251	67.2018
54	0.028369	214.07%	2.1407	23.748632	0.090139	2.1407	30.028784	0.071288	0.018852	65.0611
55	0.028506	214.07%	2.1407	25.183343	0.085004	2.1407	30.028784	0.071288	0.013716	62.9204
56	0.028598	223.53%	2.2353	26.704729	0.083705	2.2353	30.028784	0.074439	0.009266	60.6851
57	0.028646	237.72%	2.3772	28.318025	0.083948	2.3772	30.028784	0.079165	0.004783	58.3079
58	0.028646	237.72%	2.3772	30.028784	0.079165	2.3772	30.028784	0.079165	0.000000	55.9306
59	0.028599	246.88%	2.4688	31.842894	0.077530	2.4688	30.028784	0.082214	-0.004684	53.4618
60	0.028505	256.03%	2.5603	33.766599	0.075825	2.5603	30.028784	0.085263	-0.009438	50.9015

Charge 4

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life
Page 2 of 2

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0604 ^Year	(C) / (D)	(B)	1.0604 ^58	(F) / (G)	(E) - (H)	(Given)
61	0.028367	256.03%	2.5603	35.806520	0.071505	2.5603	30.028784	0.085263	-0.013758	48.3411
62	0.028185	261.70%	2.6170	37.969677	0.068924	2.6170	30.028784	0.087151	-0.018227	45.7241
63	0.027960	265.48%	2.6548	40.263515	0.065936	2.6548	30.028784	0.088409	-0.022473	43.0693
64	0.027698	265.48%	2.6548	42.695930	0.062180	2.6548	30.028784	0.088409	-0.026230	40.4144
65	0.027402	263.96%	2.6396	45.275293	0.058302	2.6396	30.028784	0.087903	-0.029601	37.7748
66	0.027074	263.31%	2.6331	48.010481	0.054844	2.6331	30.028784	0.087686	-0.032842	35.1417
67	0.026714	263.31%	2.6331	50.910908	0.051720	2.6331	30.028784	0.087686	-0.035966	32.5086
68	0.026343	251.34%	2.5134	53.986557	0.046556	2.5134	30.028784	0.083699	-0.037143	29.9952
69	0.025949	248.34%	2.4834	57.248014	0.043381	2.4834	30.028784	0.082702	-0.039322	27.5118
70	0.025531	248.34%	2.4834	60.706502	0.040909	2.4834	30.028784	0.082702	-0.041793	25.0283
71	0.025133	224.39%	2.2439	64.373927	0.034857	2.2439	30.028784	0.074724	-0.039867	22.7845
72	0.024719	221.72%	2.2172	68.262909	0.032481	2.2172	30.028784	0.073837	-0.041356	20.5672
73	0.024287	221.72%	2.2172	72.386833	0.030630	2.2172	30.028784	0.073837	-0.043207	18.3500
74	0.023908	187.10%	1.8710	76.759894	0.024375	1.8710	30.028784	0.062308	-0.037933	16.4790
75	0.023515	187.10%	1.8710	81.397142	0.022986	1.8710	30.028784	0.062308	-0.039322	14.6079
76	0.023117	183.31%	1.8331	86.314537	0.021237	1.8331	30.028784	0.061045	-0.039807	12.7748
77	0.022783	149.17%	1.4917	91.529003	0.016298	1.4917	30.028784	0.049676	-0.033379	11.2831
78	0.022440	149.17%	1.4917	97.058488	0.015369	1.4917	30.028784	0.049676	-0.034307	9.7914
79	0.022105	141.86%	1.4186	102.922022	0.013783	1.4186	30.028784	0.047240	-0.033457	8.3728
80	0.021833	112.59%	1.1259	109.139786	0.010316	1.1259	30.028784	0.037493	-0.027177	7.2470
81	0.021556	112.59%	1.1259	115.733181	0.009728	1.1259	30.028784	0.037493	-0.027765	6.1211
82	0.021297	102.87%	1.0287	122.724897	0.008382	1.0287	30.028784	0.034258	-0.025876	5.0924
83	0.021091	80.21%	0.8021	130.139000	0.006163	0.8021	30.028784	0.026710	-0.020547	4.2903
84	0.020882	80.21%	0.8021	138.001007	0.005812	0.8021	30.028784	0.026710	-0.020898	3.4882
85	0.020699	69.35%	0.6935	146.337976	0.004739	0.6935	30.028784	0.023095	-0.018356	2.7947
86	0.020556	53.07%	0.5307	155.178601	0.003420	0.5307	30.028784	0.017673	-0.014253	2.2640
87	0.020412	53.07%	0.5307	164.553309	0.003225	0.5307	30.028784	0.017673	-0.014448	1.7333
88	0.020296	42.14%	0.4214	174.494366	0.002415	0.4214	30.028784	0.014033	-0.011618	1.3120
89	0.020209	31.21%	0.3121	185.035986	0.001687	0.3121	30.028784	0.010392	-0.008706	0.9999
90	0.020121	31.21%	0.3121	196.214450	0.001590	0.3121	30.028784	0.010392	-0.008802	0.6878
91	0.020060	21.32%	0.2132	208.068232	0.001025	0.2132	30.028784	0.007099	-0.006074	0.4747
92	0.020018	14.72%	0.1472	220.638128	0.000667	0.1472	30.028784	0.004903	-0.004236	0.3274
93	0.019975	14.72%	0.1472	233.967402	0.000629	0.1472	30.028784	0.004903	-0.004274	0.1802
94	0.019953	7.46%	0.0746	248.101930	0.000301	0.0746	30.028784	0.002484	-0.002183	0.1056
95	0.019940	4.34%	0.0434	263.090357	0.000165	0.0434	30.028784	0.001447	-0.001282	0.0621
96	0.019927	4.34%	0.0434	278.984272	0.000156	0.0434	30.028784	0.001447	-0.001291	0.0187
97	0.019924	1.14%	0.0114	295.838375	0.000039	0.0114	30.028784	0.000381	-0.000343	0.0072
98	0.019923	0.34%	0.0034	313.710675	0.000011	0.0034	30.028784	0.000115	-0.000104	0.0038
99	0.019922	0.34%	0.0034	332.662683	0.000010	0.0034	30.028784	0.000115	-0.000104	0.0003
100	0.019922	0.03%	0.0003	352.759627	0.000001	0.0003	30.028784	0.000011	-0.000011	0.0000
101	0.019922	0.00%	0.0000	374.070675	0.000000	0.0000	30.028784	0.000000	0.000000	0.0000
102	0.019922	0.00%	0.0000	396.669174	0.000000	0.0000	30.028784	0.000000	0.000000	0.0000
103	0.019922	0.00%	0.0000	420.632903	0.000000	0.0000	30.028784	0.000000	0.000000	0.0000
104	0.019922	0.00%	0.0000	446.044337	0.000000	0.0000	30.028784	0.000000	0.000000	0.0000
		100.0000	100.0000							

Charge 5

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 = 6.04%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0604 ^Year	(C) / (D)	(B)	1.0604 ^50	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000904	10.16%	0.1016	1.060412	0.095812	0.1016	18.781896	0.005409	0.090402	99.8984
2	0.002603	20.32%	0.2032	1.124474	0.180707	0.2032	18.781896	0.010819	0.169888	99.6952
3	0.004199	20.32%	0.2032	1.192407	0.170412	0.2032	18.781896	0.010819	0.159593	99.4920
4	0.005963	23.92%	0.2392	1.264443	0.189174	0.2392	18.781896	0.012736	0.176439	99.2528
5	0.007620	23.92%	0.2392	1.340831	0.178397	0.2392	18.781896	0.012736	0.165661	99.0136
6	0.009310	26.00%	0.2600	1.421833	0.182862	0.2600	18.781896	0.013843	0.169019	98.7536
7	0.011023	28.08%	0.2808	1.507730	0.186240	0.2808	18.781896	0.014951	0.171290	98.4728
8	0.012630	28.08%	0.2808	1.598815	0.175630	0.2808	18.781896	0.014951	0.160679	98.1920
9	0.014385	32.72%	0.3272	1.695404	0.192992	0.3272	18.781896	0.017421	0.175571	97.8648
10	0.016031	32.72%	0.3272	1.797827	0.181997	0.3272	18.781896	0.017421	0.164576	97.5376
11	0.017697	35.34%	0.3534	1.906438	0.185372	0.3534	18.781896	0.018816	0.166556	97.1842
12	0.019372	37.96%	0.3796	2.021610	0.187771	0.3796	18.781896	0.020211	0.167560	96.8046
13	0.020941	37.96%	0.3796	2.143741	0.177074	0.3796	18.781896	0.020211	0.156863	96.4250
14	0.022636	43.84%	0.4384	2.273249	0.192852	0.4384	18.781896	0.023342	0.169510	95.9866
15	0.024221	43.84%	0.4384	2.410582	0.181865	0.4384	18.781896	0.023342	0.158523	95.5482
16	0.025812	47.08%	0.4708	2.556211	0.184179	0.4708	18.781896	0.025067	0.159112	95.0774
17	0.027401	50.32%	0.5032	2.710637	0.185639	0.5032	18.781896	0.026792	0.158847	94.5742
18	0.028884	50.32%	0.5032	2.874393	0.175063	0.5032	18.781896	0.026792	0.148271	94.0710
19	0.030467	57.60%	0.5760	3.048042	0.188974	0.5760	18.781896	0.030668	0.158306	93.4950
20	0.031942	57.60%	0.5760	3.232182	0.178208	0.5760	18.781896	0.030668	0.147540	92.9190
21	0.033412	61.62%	0.6162	3.427446	0.179784	0.6162	18.781896	0.032808	0.146976	92.3028
22	0.034868	65.64%	0.6564	3.634506	0.180602	0.6564	18.781896	0.034949	0.145654	91.6464
23	0.036222	65.64%	0.6564	3.854075	0.170313	0.6564	18.781896	0.034949	0.135365	90.9900
24	0.037649	74.52%	0.7452	4.086909	0.182338	0.7452	18.781896	0.039677	0.142662	90.2448
25	0.038971	74.52%	0.7452	4.333809	0.171950	0.7452	18.781896	0.039677	0.132274	89.4996
26	0.040276	79.40%	0.7940	4.595624	0.172773	0.7940	18.781896	0.042275	0.130498	88.7056
27	0.041557	84.28%	0.8428	4.873257	0.172944	0.8428	18.781896	0.044873	0.128071	87.8628
28	0.042739	84.28%	0.8428	5.167662	0.163091	0.8428	18.781896	0.044873	0.118218	87.0200
29	0.043966	94.92%	0.9492	5.479853	0.173216	0.9492	18.781896	0.050538	0.122678	86.0708
30	0.045094	94.92%	0.9492	5.810903	0.163348	0.9492	18.781896	0.050538	0.112810	85.1216
31	0.046192	100.70%	1.0070	6.161954	0.163422	1.0070	18.781896	0.053615	0.109807	84.1146
32	0.047255	106.48%	1.0648	6.534212	0.162958	1.0648	18.781896	0.056693	0.106265	83.0498
33	0.048225	106.48%	1.0648	6.928960	0.153674	1.0648	18.781896	0.056693	0.096981	81.9850
34	0.049210	118.96%	1.1896	7.347555	0.161904	1.1896	18.781896	0.063338	0.098567	80.7954
35	0.050104	118.96%	1.1896	7.791438	0.152680	1.1896	18.781896	0.063338	0.089343	79.6058
36	0.050955	125.56%	1.2556	8.262137	0.151970	1.2556	18.781896	0.066852	0.085119	78.3502
37	0.051760	132.16%	1.3216	8.761272	0.150846	1.3216	18.781896	0.070366	0.080480	77.0286
38	0.052479	132.16%	1.3216	9.290562	0.142252	1.3216	18.781896	0.070366	0.071886	75.7070
39	0.053183	146.00%	1.4600	9.851827	0.148196	1.4600	18.781896	0.077734	0.070461	74.2470
40	0.053803	146.00%	1.4600	10.446999	0.139753	1.4600	18.781896	0.077734	0.062019	72.7870
41	0.054370	153.06%	1.5306	11.078127	0.138164	1.5306	18.781896	0.081493	0.056671	71.2564
42	0.054881	160.12%	1.6012	11.747383	0.136303	1.6012	18.781896	0.085252	0.051050	69.6552
43	0.055313	160.12%	1.6012	12.457070	0.128537	1.6012	18.781896	0.085252	0.043285	68.0540
44	0.055705	174.16%	1.7416	13.209632	0.131843	1.7416	18.781896	0.092728	0.039116	66.3124
45	0.056021	174.16%	1.7416	14.007657	0.124332	1.7416	18.781896	0.092728	0.031604	64.5708
46	0.056275	180.84%	1.8084	14.853893	0.121746	1.8084	18.781896	0.096284	0.025462	62.7624

Charge 5

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 = 6.04%

	(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)	1.0604 ^Year	(C) / (D)	(B)	1.0604 ^50	(F) / (G)	(E) - (H)	(Given)
47	0.056467	187.52%	1.8752	15.751252	0.119051	1.8752	18.781896	0.099841	0.019210	60.8872
48	0.056592	187.52%	1.8752	16.702822	0.112268	1.8752	18.781896	0.099841	0.012428	59.0120
49	0.056656	199.48%	1.9948	17.711879	0.112625	1.9948	18.781896	0.106209	0.006416	57.0172
50	0.056656	199.48%	1.9948	18.781896	0.106209	1.9948	18.781896	0.106209	0.000000	55.0224
51	0.056594	204.36%	2.0436	19.916555	0.102608	2.0436	18.781896	0.108807	-0.006199	52.9788
52	0.056471	209.24%	2.0924	21.119762	0.099073	2.0924	18.781896	0.111405	-0.012332	50.8864
53	0.056291	209.24%	2.0924	22.395657	0.093429	2.0924	18.781896	0.111405	-0.017976	48.7940
54	0.056050	215.92%	2.1592	23.748632	0.090919	2.1592	18.781896	0.114962	-0.024043	46.6348
55	0.055758	215.92%	2.1592	25.183343	0.085739	2.1592	18.781896	0.114962	-0.029223	44.4756
56	0.055415	217.28%	2.1728	26.704729	0.081364	2.1728	18.781896	0.115686	-0.034322	42.3028
57	0.055023	218.64%	2.1864	28.318025	0.077209	2.1864	18.781896	0.116410	-0.039201	40.1164
58	0.054587	218.64%	2.1864	30.028784	0.072810	2.1864	18.781896	0.116410	-0.043600	37.9300
59	0.054113	216.76%	2.1676	31.842894	0.068072	2.1676	18.781896	0.115409	-0.047337	35.7624
60	0.053601	216.76%	2.1676	33.766599	0.064194	2.1676	18.781896	0.115409	-0.051215	33.5948
61	0.053061	213.28%	2.1328	35.806520	0.059565	2.1328	18.781896	0.113556	-0.053992	31.4620
62	0.052497	209.80%	2.0980	37.969677	0.055255	2.0980	18.781896	0.111703	-0.056449	29.3640
63	0.051901	209.80%	2.0980	40.263515	0.052107	2.0980	18.781896	0.111703	-0.059597	27.2660
64	0.051311	197.88%	1.9788	42.695930	0.046346	1.9788	18.781896	0.105357	-0.059010	25.2872
65	0.050694	197.88%	1.9788	45.275293	0.043706	1.9788	18.781896	0.105357	-0.061651	23.3084
66	0.050080	189.68%	1.8968	48.010481	0.039508	1.8968	18.781896	0.100991	-0.061483	21.4116
67	0.049470	181.48%	1.8148	50.910908	0.035647	1.8148	18.781896	0.096625	-0.060978	19.5968
68	0.048840	181.48%	1.8148	53.986557	0.033616	1.8148	18.781896	0.096625	-0.063009	17.7820
69	0.048262	161.60%	1.6160	57.248014	0.028228	1.6160	18.781896	0.086040	-0.057812	16.1660
70	0.047667	161.60%	1.6160	60.706502	0.026620	1.6160	18.781896	0.086040	-0.059420	14.5500
71	0.047099	150.60%	1.5060	64.373927	0.023395	1.5060	18.781896	0.080184	-0.056789	13.0440
72	0.046561	139.60%	1.3960	68.262909	0.020450	1.3960	18.781896	0.074327	-0.053877	11.6480
73	0.046010	139.60%	1.3960	72.386833	0.019285	1.3960	18.781896	0.074327	-0.055042	10.2520
74	0.045540	116.92%	1.1692	76.759894	0.015232	1.1692	18.781896	0.062251	-0.047020	9.0828
75	0.045061	116.92%	1.1692	81.397142	0.014364	1.1692	18.781896	0.062251	-0.047887	7.9136
76	0.044620	105.82%	1.0582	86.314537	0.012260	1.0582	18.781896	0.056341	-0.044082	6.8554
77	0.044220	94.72%	0.9472	91.529003	0.010349	0.9472	18.781896	0.050432	-0.040083	5.9082
78	0.043813	94.72%	0.9472	97.058488	0.009759	0.9472	18.781896	0.050432	-0.040672	4.9610
79	0.043491	73.88%	0.7388	102.922022	0.007178	0.7388	18.781896	0.039336	-0.032158	4.2222
80	0.043166	73.88%	0.7388	109.139786	0.006769	0.7388	18.781896	0.039336	-0.032566	3.4834
81	0.042879	64.24%	0.6424	115.733181	0.005551	0.6424	18.781896	0.034203	-0.028652	2.8410
82	0.042633	54.60%	0.5460	122.724897	0.004449	0.5460	18.781896	0.029071	-0.024622	2.2950
83	0.042384	54.60%	0.5460	130.139000	0.004196	0.5460	18.781896	0.029071	-0.024875	1.7490
84	0.042214	37.08%	0.3708	138.001007	0.002687	0.3708	18.781896	0.019742	-0.017055	1.3782
85	0.042041	37.08%	0.3708	146.337976	0.002534	0.3708	18.781896	0.019742	-0.017209	1.0074
86	0.041904	29.38%	0.2938	155.178601	0.001893	0.2938	18.781896	0.015643	-0.013749	0.7136
87	0.041802	21.68%	0.2168	164.553309	0.001318	0.2168	18.781896	0.011543	-0.010226	0.4968
88	0.041699	21.68%	0.2168	174.494366	0.001242	0.2168	18.781896	0.011543	-0.010301	0.2800
89	0.041654	9.36%	0.0936	185.035986	0.000506	0.0936	18.781896	0.004984	-0.004478	0.1864
90	0.041609	9.36%	0.0936	196.214450	0.000477	0.0936	18.781896	0.004984	-0.004506	0.0928
91	0.041582	5.60%	0.0560	208.068232	0.000269	0.0560	18.781896	0.002982	-0.002712	0.0368
92	0.041573	1.84%	0.0184	220.638128	0.000083	0.0184	18.781896	0.000980	-0.000896	0.0184
93	0.041564	1.84%	0.0184	233.967402	0.000079	0.0184	18.781896	0.000980	-0.000901	0.0000
94	0.041564	0.00%	0.0000	248.101930	0.000000	0.0000	18.781896	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		

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	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	12,345,312	1.5	0.83%	0.01	
362.00	Station Equipment	160,587,683	1	10.84%	0.11	
362.70	Supervisory & Alarm Equipment	2,779,659	2.5	0.19%	0.00	
364.00	Poles, Towers & Fixtures	282,793,465	2	19.09%	0.38	
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	
367.00	UG Conductors & Devices	133,175,353	2.5	8.99%	0.22	
368.00	Line Transformers	340,095,762	1.5	22.96%	0.34	
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**

Curves:
R=positive
L=negative
S=0

R means right of the standard
L means left of the standard
S is at the standard

**Source: Depreciation Rates.xls (02-10-2009)

Exhibit PAC/1207
Tab 16. Losses

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	1.04527	4.53%	1.04259	4.26%
2					
3					
4					
5					
6	Primary	1.06904	6.90%	1.07920	7.92%
7					
8					
9					
10					
11	Secondary	1.10006	10.01%	1.11057	11.06%
12					

**Source: 2009 Analysis of System Losses

Exhibit PAC/1207
Tab 17. Cust. Data

Cust Data 1

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended June 30, 2011 - Actual

Line	Description	Del. Volt	(A) Average Customers	(B) % Total Class	(C) Annual MWh's	(D) % Total Class	(E) Average Billing kW	(F) % Total Class
1	Res - Schedule 4	(sec)	476,340	100.0%	5,544,795	100.0%	4,692,804	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	66,182	86.2%	607,536	54.0%	256,390	58.1%
5	15+ kW	(sec)	10,557	13.8%	517,875	46.0%	184,997	41.9%
6	Sec Subtotal		76,739	100.0%	1,125,412	100.0%	441,387	100.0%
7	Primary	(pri)	48		1,348		1,836	
8	Total		76,787		1,126,760		443,223	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,426	44.4%	434,840	21.7%	159,606	7.9%
12	51-100 kW	(sec)	3,510	35.2%	659,683	32.9%	189,511	9.4%
13	> 101kW	(sec)	2,040	20.5%	909,643	45.4%	248,109	12.3%
14	Sec Subtotal		9,976	100.0%	2,004,166	100.0%	2,014,144	29.7%
15	Primary	(pri)	54		18,807		12,855	
16	Total		10,031		2,022,973		2,026,999	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	224	28.1%	202,409	16.5%	48,730	16.6%
20	301+ kW	(sec)	573	71.9%	1,025,511	83.5%	244,088	83.4%
21	Sec Subtotal		797	100.0%	1,227,920	100.0%	292,817	100.0%
22	Primary	(pri)	54		90,988		21,045	
23	Total		850		1,318,908		313,863	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	112	98.2%	549,225	91.4%	142,690	90.5%
27	> 4 MW	(sec)	2	1.8%	51,470	8.6%	14,919	9.5%
28	Sec Subtotal		114	100.0%	600,695	100.0%	157,609	100.0%
29	1 - 4 MW	(pri)	65	67.4%	474,189	31.2%	119,309	33.1%
30	> 4 MW	(pri)	31	32.6%	1,043,759	68.8%	240,966	66.9%
31	Pri Subtotal		96	100.0%	1,517,948	100.0%	360,276	100.0%
32	Trans	(trn)	5		450,884		156,904	
33	Total		215		2,569,527		674,789	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	3,233	100.0%	200,049	100.0%	121,252	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	8,312					

Source:
Columns B & D - PacifiCorp, Pricing Department

Cust Data 2

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended December 2013 - Normalized

Line	Description	Del. Volt	(A) Average Customers	(B) % Total Class	(C) Annual MWh's	(D) % Total Class	(E) Average Billing kW	(F) % Total Class
1	Res - Schedule 4	(sec)	479,457	100.0%	5,400,866	100.0%	4,692,804	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	64,929	86.2%	589,821	54.0%	256,390	58.1%
5	15+ kW	(sec)	10,357	13.8%	502,774	46.0%	184,997	41.9%
6	Sec Subtotal		75,286	100.0%	1,092,595	100.0%	441,387	100.0%
7	Primary	(pri)	48		1,331		1,836	
8	Total		75,334		1,093,926		443,223	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,332	44.4%	426,951	21.7%	159,606	7.9%
12	51-100 kW	(sec)	3,436	35.2%	647,714	32.9%	189,511	9.4%
13	> 101kW	(sec)	1,997	20.5%	893,140	45.4%	248,109	12.3%
14	Sec Subtotal		9,765	100.0%	1,967,805	100.0%	597,225	29.7%
15	Primary	(pri)	52		18,795		12,855	
16	Total		9,817		1,986,600		610,080	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	215	28.1%	200,164	16.5%	48,730	16.6%
20	301+ kW	(sec)	549	71.9%	1,014,139	83.5%	244,088	83.4%
21	Sec Subtotal		764	100.0%	1,214,303	100.0%	292,817	100.0%
22	Primary	(pri)	51		89,386		21,045	
23	Total		815		1,303,689		313,863	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	107	98.2%	565,086	91.4%	142,690	90.5%
27	> 4 MW	(sec)	2	1.8%	52,957	8.6%	14,919	9.5%
28	Sec Subtotal		109	100.0%	618,043	100.0%	157,609	100.0%
29	1 - 4 MW	(pri)	63	67.4%	496,681	31.2%	119,309	33.1%
30	> 4 MW	(pri)	30	32.6%	1,093,266	68.8%	240,966	66.9%
31	Pri Subtotal		93	100.0%	1,589,947	100.0%	360,276	100.0%
32	Trans	(trn)	6		795,520		156,904	
33	Total		208		3,003,510		674,789	
34								
35								
36	Irrigation - Schedule 41 (Average)	(sec)	3,154	100.0%	210,342	100.0%	121,252	100.0%
37								
38								
39	Irrigation - Schedule 41 (Annual)	(sec)	8,090	100.0%	210,342	100.0%	121,252	100.0%

Source:
Columns B & D - PacifiCorp, Pricing Department

Cust Data 3

PacifiCorp
Oregon Marginal Cost Study
Customer Class Split between
Three Phase / Single Phase

Line	Customer Class		Voltage Level	(A) Three Phase	(B) Total Customers	(C) Three Phase % of Customers (A) / (B)	(D) Single Phase % of Customers 100% - (C)
1	Res - Schedule 4		(sec)	-	476,340	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	11,734	66,182	17.7305%	82.2695%
5	15+ kW		(sec)	5,750	10,557	54.4635%	45.5365%
6		Sec Subtotal		17,484	76,739		
7	Primary		(pri)	48	48	100.0000%	0.0000%
8		Total		17,532	76,787	22.8318%	77.1682%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	3,110	4,426	70.2782%	29.7218%
12	51-100 kW		(sec)	3,038	3,510	86.5587%	13.4413%
13	> 101kW		(sec)	1,984	2,040	97.2287%	2.7713%
14		Sec Subtotal		8,132	9,976		
15	Primary		(pri)	54	54	100.0000%	0.0000%
16		Total		8,187	10,031	81.6183%	18.3817%
17							
18	GS - Schedule 30						
19	0-300 kW			224	224	99.8511%	0.1489%
20	301+ kW			572	573	99.8244%	0.1756%
21		Sec Subtotal		795	797		
22	Primary			54	54	100.0000%	0.0000%
23		Total		849	850	99.8425%	0.1575%
24							
25	LPS - Schedule 48T						
26	1 - 4 MW		(sec)	112	112	100.0000%	0.0000%
27	1 - 4 MW		(pri)	65	65	100.0000%	0.0000%
28	> 4 MW		(sec)	2	2	100.0000%	0.0000%
29	> 4 MW		(pri)	31	31	100.0000%	0.0000%
30	Trans		(trn)	5	5	100.0000%	0.0000%
31	Total			215	215	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	7,055	8,312	84.8712%	15.1288%
34							
35							
36	TOTAL			33,836	572,534	5.9099%	94.0901%

Cust Data 4

PacifiCorp
Oregon Marginal Cost Study
Customer Loads
12 Months Ended December 2013

	(A)	(B)	(C)	(D)	(E)
			MW @ Sales		
Line	Description	Del. Volt	System	Distribution	Transformer
1	Res - Schedule 4	(sec)	873	995	3,144
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	91	90	179
5	15+ kW	(sec)	77	73	129
6	Primary	(pri)	0	0	2
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	74	72	160
10	51-100 kW	(sec)	106	104	190
11	> 101kW	(sec)	138	140	248
12					
13	Primary	(pri)	3	3	13
14					
15	GS - Schedule 30				
16	0-300 kW	(sec)	30	31	49
17	301+ kW	(sec)	148	151	244
18	Primary	(pri)	14	14	21
19					
20	LPS - Schedule 48T				
21	1 - 4 MW	(sec)	83	87	143
22	1 - 4 MW	(pri)	70	74	119
23	> 4 MW	(sec)	8	8	15
24	> 4 MW	(pri)	148	152	241
25	Trans	(trn)	88	0	157
26					
27	Irrigation - Sch 41	(sec)	25	22	121

Source:
Columns C, D & F - PacifiCorp, Load Research Dept.
Column E - Column F x Column H
Column H - PacifiCorp Distribution Construction Standard, DA 411

Cust Data 5

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2013

Line	Description		(A) Del. Volt	(B) Revenues December 2013 Commercial	(C) Revenues December 2013 Industrial	(D) Percent of Total Revenues Commercial	(E) Percent of Total Revenues Industrial	(F) Allocated Net Uncollectible Commercial	(G) Allocated Net Uncollectible Industrial	(H) Allocated Net Uncollectible Total
1	Res - Schedule 4		(sec)	0	0	0.00%	0.00%	-	-	4,041,068
2										
3	GS - Schedule 23									
4			(sec)	117,427,785	2,497,627	27.77%	1.58%	135,897	687	136,585
5			(pri)	108,181	35,712	0.03%	0.02%	125	10	135
6		Total		$117,535,966	$2,533,339	27.80%	1.61%	136,023	697	136,720
7										
8	GS - Schedule 28									
9			(sec)	151,513,323	8,368,513	35.83%	5.31%	175,344	2,303	177,647
10			(pri)	983,476	400,843	0.23%	0.25%	1,138	110	1,248
11		Total		$152,496,799	$8,769,356	36.07%	5.56%	176,482	2,413	178,895
12										
13	GS - Schedule 30									
14			(sec)	75,271,996	16,111,522	17.80%	10.22%	87,111	4,433	91,544
15			(pri)	5,518,850	1,216,023	1.31%	0.77%	6,387	335	6,721
16		Total		$80,790,846	$17,327,545	19.11%	10.99%	93,498	4,768	98,266
17										
18	LPS - Schedule 48T									
19			(sec)	24,504,311	20,701,052	5.80%	13.13%	28,358	5,696	34,055
20			(pri)	27,740,538	80,161,680	6.56%	50.83%	32,104	22,058	54,161
21			(trn)	19,756,696	28,219,760	4.67%	17.89%	22,864	7,765	30,629
22		Total		$72,001,545	$129,082,492	17.03%	81.85%	83,326	35,519	118,845
23										
24	Irrigation - Schedule 41		(sec)	-	$24,872,106	0.00%	100.00%	-	15,627	15,627
25				$0	$24,872,106	0.00%	100.00%	-	15,627	15,627
26										
27	Total			$422,825,156	$182,584,838			489,329	59,024	4,589,422

DIRECT TESTIMONY OF WILLIAM R. GRIFFITH

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ATTACHED EXHIBITS

Exhibit PAC/1301 – Proposed Tariffs

Exhibit PAC/1302 – Target Functionalized Revenues and Billing Determinants

Exhibit PAC/1303 – Estimated Effect of Proposed Rates

Exhibit PAC/1304 – Transmission Investment Adjustment Proposed Rate Spread and Illustrative Tariff

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

A. My name is William R. Griffith. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon. My current position is Vice President, Regulation.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree with High Honors and distinction in Political Science and Economics from San Diego State University and a Master of Arts degree in Political Science from that same institution; I was subsequently employed on the faculty for one year. I also attended the University of Oregon and completed all course work towards a Ph.D. in Political Science. I joined the Company in the Pricing & Regulatory Affairs Department in December 1983. In June 1989, I became Manager, Pricing in the Regulation Department. In February 2001, I assumed the role of Director, Pricing, Cost of Service & Regulatory Operations, in the Regulation Department. In February 2012, I assumed my current responsibilities.

Purpose of Testimony

Q. What are your responsibilities in these proceedings?

A. I am responsible for the design of the Company's proposed prices in these proceedings. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Commission's rules under OAR 860-038-0200. I am sponsoring the Company's Oregon electric tariff schedules

submitted for approval in this filing. Exhibit PAC/1301 contains the proposed tariffs.

Allocation of the Functionalized Revenue Requirement

Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this case?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's rules for Direct Access Regulation in OAR 860, Division 38. The rules indicate that rates are to be based on cost. As stated in OAR 860-038-0240(2)(b), "rates for any class of consumer must be based on the unbundled costs to serve that class." In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study sponsored by Company witness Mr. C. Craig Paice. The Company's proposed base rates for each class are based on the unbundled costs to serve that class.

Q. Please explain in detail how PacifiCorp's proposed rate spread appropriately reflects cost of service.

A. The Company's base rates are designed directly based on the results of the cost of service study presented by Mr. Paice. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the base rate increase to each rate schedule reflects the costs to serve consumers under that schedule, as determined by the cost of service study.

Q. Do you have an exhibit which summarizes the functionalized results of the cost of service study presented by Mr. Paice?

A. Yes. Exhibit PAC/1302, pages one and two, summarizes the functionalized results of the cost of service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, Distribution, Generation Energy Other (Non-NPC) and Generation Energy NPC.

Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement.

A. The summary level for revenue requirement shown in Exhibit PAC/1302, pages one and two, summarizes the cost of service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company first implemented in UE 116. For each rate schedule, the functionalized costs developed by Mr. Paice are applied to rates as follows: distribution, billing, metering and customer costs are included in each proposed delivery service schedule's Distribution rates; the Federal Energy Regulatory Commission ("FERC") regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; non-net power cost generation costs are included in Schedule 200, Base Supply Service rates; and net power costs are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost of service study sponsored by Mr. Paice?

A. Yes, the Company has made one adjustment. The functionalized revenue requirement has been adjusted to remove the proposed changes to net power costs ("NPC") collected through Schedule 201. Changes to Schedule 201 are implemented through the Transition Adjustment Mechanism ("TAM") which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that docket. The modified cost of service results reflecting this adjustment removing the NPC increase from the functionalized revenue requirement is shown in Exhibit PAC/1302, pages one and two, column (5). This column displays the target functionalized revenue requirement utilized in the design of rates proposed in this general rate case.

Q. Do the Company's proposed rates collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) of Exhibit PAC/1302, pages one and two. A direct comparison to the target functionalized revenues shown in column (5) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown in Exhibit PAC/1302, pages three through twelve.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. Exhibit PAC/1303 shows the estimated effect of the Company's proposed prices. It contains a summary table showing the effect of the proposed prices by delivery service rate schedule (Table 1303-1), along with monthly billing comparisons for each of the affected delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. Table 1303-1 contains the effect of the price change on both base rates and on net rates. Base rates show the effect on rates before the impacts of any adjustment tariffs.

The net rates in Table 1303-1 (Columns (7) and (10)) exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297). Table 1303-2 shows the calculation of the adjustments included in Table 1303-1. Table 1303-3 shows the present and proposed rates for these adjustment schedules.

Q. Please explain Table 1303-1 in Exhibit PAC/1303 in detail.

A. Table 1303-1 shows the estimated effect of the proposed general rate case price change by rate schedule for the forecast test period. The table displays the schedule number, the average number of customers during the test period, and the megawatt-hours of energy use in Columns (2) through (4). Revenues by tariff schedule are divided into six columns—three for present revenues and three for

proposed revenues. Column (5) shows annualized revenues under present base rates; Column (6) shows present revenues from current adjustment tariffs (Schedules 96, 102, 194, 195, 204, 291, and 299); and Column (7) shows net present revenues. Column (8) shows annualized revenues under proposed base rates; Column (9) shows proposed revenues from all adjustment tariffs (Schedules 96, 102, 194, 195, 204, 291, and 299); and Column (10) shows the net estimated revenues which would be received if the proposed prices were in effect during the entire test period as forecast. Columns (11) and (12) show the dollar and percentage changes in base rates. Columns (13) and (14) show the dollar and percentage changes comparing present net rates with proposed net rates.

Q. What are the Company's rate spread objectives in this case?

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the Company's rate spread proposal in this case?

A. Based on the cost of service results and in order to achieve the Company's rate spread objectives in this case, the Company proposes the following net price changes for the major rate schedule classes:

Residential Schedule 4	3.5%
General Service	
Schedule 23/723 (0-30kW)	2.0%
Schedule 28/728 (31-200kW)	3.5%
Schedule 30/730 (201-999kW)	3.5%
Large General Service	
Schedules 47/747, 48/748 (≥1,000kW)	4.4%
Agricultural Pumping Service Schedule 41/741	3.5%
Lighting Schedules	2.0%
Overall	3.5%

The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs and minimizing subsidization across rate schedule classes. As a result, the Company proposes revisions to the Rate Mitigation Adjustment ("RMA") in order to achieve these goals.

Q. Please describe the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in UE 116. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Besides rate mitigation across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present RMA rates were designed to be revenue neutral in the calendar year 2011 test period from the Company's last general rate case (UE 217); however, due to changes in rate schedule loads, present Schedule 299 RMA rates do not produce revenue neutrality in the calendar year 2013 test period of this case. The present RMA rates result in RMA credits that exceed RMA charges by $2.8 million for the 2013 test period loads (see Exhibit PAC/1303, Table 1303-2, Column 9, Row 19). Consistent with prior RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2013 test period. As a result of this realignment, the proposed net rate increase in this case is $41.2 million--a $2.8 million adjustment due to the RMA in addition to the base revenue requirement increase of $38.4 million in this case. (Exhibit PAC/1303, Table 1303-1)

Q. Has the RMA required rebalancing in prior general rate cases?

A. Yes. For example, in UE 217 the RMA required a rebalancing adjustment of $1.0 million.

Q. What are the present and proposed RMA rates in this case?

A. The present and proposed RMA rates are shown in Exhibit PAC/1303, Table 1303-3.

Q. What is the Company's RMA objective in this case?

A. The Company's RMA objective in this case is to minimize rate schedule subsidization through the RMA while minimizing rate impacts on customers. As a result, the Company has limited RMA charges and credits as much as possible while minimizing rate impacts across rate schedules. The Company proposes no increase to present RMA credit rates. In addition, the Company proposes to reduce RMA credit rates if the continuation of the present RMA credit rates would result in a percentage increase lower than the overall net percentage increase. As a result, the Company is proposing to reduce the RMA credit to Schedule 41/741, Agricultural Pumping Service by approximately $2.9 million in order to achieve a net rate impact for Schedule 41/741 equal to the net jurisdictional percentage of 3.5 percent. The Company is also proposing to eliminate the RMA credit to Schedule 23, General Service. In addition, for Schedule 23/723, the Company proposes an RMA charge in order to balance the revenue neutrality of the RMA while assuring that no rate schedule class receives a price increase less than 2.0 percent.

For Large General Service Schedules 47/747 and 48/748, the Company proposes no change to the present RMA credit rates in order to minimize rate impacts to these customers. The proposed net increase for Schedules 47/747 and 48/748 is 4.4 percent or approximately 1.3 times the overall net percentage increase in this case. With this proposal, Schedule 47/747 and 48/748 will receive the largest RMA credit rates of any rate schedule class, ranging from 0.329 cents/kWh to 0.509 cents per kWh, depending on voltage level, and will produce

over $12.5 million of annual subsidy to these rate schedules. Nonetheless, the Company believes the proposed RMA credits for Schedule 47/747 and 48/748 are reasonable in light of the overall percentage increase proposed for these customers.

Residential Schedule 4 and General Service Schedules 28/728 and 30/730 will see a reduction in their RMA surcharge rates and will see a rate increase equal to the overall net percentage increase. Lighting schedules continue to pay an RMA surcharge rate; however, as a result they will still receive a net increase of only 2.0 percent, lower than the overall net percentage increase in this case.

Overall, the Company believes that these proposals are fair and will minimize rate impacts while reducing subsidization through the RMA.

Rate Design

Q. Please generally describe the process for designing rates which collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kilowatts and kilowatt-hours consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2013.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historic test period billing determinants.

A three step process occurs in developing test period billing determinants. First, monthly forecast test period bills and energy by class and by rate schedule are prepared by the Company as described by Company witness Mr. Gregory N. Duvall.

Second, a full set of billing determinants, including all rate elements such as demand, load size, reactive power quantities and kilowatt-hours by rate block, are retrieved at the customer invoice level from the Company's billing system for the base period – in this case, the 12 months ended June 2011. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical test period data and the forecast test period information. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the load forecast.

Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Exhibit PAC/1302, pages three through twelve, prepared under my supervision contains historical and forecast billing determinants along with present and proposed base rates.

Q. What rate design changes does the Company propose?

A. The basic structure of the Company's current tariffs, broken out into Delivery Service and Supply Service tariffs as first approved in UE 116, is proposed to remain in effect. The Company is proposing separate treatment for the collection

of the Mona-to-Oquirrh transmission investment, discussed later in my testimony. Additionally, the Company is proposing a Power Cost Adjustment Mechanism to be implemented through a separate rate schedule, also discussed later in my testimony.

Q. Please explain the proposed tariffs for residential customers.

A. Residential customers are served on Delivery Service Schedule 4. For the Basic Charge, the Company proposes to increase the current Basic Charge by $0.50 per month. This results in a proposed Basic Charge of $9.50 per month. This change will better reflect the fixed costs of serving residential customers while, in conjunction with the proposed energy charges, keeping customer impacts in line with the overall rate change for smaller users. In addition, even with this change, the Company's Basic Charge will remain below the Basic/Minimum Charges of more than half of 24 electric utilities surveyed by the Company in Oregon. The 24 utilities include the major investor-owned and municipally-owned utilities along with people's utility districts and electric cooperatives serving in Oregon.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-net power cost generation revenue requirement as indicated in Exhibit PAC/1302, pages one and two. The Company proposes to keep the same rate blocks and ratio between the rates for each block as in the currently effective rates. The portfolio options (Schedules 210 through 213) do not require changes since they are adders to customers' Schedule 200 rates.

Q. Please explain the proposed tariffs for general service customers.

A. The proposed general service tariffs are Schedule 23/723 for small (less than 31 kW) nonresidential general service customers, Schedule 28/728 for general service customers between 31 and 200 kW, and Schedule 30/730 for general service customers over 200 kW but less than 1,000 kW. The Company automatically migrates these customers to the appropriate rate schedule once they meet its applicability criteria. The Company has proposed to modify base delivery and Schedule 200 Base Supply Service prices, at different voltage levels, to collect the target functionalized revenue requirement. For Schedule 30/730 the Company proposes to increase the Schedule 200 demand charges by $0.05 per kilowatt. This increase continues movement toward cost of service while minimizing rate impacts to customers.

Q. Please explain the proposed tariffs for irrigation customers.

A. In line with the changes for general service customers, Schedule 41/741, Agricultural Pumping Service rates have been modified to collect the target revenue requirement and to track unit costs more closely.

Q. How has the Company treated Schedule 33 Klamath Basin Irrigation and Drainage Pumping customers in this general rate case?

A. In accordance with the law and with Order No. 06-172, as clarified in Order No. 06-440, the seven year rate mitigation transition period for the Klamath Basin irrigation and drainage pumping customers served under the Company's Schedule 33 will conclude on April 16, 2013, within the test year for this case. At that time, these customers will be migrated to standard tariff, Schedule 41/741,

Agricultural Pumping Service. For irrigation customers, the pumping season typically does not begin before April 16 each year. Thus, the Company has assumed for the forecast test period that Schedule 33 customers are served under standard irrigation tariff Schedule 41/741 for the full year. All present and proposed revenues, rates and all billing determinants shown in my exhibits reflect the inclusion of the former Schedule 33 Klamath Basin irrigation customers in Schedule 41/741 for the 2013 test year.

Q. Please explain the proposed tariffs for large general service customers.

A. For Schedules 48/748, Large General Service, the Company has proposed to modify base prices, at different voltage levels, to collect the target functionalized revenue requirement. For partial requirements customers served on Schedule 47/747, most prices are linked to changes in Schedule 48/748 prices. Changes to Schedule 48/748 continue to flow through to Schedule 47/747. The Company proposes to maintain the current Schedule 48/748 rate structure, including an on-peak period demand charge only and the current on-peak/off-peak time of use energy charge differential. As with Schedule 30/730, the Company proposes to increase Schedule 47/747 and 48/748 Schedule 200 demand charges by $0.05 per kilowatt, equal to the overall base percentage increase for the rate schedule, in order to better reflect the cost of service while minimizing customer impacts.

Q. Please explain the proposed tariffs for lighting customers.

A. For lighting (Schedules 15, 50, 51/55/751, 52/752, 53/753, and 54/754) the proposed revisions are designed to collect the overall functionalized target revenue requirement.

Q. How has the Company treated the currently effective Schedule 80 Populus to Terminal Adjustment and Schedule 205 TAM Adjustment for Other Revenues?

A. The Company has reflected the costs originally collected through these adjustment schedules within the base revenue requirement in this case. The Company therefore proposes to cancel Schedule 80. In addition, the Company proposes to keep Schedule 205 in place, but to set its rates to zero as a placeholder for future use.

Illustrative Transmission Investment Adjustment

Q. Please explain the proposed rate treatment of the Mona-to-Oquirrh transmission investment in this general rate case.

A. As discussed in the testimony of Company witness Mr. R. Bryce Dalley, the Company proposes to place in rates the transmission investment for Mona-to-Oquirrh following a prudence review in this case and once the investment becomes used and useful. The in-service date is expected to occur prior to June 1, 2013. Exhibit PAC/1304 presents the proposed rate spread and rates for this adjustment along with an illustrative version of the Transmission Investment Adjustment tariff. Following a prudence review in this case, the Company proposes to submit an advice filing in 2013 for approval of the proposed Transmission Adjustment Tariff no less than 30 days prior to the in-service date of Mona-to-Oquirrh.

Q. How are the proposed transmission investment adjustment rates calculated?

A. The transmission investment adjustment costs are allocated to customer classes

based on the functionalized transmission costs from the cost of service study. The proposed tariff rider rates have been designed to collect these costs through energy or demand charges, as appropriate to each rate schedule. This proposed rate design mirrors present transmission rates for each delivery service schedule, and recovers this investment in the same way as other transmission costs.

Q. Why has the Company proposed separate treatment of the costs for this transmission investment project?

A. As discussed by Company witness Mr. Richard P. Reiten, the Company has proposed this treatment for these transmission investment costs so the prudency of this project may be reviewed in this general rate case and the project may be properly reflected in rates in a timely manner once it becomes used and useful.

Q. Are the rates for the transmission investment adjustment reflected in the proposed rate spread, rate design and rate impact Exhibits PAC/1302 and PAC/1303?

A. No. Since this investment is anticipated to become used and useful following the January 1, 2013 effective date of proposed rates in this case, the effects of this proposed adjustment are not included in these exhibits.

Q. What will be the rate change attributable to the Transmission Investment Adjustment tariff proposed to become effective in June 2013?

A. As shown in Exhibit PAC/1304 the annualized effect of the Transmission Investment Adjustment tariff is approximately $13.1 million, equal to an increase of approximately 1.1 percent.

Power Cost Adjustment Mechanism

Q. As presented in the testimony of Company witness Mr. Gregory N. Duvall, the Company has proposed to implement a Power Cost Adjustment Mechanism ("PCAM") in this general rate case. How does the Company propose to spread the revenues associated with the PCAM balancing account?

A. The Company proposes to spread the PCAM balancing account to rate schedules on the same basis utilized for the Schedule 201 TAM rates that were in effect during the one-year PCAM accrual period. The TAM rate spread is set by the TAM guidelines and is allocated by rate schedule based on functionalized generation costs from the general rate case filed concurrently with the TAM or on the basis of the spread of current Schedule 201 revenues, in the case of a stand-alone TAM. The Company proposes setting rates for the PCAM balancing account on a cents per kilowatt-hour basis differentiated by voltage level for each rate schedule.

Q. Does the Company propose that any consumers be exempt from the PCAM adjustment?

A. Yes. The Company proposes that consumers who did not pay cost-based net power costs though Schedule 201 during the year in which the PCAM accrued would not be subject to the PCAM adjustment for that year of service. Specifically, consumers who chose to be served under market prices under Standard Offer Supply Service Schedule 220 or who chose direct access during a calendar year would be exempt from the PCAM adjustment based on that year.

Q. Have you prepared a proposed PCAM tariff?

A. Yes. Exhibit PAC/1301 contains the Company's proposed PCAM tariff, Schedule 206. Because the accrual period begins on January 1, 2013, the proposed tariff displays rates equal to zero for all rate schedules.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-246
Exhibit PAC/1301
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Proposed Tariffs

March 2012

TABLE OF CONTENTS - SCHEDULES

Schedule No.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 4

RESIDENTIAL SERVICE
DELIVERY SERVICE

Available

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

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements when all service is supplied at one point of delivery. Three-phase service will be supplied only when service is available from Company's presently existing facilities, or where such facilities can be installed under Company's Line Extension Rules, and, in any event, only when deliveries can be made by using one service for Consumer's single-phase and three-phase requirements.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, per month	$9.50	(I)
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	3.831¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.378¢	(R)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Special Conditions

Consumer shall so arrange his wiring as to make possible the separate metering of the three-phase demand at a location adjacent to the kWh meter. If, on November 25, 1975, any present Consumer's wiring was arranged only for combined single and three-phase demand measurement, and continues to be so arranged, such demands will be metered and billed hereunder except that the first 10 kW of such combined demand will be deducted before applying demand charges for three phase service. No new combined demand installations will be allowed such a demand deduction.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 15

OUTDOOR AREA LIGHTING SERVICE - NO NEW SERVICE
DELIVERY SERVICE

Available

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

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of presently-installed Company-owned mercury vapor or high-pressure sodium luminaires which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Type of Luminaire	Nominal Rating	Monthly kWh	Rate Per Luminaire	
Mercury Vapor	7,000	76	$6.18	(I)
Mercury Vapor	21,000	172	$11.14	|
Mercury Vapor	55,000	412	$21.96	|
High Pressure Sodium	5,800	31	$8.65	|
High Pressure Sodium	22,000	85	$11.76	|
High Pressure Sodium	50,000	176	$18.09	(I)

Pole Charge

A monthly charge of $1.00 per pole shall be made for each additional pole required in excess of the number of luminaires installed.

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Special Conditions

1. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.

2. The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

3. Temporary disconnection and subsequent reconnection of electrical service requested by the Consumer shall be at the Consumer's expense. The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by the Company's estimated average monthly relamping and energy costs for the luminaire. The facilities may be considered idle and may be removed after 12 months of inactivity. The Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by the Consumer.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 23

GENERAL SERVICE - SMALL NONRESIDENTIAL
DELIVERY SERVICE

Available

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

Applicable

To Small Nonresidential Consumers whose entire electric service requirements are supplied hereunder and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Charge, per month	$18.55	$18.55	(R)
Three Phase, per month	$27.65	$27.65	(R)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$1.30	$1.30	
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$4.30	$4.18	(R)
Distribution Energy Charge, per kWh	2.704¢	2.628¢	(R)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.361¢	0.351¢	(R)

kW Load Size

For determination of the Basic Charge and Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

(continued)

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Communication Devices

Communication devices with fixed loads that are installed on streetlights, traffic signals or elsewhere and connected to the Company's system for electric service may be unmetered and shall be served under this schedule in accordance with Rule 7.C. Such unmetered devices not exceeding 35 line watts per unit, served under multiple Points of Delivery to a single Consumer, may be grouped under a single Consumer account for billing purposes such that the Consumer pays a single Basic Charge for multiple units in addition to a per unit energy-based charge. Not more than 100 units shall be grouped under a single account.

All devices are required to be installed and maintained under a pole attachment agreement. The Consumer is required to notify the Company in writing and receive subsequent approval prior to installation, modification or removal of any device.

All devices mounted to Company owned facilities shall be installed, maintained, transferred or removed only by qualified personnel approved in advance by the Company. If approved qualified personnel are not available or at the Company's discretion, the Company may perform these functions at the Consumer's expense.

Supply Service Options

All Small Nonresidential Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212, Schedule 213, or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 723, Direct Access Delivery Service.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 28

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Available

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

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 20.00	$ 24.00	(I)
Load Size 51-100 kW, per month	$ 37.00	$ 41.00	|
Load Size 101 - 300 kW, per month	$ 89.00	$ 98.00	|
Load Size > 300 kW, per month	$ 127.00	$ 140.00	(I)
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.25	$ 1.35	(I)
51 - 100 kW, per kW Load Size	$ 1.00	$ 1.15	|
101 – 300 kW, per kW Load Size	$ 0.60	$ 0.65	|
> 300 kW, per kW Load Size	$ 0.40	$ 0.35	|
Demand Charge, per kW	$ 4.37	$ 4.78	|
Distribution Energy Charge, per kWh	0.435¢	0.077¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 1.12	$ 1.00	(R),(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 28

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW, but not less than 15 kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 728, Direct Access Delivery Service.

Special Conditions

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company.

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 30

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW to 999 KW
DELIVERY SERVICE

Available

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

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤200 kW, per month	$514.00	$482.00	(I)
Load Size 201 - 300 kW, per month	$154.00	$152.00	(I)
Load Size > 300 kW, per month	$403.00	$395.00	(I)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$1.80	$1.65	(I)
> 300 kW, per kW Load Size	$0.85	$0.85	(I)
Demand Charge, per kW	$4.60	$4.42	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$1.24	$1.16	(R)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 730, Direct Access Delivery Service.

Special Conditions

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company.

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 41

AGRICULTURAL PUMPING SERVICE
DELIVERY SERVICE

Available

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

Applicable

To Consumers desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 47 or 48. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the monthly billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$310.00	$300.00	(R)
Three Phase Load Size > 300 kW	$1,210.00	$1,180.00	(R)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$15.00	$15.00	(R)
Three Phase 51 - 300 kW, per kW Load Size	$10.00	$10.00	(R)
Three Phase > 300 kW, per kW Load Size	$6.00	$6.00	(R)
Single Phase, Minimum Charge	$50.00	$50.00	(R)
Three Phase, Minimum Charge	$90.00	$85.00	(R)
Distribution Energy Charge, per kWh	3.563¢	3.463¢	(R)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.295¢	0.287¢	(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

kW Load Size *(continued)*

If Motor Size Is:	**Monthly kW is:**
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

In no case shall the Monthly kW be less than the average kW determined as:

$$\text{Average kW} = \frac{\text{kWh for billing month}}{\text{hours in billing month}}$$

Reactive Power Charge

The maximum 15-minute reactive takings for the billing month in kilovolt-amperes in excess of 40% of the Monthly kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. A Small Nonresidential Consumer taking Delivery Service under this schedule shall additionally specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212, Schedule 213, or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. A Large Nonresidential Consumer taking Delivery Service under this Schedule shall additionally specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 741, Direct Access Delivery Service.

Special Conditions

1) For new or terminating service, the Basic Charge and the Load Size Charge shall be prorated based upon the length of time the account is active during the 12-month period December through November; provided, however, that proration of the Basic Charge and the Load Size Charge will be available on termination only if a full Basic Charge and Load Size Charge was paid for the delivery point for the preceding year.
2) For new service or for reestablishment of service, the Company will require a written contract.
3) In the absence of a Consumer or Applicant willing to contract for service, the Company may remove its facilities.
4) Energy use may be carried forward and be billed in a subsequent billing month; provided, however, that energy will not be carried forward and be charged for at a higher rate than was applicable for the billing months during which the energy was used.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 47

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DELIVERY SERVICE

Available

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

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$490.00	$540.00	$1,020.00	(I)
Facility Capacity > 4,000 kW, per month	$920.00	$960.00	$1,880.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$1.45	$0.80	$1.15	(I)
> 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$1.15	(I)
On-Peak Demand Charge, per kW	$4.47	$4.66	$4.75	(I)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company approved Self-Supply Agreement)				
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$0.76	$0.82	$1.25	(R)

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Pacific Prevailing Time (PPT) Monday through Saturday, excluding North American Electric Reliability Council (NERC) holidays.

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

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

Facility Capacity shall be the average of the two greatest non-zero monthly Demands established during the 12 month period which includes and ends with the current Billing Month, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 48

LARGE GENERAL SERVICE 1,000 KW AND OVER
DELIVERY SERVICE

Available

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

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$490.00	$540.00	$1,020.00	(I)
Facility Capacity > 4,000 kW, per month	$920.00	$960.00	$1,880.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$1.45	$0.80	$1.15	(I)
> 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$1.15	(I)
On-Peak Demand Charge, per kW	$4.47	$4.66	$4.75	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$1.30	$1.36	$1.79	(R)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday, excluding NERC holidays.

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

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Supply Service Options

All Consumers taking Delivery Service under this Schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 748, Direct Access Delivery Service.

Special Conditions

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 50

MERCURY VAPOR STREET LIGHTING SERVICE
NO NEW SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished from dusk to dawn for the lighting of public streets, highways, alleys and parks by means of presently-installed mercury vapor lights. Street lights will be served by either series or multiple circuits as the Company may determine. The type and kind of fixtures and supports will be in accordance with the Company's specifications. Service includes installation, maintenance, energy, lamp and glassware renewals.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A. Company-owned Overhead System

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

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$5.78	$10.03	$19.42	(I)
Vertical, per lamp	$5.31	$9.20		(I)

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

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$7.93			(I)
On 26-foot poles, vertical, per lamp	$7.40			(I)
On 30-foot poles, horizontal , per lamp		$12.56		(I)
On 30-foot poles, vertical, per lamp		$11.73		(I)
On 33-foot poles, horizontal , per lamp			$21.92	(I)

B. Company-owned Underground System

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$7.93			(I)
On 26-foot poles, vertical, per lamp	$7.40			(I)
On 30-foot poles, horizontal , per lamp		$12.03		(I)
On 30-foot poles, vertical, per lamp		$11.25		(I)
On 33-foot poles, horizontal , per lamp			$21.39	(I)
plus rate per foot of underground cable:				
In paved area	$0.05	$0.05	$0.05	
in unpaved area	$0.03	$0.03	$0.03	

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 51

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
DELIVERY SERVICE

Available

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

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor							
Lumen Rating	5,800*	9,500	16,000	22,000*	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Functional Lighting	$ 5.17	$ 5.77	$ 7.00	$ 8.22	$ 10.58	$ 12.97	(I)
Decorative - Series 1	N/A	$ 19.54	$ 19.48	N/A	N/A	N/A	(I)
Decorative - Series 2	N/A	$ 16.76	$ 16.65	N/A	N/A	N/A	(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	
Watts	100	175	250	400	
Monthly kWh	39	68	94	149	
Functional Lighting	N/A	$ 13.65	$ 15.31	$ 14.79	(I)
Decorative - Series 1	$ 19.66	$ 20.98	N/A	N/A	(I)
Decorative - Series 2	$ 18.10	$ 18.13	N/A	N/A	(I)

*Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures or to Metal Halide fixtures of any size.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 52

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
NO NEW SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished by means of the Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. The Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A flat rate equal to one-twelfth of the Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including Distribution Charge as follows:

For dusk to dawn operation, per kWh	1.635¢	(I)
For dusk to midnight operation, per kWh	1.946¢	(I)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 752, Direct Access Delivery Service.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.
2. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.
3. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable fixtures and facilities from the Company's Construction Standards.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 53

STREET LIGHTING SERVICE CONSUMER-OWNED SYSTEM
DELIVERY SERVICE

Available

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

Applicable

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.29	$ 1.84	$ 2.67	$ 3.55	$ 4.80	$ 7.35

(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	107,800*
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.63	$ 2.84	$ 3.92	$ 6.22	$ 14.78

(I)

*Existing fixtures only. Service is not available under this Schedule to new Metal Halide fixtures of any size.

For non-listed luminaires the cost will be calculated for 3940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.174

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 54

RECREATIONAL FIELD LIGHTING - RESTRICTED DELIVERY SERVICE

Available

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

Applicable

To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At the Consumer's option, service for recreational field lighting may be taken under the Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge

Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.087¢	(I)

Transmission & Ancillary Services Charge

per kWh	0.068¢	(R)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 754, Direct Access Delivery Service.

Special Conditions

The Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 55

LED PILOT STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon. Service under this schedule shall be available for up to 250 luminaires on a first-come, first-served basis. Each entity requesting service under this schedule shall be limited to 25 luminaires.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control.

Monthly Billing

The Monthly Billing shall be the sum of the rates per luminaire as specified in the rate tables below plus the applicable rate for Schedule 51 shown in Schedule 80 and all adjustments that are applicable for Schedule 51 as specified in Schedule 90.

Light-Emitting Diode (LED)		
Compares to HPSV lamp size of (Watts)	100	150
Monthly kWh	29	41
LED Luminaire Rate	$ 4.92	$ 6.87

(I)

Supply Service Option:

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.

2. Company will install only Company approved street lighting equipment at locations acceptable to Company.

3. Where provided by this tariff, and following notification by the Consumer, inoperable lights will be repaired as soon as possible, during regular business hours or as allowed by Company's operating schedule and requirements.

4. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable fixtures and facilities from the Company's Construction Standards.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 76R

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS SERVICE
ECONOMIC REPLACEMENT POWER RIDER
DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Transmission & Ancillary Services Charge				
Per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.030	$0.032	$0.049	(R)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.174	$0.182	$0.185	(I)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

(continued)

Purpose

This schedule reflects an adjustment associated with the Populus to Terminal transmission investment, consistent with Order No. 10-473.

Monthly Billing

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.36 shall have applied an amount equal to the product of all kWh, or, as appropriate, kW, multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	Secondary	Primary	Transmission
Schedule 4, per kWh	(0.040¢)		
Schedule 15, per kWh	(0.007¢)		
Schedule 23, 723, per kWh	(0.039¢)	(0.038¢)	
Schedule 28, 728, per kW	($0.12)	($0.08)	
Schedule 30, 730, per kW	($0.13)	($0.13)	
Schedule 41, 741, per kWh	(0.031¢)	(0.030¢)	
Schedule 47, 747, per On-Peak kW	($0.13)	($0.15)	($0.19)
Schedule 48, 748, per On-Peak kW	($0.13)	($0.15)	($0.19)
Schedule 50, per kWh	(0.007¢)		
Schedule 51, 751, per kWh	(0.007¢)		
Schedule 52, 752, per kWh	(0.007¢)		
Schedule 53, 753, per kWh	(0.007¢)		
Schedule 54, 754, per kWh	(0.007¢)		

Rates “per kWh” shall apply to all kilowatt-hours of use per month.
Rates “per kW” and “per On-Peak kW” shall be charged based on measured monthly Demand and On-Peak Demand, respectively, as defined in each respective Delivery Service schedule.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

Schedule	91	92	93	96	97	98*	102	194	195	199	202	203	204	205	206*	290	291	294*	295*	297*	299	(N)
4	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x			x	x	
15	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
23	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
28	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
30	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
33	x		x	x		x	x	x	x	x	x	x	x		x	x	x	x	x	x		
41	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
47	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
48	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
50	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
51	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
52	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
53	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
54	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
723	x	x	x	x		x	x	x	x	x			x	x	x	x	x	x	x	x	x	
728	x	x	x	x		x	x	x	x	x			x	x	x	x	x	x	x	x	x	
730	x	x	x	x		x	x	x	x	x			x	x	x	x	x	x	x	x	x	
741	x	x	x	x		x	x	x	x	x			x	x	x	x	x	x	x	x	x	
747	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	x	x	x	
748	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	x	x	x	
751	x	x	x	x			x	x	x	x			x	x	x	x	x	x	x	x	x	
752	x	x	x	x			x	x	x	x			x	x	x	x	x	x	x	x	x	
753	x	x	x	x			x	x	x	x			x	x	x	x	x	x	x	x	x	
754	x	x	x	x			x	x	x	x			x	x	x	x	x	x	x	x	x	(N)

*Not applicable to all consumers. See Schedule for details.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Available

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

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

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

Delivery Service Schedule No.			Delivery Voltage			
			Secondary	Primary	Transmission	
4	Per kWh	0 – 1000 kWh	2.591¢			(R)
		> 1000 kWh	3.538¢			(R)
	For Schedule 4, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).					
23, 723	First 3,000 kWh, per kWh		2.984¢	2.900¢		(R)
	All additional kWh, per kWh		2.215¢	2.153¢		(R)
28, 728	First 20,000 kWh, per kWh		2.867¢	2.776¢		(R)
	All additional kWh, per kWh		2.790¢	2.701¢		(R)
30, 730	Demand Charge, per kW		$1.30	$1.30		(I)
	First 20,000 kWh, per kWh		2.761¢	2.658¢		(R)
	All additional kWh, per kWh		2.394¢	2.298¢		(R)
	Demand shall be as defined in the Delivery Service Schedule					
41, 741	Winter, first 100 kWh/kW, per kWh		3.956¢	3.844¢		(R)
	Winter, all additional kWh, per kWh		2.697¢	2.621¢		(R)
	Summer, all kWh, per kWh		2.697¢	2.621¢		(R)
	For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.					

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage			
		Secondary	Primary	Transmission	
47/48,	Demand Charge, per kW of On-Peak Demand	$1.19	$1.20	$1.21	(I)
747/748	Per kWh, On-Peak	2.492¢	2.425¢	2.391¢	(R)
	Per kWh, Off-Peak	2.442¢	2.375¢	2.341¢	(R)

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

On-Peak Demand shall be as defined in the Delivery Service Schedule.

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

52, 752	For dusk to dawn operation, per kWh	2.644¢	(R)
	For dusk to midnight operation, per kWh	2.644¢	(R)
54, 754	Per kWh	1.941¢	(R)

15	Type of Luminaire	Nominal Rating	Monthly kWh	Rate Per Luminaire	
	Mercury Vapor	7,000	76	$1.84	(R)
	Mercury Vapor	21,000	172	$4.17	
	Mercury Vapor	55,000	412	$9.98	
	High Pressure Sodium	5,800	31	$0.75	
	High Pressure Sodium	22,000	85	$2.06	
	High Pressure Sodium	50,000	176	$4.26	(R)

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$1.66	$3.76	$9.00	(R)
Vertical, per lamp	$1.66	$3.76		(R)

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

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.66			(R)
On 26-foot poles, vertical, per lamp	$1.66			(R)
On 30-foot poles, horizontal, per lamp		$3.76		(R)
On 30-foot poles, vertical, per lamp		$3.76		(R)
On 33-foot poles, horizontal, per lamp			$9.00	(R)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

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

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.66			(R)
On 26-foot poles, vertical, per lamp	$1.66			(R)
On 30-foot poles, horizontal, per lamp		$3.76		(R)
On 30-foot poles, vertical, per lamp		$3.76		(R)
On 33-foot poles, horizontal, per lamp			$9.00	(R)

51, 751

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$1.07	(R)
High Pressure Sodium	9,500	100	44	$1.52	
High Pressure Sodium	16,000	150	64	$2.21	
High Pressure Sodium	22,000	200	85	$2.93	
High Pressure Sodium	27,500	250	115	$3.97	
High Pressure Sodium	50,000	400	176	$6.07	
Metal Halide	9,000	100	39	$1.35	
Metal Halide	12,000	175	68	$2.35	
Metal Halide	19,500	250	94	$3.24	
Metal Halide	32,000	400	149	$5.14	(R)

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.35	(R)
High Pressure Sodium	9,500	100	44	$0.50	
High Pressure Sodium	16,000	150	64	$0.72	
High Pressure Sodium	22,000	200	85	$0.96	
High Pressure Sodium	27,500	250	115	$1.30	
High Pressure Sodium	50,000	400	176	$1.99	
Metal Halide	9,000	100	39	$0.44	
Metal Halide	12,000	175	68	$0.77	
Metal Halide	19,500	250	94	$1.06	
Metal Halide	32,000	400	149	$1.68	
Metal Halide	107,800	1,000	354	$4.00	(R)
Non-Listed Luminaire, per kWh			1.129¢		(R)

55

Types of Luminaire	Compares to HPSV Lamp Size of (Watts)	Monthly kWh	Rate Per Luminaire	
Light Emitting Diode	100	29	$1.00	(R)
Light Emitting Diode	150	41	$1.41	(R)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER REVENUES

Purpose

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

Applicable

To all Residential Consumers and Nonresidential Consumers.

Energy Charge

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

Delivery Service Schedule No.			Delivery Voltage			
			Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	0.000¢			(R)
		> 1000 kWh	0.000¢			(R)
	For Schedule 4, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).					
23, 723	First 3,000 kWh, per kWh		0.000¢	0.000¢		(R)
	All additional kWh, per kWh		0.000¢	0.000¢		(R)
28, 728	First 20,000 kWh, per kWh		0.000¢	0.000¢		(R)
	All additional kWh, per kWh		0.000¢	0.000¢		(R)
30, 730	First 20,000 kWh, per kWh		0.000¢	0.000¢		(R)
	All additional kWh, per kWh		0.000¢	0.000¢		(R)
41, 741	Winter, first 100 kWh/kW, per kWh		0.000¢	0.000¢		(R)
	Winter, all additional kWh, per kWh		0.000¢	0.000¢		(R)
	Summer, all kWh, per kWh		0.000¢	0.000¢		(R)

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

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	0.000¢	0.000¢	0.000¢	(R)
747/748	Per kWh, Off-Peak	0.000¢	0.000¢	0.000¢	(R)

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

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

52, 752	For dusk to dawn operation, per kWh	0.000¢	(R)
	For dusk to midnight operation, per kWh	0.000¢	(R)
54,754	Per kWh	0.000¢	(R)

	Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
15	Mercury Vapor	7,000	76	$0.00	(R)
	Mercury Vapor	21,000	172	$0.00	
	Mercury Vapor	55,000	412	$0.00	
	High Pressure Sodium	5,800	31	$0.00	
	High Pressure Sodium	22,000	85	$0.00	
	High Pressure Sodium	50,000	176	$0.00	(R)

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$0.00	$0.00	$0.00	(R)
Vertical, per lamp	$0.00	$0.00		(R)

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

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.00			(R)
On 26-foot poles, vertical, per lamp	$0.00			(R)
On 30-foot poles, horizontal, per lamp		$0.00		(R)
On 30-foot poles, vertical, per lamp		$0.00		(R)
On 33-foot poles, horizontal, per lamp			$0.00	(R)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER REVENUES

Energy Charge (continued)

Delivery Service Schedule No.

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

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.00			(R)
On 26-foot poles, vertical, per lamp	$0.00			(R)
On 30-foot poles, horizontal, per lamp		$0.00		(R)
On 30-foot poles, vertical, per lamp		$0.00		(R)
On 33-foot poles, horizontal, per lamp			$0.00	(R)

51, 751

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

53, 753

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

Non-Listed Luminaire, per kWh 0.000¢

55

Types of Luminaire	Compares to HPSV Lamp Size of (Watts)	Monthly kWh	Rate Per Luminaire	
Light Emitting Diode	100	29	$0.00	(R)
Light Emitting Diode	150	41	$0.00	(R)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 206

POWER COST ADJUSTMENT MECHANISM - ADJUSTMENT

(N)

Purpose

This schedule implements the Company's annual Power Cost Adjustment Mechanism adjustment consistent with Order No. XXX.

Applicable

To all Residential Consumers and Nonresidential Consumers except Nonresidential Consumers who took service under Standard Offer Supply Service Schedule 220 or who were served under a Direct Access Delivery Service Schedule during the accrual period of this Power Cost Adjustment Mechanism adjustment.

Monthly Billing

The adjustment shall be calculated as an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service Schedule.

Delivery Service Schedule	Secondary	Primary	Transmission
Schedule 4, per kWh	0.000¢		
Schedule 15, per kWh	0.000¢		
Schedule 23, 723, per kWh	0.000¢	0.000¢	
Schedule 28, 728, per kWh	0.000¢	0.000¢	
Schedule 30, 730, per kWh	0.000¢	0.000¢	
Schedule 41, 741, per kWh	0.000¢	0.000¢	
Schedule 47, 747, per kWh	0.000¢	0.000¢	0.000¢
Schedule 48, 748, per kWh	0.000¢	0.000¢	0.000¢
Schedule 50, per kWh	0.000¢		
Schedule 51, 751, per kWh	0.000¢		
Schedule 52, 752, per kWh	0.000¢		
Schedule 53, 753, per kWh	0.000¢		
Schedule 54, 754, per kWh	0.000¢		

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 230

EMERGENCY SUPPLY SERVICE

Available

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

Applicable

To Nonresidential Consumers. Service commences upon the Company becoming aware that the Nonresidential Consumer's ESS is no longer providing service. Delivery Service shall be billed under the Consumer's applicable rate schedule from the following: Schedule 23, 28, 30, 41, 47, 48, 51, 52, 53, 54. The Consumer must move off of this service within five business days of commencing service under this Schedule.

Energy Charge

The Energy Charge shall be based on the Energy Charge Daily Rate as described below.
The Energy Charge Daily Rate is the Dow Jones Mid-Columbia Daily Electricity Firm Price Index (DJ-Mid-C Index) plus the Emergency Default Risk Premium plus the adjustment for losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices shall be used to determine the price for the non-reported period.

On-peak and off-peak hours shall be defined as reported by Dow Jones for the Mid-Columbia Index. Currently, on-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-peak hours are all remaining hours.

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

The Emergency Default Risk Premium shall be 25 percent of the DJ-Mid-C Index.

The loss adjustment shall be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Transmission Delivery Voltage	1.04527	(I)
Primary Delivery Voltage	1.06904	(I)
Secondary Delivery Voltage	1.10006	(I)

In addition to this energy charge, all customers purchasing this service are required to pay for ancillary services at the rates determined by the appropriate pro forma transmission tariffs.

Energy Charge (continued)

Unscheduled Energy

Any Electricity provided to the Consumer that does not qualify as Baseline Energy or Scheduled Maintenance Energy shall be Unscheduled Energy and priced at an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex Mid-C Hourly Firm Index) plus 0.14¢ per kWh, plus the adjustment for Losses. Prices reported with no transaction volume or as survey-based shall be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Pacific Prevailing Time (PPT) Monday through Saturday excluding North American Electric Reliability Council (NERC) holidays. Off-peak hours are all remaining hours.

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

The Company may request that a Consumer taking a significant amount of Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

Losses

Losses shall be included by multiplying the applicable Energy Charge by the following adjustment factors:

Transmission Delivery Voltage	1.04527	(I)
Primary Delivery Voltage	1.06904	(I)
Secondary Delivery Voltage	1.10006	(I)

Special Conditions

Special conditions contained in Delivery Service Schedule 47 apply to this Schedule.

Rules and Regulations

Service and rates under this Schedule are subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

Losses

Losses shall be included by multiplying the ERP Charge by the following adjustment factors:

Transmission Delivery Voltage	1.04527	(I)
Primary Delivery Voltage	1.06904	(I)
Secondary Delivery Voltage	1.10006	(I)

Special Conditions

1. Prior to receiving service under this schedule, the Consumer and the Company must enter into a written agreement governing the terms and conditions of service, including, but not limited to, consequences of failure to perform. In particular, the written agreement shall specify that under a *force majeure* event, Company and Consumer shall make best efforts to mitigate damages.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule, the ERPA and the corresponding written agreement. All other Energy supplied will be made under the terms of Schedule 247. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Consumer is required to maintain Schedule 247 service unless otherwise agreed to by the Company.

3. All charges and requirements of Schedule 247 shall apply except as provided for under this schedule.

4. ERP supplied shall not be resold.

5. The Company may interrupt ERP due to Transmission constraints.

6. The Company is not responsible for providing market information to Consumer other than as specified in this tariff.

7. The Company has no obligation to provide the Consumer with ERP except as explicitly agreed to by both parties.

8. Each day of delivery begins HE 0100 and ends HE 2400 under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 299

RATE MITIGATION ADJUSTMENT

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

	Secondary	Primary	Transmission	
Schedule 4	0.094¢			(C)
Schedule 15	2.830¢			
Schedule 23, 723	0.275¢	0.275¢		
Schedule 28, 728	0.161¢	0.161¢		
Schedule 30, 730	0.054¢	0.054¢		
Schedule 41, 741	(0.293¢)	(0.293¢)		(C)
Schedule 47, 747	(0.329¢)	(0.411¢)	(0.509¢)	
Schedule 48, 748	(0.329¢)	(0.411¢)	(0.509¢)	
Schedule 50	2.628¢			(C)
Schedule 51, 751	4.183¢			
Schedule 52, 752	2.760¢			
Schedule 53, 753	1.571¢			
Schedule 54, 754	1.977¢			(C)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 723

GENERAL SERVICE – SMALL NONRESIDENTIAL
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

To Small Nonresidential Consumers who have chosen to receive electricity from an ESS, and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$18.55	$18.55	(R)
Three Phase, per month	$27.65	$27.65	(R)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 1.30	$ 1.30	
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 4.30	$ 4.18	(R)
Distribution Energy Charge, per kWh	2.704¢	2.628¢	(R)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW.

(continued)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Communication Devices

Communication devices with fixed loads that are installed on streetlights, traffic signals or elsewhere and connected to the Company's system for electric service may be unmetered and shall be served under this schedule in accordance with Rule 7.C. Such unmetered devices not exceeding 35 line watts per unit, served under multiple Points of Delivery to a single Consumer, may be grouped under a single Consumer account for billing purposes such that the Consumer pays a single Basic Charge for multiple units in addition to a per unit energy-based charge. Not more than 100 units shall be grouped under a single account.

All devices are required to be installed and maintained under a pole attachment agreement. The Consumer is required to notify the Company in writing and receive subsequent approval prior to installation, modification or removal of any device.

All devices mounted to Company owned facilities shall be installed, maintained, transferred or removed only by qualified personnel approved in advance by the Company. If approved qualified personnel are not available or at the Company's discretion, the Company may perform these functions at the Consumer's expense.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under the schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this schedule to any person, except by permission of the Company.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 728

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 20.00	$ 24.00	(I)
Load Size 51-100 kW, per month	$ 37.00	$ 41.00	(I)
Load Size 101 - 300 kW, per month	$ 89.00	$ 98.00	(I)
Load Size > 300 kW, per month	$ 127.00	$ 140.00	(I)
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.25	$ 1.35	(I)
51-100 kW, per kW Load Size	$ 1.00	$ 1.15	(I)
101 – 300 kW, per kW Load Size	$ 0.60	$ 0.65	(I)
> 300 kW, per kW Load Size	$ 0.40	$ 0.35	(I)
Demand Charge, per kW	$ 4.37	$ 4.78	(I)
Distribution Energy Charge, per kWh	0.435¢	0.077¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 15 kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under the schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company.

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which This Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 730

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW TO 999 KW
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$514.00	$482.00	(I)
Load Size 201 - 300 kW, per month	$154.00	$152.00	(I)
Load Size > 300 kW, per month	$403.00	$395.00	(I)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.80	$ 1.65	(I)
> 300 kW, per kW Load Size	$ 0.85	$ 0.85	(I)
Demand Charge, per kW	$ 4.60	$ 4.42	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

(continued)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under the schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company.

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which This Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 741

AGRICULTURAL PUMPING SERVICE
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

To Consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the Monthly Billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 310.00	$ 300.00	(R)
Three Phase Load Size > 300 kW	$1,210.00	$1,180.00	(R)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 15.00	$ 15.00	(R)
Three Phase 51 - 300 kW, per kW Load Size	$ 10.00	$ 10.00	
Three Phase > 300 kW, per kW Load Size	$ 6.00	$ 6.00	
Single Phase, Minimum Charge	$ 50.00	$ 50.00	
Three Phase, Minimum Charge	$ 90.00	$ 85.00	
Distribution Energy Charge, per kWh	3.563¢	3.463¢	(R)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	**Monthly kW is:**
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

kW Load Size (continued)

In no case shall the Monthly kW be less than the average kW determined as:

$$\text{Average kW} = \frac{\text{kWh for billing month}}{\text{hours in billing month}}$$

Reactive Power Charge

The maximum 15-minute reactive takings for the billing month in kilovolt-amperes in excess of 40% of the Monthly kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

1) For new or terminating service, the Basic Charge and the Load Size Charge shall be prorated based upon the length of time the account is active during the 12-month period December through November; provided, however, that proration of the Basic Charge and the Load Size Charge will be available on termination only if a full Basic Charge and Load Size Charge was paid for the delivery point for the preceding year.

2) For new service or for reestablishment of service, Company will require a written contract.

3) In the absence of a Consumer or Applicant willing to contract for service, Company may remove its facilities.

4) Energy use may be carried forward and be billed in a subsequent billing month; provided, however, that energy will not be carried forward and be charged for at a higher rate than was applicable for the billing months during which the energy was used.

Term of Contract

Not less than three years.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 747

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Reserves Charges plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$490.00	$540.00	$1,020.00	(I)
Facility Capacity > 4,000 kW, per month	$920.00	$960.00	$1,880.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$1.45	$0.80	$1.15	(I)
> 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$1.15	(I)
On-Peak Demand Charge, per kW	$4.47	$4.66	$4.75	(I)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves				
(with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Pacific Prevailing Time (PPT) Monday through Saturday, excluding North American Electric Reliability Council (NERC) holidays.

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

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

Facility Capacity shall be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Month, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 748

LARGE GENERAL SERVICE 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$490.00	$540.00	$1,020.00	(I)
Facility Capacity > 4000 kW, per month	$920.00	$960.00	$1,880.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$1.45	$0.80	$1.15	(I)
> 4000 kW, per kW Facility Capacity	$1.35	$0.75	$1.15	(I)
On-Peak Demand Charge, per kW	$4.47	$4.66	$4.75	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday, excluding NERC holidays.

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

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718. (I)

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290. (R)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 751

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor							
Lumen Rating	5,800*	9,500	16,000	22,000*	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Functional Lighting	$ 5.15	$ 5.74	$ 6.96	$ 8.16	$ 10.50	$ 12.85	(I)
Decorative - Series 1	N/A	$ 19.51	$ 19.44	N/A	N/A	N/A	(I)
Decorative - Series 2	N/A	$ 16.73	$ 16.61	N/A	N/A	N/A	(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	
Watts	100	175	250	400	
Monthly kWh	39	68	94	149	
Functional Lighting	N/A	$ 13.60	$ 15.25	$ 14.69	(I)
Decorative - Series 1	$ 19.63	$ 20.93	N/A	N/A	(I)
Decorative - Series 2	$ 18.07	$ 18.08	N/A	N/A	(I)

*Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures or Metal Halide fixtures of any size.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 752

STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM - NO NEW SERVICE
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To service furnished by means of Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

For systems owned, operated and maintained by Company. The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A flat rate equal to one-twelfth of Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including energy costs as follows:

For dusk to dawn operation, per kWh	1.567¢	(I)
For dusk to midnight operation, per kWh	1.878¢	(I)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Suspension of Service

The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by Company's estimated average monthly relamping and energy costs for the luminaire. Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by Consumer.

Termination of Service

Service furnished hereunder by means of incandescent and mercury-vapor lights is subject to termination by not less than sixty (60) days written notice given by Company to Consumer.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Available

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

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.27	$ 1.81	$ 2.63	$ 3.49	$ 4.72	$ 7.23

(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	107,800*
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.60	$ 2.79	$ 3.86	$ 6.12	$ 14.54

(I)

*Existing fixtures only. Service is not available under this schedule to new Metal Halide fixtures of any size.

For non-listed luminaires the cost will be calculated for 3940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.106

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 754

RECREATIONAL FIELD LIGHTING - RESTRICTED
DIRECT ACCESS DELIVERY SERVICE

Available

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

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge

Basic Charge, Single Phase, per month	$	6.00
Basic Charge, Three Phase, per month	$	9.00
Distribution Energy Charge, per kWh		4.087¢ (I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery. Company will supply one transformer, or transformer bank, for each athletic or recreational field; any additional transformers required shall be supplied and owned by Consumer. All transformers owned by Consumer must be properly fused and of such types and characteristics as conform to Company's standards. When service is supplied to more than one transformer or transformer bank, Company may meter such an installation at primary voltage.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 776R

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS
SERVICE-ECONOMIC REPLACEMENT SERVICE RIDER
DIRECT ACCESS DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERS On-Peak Demand	$0.174	$0.182	$0.185	(I)

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

Docket No. UE-246
Exhibit PAC/1302
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Target Functionalized Revenues and Billing Determinants

March 2012

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenue
Forecast 12 Months Ended December 31, 2013

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 4, Residential					
	Transmission & Ancillary Services[1]	$22,360	$20,399	$20,399	$20,415
	Distribution	$228,218	$261,617	$261,617	$261,610
	Other Adjustments	-$733	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$163,370	$153,699	$153,699	$153,695
	Generation Energy - Net Power Costs (Sch 201)	$151,277	$155,509	$151,277	$151,277
	Total	$564,491	$591,224	$586,993	$586,997
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$4,474	$3,949	$3,949	$3,949
	Distribution	$51,911	$51,447	$51,447	$51,452
	Other Adjustments	-$137	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$33,136	$30,826	$30,826	$30,823
	Generation Energy - Net Power Costs (Sch 201)	$30,685	$31,189	$30,685	$30,685
	Total	$120,069	$117,412	$116,908	$116,909
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$7,956	$7,423	$7,423	$7,425
	Distribution	$37,843	$50,004	$50,004	$49,992
	Other Adjustments	-$270	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$59,369	$55,985	$55,985	$55,987
	Generation Energy - Net Power Costs (Sch 201)	$54,984	$56,644	$54,984	$54,984
	Total	$159,882	$170,057	$168,396	$168,388
Primary Voltage					
	Transmission & Ancillary Services[1]	$57	$66	$66	$66
	Distribution	$321	$456	$456	$456
	Other Adjustments	-$1	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$523	$515	$515	$515
	Generation Energy - Net Power Costs (Sch 201)	$484	$521	$484	$484
	Total	$1,384	$1,558	$1,521	$1,521
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$4,572	$4,231	$4,231	$4,231
	Distribution	$17,493	$23,446	$23,446	$23,228
	Other Adjustments	-$120	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$36,063	$33,964	$33,964	$34,195
	Generation Energy - Net Power Costs (Sch 201)	$33,376	$34,364	$33,376	$33,376
	Total	$91,384	$96,005	$95,017	$95,030
Primary Voltage					
	Transmission & Ancillary Services[1]	$361	$316	$316	$317
	Distribution	$1,343	$1,749	$1,749	$1,746
	Other Adjustments	-$13	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,626	$2,452	$2,452	$2,455
	Generation Energy - Net Power Costs (Sch 201)	$2,418	$2,481	$2,418	$2,418
	Total	$6,735	$6,999	$6,936	$6,937
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$681	$620	$620	$620
	Distribution	$12,609	$10,907	$10,907	$10,907
	Other Adjustments	-$12	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$6,055	$5,695	$5,695	$5,696
	Generation Energy - Net Power Costs (Sch 201)	$5,607	$5,762	$5,607	$5,607
	Total	$24,940	$22,985	$22,830	$22,830

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenue
Forecast 12 Months Ended December 31, 2013

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$2,278	$2,164	$2,164	$2,162
	Distribution	$7,727	$11,239	$11,239	$11,270
	Other Adjustments	-$56	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$18,270	$17,304	$17,304	$17,271
	Generation Energy - Net Power Costs (Sch 201)	$16,986	$17,508	$16,986	$16,986
	Total	$45,205	$48,214	$47,692	$47,689
Primary Voltage					
	Transmission & Ancillary Services[1]	$5,673	$5,115	$5,115	$5,109
	Distribution	$14,924	$22,348	$22,348	$22,356
	Other Adjustments	-$166	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$45,435	$42,769	$42,769	$42,761
	Generation Energy - Net Power Costs (Sch 201)	$42,036	$43,273	$42,036	$42,036
	Total	$107,902	$113,506	$112,269	$112,263
Transmission Voltage					
	Transmission & Ancillary Services[1]	$2,310	$2,097	$2,097	$2,099
	Distribution	$4,050	$7,121	$7,121	$7,098
	Other Adjustments	-$32	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$21,624	$20,248	$20,248	$20,266
	Generation Energy - Net Power Costs (Sch 201)	$20,025	$20,487	$20,025	$20,025
	Total	$47,976	$49,953	$49,491	$49,488
Schedules 51, 53, 54, Lighting[2]					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$15	$15	$15	$15
	Distribution	$1,630	$1,688	$1,688	$1,688
	Other Adjustments	$3	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$541	$500	$500	$501
	Generation Energy - Net Power Costs (Sch 201)	$501	$506	$501	$501
	Total	$2,690	$2,708	$2,704	$2,704
TOTAL		**$1,172,659**	**$1,220,621**	**$1,210,756**	**$1,210,756**
Additional Rate Schedules					
	Schedule 47	$3,585		$3,843	$3,843
	Lighting 15, 50, 51[2], 52	$3,860		$3,878	$3,878
	Employee Discount	($445)		($462)	($462)
Total Oregon		**$1,179,659**		**$1,218,015**	**$1,218,015**
			Revenue Increase	**$38,356**	**$38,356**

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.
[2]Cost of Service study includes only certain lamp types under Schedule 51.

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Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,607,431,415	5,544,795,299	5,400,866,473	kWh	0.414 ¢	$22,359,587	0.378 ¢	$20,415,275
Distribution Charge								
Basic Charge, per month	5,716,077	5,716,077	5,753,484	bill	$9.00	$51,781,356	$9.50	$54,658,098
Three Phase Demand Charge, per kW demand	18,062	18,062	17,593	kW	$2.20	$38,705	$2.20	$38,705
Three Phase Minimum Demand Charge, per month	1,529	1,529	1,539	bill	$3.80	$5,848	$3.80	$5,848
Distribution Energy Charge, per kWh	5,607,431,415	5,544,795,299	5,400,866,473	kWh	3.266 ¢	$176,392,299	3.831 ¢	$206,907,195
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,099,028,935	4,053,241,935	3,948,030,052	kWh	2.754 ¢	$108,728,748	2.591 ¢	$102,293,459
Second Block kWh (> 1,000)	1,508,402,480	1,491,553,364	1,452,836,421	kWh	3.761 ¢	$54,641,178	3.538 ¢	$51,401,353
Subtotal	5,607,431,415	5,544,795,299	5,400,866,473	kWh		$413,947,721		$435,719,933
Populus to Terminal Adjustment (80), per kWh	5,607,431,415	5,544,795,299	5,400,866,473	kWh	-0.040 ¢	($2,160,347)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	4,099,028,935	4,053,241,935	3,948,030,052	kWh	0.024 ¢	$947,527	0.000 ¢	$0
Second Block kWh (> 1,000)	1,508,402,480	1,491,553,364	1,452,836,421	kWh	0.033 ¢	$479,436	0.000 ¢	$0
Subtotal						$413,214,337		$435,719,933
Schedule 201								
First Block kWh (0-1,000)	4,099,028,935	4,053,241,935	3,948,030,052	kWh	2.550 ¢	$100,674,766	2.550 ¢	$100,674,766
Second Block kWh (> 1,000)	1,508,402,480	1,491,553,364	1,452,836,421	kWh	3.483 ¢	$50,602,293	3.483 ¢	$50,602,293
Total	5,607,431,415	5,544,795,299	5,400,866,473	kWh		$564,491,396		$586,996,992
							Change	$22,505,596
Schedule No. 4 - Employee Discount								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	17,653,331	17,653,331	17,195,095	kWh	0.414 ¢	$71,188	0.378 ¢	$64,997
Distribution Charge								
Basic Charge, per month	13,922	13,922	14,013	bill	$9.00	$126,117	$9.50	$133,124
Three Phase Demand Charge, per kW demand	86	86	84	kW	$2.20	$185	$2.20	$185
Three Phase Minimum Demand Charge, per month	12	12	12	bill	$3.80	$46	$3.80	$46
Distribution Energy Charge, per kWh	17,653,331	17,653,331	17,195,095	kWh	3.266 ¢	$561,592	3.831 ¢	$658,744
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	11,790,524	11,790,524	11,484,472	kWh	2.754 ¢	$316,282	2.591 ¢	$297,563
Second Block kWh (> 1,000)	5,862,807	5,862,807	5,710,623	kWh	3.761 ¢	$214,777	3.538 ¢	$202,042
Subtotal	17,653,331	17,653,331	17,195,095	kWh		$1,290,187		$1,356,701
Populus to Terminal Adjustment (80), per kWh	17,653,331	17,653,331	17,195,095	kWh	-0.040 ¢	($6,878)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	11,790,524	11,790,524	11,484,472	kWh	0.024 ¢	$2,756	0.000 ¢	$0
Second Block kWh (> 1,000)	5,862,807	5,862,807	5,710,623	kWh	0.033 ¢	$1,885	0.000 ¢	$0
Subtotal						$1,287,950		$1,356,701
Schedule 201								
First Block kWh (0-1,000)	11,790,524	11,790,524	11,484,472	kWh	2.550 ¢	$292,854	2.550 ¢	$292,854
Second Block kWh (> 1,000)	5,862,807	5,862,807	5,710,623	kWh	3.483 ¢	$198,901	3.483 ¢	$198,901
Total	17,653,331	17,653,331	17,195,095	kWh		$1,779,705		$1,848,456
Schedule 201 Employee Discount						($122,939)		($122,939)
Total Employee Discount						($444,926)		($462,114)

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Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite								
General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,125,411,853	1,128,427,446	1,092,594,951	kWh	0.409 ¢	$4,468,713	0.361 ¢	$3,944,268
Distribution Charge								
Basic Charge								
Single Phase, per month	711,057	711,057	697,562	bill	$18.70	$13,044,409	$18.55	$12,939,775
Three Phase, per month	209,808	209,808	205,865	bill	$27.90	$5,743,634	$27.65	$5,692,167
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	925,557	925,557	897,096	kW	$1.30	$1,166,225	$1.30	$1,166,225
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	478,010	478,010	463,326	kW	$4.34	$2,010,835	$4.30	$1,992,302
Reactive Power Charge, per kvar	80,694	80,694	78,843	kvar	65.00 ¢	$51,248	65.00 ¢	$51,248
Distribution Energy Charge, per kWh	1,125,411,853	1,128,427,446	1,092,594,951	kWh	2.730 ¢	$29,827,842	2.704 ¢	$29,543,767
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	882,298,260	884,661,260	856,570,502	kWh	3.208 ¢	$27,478,782	2.984 ¢	$25,560,064
All additional kWh, per kWh	243,113,593	243,766,186	236,024,449	kWh	2.381 ¢	$5,619,742	2.215 ¢	$5,227,942
Subtotal	1,125,411,853	1,128,427,446	1,092,594,951	kWh		$89,411,430		$86,117,758
Populus to Terminal Adjustment (80), per kWh	1,125,411,853	1,128,427,446	1,092,594,951	kWh	-0.039 ¢	($426,112)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	882,298,260	884,661,260	856,570,502	kWh	0.028 ¢	$239,840	0.000 ¢	$0
All additional kWh, per kWh	243,113,593	243,766,186	236,024,449	kWh	0.021 ¢	$49,565	0.000 ¢	$0
Subtotal						$89,274,723		$86,117,758
Schedule 201								
1st 3,000 kWh, per kWh	882,298,260	884,661,260	856,570,502	kWh	2.971 ¢	$25,448,710	2.971 ¢	$25,448,710
All additional kWh, per kWh	243,113,593	243,766,186	236,024,449	kWh	2.204 ¢	$5,201,979	2.204 ¢	$5,201,979
Total	1,125,411,853	1,128,427,446	1,092,594,951	kWh	0.000 0	$119,925,412		$116,768,447
							Change	($3,156,965)
Schedule No. 23/723 - Composite								
General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,348,277	1,348,277	1,330,980	kWh	0.396 ¢	$5,271	0.351 ¢	$4,672
Distribution Charge								
Basic Charge								
Single Phase, per month	321	321	315	bill	$18.70	$5,891	$18.55	$5,843
Three Phase, per month	251	251	258	bill	$27.90	$7,198	$27.65	$7,134
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	5,508	5,508	5,611	kW	$1.30	$7,294	$1.30	$7,294
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	2,234	2,234	2,237	kW	$4.22	$9,440	$4.18	$9,351
Reactive Power Charge, per kvar	2,812	2,812	2,920	kvar	60.00 ¢	$1,752	60.00 ¢	$1,752
Distribution Energy Charge, per kWh	1,348,277	1,348,277	1,330,980	kWh	2.644 ¢	$35,191	2.628 ¢	$34,978
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	853,168	853,168	836,443	kWh	3.107 ¢	$25,988	2.900 ¢	$24,257
All additional kWh, per kWh	495,109	495,109	494,537	kWh	2.306 ¢	$11,404	2.153 ¢	$10,647
Subtotal	1,348,277	1,348,277	1,330,980	kWh		$109,429		$105,928
Populus to Terminal Adjustment (80), per kWh	1,348,277	1,348,277	1,330,980	kWh	-0.038 ¢	($506)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	853,168	853,168	836,443	kWh	0.028 ¢	$234	0.000 ¢	$0
All additional kWh, per kWh	495,109	495,109	494,537	kWh	0.020 ¢	$99	0.000 ¢	$0
Subtotal						$109,256		$105,928
Schedule 201								
1st 3,000 kWh, per kWh	853,168	853,168	836,443	kWh	2.878 ¢	$24,073	2.878 ¢	$24,073
All additional kWh, per kWh	495,109	495,109	494,537	kWh	2.136 ¢	$10,563	2.136 ¢	$10,563
Total	1,348,277	1,348,277	1,330,980	kWh	0.000 0	$143,892		$140,564
							Change	($3,328)

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Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,768,502	6,768,502	6,629,746	kW	$1.20	$7,955,695	$1.12	$7,425,316
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	54,876	54,876	53,753	bill	$15.00	$806,295	$20.00	$1,075,060
Load Size 51-100 kW, per month	41,602	41,602	40,722	bill	$28.00	$1,140,216	$37.00	$1,506,714
Load Size 101-300 kW, per month	22,797	22,797	22,283	bill	$67.00	$1,492,961	$89.00	$1,983,187
Load Size > 300 kW, per month	438	438	428	bill	$96.00	$41,088	$127.00	$54,356
Load Size Charge								
≤ 50 kW, per kW	2,104,760	2,104,760	2,057,029	kW	$0.95	$1,954,178	$1.25	$2,571,286
51-100 kW, per kW	2,889,797	2,889,797	2,828,186	kW	$0.75	$2,121,140	$1.00	$2,828,186
101-300 kW, per kW	3,425,109	3,425,109	3,360,475	kW	$0.45	$1,512,214	$0.60	$2,016,285
>300 kW, per kW	183,478	183,478	180,103	kW	$0.30	$54,031	$0.40	$72,041
Demand Charge, per kW	6,768,502	6,768,502	6,629,746	kW	$3.31	$21,944,459	$4.37	$28,971,990
Reactive Power Charge, per kvar	599,342	599,342	595,353	kvar	65.00 ¢	$386,979	65.00 ¢	$386,979
Distribution Energy Charge, per kWh	2,004,166,036	2,004,166,036	1,960,069,773	kWh	0.326 ¢	$6,389,827	0.435 ¢	$8,526,304
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	1,435,479,865	1,441,165,865	1,409,538,253	kWh	3.040 ¢	$42,849,963	2.867 ¢	$40,411,462
All additional kWh, per kWh	568,686,171	570,944,867	558,266,695	kWh	2.959 ¢	$16,519,112	2.790 ¢	$15,575,641
Subtotal	2,004,166,036	2,012,110,732	1,967,804,948	kWh		$105,168,158		$113,404,807
Populus to Terminal Adjustment (80), per kW	6,768,502	6,768,502	6,629,746	kW	($0.12)	($795,570)	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	1,435,479,865	1,441,165,865	1,409,538,253	kWh	0.027 ¢	$380,575	0.000 ¢	$0
All additional kWh, per kWh	568,686,171	570,944,867	558,266,695	kWh	0.026 ¢	$145,149	0.000 ¢	$0
Subtotal						$104,898,312		$113,404,807
Schedule 201								
1st 20,000 kWh, per kWh	1,435,479,865	1,441,165,865	1,409,538,253	kWh	2.816 ¢	$39,692,597	2.816 ¢	$39,692,597
All additional kWh, per kWh	568,686,171	570,944,867	558,266,695	kWh	2.739 ¢	$15,290,925	2.739 ¢	$15,290,925
Total	2,004,166,036	2,012,110,732	1,967,804,948	kWh		$159,881,834		$168,388,329
							Change	$8,506,495
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	65,682	65,682	65,892	kW	$0.87	$57,326	$1.00	$65,892
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	99	99	96	bill	$17.00	$1,632	$24.00	$2,304
Load Size 51-100 kW, per month	163	163	158	bill	$29.00	$4,582	$41.00	$6,478
Load Size 101-300 kW, per month	355	355	341	bill	$69.00	$23,529	$98.00	$33,418
Load Size > 300 kW, per month	35	35	34	bill	$99.00	$3,366	$140.00	$4,760
Load Size Charge								
≤ 50 kW, per kW	3,294	3,294	3,251	kW	$0.95	$3,088	$1.35	$4,389
51-100 kW, per kW	12,248	12,248	12,246	kW	$0.80	$9,797	$1.15	$14,083
101-300 kW, per kW	61,575	61,575	61,812	kW	$0.45	$27,815	$0.65	$40,178
>300 kW, per kW	14,953	14,953	14,881	kW	$0.25	$3,720	$0.35	$5,208
Demand Charge, per kW	65,682	65,682	65,892	kW	$3.37	$222,056	$4.78	$314,964
Reactive Power Charge, per kvar	25,905	25,905	25,889	kvar	60.00 ¢	$15,533	60.00 ¢	$15,533
Distribution Energy Charge, per kWh	18,807,080	18,807,080	18,795,139	kWh	0.032 ¢	$6,014	0.077 ¢	$14,472
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	9,645,695	9,645,695	9,685,033	kWh	2.817 ¢	$272,827	2.776 ¢	$268,857
All additional kWh, per kWh	9,161,385	9,161,385	9,110,106	kWh	2.741 ¢	$249,708	2.701 ¢	$246,064
Subtotal	18,807,080	18,807,080	18,795,139	kWh		$900,993		$1,036,600
Populus to Terminal Adjustment (80), per kW	65,682	65,682	65,892	kW	($0.08)	($5,271)	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	9,645,695	9,645,695	9,685,033	kWh	0.025 ¢	$2,421	0.000 ¢	$0
All additional kWh, per kWh	9,161,385	9,161,385	9,110,106	kWh	0.024 ¢	$2,186	0.000 ¢	$0
Subtotal						$900,329		$1,036,600
Schedule 201								
1st 20,000 kWh, per kWh	9,645,695	9,645,695	9,685,033	kWh	2.609 ¢	$252,683	2.609 ¢	$252,683
All additional kWh, per kWh	9,161,385	9,161,385	9,110,106	kWh	2.539 ¢	$231,306	2.539 ¢	$231,306
Total	18,807,080	18,807,080	18,795,139	kWh		$1,384,318		$1,520,589
							Change	$136,271

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Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	7,208	7,208	6,850					
Transmission & Ancillary Services Charge								
per kWh	10,398,287	10,398,287	9,709,823	kWh	0.069 ¢	$6,528	0.068 ¢	$6,528
Distribution Charge								
Distribution Charge, per kWh	10,398,287	10,398,287	9,709,823	kWh	7.995 ¢	$776,284	8.277 ¢	$803,729
Energy Charge - Schedule 200								
per kWh	10,398,287	10,398,287	9,709,823	kWh	2.620 ¢	$254,343	2.422 ¢	$235,181
Subtotal	10,398,287	10,398,287	9,709,823	kWh		$1,037,155		$1,045,438
Populus to Terminal Adjustment (80), per kWh	10,398,287	10,398,287	9,709,823	kWh	-0.007 ¢	($680)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	10,398,287	10,398,287	9,709,823	kWh	0.025 ¢	$2,427	0.000 ¢	$0
Subtotal						$1,038,902		$1,045,438
Schedule 201								
per kWh	10,398,287	10,398,287	9,709,823	kWh	2.664 ¢	$258,367	2.664 ¢	$258,367
Total	10,398,287	10,398,287	9,709,823	kWh		$1,297,269		$1,303,805
							Change	$6,536
Schedule No. 50								
Mercury Vapor Street Lighting Service								
No. of Customers	251	251	250					
Transmission & Ancillary Services Charge								
per kWh	9,273,884	9,273,884	8,845,474	kWh	0.069 ¢	$5,908	0.068 ¢	$5,908
Distribution Charge								
Distribution Charge, per kWh	9,273,884	9,273,884	8,845,474	kWh	6.916 ¢	$611,713	7.168 ¢	$634,020
Energy Charge - Schedule 200								
per kWh	9,273,884	9,273,884	8,845,474	kWh	2.363 ¢	$209,325	2.185 ¢	$193,249
Subtotal	9,273,884	9,273,884	8,845,474	kWh		$826,947		$833,177
Populus to Terminal Adjustment (80), per kWh	9,273,884	9,273,884	8,845,474	kWh	-0.007 ¢	($619)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	9,273,884	9,273,884	8,845,474	kWh	0.021 ¢	$1,858	0.000 ¢	$0
Subtotal						$828,186		$833,177
Schedule 201								
per kWh	9,273,884	9,273,884	8,845,474	kWh	2.190 ¢	$193,380	2.190 ¢	$193,380
Total	9,273,884	9,273,884	8,845,474	kWh		$1,021,566		$1,026,557
							Change	$4,992
Schedule No. 51/751, 55								
Street Lighting Service, Company-Owned System								
No. of Customers	701	701	733					
Transmission & Ancillary Services Charge								
per kWh	18,551,166	18,551,166	18,679,735	kWh	0.069 ¢	$12,811	0.068 ¢	$12,811
Distribution Charge								
Distribution Charge, per kWh	18,551,166	18,551,166	18,679,735	kWh	11.096 ¢	$2,072,713	11.494 ¢	$2,146,957
Energy Charge - Schedule 200								
per kWh	18,551,166	18,551,166	18,679,735	kWh	3.732 ¢	$696,812	3.450 ¢	$644,632
Subtotal	18,551,166	18,551,166	18,679,735	kWh		$2,782,335		$2,804,399
Populus to Terminal Adjustment (80), per kWh	18,551,166	18,551,166	18,679,735	kWh	-0.007 ¢	($1,308)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	18,551,166	18,551,166	18,679,735	kWh	0.033 ¢	$6,164	0.000 ¢	$0
Subtotal						$2,787,191		$2,804,399
Schedule 201								
per kWh	18,551,166	18,551,166	18,679,735	kWh	3.456 ¢	$645,497	3.456 ¢	$645,497
Total	18,551,166	18,551,166	18,679,735	kWh		$3,432,688		$3,449,896
							Change	$17,208
Schedule No. 52/752								
Street Lighting Service, Company-Owned System								
No. of Customers	55	55	50					
Transmission & Ancillary Services Charge								
per kWh	788,080	788,080	599,203	kWh	0.069 ¢	$413	0.068 ¢	$407
Distribution Charge								
Distribution Charge, per kWh	788,080	788,080	599,203	kWh	6.606 ¢	$39,585	6.902 ¢	$41,359
Energy Charge - Schedule 200								
per kWh	788,080	788,080	599,203	kWh	2.860 ¢	$17,137	2.644 ¢	$15,843
Subtotal	788,080	788,080	599,203	kWh		$57,136		$57,609
Populus to Terminal Adjustment (80), per kWh	788,080	788,080	599,203	kWh	-0.007 ¢	($42)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	788,080	788,080	599,203	kWh	0.025 ¢	$150	0.000 ¢	$0
Subtotal						$57,244		$57,609
Schedule 201								
per kWh	788,080	788,080	599,203	kWh	2.647 ¢	$15,861	2.647 ¢	$15,861
Total	788,080	788,080	599,203	kWh		$73,105		$73,470
							Change	$365

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	255	255	260					
Transmission & Ancillary Services Charge								
per kWh	9,548,236	9,548,236	9,578,780	kWh	0.069 ¢	$6,609	0.068 ¢	$6,514
Distribution Charge								
Distribution Charge, per kWh	9,548,236	9,548,236	9,578,780	kWh	4.062 ¢	$389,107	4.191 ¢	$401,464
Energy Charge - Schedule 200								
per kWh	9,548,236	9,548,236	9,578,780	kWh	1.221 ¢	$116,957	1.129 ¢	$108,144
Subtotal	9,548,236	9,548,236	9,578,780	kWh		$512,673		$516,122
Populus to Terminal Adjustment (80), per kWh	9,548,236	9,548,236	9,578,780	kWh	-0.007 ¢	($671)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	9,548,236	9,548,236	9,578,780	kWh	0.011 ¢	$1,054	0.000 ¢	$0
Subtotal						$513,056		$516,122
Schedule 201								
per kWh	9,548,236	9,548,236	9,578,780	kWh	1.130 ¢	$108,240	1.130 ¢	$108,240
Total	9,548,236	9,548,236	9,578,780	kWh		$621,297		$624,362
							Change	$3,065
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,138,574	1,138,574	1,189,338	kWh	0.069 ¢	$821	0.068 ¢	$809
Distribution Charge								
Basic Charge, Single Phase, per month	822	822	813	bill	$6.00	$4,878	$6.00	$4,878
Basic Charge, Three Phase, per month	427	427	423	bill	$9.00	$3,807	$9.00	$3,807
Distribution Energy Charge, per kWh	1,138,574	1,138,574	1,189,338	kWh	3.871 ¢	$46,039	4.087 ¢	$48,608
Energy Charge - Schedule 200								
per kWh	1,138,574	1,138,574	1,189,338	kWh	2.100 ¢	$24,976	1.941 ¢	$23,085
Subtotal	1,138,574	1,138,574	1,189,338	kWh		$80,521		$81,187
Populus to Terminal Adjustment (80), per kWh	1,138,574	1,138,574	1,189,338	kWh	-0.007 ¢	($83)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	1,138,574	1,138,574	1,189,338	kWh	0.019 ¢	$226	0.000 ¢	$0
Subtotal						$80,664		$81,187
Schedule 201								
per kWh	1,138,574	1,138,574	1,189,338	kWh	1.947 ¢	$23,156	1.947 ¢	$23,156
Total	1,138,574	1,138,574	1,189,338	kWh		$103,820		$104,343
							Change	$523
TOTAL OREGON	13,091,819,591	13,057,536,168	13,097,739,985			$1,180,103,926		$1,218,476,880
Employee Discount						($444,926)		($462,114)
TOTAL OREGON (WITH EMPLOYEE DISCOUNT)						$1,179,659,000		$1,218,014,766

Docket No. UE-246
Exhibit PAC/1303
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Estimated Effect of Proposed Rates

March 2012

GRC Price Change - Table 1303-1

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

Line No.	Description	Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	479,457	5,400,866	$564,491	$12,962	$577,453	$586,997	$10,370	$597,367	$22,506	4.0%	$19,914	3.5%	1
2	**Total Residential**		479,457	5,400,866	$564,491	$12,962	$577,453	$586,997	$10,370	$597,367	$22,506	4.0%	$19,914	3.5%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	75,333	1,093,926	$120,069	($1,442)	$118,627	$116,909	$4,082	$120,991	($3,160)	-2.6%	$2,364	2.0%	3
4	Gen. Svc. 31 - 200 kW	28	9,818	1,986,600	$161,266	$7,928	$169,194	$169,909	$5,148	$175,057	$8,643	5.4%	$5,863	3.5%	4
5	Gen. Svc. 201 - 999 kW	30	815	1,303,689	$98,119	$2,348	$100,467	$101,966	$1,995	$103,961	$3,847	3.9%	$3,494	3.5%	5
6	Large General Service >= 1,000 kW	48	208	3,003,510	$201,084	($9,613)	$191,471	$209,440	($9,613)	$199,827	$8,356	4.2%	$8,356	4.4%	6
7	Partial Req. Svc. >= 1,000 kW	47	5	50,204	$3,585	($177)	$3,408	$3,843	($177)	$3,666	$258	4.2%	$258	4.4%	7
8	Agricultural Pumping Service	41	8,090	210,342	$24,940	($3,282)	$21,658	$22,830	($408)	$22,422	($2,110)	-8.5%	$764	3.5%	8
9	**Total Commercial & Industrial**		94,269	7,648,271	$609,063	($4,238)	$604,825	$624,897	$1,027	$625,924	$15,834	2.6%	$21,099	3.5%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,850	9,710	$1,298	$257	$1,555	$1,304	$282	$1,586	$6	0.5%	$31	2.0%	10
11	Street Lighting Service	50	250	8,845	$1,022	$221	$1,243	$1,027	$241	$1,268	$5	0.5%	$25	2.0%	11
12	Street Lighting Service HPS	51	733	18,680	$3,433	$732	$4,165	$3,450	$800	$4,250	$17	0.5%	$85	2.0%	12
13	Street Lighting Service	52	50	599	$73	$16	$89	$73	$18	$91	$0	0.0%	$2	2.3%	13
14	Street Lighting Service	53	260	9,579	$621	$147	$768	$624	$159	$783	$3	0.5%	$15	2.0%	14
15	Recreational Field Lighting	54	103	1,189	$104	$22	$126	$104	$25	$129	$0	0.0%	$3	2.4%	15
16	**Total Public Street Lighting**		8,246	48,602	$6,551	$1,395	$7,946	$6,582	$1,525	$8,107	$31	0.5%	$161	2.0%	16
17	**Total Sales to Ultimate Consumers**		581,972	13,097,739	$1,180,105	$10,119	$1,190,224	$1,218,476	$12,922	$1,231,398	$38,371	3.3%	$41,174	3.5%	17
18	**Employee Discount**			17,195	($445)	($10)	($455)	($462)	($8)	($470)	($17)		($15)		18
19	**Total Sales with Employee Discount**		581,972	13,097,739	$1,179,660	$10,109	$1,189,769	$1,218,014	$12,914	$1,230,928	$38,354	3.3%	$41,159	3.5%	19
20	AGA Revenue				$2,716		$2,716	$2,716		$2,716	$0		$0		20
21	**Total Sales with Employee Discount and AGA**		581,972	13,097,739	$1,182,376	$10,109	$1,192,485	$1,220,730	$12,914	$1,233,644	$38,354	3.2%	$41,159	3.5%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Exhibit PAC/1303
Griffith/1

Table 1303-2
PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

Line No.	Description	Sch No.	Prop. Sales 96 ($000)	Tax Adj 102 ($000)	MEHC Sev 194 ($000)	Grid West 195 ($000)	Sol. Inctv. 204 ($000)	2010 Prtcl. 291 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) PRE	(10) PRO	(11) PRE	(12) PRO
	Residential											
1	Residential	4	($1,458)	$6,373	$864	$162	$378	($1,026)	$7,669	$5,077	$12,962	$10,370
2	**Total Residential**		($1,458)	$6,373	$864	$162	$378	($1,026)	$7,669	$5,077	$12,962	$10,370
	Commercial & Industrial											
3	Gen. Svc. < 31 kW	23	($295)	$1,291	$175	$33	$77	($207)	($2,516)	$3,008	($1,442)	$4,082
4	Gen. Svc. 31 - 200 kW	28	($536)	$2,345	$318	$60	$139	($377)	$5,979	$3,199	$7,928	$5,148
5	Gen. Svc. 201 - 999 kW	30	($352)	$1,539	$209	$39	$91	($234)	$1,056	$703	$2,348	$1,995
6	Large General Service >= 1,000 kW	48	($811)	$3,544	$481	$90	$211	($511)	($12,617)	($12,617)	($9,613)	($9,613)
7	Partial Req. Svc. >= 1,000 kW	47	($14)	$59	$9	$2	$4	($9)	($228)	($228)	($177)	($177)
8	Agricultural Pumping Service	41	($57)	$248	$34	$6	$15	($38)	($3,490)	($616)	($3,282)	($408)
9	**Total Commercial & Industrial**		($2,065)	$9,026	$1,226	$230	$537	($1,376)	($11,816)	($6,551)	($4,238)	$1,027
	Lighting											
10	Outdoor Area Lighting Service	15	($3)	$11	$1	$0	$0	($1)	$249	$274	$257	$282
11	Street Lighting Service	50	($2)	$10	$1	$0	$1	($1)	$212	$232	$221	$241
12	Street Lighting Service HPS	51	($5)	$22	$3	$1	$2	($4)	$713	$781	$732	$800
13	Street Lighting Service	52	$0	$1	$0	$0	$0	$0	$15	$17	$16	$18
14	Street Lighting Service	53	($3)	$11	$2	$0	$0	($1)	$138	$150	$147	$159
15	Recreational Field Lighting	54	$0	$1	$0	$0	$0	$0	$21	$24	$22	$25
16	**Total Public Street Lighting**		($13)	$56	$7	$1	$3	($7)	$1,348	$1,478	$1,395	$1,525
17	**Total**		($3,536)	$15,455	$2,097	$393	$918	($2,409)	($2,799)	$4	$10,119	$12,922
18	**Employee Discount**		$1	($5)	($1)	$0	$0	$1	($6)	($4)	($10)	($8)
19	**Total Sales with Employee Discount**		($3,535)	$15,450	$2,096	$393	$918	($2,408)	($2,805)	$0	$10,109	$12,914

Exhibit PAC/1303
Griffith/2

Table 1303-3
PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

Line No.	Description	Sch No.	Prop. Sales 96 ¢/kWh	Tax Adj 102 ¢/kWh	MEHC Sev 194 ¢/kWh	Grid West 195 ¢/kWh	Sol. Inctv. 204 ¢/kWh	2010 Prtcl. 291 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) PRE	(10) PRE	(11) PRE	(12) PRO	(13) PRO	(14) PRO
	Residential													
1	Residential	4	(0.027)	0.118	0.016	0.003	0.007	(0.019)	0.142			0.094		
	Commercial & Industrial													
2	Gen. Svc. < 31 kW	23	(0.027)	0.118	0.016	0.003	0.007	(0.019)	(0.230)	(0.230)		0.275	0.275	
3	Gen. Svc. 31 - 200 kW	28	(0.027)	0.118	0.016	0.003	0.007	(0.019)	0.301	0.301		0.161	0.161	
4	Gen. Svc. 201 - 999 kW	30	(0.027)	0.118	0.016	0.003	0.007	(0.018)	0.081	0.081		0.054	0.054	
5	Large General Service >= 1,000 kW	48	(0.027)	0.118	0.016	0.003	0.007	(0.017)	(0.329)	(0.411)	(0.509)	(0.329)	(0.411)	(0.509)
6	Partial Req. Svc. >= 1,000 kW	47	(0.027)	0.118	0.016	0.003	0.007	(0.017)	(0.329)	(0.411)	(0.509)	(0.329)	(0.411)	(0.509)
7	Agricultural Pumping Service	41	(0.027)	0.118	0.016	0.003	0.007	(0.018)	(1.659)	(1.659)		(0.293)	(0.293)	
	Lighting													
8	Outdoor Area Lighting Service	15	(0.027)	0.118	0.016	0.003	0.006	(0.017)	2.575			2.830		
9	Street Lighting Service	50	(0.027)	0.118	0.016	0.003	0.006	(0.015)	2.393			2.628		
10	Street Lighting Service HPS	51	(0.027)	0.118	0.016	0.003	0.009	(0.023)	3.819			4.183		
11	Street Lighting Service	52	(0.027)	0.118	0.016	0.003	0.007	(0.018)	2.450			2.760		
12	Street Lighting Service	53	(0.027)	0.118	0.016	0.003	0.003	(0.008)	1.440			1.571		
13	Recreational Field Lighting	54	(0.027)	0.118	0.016	0.003	0.005	(0.013)	1.800			1.977		

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Difference	Percent Difference
100	$19.47	$20.32	$0.85	4.37%
200	$28.82	$30.02	$1.20	4.16%
300	$38.17	$39.72	$1.55	4.06%
400	$47.52	$49.42	$1.90	4.00%
500	$56.87	$59.11	$2.24	3.94%
600	$66.22	$68.79	$2.57	3.88%
700	$75.57	$78.49	$2.92	3.86%
800	$84.92	$88.20	$3.28	3.86%
900	$94.28	$97.89	$3.61	3.83%
950	**$98.94**	**$102.72**	**$3.78**	**3.82%**
1,000	$103.62	$107.58	$3.96	3.82%
1,100	$115.51	$119.73	$4.22	3.65%
1,200	$127.39	$131.89	$4.50	3.53%
1,300	$139.28	$144.06	$4.78	3.43%
1,400	$151.17	$156.22	$5.05	3.34%
1,500	$163.06	$168.37	$5.31	3.26%
1,600	$174.93	$180.52	$5.59	3.20%
2,000	$222.48	$229.16	$6.68	3.00%
3,000	$341.34	$350.75	$9.41	2.76%
4,000	$460.19	$472.34	$12.15	2.64%
5,000	$579.05	$593.92	$14.87	2.57%

* Net rate including Schedules 91, 98, 199, 290 and 297.
Note: Assumed average billing cycle length of 30.42 days.

Exhibit PAC/1303
Griffith/4

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
		Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$69	$78	$70	$79	1.41%	1.11%
	750	$94	$103	$95	$104	1.62%	1.39%
	1,000	$118	$128	$120	$130	1.77%	1.56%
	1,500	$168	$177	$171	$180	1.91%	1.75%
10	1,000	$118	$128	$120	$130	1.77%	1.56%
	2,000	$217	$227	$222	$231	1.99%	1.87%
	3,000	$316	$326	$323	$332	2.08%	1.99%
	4,000	$399	$408	$408	$418	2.38%	2.30%
20	4,000	$428	$437	$437	$447	2.17%	2.10%
	6,000	$593	$603	$608	$618	2.55%	2.49%
	8,000	$758	$768	$779	$788	2.76%	2.72%
	10,000	$923	$933	$950	$959	2.90%	2.86%
30	9,000	$899	$908	$922	$932	2.61%	2.57%
	12,000	$1,146	$1,156	$1,179	$1,188	2.81%	2.78%
	15,000	$1,394	$1,403	$1,435	$1,444	2.94%	2.91%
	18,000	$1,642	$1,651	$1,691	$1,701	3.03%	3.00%

* Net rate including Schedules 91, 199, 290 and 297.

Exhibit PAC/1303
Griffith/5

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$175	$202	$175	$187	$212	$155	6.69%	5.33%	-11.76%
	3,000	$262	$289	$175	$280	$306	$155	6.69%	5.74%	-11.76%
	5,000	$437	$464	$175	$467	$492	$155	6.69%	6.10%	-11.76%
Three Phase										
20	4,000	$350	$403	$350	$373	$425	$309	6.69%	5.33%	-11.76%
	6,000	$525	$578	$350	$560	$611	$309	6.69%	5.74%	-11.76%
	10,000	$875	$928	$350	$933	$985	$309	6.69%	6.10%	-11.76%
100	20,000	$1,749	$2,016	$1,504	$1,866	$2,124	$1,349	6.69%	5.33%	-10.27%
	30,000	$2,624	$2,891	$1,504	$2,799	$3,057	$1,349	6.69%	5.74%	-10.27%
	50,000	$4,373	$4,640	$1,504	$4,666	$4,923	$1,349	6.69%	6.10%	-10.27%
300	60,000	$5,248	$6,049	$3,770	$5,599	$6,372	$3,409	6.69%	5.33%	-9.56%
	90,000	$7,872	$8,673	$3,770	$8,398	$9,171	$3,409	6.69%	5.74%	-9.56%
	150,000	$13,120	$13,921	$3,770	$13,997	$14,770	$3,409	6.69%	6.10%	-9.56%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Exhibit PAC/1303
Griffith/11

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$253	$279	$175	$272	$297	$155	7.51%	6.50%	-11.76%
	4,000	$337	$363	$175	$362	$387	$155	7.51%	6.74%	-11.76%
	5,000	$421	$447	$175	$453	$478	$155	7.51%	6.88%	-11.76%
Three Phase										
20	6,000	$505	$557	$350	$543	$593	$309	7.51%	6.50%	-11.76%
	8,000	$674	$726	$350	$724	$774	$309	7.51%	6.73%	-11.76%
	10,000	$842	$894	$350	$906	$956	$309	7.51%	6.88%	-11.76%
100	30,000	$2,527	$2,785	$1,494	$2,717	$2,967	$1,339	7.51%	6.50%	-10.34%
	40,000	$3,369	$3,628	$1,494	$3,622	$3,872	$1,339	7.51%	6.73%	-10.34%
	50,000	$4,212	$4,470	$1,494	$4,528	$4,778	$1,339	7.51%	6.88%	-10.34%
300	90,000	$7,581	$8,356	$3,760	$8,150	$8,900	$3,399	7.51%	6.50%	-9.59%
	120,000	$10,108	$10,883	$3,760	$10,867	$11,616	$3,399	7.51%	6.73%	-9.59%
	150,000	$12,635	$13,410	$3,760	$13,583	$14,333	$3,399	7.51%	6.88%	-9.59%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Exhibit PAC/1303
Griffith/12

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

kW Load Size	kWh	Monthly Billing		Percent Difference
		Present Price	Proposed Price	
1,000	300,000	$23,825	$25,521	7.12%
	500,000	$35,142	$36,424	3.65%
	700,000	$46,458	$47,327	1.87%
2,000	600,000	$47,299	$50,538	6.85%
	1,000,000	$68,403	$70,813	3.52%
	1,400,000	$90,225	$91,807	1.75%
6,000	1,800,000	$137,724	$147,274	6.93%
	3,000,000	$203,189	$210,255	3.48%
	4,200,000	$268,655	$273,236	1.71%
12,000	3,600,000	$274,300	$293,101	6.85%
	6,000,000	$405,230	$419,063	3.41%
	8,400,000	$536,160	$545,024	1.65%

Notes:

On-Peak kWh	64.59%
Off-Peak kWh	35.41%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Exhibit PAC/1303
Griffith/13

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

kW Load Size	kWh	Monthly Billing		Percent Difference
		Present Price	Proposed Price	
1,000	300,000	$22,823	$24,384	6.84%
	500,000	$33,623	$34,762	3.38%
	700,000	$44,424	$45,139	1.61%
2,000	600,000	$45,276	$48,211	6.48%
	1,000,000	$65,346	$67,437	3.20%
	1,400,000	$86,134	$87,381	1.45%
6,000	1,800,000	$131,911	$140,490	6.50%
	3,000,000	$194,276	$200,322	3.11%
	4,200,000	$256,641	$260,153	1.37%
12,000	3,600,000	$262,662	$279,492	6.41%
	6,000,000	$387,392	$399,155	3.04%
	8,400,000	$512,122	$518,817	1.31%

Notes:

On-Peak kWh	61.78%
Off-Peak kWh	38.22%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Exhibit PAC/1303
Griffith/14

Pacific Power
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		Percent Difference
		Present Price	Proposed Price	
1,000	500,000	$32,705	$34,816	6.46%
	700,000	$42,960	$44,656	3.95%
2,000	1,000,000	$63,282	$67,052	5.96%
	1,400,000	$82,981	$85,918	3.54%
6,000	3,000,000	$188,155	$198,939	5.73%
	4,200,000	$247,253	$255,540	3.35%
12,000	6,000,000	$374,709	$395,443	5.53%
	8,400,000	$492,903	$508,643	3.19%

Notes:

On-Peak kWh	56.38%
Off-Peak kWh	43.62%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Exhibit PAC/1303
Griffith/15

PACIFIC POWER
STATE OF OREGON
Functionalized Mona-Oquirrh Capital Addition Revenue Requirement
Forecast 12 Months Ended December 31, 2013
Dollars in Thousands

Line	Description	Total	(A) Residential	(B) General Service	(C)	(D) General Service	(E)	(F) General Service	(G)	(H) Large Power Service	(I)	(J)	(K) Irrigation	(L) Street Lgt.
				Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	Mona-Oquirrh Revenue Requirement	$13,083												
2	Mona-Oquirrh Collection for Schedules not included in COS Study*	$63												
3	Mona-Oquirrh for Schedules Included in COS Study	$13,020												
4														
5														
6	Transmission Allocation Factors from GRC	100.00%	44.04%	8.51%	0.01%	16.03%	0.14%	9.11%	0.68%	4.66%	10.99%	4.47%	1.33%	0.03%
7														
8														
9	**Functionalized Mona-Oquirrh Revenue Requirement- (Target)**	**$13,020**	**$5,734**	**$1,107**	**$1**	**$2,087**	**$19**	**$1,186**	**$89**	**$607**	**$1,431**	**$583**	**$173**	**$3**

*Revenues by rate schedule as follows:

Schedule 47 Primary	$42
Schedule 47 Transmission	$21
Schedule 15	$2
Schedule 50	$1
Schedule 51 (partial)	$1
Schedule 52	$0
Employee Discount	($5)
Total not in study	$63

Exhibit PAC/1304
Griffith/1

PACIFIC POWER
STATE OF OREGON
Mona-Oquirrh Capital Addition Proposed Rates and Rate Spread

Forecast 12 Months Ended December 31, 2013

Rate Schedule	Annual Forecast Energy or Demand			Proposed Mona-Oquirrh Capital Addition Adjustment Rates		Revenues
Schedule 4, Residential	5,400,866,473		kWh	0.106	¢/kWh	$5,724,918
Secondary Voltage						
Schedule 23, Small General Service						
Secondary Voltage	1,092,594,951		kWh	0.101	¢/kWh	$1,103,521
Primary Voltage	1,330,980		kWh	0.098	¢/kWh	$1,304
Schedule 28, General Service 31-200kW						
Secondary Voltage	6,629,746		kW	$0.31	$/kW	$2,055,221
Primary Voltage	65,892		kW	$0.28	$/kW	$18,450
Schedule 30, General Service 201-999kW						
Secondary Voltage	3,412,157		kW	$0.35	$/kW	$1,194,255
Primary Voltage	273,642		kW	$0.32	$/kW	$87,565
Schedule 41, Agricultural Pumping Service						
Secondary Voltage	209,714,409		kWh	0.082	¢/kWh	$171,966
Primary Voltage	627,888		kWh	0.080	¢/kWh	$502
Schedule 47, Large General Service, Partial Requirements 1,000kW and over						
Secondary Voltage	0	On-Peak	kW	$0.36	$/kW	$0
Primary Voltage	110,285	On-Peak	kW	$0.38	$/kW	$41,908
Transmission Voltage	42,610	On-Peak	kW	$0.50	$/kW	$21,305
Schedule 48, Large General Service, 1,000kW and over						
Secondary Voltage	1,663,005	On-Peak	kW	$0.36	$/kW	$598,682
Primary Voltage	3,756,978	On-Peak	kW	$0.38	$/kW	$1,427,652
Transmission Voltage	1,172,561	On-Peak	kW	$0.50	$/kW	$586,281
Schedule 15, Outdoor Area Lighting Service						
Secondary Voltage	9,709,823		kWh	0.016	¢/kWh	$1,554
Schedule 50, Mercury Vapor Street Lighting Service						
Secondary Voltage	8,845,474		kWh	0.016	¢/kWh	$1,415
Schedule 51, 55, Street Lighting Service, Company-Owned System						
Secondary Voltage	18,679,735		kWh	0.016	¢/kWh	$2,989
Schedule 52, Street Lighting Service, Company-Owned System						
Secondary Voltage	599,203		kWh	0.016	¢/kWh	$96
Schedule 53, Street Lighting Service, Consumer-Owned System						
Secondary Voltage	9,578,780		kWh	0.016	¢/kWh	$1,533
Schedule 54, Recreational Field Lighting						
Secondary Voltage	1,189,338		kWh	0.016	¢/kWh	$190
TOTAL Before Employee Discount						$13,041,307
Employee Discount						-$4,678
TOTAL						**$13,036,629**