PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 2, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

RE: Docket No. UE-___
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 27 copies of the following proposed tariff pages associated with the Company's Tariff P.U.C. OR No. 35 applicable to electric service in the State of Oregon, together with the Pretrial Brief, supporting direct testimony and exhibits. The tariffs reflect an effective date of May 2, 2009. Provided on the enclosed CDs (3) are electronic versions of the testimony, exhibits and workpapers, in their original format when available.

Thirty-third Revision of Sheet No. B-1A		Tariff Index Sheet
Seventh Revision of Sheet No.4	Schedule 4	Residential Service Delivery Service
Twelfth Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service No New Service Delivery Service
Sixth Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Fourth Revision of Sheet No. 23-2	Schedule 23	General Service – Small Nonresidential Delivery Service
Fourth Revision of Sheet No. 28-1	Schedule 28	General Service – Large Nonresidential - Less than 1,000 kW Delivery Service
Second Revision of Sheet No. 28-2	Schedule 28	General Service – Large Nonresidential - Less than 1,000 kW Delivery Service
Fourth Revision of Sheet No. 30-1	Schedule 30	General Service-Large Nonresidential 201 KW to 999 KW Delivery Service
Second Revision of Sheet No. 30-2	Schedule 30	General Service-Large Nonresidential 201 KW to 999 KW Delivery Service
Eighth Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service

Fourth Revision of Sheet No. 41-2	Schedule 41	Agricultural Pumping Service Delivery Service
Sixth Revision of Sheet No. 47-1	Schedule 47	Large General Service/Partial Requirements Service – Nameplate Rating 1,000 kW and Over Delivery Service
Fourth Revision of Sheet No. 47-2	Schedule 47	Large General Service/Partial Requirements Service – Nameplate Rating 1,000 kW and Over Delivery Service
Sixth Revision of Sheet No. 48-1	Schedule 48	Large General Service - 1,000 kW and Over Delivery Service
Fourth Revision of Sheet No. 48-2	Schedule 48	Large General Service - 1,000 kW and Over Delivery Service
Thirteenth Revision of Sheet No. 50-1	Schedule 50	Mercury Vapor Street Lighting Service No New Service Delivery Service
Thirteenth Revision of Sheet No. 51-1	Schedule 51	High Pressure Sodium Vapor Street Lighting Service/Company-Owned System Delivery Service
Eleventh Revision of Sheet No. 52-1	Schedule 52	Street Lighting Service Company-Owned System Delivery Service
Twelfth Revision of Sheet No. 53-1	Schedule 53	Street Lighting Service Consumer-Owned System Delivery Service
Seventeenth Revision of Sheet No. 54-1	Schedule 54	Recreational Field Lighting Restricted Delivery Service
Second Revision of Sheet No. 76R-1	Schedule 76R	Large General Service/Partial Requirements Service – Economic Replacement Power Rider Delivery Service
Third Revision of Sheet No. 92	Schedule 92	Klamath Rate Reconciliation Adjustment
Fourteenth Revision of Sheet No. 200-1	Schedule 200	Cost-Based Supply Service
Fourteenth Revision of Sheet No. 200-2	Schedule 200	Cost-Based Supply Service
Thirteenth Revision of Sheet No. 200-3	Schedule 200	Cost-Based Supply Service
Original Sheet No. 201-1	Schedule 201	Net Power Costs Supply Service Adjustment
Original Sheet No. 201-2	Schedule 201	Net Power Costs Supply Service Adjustment
Original Sheet No. 201-3	Schedule 201	Net Power Costs Supply Service Adjustment
Original Sheet No. 202-1	Schedule 202	Renewable Adjustment Clause Supply Service Adjustment
Third Revision of Sheet No. 220-2	Schedule 220	Standard Offer Supply Service
Sixth Revision of Sheet No. 230	Schedule 230	Emergency Supply Service

Third Revision of Sheet No. 247-2	Schedule 247	Partial Requirements Supply Service
Second Revision of Sheet No. 276R-4	Schedule 276R	Large General Service/Partial Requirements Service – Economic Replacement Power Rider Supply Service
Fifth Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
Fifth Revision of Sheet No. 723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Third Revision of Sheet No. 723-2	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Fourth Revision of Sheet No. 728-1	Schedule 728	General Service – Large Nonresidential 31KW to 200KW Direct Access Delivery Service
Second Revision of Sheet No. 728-2	Schedule 728	General Service – Large Nonresidential 31KW to 200KW Direct Access Delivery Service
Fourth Revision of Sheet No. 730-1	Schedule 730	General Service – Large Nonresidential 201KW to 999KW Direct Access Delivery Service
Second Revision of Sheet No. 730-2	Schedule 730	General Service – Large Nonresidential 201KW to 999KW Direct Access Delivery Service
Sixth Revision of Sheet No. 741-1	Schedule 741	Agricultural Pumping Service Direct Access
Third Revision of Sheet No. 741-2	Schedule 741	Agricultural Pumping Service Direct Access
Fifth Revision of Sheet No. 747-1	Schedule 747	Large General Service Partial Requirements Service – 1,000 KW and Over Direct Access Delivery Service
Fourth Revision of Sheet No. 747-2	Schedule 747	Large General Service Partial Requirements Service – 1,000 KW and Over Direct Access Delivery Service
Seventh Revision of Sheet No. 748-1	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Sixth Revision of Sheet No. 748-2	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Twelfth Revision of Sheet No. 751-1	Schedule 751	High Pressure Sodium Vapor Street Lighting Service - Company-Owned System Direct Access Delivery Service

Ninth Revision of Sheet No. 752	Schedule 752	Street Lighting Service Company Owned System Direct Access Delivery Service
Ninth Revision of Sheet No. 753	Schedule 753	Street Lighting Service Consumer Owned System Direct Access Delivery service
Seventh Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting Restricted Direct Access Delivery Service
Second Revision of Sheet No. 776R	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 Joelle Steward, Regulatory Manager, at (503) 813-5542.

A copy of this filing has been served on all parties to PacifiCorp's last general rate case proceeding, UE 179, as indicated on the attached certificate of service.

Very truly yours,

Andrea L. Kelly

Andrea L. Kelly
Vice President, Regulation

Enclosure

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document on the parties of record from PacifiCorp's last general rate case, Docket UE 179, on the date indicated below by email and overnight delivery, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: April 2, 2009.

Ariel Son

Ariel Son
Coordinator, Administrative Services

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

GENERAL RATE CASE

Direct Testimony and Exhibits

April 2009

Brief

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE_____

In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon.	**PACIFICORP'S PRETRIAL BRIEF**

I. INTRODUCTION

Pursuant to ORS 757.205 and ORS 757.220, PacifiCorp d.b.a. Pacific Power ("Company"), is filing a general rate increase to revise its tariff schedules to adjust prices for its Oregon electric customers. 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 in system infrastructure. The Company files this brief in accordance with OAR 860-013-0075.

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

Communications regarding this filing should be addressed to:

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Communications regarding discovery matters, including data requests issued to the Company, should be addressed to:

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II. CASE SUMMARY

This case is based upon a historical base period of twelve months ending June 2008, forecast to a calendar year 2010 test period. The new rates will become effective no later than February 3, 2010, 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 matches the test period in this case.

A. Return on Equity

The Company is currently earning a return on equity ("ROE") in Oregon of approximately 6.5 percent for the test period. In this case, the Company seeks an ROE of 11.00 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. To achieve the 11.00 percent ROE, an overall price increase of $92.1 million is necessary. The proposed rate increase constitutes an average overall price increase of 9.1 percent in base rates. Even with this requested rate increase, the Company's Oregon customers still benefit from some of the lowest electricity rates in the nation.

B. New Investment is the Primary Cost Driver

The Company's continued investment in new plant is driving the rate adjustment sought in this case. Oregon-allocated net electric plant in service has increased by approximately $500 million since the Company's last general rate case, Docket UE 179 ("2006 Rate Case"). These investments include substantial and prudent investments the Company has made in new wind resources and the addition of the Lake Side and Chehalis natural gas plants. These investments were all acquired consistent with the Company's acknowledged integrated resource plans ("IRP"). The Lake Side plant began serving Oregon customers in September 2007 and the Chehalis plant began serving customers in September 2008. In this case, the Company also seeks inclusion of the following wind resources in rates: Glenrock III, Seven Mile Hill II, and High Plains. Several other renewable resources—added since the 2006 Rate Case—are already included in rates through the Company's Renewable Adjustment Clause.

All the resources the Company has included in rates for this case reflect prudently incurred costs for resources that are used and useful for service to the Company's Oregon customers or will be used and useful for service prior to the effective date of the rates. The renewable resources also reflect the Company's commitment to Oregon's renewable portfolio standards and commitment to provide the least cost power to its customers while minimizing the environmental impact of that power production.

The increase in plant also includes investments in all facets of the system. These investments include transmission and distribution investments to bolster reliability and improve power delivery and investments in hydro plant to conform to the relicensing agreements for the Lewis River and North Umpqua hydro systems.

C. Mitigation Efforts

The Company recognizes that the current economic climate has placed significant financial pressure on its customers. To minimize the effect of the proposed rate adjustment on customers and streamline Company operations to better weather the current economic storm, PacifiCorp has taken several steps to mitigate the rate increase request and improve its operating efficiency. Because of its extensive and successful efforts to minimize costs, the Company has been able to avoid filing a general rate case for three years.

1. Operations and Maintenance Costs

The Company proactively and aggressively controlled the operations and maintenance ("O&M") costs sought in this case. The total-Company budget for 2010 is approximately $40.5 million less than the level of O&M expense justified through other normalizing adjustments. This is a result of an adjustment included by the Company to reduce the total-Company non-net power cost O&M expense to the Company's budgeted level. The Oregon-allocated impact of this adjustment is an approximate $11.3 million reduction to the requested revenue requirement increase.

Oregon-allocated O&M costs are only approximately $5 million <u>more</u> than the O&M costs sought in the 2006 Rate Case. This small increase is remarkable in light of the extensive additions to generation plant since the 2006 Rate Case. The increase in O&M related to new generation facilities alone has been $20 million since the June 2008 base period. The Company has offset the O&M for incremental generation by aggressively pursuing efficiency gains in other O&M expenses. This resulted in significant savings for customers and created a more streamlined operation moving forward—without compromising the Company's ability to provide safe, reliable, and efficient power to its customers.

2. Administrative and General Costs

The Company has also minimized administrative and general ("A&G") costs. The Company's efficient management of its A&G costs has led to A&G costs in this case that are approximately $12 million <u>less</u> than the A&G costs sought in the 2006 Rate Case. The Company has accomplished this level of cost control by challenging its management to absorb inflationary pressures through productivity gains.

3. FTE Levels

Part of the decrease in requested A&G expense is due to a reduction in the number of full-time equivalent employees ("FTEs"). The Company reduced the number of FTEs by approximately 200 from the 2006 Rate Case through June 2008. In addition, the Company did not assume any escalation of FTEs in the 2010 test period, except for the addition of 13 employees to comply with enhanced reliability standards.

4. AFUDC Equity Flow-Through

The Company proposes to flow-through to customers the benefit associated with Allowance for Funds Used During Construction ("AFUDC") Equity. By utilizing this flow-through treatment—rather than normalization—the Company reduced the revenue requirement in this case by approximately $22 million.

5. Cost of Capital

The Company has moderated increases to its requested cost of capital, notwithstanding the current challenges in the financial markets, by successfully securing favorable interest rates for recent bond issuances and by requesting a return on equity that is at the low point of the range supported by the Company's expert witness.

D. Waiver of OAR 860-038-0080(1)(b)

Pursuant to OAR 860-038-0001(4) and SB 838, the Company also asks the Commission to waive the application of OAR 860-038-0080(1)(b) to the Company's acquisition of the Lake Side and Chehalis natural gas plants. OAR 860-038-0080(1)(b) requires new resources to be reflected in rates at market—not cost—and precludes their inclusion in rate base. Under OAR 860-038-0001(4), the Commission can waive the applicability of this rule for "good cause shown." The Company seeks this waiver so that it can include the capital costs of these resources in its rate base and the O&M costs in its revenue requirement.

"Good cause" to waive OAR 860-038-0080(1)(b) exists if "customers are likely to be better served by a utility-owned resource, included in rates at cost, instead of comparable market alternatives." *In the Matter of Portland General Electric 2004 Integrated Resource Plan*, Docket LC 33, Order No. 06-419 at 3 (July 20, 2006) ("Order No. 06-419"). *See also In the Matter of Pacific Power & Light Request for a General Rate Increase,* Docket UE 170, Order No. 05-1050 at 25-26 (Sept. 28, 2005) (waiver granted because prudently acquired resource benefited customers and was a least cost option).

PacifiCorp is not seeking a waiver of OAR 860-030-0080(1)(b) for its new wind resources because the rule was superseded for renewable resources by Section 13 of SB 838, codified as ORS 469A.120. This provision allows for the recovery in rates of all prudently incurred costs associated with compliance with a renewable portfolio standard. The three new wind resources in this case are renewable resources acquired pursuant to the renewable portfolio standards in SB 838. Therefore, the costs are recoverable in rates and OAR 860-038-0080(1)(b) is inapplicable.

III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of ten 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 will present support for the requested authorized ROE of 11.00 percent to account for the risks and operating challenges that the Company faces.

Bruce N. Williams, Treasurer, describes the calculation of PacifiCorp's capital structure, cost of debt, and preferred stock.

Stefan A. Bird, Vice President, Commercial and Trading, demonstrates the prudence of the acquisition of the Chehalis Plant and shows that it is in the best interest of Oregon customers.

Gregory N. Duvall, Director, Long Range Planning and Net Power Costs, presents the evidence that supports PacifiCorp's decision to acquire the Chehalis

Plant and demonstrates that the Chehalis Plant is used and useful for service to Oregon customers.

Mark R. Tallman, Vice President, Renewable Resource Development, describes the acquisition of the new Company-owned wind resources Seven Mile Hill II, Glenrock III and High Plains wind resources and the power purchase agreement for Three Buttes. Mr. Tallman also describes the acquisition of Lake Side.

Erich D. Wilson, Director, Human Resources, presents an overview of compensation and benefit plans and supports the costs related to these areas included in the test period. He also demonstrates that the Company has prudently contained increase in labor costs since the last rate case.

R. Bryce Dalley, Manager, Revenue Requirement, presents the Company's overall revenue requirement based on the test period (a future twelve-month period ending December 31, 2010).

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

William R. Griffith, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's proposed rate spread, rate design and tariffs.

Pursuant to OAR 860-013-0075(b), attached as Exhibit A is the summary setting forth the information required to be filed in connection with applications for general rate increases.

IV. CONCLUSION

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

DATED: April 2, 2009.

Counsel for PacifiCorp

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed April 2, 2009

(A)	Total Revenues collected under proposed rates:	$1,061,970,204[1]
(B)	Revenue change requested:	
	Total amount:	$92,057,256
	Net of credits from federal agencies:	$92,057,256
(C)	Percentage change of requested increase:	
	Total %:	9.1%
	Net of credits from federal agencies:	9.1%
(D)	Test period:	Calendar year 2010
(E)	Requested return on capital:	8.55%
	Requested return on equity:	11.00%
(F)	Rate base in filing:	$2,958,307,000
(G)	Results of Operation:	
	Utility operating income, before proposed change:	$184,994,000
	Utility operating income, after proposed change:	$252,892,000
(H)	Effect of rate change on each customer class	
	• Residential –	6.3%
	• Small General Service (Schedule 23)	13.7%
	• General Service 31-200 kW (Schedule 28)	9.7%
	• General Service 201-999 kW (Schedule 30)	9.7%
	• Large General Service >= 1,000 kW (Schedule 48)	13.7%
	• Agricultural Pumping Service (Schedule 41)	17.5%
	• Street lighting–	17.5%

[1] Includes the requested $20.6 million increase in the March 2009 Transition Adjustment Mechanism filing.

Docket No. UE-
Exhibit PPL/100
Witness: Richard P. Reiten

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Richard P. Reiten

April 2009

Q. Please state your name, business address and present position with PacifiCorp (the 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 deputy director of the U.S. Bureau of Land Management.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

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. Finally, my testimony introduces the other witnesses providing testimony on behalf of PacifiCorp.

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. This is the first general rate case filing by PacifiCorp in Oregon in three years. The last general rate case was in Docket UE 179 ("2006 Rate Case"). Based on the evidence provided in the direct testimony of Company witness Mr. R. Bryce Dalley, PacifiCorp is currently earning a return on equity ("ROE") in Oregon of 6.5 percent for the test period. This return is less than the 11.00 percent ROE requested by the Company, supported by Company witness Dr. Samuel C. Hadaway in his direct testimony. An overall price increase of $92.1 million or 9.1 percent is required to produce the 11.00 percent ROE necessary to maintain the financial integrity of the Company.

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 twelve-months ending December 31, 2010.

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 energy policy objectives. The Company's need for this rate increase is primarily driven by increases in investments in the system.

As shown 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 approximately $500 million from the 2006 Rate Case. This amount is in excess of the investment in renewable resources that is being recovered in the Renewable Adjustment Clause. This filing includes the investments the Company has made in three new wind resources - Seven Mile Hill II, Glenrock III and High Plains, as well as the addition of the Lake Side natural gas plant ("Lake Side") and the Chehalis natural gas plant ("Chehalis Plant"). The new wind resources, as described in the testimony of Company witness Mr. Mark R. Tallman, are cost-effective additions to the system that were acquired consistent with the Company's integrated resource plans. Mr. Tallman similarly demonstrates the prudent acquisition of Lake Side, which began serving Oregon customers in September 2007. The testimony of Company witnesses Mr. Stefan A. Bird and Mr. Gregory N. Duvall present the analysis that was performed by the Company in deciding to acquire the Chehalis Plant, demonstrate the prudence of the acquisition of the Chehalis Plant, explain the approval of the waiver to the competitive bidding guidelines, and establish that the resource is used and useful for service to the Company's Oregon customers since it was acquired in September 2008.

In addition to the major generation plant additions, this increase includes significant investments in all facets of the system, including transmission and distribution investment to bolster reliability and improve power delivery and investment in hydro plant to conform with the relicensing agreements for the

Lewis River and North Umpqua hydro systems.

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

A. No. The Company is filing a separate Transition Adjustment Mechanism to recover increases in its net power costs. In accordance with the Transition Adjustment Mechanism, rate changes related to net power costs will have an effective date of January 1, 2010.

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

A. No. Other utilities are facing the same types of cost pressures. As such, even with the price increase proposed in this case, PacifiCorp's prices will remain competitive when measured against other utilities within the state.

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 has proactively and aggressively controlled operations and maintenance ("O&M") expenses and administrative and general ("A&G") expenses. The Company's total-company budget for 2010 is approximately $40.5 million less than the level of O&M expense justified through the Company's other normalizing adjustments detailed in the testimony of Mr. Dalley. As a result, the Company has included an adjustment to reduce total company non-power cost O&M expenses to the Company's budgeted level. The Oregon-allocated impact of this adjustment is an approximate $11.3 million reduction to the revenue requirement requested in this proceeding.

As a result of the Company's cost-control efforts, Oregon-allocated O&M costs in this case are only $5 million higher than what the Company included in its 2006 Rate Case. This increase is remarkably small in light of the additional O&M for new generation facilities, which is nearly $20 million over the base period. The Company has been able to keep the overall O&M expense low by aggressively pursuing efficiency gains in other O&M expenses which has allowed the Company to offset the O&M expense for new generation.

Likewise, the Company has made great strides towards minimizing increases in A&G costs. A&G costs included in this case are $12 million *less than* what the Company requested in the 2006 Rate Case. The Company has accomplished this level of cost control by challenging its management to absorb inflationary pressures through productivity gains. As Mr. Dalley demonstrates in his testimony, the Company has successfully exceeded the commitment it made in its acquisition by MidAmerican Energy Holdings Company to reduce A&G expense.

Contributing to these lower levels of O&M and A&G expense is a reduction in the number of full-time equivalent employees ("FTEs") by approximately 200 from the 2006 Rate Case through June 2008 – again net of increases in FTEs related to new generation facilities. In addition, the Company did not assume any escalation of FTEs in the 2010 test period, except for the addition of 13 employees to comply with enhanced reliability standards.

Second, the Company is proposing to flow-through to customers in this case the benefit associated with Allowance for Funds Used During Construction

("AFUDC") Equity. By flowing through this benefit, rather than normalizing it, the revenue requirement in this case is reduced by $22 million. As explained in Mr. Dalley's testimony, if the Commission does not accept this proposal, the revenue requirement will need to increase by this amount to reflect a full normalization policy for this item.

Finally, the Company has moderated increases to its requested cost of capital notwithstanding the current challenges in the financial markets. As discussed in the direct testimony of Company witness Mr. Bruce N. Williams, the Company has been successful in securing favorable interest rates for recent bond issuances. These favorable interest rates directly benefit customers by reducing the Company's cost of long-term debt in the capital structure. Additionally, Company witness Dr. Samuel C. Hadaway is recommending an ROE that is at the low point of the range supported by his analysis, rather than at the mid-point of the range.

Q. In light of the passage of the federal American Recovery and Reinvestment Act ("ARRA") and the recent Commission decision authorizing a decoupling mechanism for Portland General Electric ("PGE"), is the Company proposing a decoupling mechanism in this case?

A. No. The Company is not proposing a decoupling mechanism at this time. Company executives have explored the topic in discussions with key stakeholders and will continue to do so. At this time, however, the Company is opting to monitor the mechanisms approved in the region, including the PGE and Idaho Power Company mechanisms, and participate in Commission proceedings related to the ARRA. The Company may propose a decoupling mechanism in the future.

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 will present support for the requested authorized ROE of 11.00 percent to account for the risks and operating challenges that the Company faces.

Bruce N. Williams, Treasurer, describes the calculation of PacifiCorp's capital structure, cost of debt and preferred stock.

Stefan A. Bird, Vice President, Commercial and Trading, demonstrates the prudence of the acquisition of the Chehalis Plant and shows that it is in the best interest of Oregon customers.

Gregory N. Duvall, Director, Long Range Planning and Net Power Costs, presents the evidence that supports PacifiCorp's decision to acquire the Chehalis Plant and demonstrates that the Chehalis Plant is used and useful for service to Oregon customers.

Mark R. Tallman, Vice President, Renewable Resource Development, describes the acquisition of the new Company-owned wind resources Seven Mile Hill II, Glenrock III and High Plains and the power purchase agreement for Three Buttes. Mr. Tallman also describes the acquisition of Lake Side.

Erich D. Wilson, Director, Human Resources, presents an overview of compensation and benefit plans and supports the costs related to these areas included in the test period. He also demonstrates that the Company has prudently contained the increase in labor costs since the last rate case.

R. Bryce Dalley, Manager, Revenue Requirement, presents the Company's overall revenue requirement based on the test period (a future twelve-month period ending December 31, 2010).

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

William R. Griffith, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's proposed rate spread, rate design and tariffs.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/200
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Samuel C. Hadaway

April 2009

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 (hereinafter the Company).

Q. Briefly describe your educational and professional background.

A. I have a Bachelor's degree in economics from Southern Methodist University, as well as MBA and Ph.D. degrees with concentrations in finance and economics from the University of Texas at Austin (UT Austin). For the past 25 years, I have been an owner and full-time employee of FINANCO, Inc. FINANCO provides financial research concerning the cost of capital and financial condition for regulated companies as well as financial modeling and other economic studies in litigation support. In addition to my work at FINANCO, I have served as an adjunct professor in the McCombs School of Business at UT Austin and in what is now the McCoy College of Business at Texas State University. In my prior academic work, I taught economics and finance courses and I conducted research and directed graduate students in the areas of investments and capital market research. I was previously Director of the Economic Research Division at the Public Utility Commission (Commission) of Texas where I supervised the Commission's finance, economics, and accounting staff, and served as the Commission's chief financial witness in electric and telephone rate cases. I have taught courses at various utility conferences on cost of capital, capital structure, utility financial condition, and cost allocation and rate design issues. I have made presentations before the New York Society of Security Analysts, the National Rate of Return Analysts Forum, and various other professional and legislative groups. I have served as a vice president and on the board of directors of the Financial Management Association.

A list of my publications and testimony I have given before various regulatory bodies and in state and federal courts is contained in my resume, which is included as Exhibit PPL/201.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to estimate the market required rate of return on equity capital (ROE) for PacifiCorp.

Q. Please state your ROE recommendation and summarize the results of your cost of equity studies.

A. I estimate the cost of equity for PacifiCorp to be 11.0 percent. My discounted cash flow (DCF) analysis indicates a reasonable ROE range of 11.0 percent to 11.6 percent. My risk premium analysis indicates an ROE range of 10.73 percent to 11.03 percent, with other risk premium data indicating ROEs of 10.9 percent or higher. Based on these quantitative results and my further review of other economic data, I recommend a point estimate of 11.0 percent. This recommendation, which is below the mid-point of the range of my quantitative model results, is both reasonable and conservative.

Q. How is your analysis structured?

In my DCF analysis, I apply a comparable company approach. PacifiCorp's cost of equity cannot be estimated directly from its own market data because the Company is 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 cost of equity directly. I begin my comparable company review with all the electric utilities that are included in the *Value Line Investors Service* (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 A3 from Moody's Investors Service (Moody's), I restricted the group to companies with senior secured bond ratings of at least A- by S&P or A3 by Moody's. I also required the comparable companies to derive at least 70 percent of revenues from regulated utility sales, to have consistent financial records not affected by recent mergers or restructuring, and to have a consistent dividend record as required by the DCF model. The fundamental characteristics and bond ratings of the nineteen companies in my comparable group are presented in Exhibit PPL/202.

In my risk premium analysis, I relied on current and projected single-A utility bond interest rates. These rates are consistent with PacifiCorp's bond rating. Under current market conditions, I believe this combination of DCF and risk premium approaches is the most reliable method for estimating the cost of equity. The data sources and the details of my cost of equity studies are contained in Exhibits PPL/202 through PPL/207.

Q. How is the remainder of your testimony organized?

A. My testimony is divided into three additional sections. Following this introduction, I review various methods for estimating the cost of equity. In this section, I discuss comparable earnings methods, risk premium methods, and the discounted cash flow model. In the following section, I review general capital market costs and conditions and discuss recent developments in the electric utility industry that may affect the cost of capital. In the final section, I discuss the details of my cost of equity studies and summarize my ROE recommendations.

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 present a general definition of the cost of equity capital and to compare the strengths and weaknesses of several of the most widely used methods for estimating the cost of equity. Estimating the cost of equity 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 ROE estimation process.

Q. Please define the term "cost of equity capital" and provide an overview of the cost estimation process.

A. The cost of equity capital is the rate of return that equity investors expect to receive. Conceptually it is no different than the cost of debt or the cost of preferred stock. The cost of equity 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. 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. Unlike returns from debt and preferred stocks, however, the equity return is not directly observable in advance and, therefore, it must be estimated or inferred from capital market data and trading activity.

An example helps to illustrate the cost of equity 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 = 5.0 percent). If the stock price is also expected to increase to $21.20 after one year, this one dollar and 20 cent expected gain adds an additional 6.0 percent to the expected total rate of return ($1.20 / $20 = 6.0 percent). Therefore, buying the stock at $20 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. In this context, to estimate the cost of equity one must apply informed judgment about the relative risk of the company in question and knowledge about the risk and expected rate of return characteristics of other available investments as well.

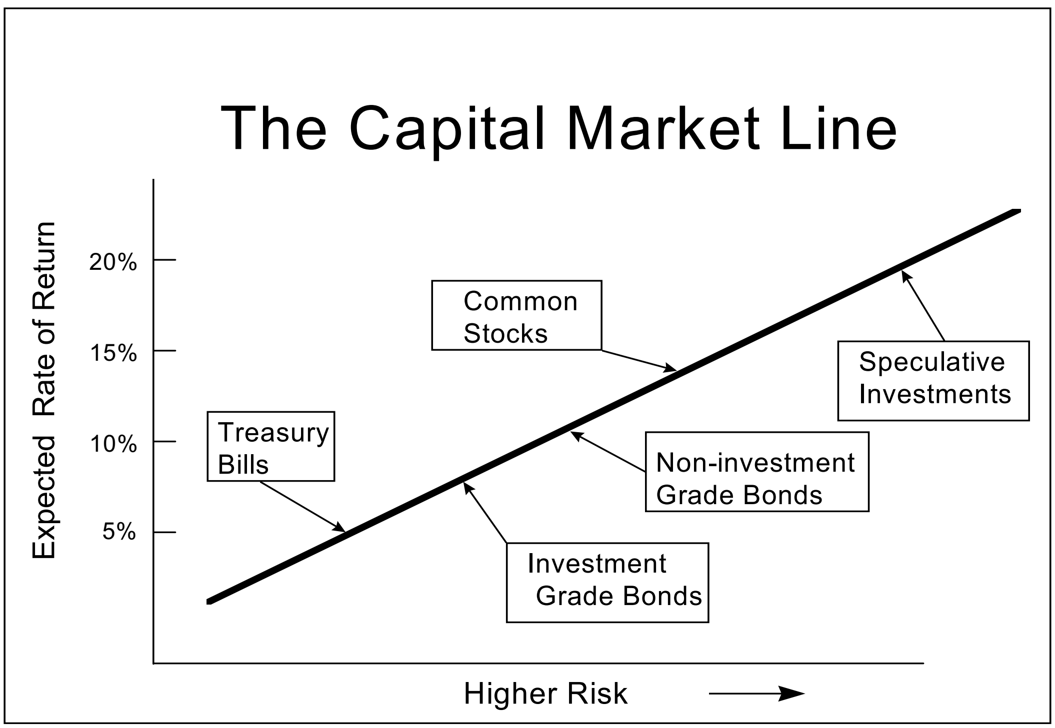
Q. How does the market account for risk differences among the various investments?

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, such 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; that 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. In nominal terms (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 add further 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, therefore, they 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. 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).

I understand that this standard has been codified in Oregon law. *See* ORS 756.040. Based on these principles, the fair rate of return should closely parallel investor opportunity costs as discussed above. If a utility earns its market cost of equity, neither its stockholders nor its customers should be disadvantaged.

Q. What specific methods and capital market data are used to evaluate the cost of equity?

A. Techniques for estimating the cost of equity normally fall into three groups:

comparable earnings methods, risk premium methods, and DCF methods. The first set of estimation techniques, the comparable earnings methods, 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, therefore, accounting-based methods do not generally provide reliable cost of equity 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 cost of equity 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 cost of equity directly by combining the "risk-free" government bond rate with explicit risk measures to determine the risk premium required by the market. Although these 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. For example, in the last Oregon case in which PacifiCorp's cost of capital was litigated, Order No. 01-787, the Commission gave no weight to the CAPM model in determining PacifiCorp's return on equity. The basic risk premium methods provide a useful parallel approach with the DCF model and assures 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 cost of equity 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 ROE 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, a combination of DCF and risk premium methods provides 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 capital market behavior. The risk premium methods provide a good parallel approach to the DCF model and further ensure that current market conditions are accurately reflected in the cost of equity estimate.

Q. Please explain the DCF model.

A. The DCF model is predicated on the concept that stock prices represent 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.

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.

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.

Recent events and current market conditions in the electric utility industry as discussed later appear to challenge 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. have reduced or eliminated their common dividends over 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.

Q. Can the DCF model be applied when the constant growth assumption is violated?

A. Yes. 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.

Under the "terminal price" nonconstant 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.

Under the "multistage" nonconstant 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:

$$P_0 = D_0(1+g_1)/(1+k) + ... + D_0(1+g_2)^n/(1+k)^n +$$

$$... + D_0(1+g_T)^{(T+1)}/(k-g_T) \qquad (4)$$

where the variables are the same as in equation (1), but g_1 represents the growth rate for the first period, g_2 for a second period, and g_T for the period from year T (the end of the transition period) to infinity. The first two growth rates are simply estimates for fluctuating growth over "n" years (typically 5 or 10 years) and g_T is a constant growth rate assumed to prevail forever after year T. 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 nonconstant growth models are based on the same valid capital market assumptions as the constant growth version. The nonconstant growth 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. Both constant and nonconstant growth DCF analyses are presented in a subsequent section of my testimony.

Q. Please explain the risk premium methodology.

A. Risk premium methods 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 guaranteed, 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.

Q. Are risk premium estimates of the cost of equity consistent with other current capital market costs?

A. Yes. The risk premium approach is especially 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 capital market costs.

Q. Is there consensus about how risk premium data should be employed?

A. No. In regulatory practice there is often considerable debate about how risk premium data should be interpreted and used. Since the analyst's basic task is to gauge investors' required returns on long-term investments, some argue that the estimated equity risk premium should be based on 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 observations should be given any weight 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 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?" The risk premium studies and analyses I discuss later address this question. My risk premium recommendation is based on an intermediate position that avoids some of the problems and concerns that have been expressed about both very long and very short periods of analysis with the risk premium model.

Q. Please summarize your discussion of cost of equity estimation techniques.

A. Estimating the cost of equity is one of the most controversial issues in utility ratemaking. Because actual investor requirements are not directly observable, several methods have been developed to assist in the estimation process. The comparable earnings method is the oldest but perhaps least reliable. Its use of accounting rates of return, or even historical market returns, may or may not reflect current investor requirements. Differences in accounting methods among companies and issues of comparability also detract from this approach.

The DCF and risk premium methods have become the most widely accepted in regulatory practice. In my professional judgment, a combination of the DCF model and a review of risk premium data provides the most reliable cost of equity estimate. While the DCF model does require judgment about future growth rates, the dividend yield is straightforward, and the model's results are generally consistent with actual capital market behavior. For these reasons, I will rely on a combination of the DCF model and a risk premium analysis in the cost of equity studies that follow.

Fundamental Factors That Affect the Cost of Equity

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

A. In this section, I review recent capital market conditions and industry factors that should be reflected in the cost of capital estimate.

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

A. In Exhibit PPL/203, page 1, I provide a review of annual interest rates and rates of inflation in the U.S. economy over the past ten years. During that time inflation and fixed income market costs declined and, generally, have been lower than rates that prevailed in the previous decade. Inflation, as measured by the Consumer Price Index (CPI), until 2003 had remained at historically low levels not seen consistently since the early 1960s. Since 2003, however, inflation rates have increased with the average for 2004 though 2006 similar to the longer-term historical average above 3 percent. The inflation rate for 2007 was even higher at 4.1 percent. Following the economic slowdown, and especially the sharp drop in energy prices, the consumer price index was essentially unchanged in 2008.

Having reduced the Federal Funds overnight bank interest rate to virtually zero, the Federal Reserve System's current monetary policy options are limited. During the period from mid-2004 until mid-2006, the Federal Reserve System increased the short-term Federal Funds interest rate 17 times, raising it from 1 percent to 5.25 percent. In late 2007, in response to the early turbulence in the sub-prime credit markets, the Federal Reserve Open Market Committee began aggressively reducing the Federal Funds rate. Since September 2007, the rate has been lowered eleven times to its current target level of between zero and one-quarter percent. Also, with the "flight to safety" that the markets' recent turmoil has caused, U.S. Treasury rates have declined significantly, with short-term Treasury bill rates at the lowest levels ever. However, corporate borrowers are being required to pay historically high risk premiums. As a result, corporate spreads relative to Treasuries are near the widest in history and corporate interest rates have increased significantly.

Q. Has the recent extreme turbulence in the capital markets affected the cost of capital for utilities?

A. Yes. During the past several months, capital markets in the U.S. have been more turbulent than at any time since the 1930s. Extremely large daily swings in the stock market and unprecedented corporate interest rate spreads in the debt markets have resulted in near chaos. The S&P 500 and the Dow Jones Industrial Average have fluctuated by 50 percent since November 2007. In this environment, many large financial institutions such as Countrywide Financial, Washington Mutual, the Federal Home Loan Mortgage Association, the Federal National Mortgage Association, Wachovia, Bear Sterns, and Merrill Lynch were unable to survive as independent institutions. Lehman Brothers was forced to file for bankruptcy. Other surviving institutions such as Citigroup, Goldman Sachs, American International Group, Morgan Stanley and others have required multibillion dollar capital infusions.

The Federal government enacted emergency legislation (the $700 billion Troubled Asset Relief Program) in October 2008 in an attempt to stabilize the economy. As part of that effort the government has increased federal deposit insurance, lent billions of dollars to financial institutions, purchased hundreds of billions of dollars in illiquid securities, guaranteed loans between financial institutions, and purchased equity in banks. In November 2008, the Federal Reserve pledged to pump another $800 billion into ailing credit markets - $600 billion to purchase federal government agency mortgage securities and, with support from the U.S. Treasury, the Federal Reserve will provide up to $200 billion in financing to investors buying securities tied to student loans, car loans, credit card debt and small business loans. In addition, President Obama has signed an additional $789 billion economic package in hopes of providing further economic stimulus for the economy. There is no question that the economic and financial uncertainties generated by the credit crisis have significantly impacted the risks surrounding public utility company cost of capital.

Q. Can you be more specific regarding the impact of the credit crisis on the cost of capital of public utilities?

A. Yes. In Exhibit PPL/203, page 2, I provide data that illustrate the dramatic increase in the spread between the yields on utility debt and U.S. Treasury securities. The exhibit shows that during the past several months single-A spreads for utility companies have been in excess of 300 basis points. This level is three times higher than the spreads that existed little more than a year ago. The month-by-month interest rates paid by single-A rated utilities and the U.S. Treasury over the past two years are presented in Exhibit PPL/203, page 2. These interest rate data are summarized in Table 1 below.

Table 1
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-07	5.96	4.85	1.11
Feb-07	5.90	4.82	1.08
Mar-07	5.85	4.72	1.13
Apr-07	5.97	4.87	1.10
May-07	5.99	4.90	1.09
Jun-07	6.30	5.20	1.10
Jul-07	6.25	5.11	1.14
Aug-07	6.24	4.93	1.31
Sep-07	6.18	4.79	1.39
Oct-07	6.11	4.77	1.34
Nov-07	5.97	4.52	1.45
Dec-07	6.16	4.53	1.63
Jan-08	6.02	4.33	1.69
Feb-08	6.21	4.52	1.69
Mar-08	6.21	4.39	1.82
Apr-08	6.29	4.44	1.85
May-08	6.28	4.60	1.68
Jun-08	6.38	4.69	1.69
Jul-08	6.40	4.57	1.83
Aug-08	6.37	4.50	1.87
Sep-08	6.49	4.27	2.22
Oct-08	7.56	4.17	3.39
Nov-08	7.60	4.00	3.60
Dec-08	6.52	2.87	3.65
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
3-Mo Avg	**6.40**	**3.20**	**3.21**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates). Three month average is for Dec '08 - Feb '09.

The data in Table 1 show that over the past two years, single-A utility interest rates have fluctuated widely. The November 2008 level was the highest seen during the past decade. More important, continuing market turbulence has increased interest rate spreads to the highest levels on record. The Federal Reserve's efforts to reduce short-term borrowing costs for banks (the Fed Funds rate) and lower rates on U.S. Treasury bonds have not helped corporate borrowers. In fact, increased risk aversion and market illiquidity have resulted in significantly higher borrowing costs for corporations. While the effects of market turbulence may not be easily captured in financial models for estimating the rate of return, the much higher borrowing costs that corporations now face should be considered explicitly in estimates of the cost of equity capital.

Q. What levels of interest rates are forecast for the coming year?

A. While Treasury rate forecasts have moderated in recent months, corporate spreads relative to Treasuries have widened significantly. Exhibit PPL/203, page 3, provides S&P's most recent economic forecast from its *Trends & Projection*s publication for February 2009. S&P forecasts significant economic contraction in the 1st and 2nd Quarters of 2009. For all of 2009, S&P forecasts that real GDP will decline by 2.5 percent. These projected growth rates compare to positive real GDP growth rates of 2.0 percent for 2007 and 1.3 percent for all of 2008.

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

Table 3
Standard & Poor's Interest Rate Forecast

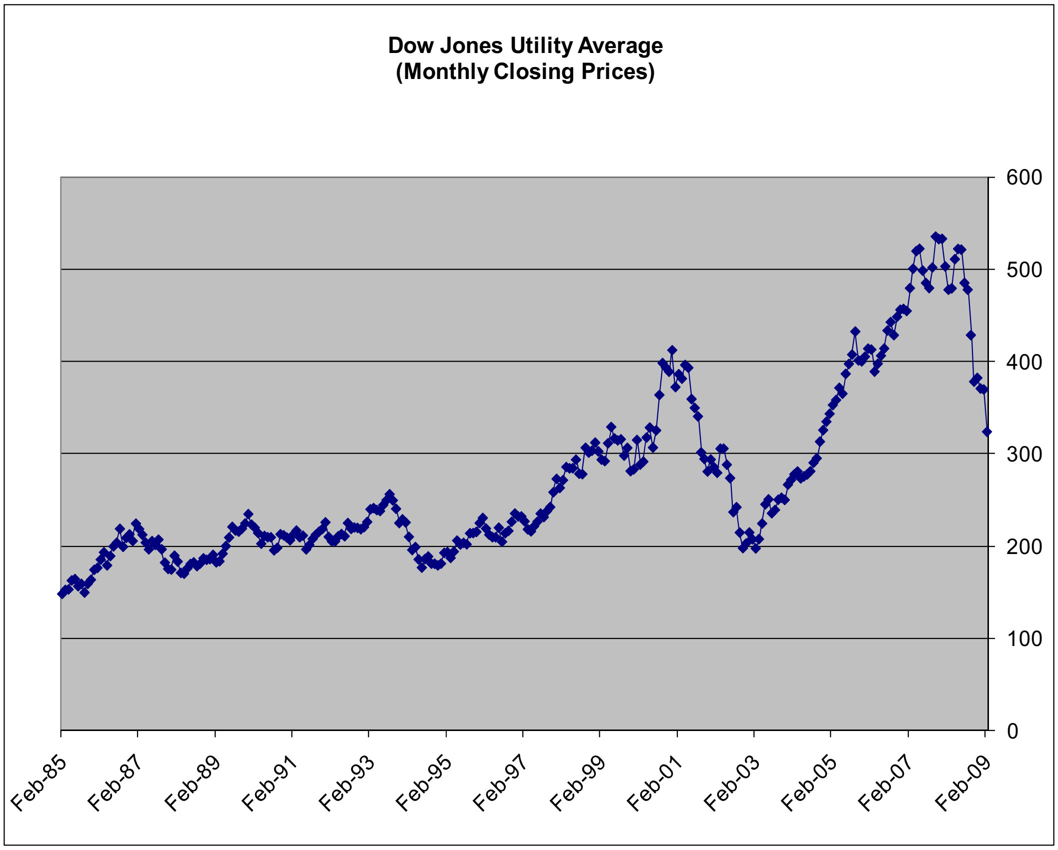
	Feb. 2009 Average	Average 2008	Average 2009 Est.
Treasury Bills	0.3%	1.4%	0.2%
10-Yr. T-Bonds	2.9%	3.7%	3.0%
30-Yr. T-Bonds	3.6%	4.3%	3.7%
Aaa Corporate Bonds	5.3%	5.6%	5.7%

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

The data in Table 3 show that long-term Treasury interest rates during 2009 are projected to increase slightly from current levels. The rate on Aaa corporate bonds is also expected to increase somewhat. Although it is difficult to project rates for lower rated securities, the wider spreads for utilities that were shown previously in Table 1 offer important perspective for judging the cost of capital in the present case.

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

A. Utility stock prices have fluctuated widely. After reaching a level of over 400 in 2000, the Dow Jones Utility Average (DJUA) dropped to about 200 by October 2002. From late 2002 until mid-2008, the DJUA trended upward. Its current level is approximately 40 percent below the record high level attained in 2007. The following graph of DJUA prices over the past 25 years vividly illustrates the wider fluctuations that have occurred in more recent years.



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. What is the industry's current fundamental position?

A. Many electric utilities are attempting to return to their core businesses and hope to see more stable results over the next several years. S&P reflects this sentiment in its most recent *Electric Utility Industry Survey*:

> **<u>Standard & Poor's Industry Surveys</u>**
>
> We expect the performance of both the electric utility sector and the individual companies within the sector to remain relatively volatile over the next several years. However, assuming that the housing, financial, and credit markets begin to stabilize, we believe the stocks will be less volatile in 2009 than they were in 2008, or during the first few years of this

> decade…. *** The performance of the sector, however, will remain sensitive to the macroeconomic environment and market forces surrounding it. (Standard & Poor's *Industry Surveys*, Electric Utilities, February 26, 2009, p. 6)

Value Line also reflects concerns about prospects for the industry:

> **<u>Value Line Investors' Service</u>**
>
> Declining energy sales, coupled with higher financing costs, have led several utilities in the group to cut back on spending. Many projects are being postponed for future years or canceled altogether. *** Although increased spending during these rocky economic times might not seem prudent, it may well lead to more consistent earnings growth over the next 3-5 years, provided that the utilities receive reasonable regulatory treatment. (Value Line Investment Survey, Electric Utility Industry, February 27, 2009, p. 148.

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

Q. Do utilities continue to face the operating and financial risks that existed prior to the recent financial crisis?

A. Yes. Prior to the recent financial crisis, the greatest consideration for utility investors was the industry's continuing transition to more open market conditions and competition. With the passage of the National Energy Policy Act (NEPA) in 1992 and the Federal Energy Regulatory Commission's (FERC) Order 888 in 1996, the stage was set for vastly increased competition in the electric utility industry. NEPA's mandate for open access to the transmission grid and FERC's implementation through Order 888 effectively opened the market for wholesale electricity to competition. Previously protected utility service territory and lack of transmission access in some parts of the country had limited the availability of competitive bulk power prices. NEPA and Order 888 have essentially eliminated such constraints for incremental power needs.

In addition to wholesale issues at the federal level, many states implemented retail access and have opened their retail markets to competition. Prior to the Western energy crisis, investors' concerns had focused principally on appropriate transition mechanisms and the recovery of stranded costs. More recently, however, provisions for dealing with power cost adjustments have become a larger concern. As expected, the opening of previously protected utility markets to competition, the uncertainty created by the removal of regulatory protection, and continuing fuel price volatility have raised the level of uncertainty about investment returns across the entire industry.

Q. Is PacifiCorp affected by these same uncertainties and increasing utility capital costs?

A. Yes. While all electric utilities are being affected by the industry's transition to competition at some level, PacifiCorp is directly impacted in Oregon where the Legislature has adopted retail competition, while also guaranteeing customers continued access to cost-of-service rates. Although I understand that only a few companies have opted away from PacifiCorp, Oregon's competitive retail model creates potential risk to PacifiCorp in load planning, managing net power costs and other operating activities. The uncertainty associated with the changes that are transforming the utility industry as a whole, as viewed from the perspective of the investor, remain a factor in assessing any utility's required ROE, including the ROE from PacifiCorp's operations in Oregon.

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 investment 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, allowed equity returns have generally followed interest rate changes. During 2008, allowed rates have increased from the lowest levels provided during 2006 and 2007. Furthermore, the historical averages obviously cannot reflect the recent extreme market turmoil that has occurred. The following

Table 4 summarizes the overall average ROEs allowed for electric utilities since 2004:

TABLE 4
Authorized Electric Utility Equity Returns

	2004	2005	2006	2007	2008
1st Quarter	11.00%	10.51%	10.38%	10.27%	10.45%
2nd Quarter	10.54%	10.05%	10.68%	10.27%	10.57%
3rd Quarter	10.33%	10.84%	10.06%	10.02%	10.47%
4th Quarter	10.91%	10.75%	10.39%	10.56%	10.33%
Full Year Average	10.75%	10.54%	10.36%	10.36%	10.46%
Average Utility Debt Cost	6.20%	5.67%	6.08%	6.11%	6.65%
Indicated Average Risk Premium	4.55%	4.87%	4.28%	4.25%	3.81%

Source: *Regulatory Focus*, Regulatory Research Associates, Inc., Major Rate Case Decisions, January 12, 2009.

Q. Please summarize the historical equity risk premiums and indicated cost of equity demonstrated in Table 4.

A. Since 2004, equity risk premiums (the difference between allowed equity returns and utility interest rates) have ranged from 3.81 percent to 4.87 percent. At the low end of this range, based on average single-A utility interest rates for the three months ended February 2009 (as shown previously in Table 1), the indicated cost of equity is 10.2 percent (6.4% current single-A interest rate + 3.81% equity risk premium = 10.21%). At the upper end of this range, with an allowed equity risk premium of 4.87 percent, the indicated cost of equity is 11.3 percent (6.4% current single-A interest rate + 4.87% equity risk premium = 11.27%).

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 19-company group of electric utilities based on the selection criteria discussed previously. In the second part of my analysis, I apply various 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. In the third version of the DCF model, I use a two-stage growth approach, with stage one based on Value Line's three-to-five-year dividend projections and stage two based on long-term projected growth in GDP. The dividend yields in all three of the annual 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, 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. Especially for the very long-term growth rate requirements of the DCF model, the growth in nominal GDP should be considered an important input.

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 data base. That data for the period 1948 through 2008 are summarized in my Exhibit PPL/204. As shown at the bottom of that exhibit, the overall average for the period was 6.9 percent. The data also show, however, that in the more recent years since 1980, lower inflation has resulted in lower overall GDP growth. For this reason I gave more weight to the more recent years in my GDP forecast. This approach is consistent with the concept that more recent data should have a greater effect on expectations and with generally lower near- and intermediate-term growth rate forecasts that presently exist. Based on this approach, my overall forecast for long-term GDP growth is 70 basis points lower than the long-term average, at a level of 6.2 percent.

Q. The DCF model requires an estimate of investors' long-term growth rate expectations. Why do you believe your forecast of GDP growth based on long-term historical data is appropriate?

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 Exhibit PPL/204. The long-run historical average GDP growth rate is 6.9 percent, but my estimate of long-term expected growth is only 6.2 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 PPL/204 the average long-term inflation rate has been over 3 percent in all but the most recent 10- and 20- year periods. Also, earlier in 2008, it was clearly shown that a long-run 2 percent inflation rate cannot be maintained in the face of rising energy prices.

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. To the extent that even the longer-term outlooks of professional economists are also depressed, their forecasts will be low. 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 electric utility DCF analyses.

A. The DCF results for my comparable company group are presented in Exhibit PPL/205. As shown in the first column of page 1 of that exhibit, the traditional constant growth model indicates an ROE of 11.4 percent to 11.6 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 an ROE range of 11.2 percent to 11.5 percent. Finally, in the third column of page 1, I present the results from the multistage DCF model. The multistage model indicates an ROE range of 11.0 percent to 11.1 percent. The results from the DCF model, therefore, indicate a reasonable ROE range of 11.0 percent to 11.6 percent.

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

A. The details and results of my equity risk premium studies are shown in my Exhibits PPL/206 and PPL/207. These studies indicate an ROE range of 10.73 percent to 11.03 percent. Other equity risk premium data, which I will discuss below, indicate ROEs of 10.9 percent or higher.

Q. How are your equity risk premium studies structured?

A. My equity risk premium studies are divided into two parts. First, I compare electric utility authorized ROEs for the period 1980-2008 to contemporaneous long-term utility interest rates. The differences between the average authorized

ROEs and the average interest rate for the 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 ROE. 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 2 of Exhibit PPL/206 and Exhibit PPL/207, I provide regression analyses 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 cost of equity increases, but by a smaller amount. Similarly, when interest rates decline by one percentage point, the cost of equity declines by less than one percentage point. I use this negative interest rate change coefficient in conjunction with current interest rates to establish the appropriate current equity risk premium.

Q. How do the results of your equity risk premium study compare to levels found in other published equity risk premium studies?

A. Based on my equity risk premium studies, I am conservatively recommending a lower equity risk premium than is often found in other published risk premium studies. For example, the most widely followed equity risk premium data are provided in studies published annually by Morningstar. These data, for the period 1926-2007, indicate an arithmetic mean equity risk premium of 6.1 percent for common stocks versus long-term corporate bonds. Under the assumption of geometric mean compounding, the Morningstar equity risk premium for common stocks versus corporate bonds is 4.5 percent. Based on the more conservative geometric mean equity risk premium, the Morningstar data indicate a cost of equity of 10.9 percent (6.40% debt cost + 4.5% risk premium = 10.90%). Based on the arithmetic risk premium, the Morningstar data indicate a cost of equity of 12.5 percent (6.40% debt cost + 6.1% risk premium = 12.50%). Although the Morningstar (previously known as Ibbotson) results should not be extrapolated directly as stand-alone estimates of the cost of equity for regulated utilities, their results provide a reasonable long-term perspective on capital market expectations for debt and equity rates of return.

Q. Please summarize the results of your cost of equity analysis.

A. The following table summarizes my results:

TABLE 5

Summary of Cost of Equity Estimates

DCF Analysis	Indicated Cost
Constant Growth (Analysts' Growth)	11.4%-11.6%
Constant Growth (GDP Growth)	11.2%-11.5%
Multistage Growth Model	11.0%-11.1%
Reasonable DCF Range	11.0%-11.6%

Equity Risk Premium Analysis	Indicated Cost
Forecast Utility Debt + Equity Risk Premium	
Equity Risk Premium ROE (6.91% + 4.12%)	11.03%
Current Utility Debt + Equity Risk Premium	
Equity Risk Premium ROE (6.40% + 4.33%)	10.73%
Ibbotson Equity Risk Premium Analysis	
Equity Risk Premium ROE (6.4% + 4.5%)	10.90%
PacifiCorp Estimated ROE	11.0%

Q. How should these results be interpreted to determine the fair cost of equity for PacifiCorp?

A. Current market conditions make it difficult to strictly interpret quantitative model estimates of the cost of capital. While the DCF results, based on lower stock prices and higher resulting dividend yields, have increased, the changes in the cost of equity indicated by that model are much smaller than the increased borrowing costs that most utilities currently face. More current equity risk premium estimates are also conservative because they are based on historical risk premiums that may not fully reflect cost of capital increase that the current financial crisis has caused. Under these conditions, use of a lower DCF range or equity risk premium estimates based on historical risk premium relationships likely understate the cost of equity. From this perspective, and with consideration of the Company's large on-going capital requirements, a recommendation in the midto-high range of my quantitative model results would be warranted. My recommendation that a fair cost of equity capital for PacifiCorp is at least 11.0 percent is thus both reasonable and conservative.

Q. Does this conclude your testimony?

A. Yes, it does.

Docket No. UE-
Exhibit PPL/201
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Resume of Dr. Samuel C. Hadaway

April 2009

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SUMMARY OF QUALIFICATIONS

- Principal, Financial Analysis Consultants (FINANCO, Inc.).
- Ph.D. in Finance and Econometrics.
- 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, 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:

- Arkansas Public Service Commission, Docket No. 094- -U, February 2009 (AEP-SWEPCO).
- Washington Utilities and Transportation Commission, Docket UE- /General Rate Case, February 9, 2009 (PacifiCorp).
- Idaho Public Utilities Commission, Case No. PAC-E-08-07, September 19, 2008 (Rocky Mountain Power).
- Missouri Public Service Commission, Case No. ER-2009- , September 5, 2008 (Kansas City Power & Light Company).
- Kansas Corporation Commission, Docket No. 09-KCPE- -RTS, September 5, 2009 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2009- , September 5, 2009 (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).
- Texas Public Utility Commission, Docket No. 35717, June 27, 2008, (Oncor Electric Delivery Company LLC).
- Washington Utilities and Transportation Commission, Docket UG-080546/General Rate Case, March 28, 2008 (NW Natural).
- Washington Utilities and Transportation Commission, Docket UE-080220/General Rate Case, 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)
- Missouri Public Service Commission, Case No. ER-2007-0004, July 3, 2006 (Aquila, Inc.).
- New Mexico Public Regulation Commission, Case No. 06-00258-UT, June 30, 2006 (El Paso Electric Company).

- New Mexico Public Regulation Commission, Case No. 06-00210-UT, May 30, 2006 (Public Service Company of New Mexico).
- Texas Public Utility Commission, Docket No. 32093, April 14, 2006 (CenterPoint Energy-Houston Electric, LLC).
- Utah Public Service Commission, Docket No. 06-035-21, March 7, 2006 (PacifiCorp).
- Oregon Public Utility Commission, Case No. UE-179, February 23, 2006 (PacifiCorp).
- Kansas Corporation Commission, Docket No. 06-KCPE-828-RTS, January 31, 2006 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2006-0314, January 27, 2006 (Kansas City Power & Light Company).
- California Public Utilities Commission, Docket No. 05-11-022, November 29, 2005 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 31994, November 5, 2005 (Texas-New Mexico Power Company).
- New Hampshire Public Utilities Commission, Docket No. DE 05-178, November 4, 2005 (Unitil Energy Systems).
- Wyoming Public Service Commission, Docket No. 20000-ER-05-230, October 14, 2005 (PacifiCorp).
- Minnesota Public Utilities Commission, Docket. No. G-008/GR-05-1380, October 2005 (CenterPoint Energy Minnegasco).
- Texas Railroad Commission, Gas Utilities Division No. 9625, September 2005 (CenterPoint Energy Entex).
- Illinois Commerce Commission, Docket No. 05-0597, August 31, 2005 (Commonwealth Edison Company).
- Washington Utilities and Transportation Commission, Docket ,UE-050684/General Rate Case, May 2005 (PacifiCorp).
- Missouri Public Service Commission, Case No. ER-2005-0436, May 2005 (Aquila, Inc.).
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, January 14, 2005 (PacifiCorp).
- Arkansas Public Service Commission, Docket No. 04-121-U, December 3, 2004 (CenterPoint Energy Arkla).
- Oregon Public Utility Commission, Case No. UE-170, November 12, 2004 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 29206, November 8, 2004 (Texas-New Mexico Power Company).
- Texas Railroad Commission, Gas Utilities Division Nos. 9533 and 9534, October 13, 2004 (CenterPoint Energy Entex).
- Texas Public Utility Commission, Docket No. 29526, August 18 and September 2, 2004 (CenterPoint Energy Houston Electric).
- Utah Public Service Commission, Docket No. 04-2035-, August 4, 2004 (PacifiCorp).
- Oklahoma Corporation Commission, Cause No. PUD-200400187, July 2, 2004, (CenterPoint Energy Arkla).
- Minnesota Public Utilities Commission, Docket No. G-008/GR-04-901, July 2004, (CenterPoint Energy Minnegasco).
- Washington Utilities and Transportation Commission, Docket ,UE-032065/General Rate Case, December 2003 (PacifiCorp).
- Washington Utilities and Transportation Commission, Docket ,UG-031885, November 2003 (Northwest Natural Gas Company.).
- Wyoming Public Service Commission, Docket No. 20000-ER-03-198, May 2003 (PacifiCorp).
- Public Service Commission of Utah, Docket No. 03-2035-02, May 2003 (PacifiCorp).
- Public Utility Commission of Oregon, Case. UE-147, March 2003 (PacifiCorp).

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- New Hampshire Public Utilities Commission, Docket No. DE 01-247, January 2002 (Unitil Corporation).
- Washington Utilities and Transportation Commission, Docket UE-011569,70,UG-011571, November 2001 (Puget Sound Energy, Inc.).
- California Public Utilities Commission, Docket No. 01-03-026, September and December 2001 (PacifiCorp).
- New Mexico Public Regulation Commission, Docket No. 3643, July 2001 (Texas-New Mexico Power Company).
- Texas Natural Resources Conservation Commission, Docket No. 2001-1074/5-URC, May 2001 (AquaSource Utility, Inc.).
- Massachusetts Department of Telecommunications and Energy, Docket No. 99-118, May 2001 (Fitchburg Gas and Electric Light Company).
- Public Service Commission of Utah, Docket No. 01-035-01, January 2001 (PacifiCorp)
- Federal Energy Regulatory Commission, Docket No. ER-01-651, January 2001 (Southwestern Electric Power Company).
- Wyoming Public Service Commission, Docket No. 20000-ER-00-162, December 2000 (PacifiCorp).
- Public Utility Commission of Oregon, Case. UE-116, November 2000, (PacifiCorp)
- Public Utility Commission of Texas, Docket No. 22344, September 2000, (AEP Texas Companies, Entergy Gulf States, Inc., Reliant Energy HL&P, Texas-New Mexico Power Company, TXU Electric Company)
- Public Utility Commission of Oregon, Case UE-111, August 2000, (PacifiCorp)
- Texas Public Utility Commission, Docket Nos. 22352,3,4, March 2000 (Central Power and Light Co., Southwestern Electric Power Co., West Texas Utilities Co.).
- Texas Public Utility Commission, Docket No. 22355, March 2000 (Reliant Energy, Inc.).
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Antitrust Litigation:

- Marginal Cost Analysis of Concrete Production/Predatory Pricing (Stiles)
- Analysis of Lost Business Opportunity due to denial of Waste Disposal Site Permit (Browning-Ferris Industries, Inc.).
- Analysis of Electric Power Transmission Costs in Purchased Power Dispute (City of College Station, Texas).

Contract Litigation:

- Analysis of Cogeneration Contract/Economic Viability Issues(Texas-New Mexico Power Company)
- Definition of Electric Sales/Franchise Fee Contract Dispute (Reliant Energy HL&P)
- Analysis of Purchased Power Agreement/Breach of Contract (Texas-New Mexico Power Company)
- Regulatory Commission Provisions in Franchise Fee Ordinance Dispute (Central Power & Light Company)
- Analysis of Economic Damages resulting from attempted Acquisition of Highway Construction Company (Dillingham Construction Corporation).
- Analysis of Economic Damages due to Contract Interference in Acquisition of Electric Utility Cooperative (PacifiCorp).
- Analysis of Economic Damages due to Patent Infringement of Boiler Cleaning Process (Dowell-Schlumberger/The Dow Chemical Company).

Lender Liability/Securities Litigation:

- ERISA Valuation of Retail Drug Store Chain (Sommers Drug Stores Company).
- Analysis of Lost Business Opportunities in Failed Businesses where Lenders Refused to Extend or Foreclosed Loans (FirstCity Bank Texas, McAllen State Bank, General Electric Credit Corporation).
- Usury and Punitive Damages Analysis based on Property Valuation in Failed Real Estate Venture (Tomen America, Inc.).

Personal Injury/Wrongful Death/Lost Earnings Capacity Litigation:

- Analysis of Lost Earnings Capacity and Punitive Damages due to Industrial Accident (Worsham, Forsythe and Wooldridge).
- Analysis of Lost Earnings Capacity due to Improper Termination (Lloyd Gosselink, Ryan & Fowler).
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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).
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- Evaluation of Electric Utility Distribution System (Jasper-Newton Electric Cooperative).
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Docket No. UE-
Exhibit PPL/202
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Comparable Company Fundamental Characteristics

April 2009

PacifiCorp Oregon
Comparable Company Fundamental Characteristics

		(1)	(2)		(3)		
					Capital Structure (2007)		
		% Regulated	Credit Rating		Common Equity	Long-Term Debt	Preferred Stock
No.	Company	Revenue	S&P	Moody's	Ratio	Ratio	Ratio
1	ALLETE	88.9%	A-	NR	59.0%	41.0%	0.0%
2	Alliant Energy Co.	87.6%	A-	A2	60.5%	34.0%	5.5%
3	Con. Edison	84.0%	A-	A1	54.1%	45.9%	0.0%
4	DPL Inc.	100.0%	A-	A2	44.0%	55.0%	1.0%
5	DTE Energy Co.	75.3%	A-	A3	45.0%	55.0%	0.0%
6	Duke Energy	76.6%	A	A3	61.3%	38.7%	0.0%
7	Edison Internat.	79.7%	A	A2	43.0%	53.0%	4.0%
8	Entergy Corp.	78.8%	A-	Baa2	41.5%	57.0%	1.5%
9	FPL Group, Inc.	71.0%	A	Aa3	45.8%	54.2%	0.0%
10	IDACORP	81.7%	A-	A3	49.9%	50.1%	0.0%
11	NSTAR	95.5%	AA-	A1	39.5%	59.5%	1.0%
12	PG&E Corp.	100.0%	BBB+	A3	45.0%	54.0%	1.0%
13	Portland General	100.0%	A	Baa1	49.0%	51.0%	0.0%
14	Progress Energy	99.9%	A-	A2	46.0%	54.0%	0.0%
15	Sempra Energy	74.1%	A+	A1	57.0%	41.5%	1.5%
16	Southern Co.	82.1%	A	A2	44.5%	52.0%	3.5%
17	Vectren Corp.	78.8%	A	A3	51.0%	49.0%	0.0%
18	Wisconsin Energy	99.9%	A-	Aa3	48.0%	51.5%	0.5%
19	Xcel Energy Inc.	99.3%	A-	A3	47.5%	51.5%	1.0%
		87.0%	A/A-	A2	49.0%	49.9%	1.1%

Column Sources:
(1) Most recent company 10-Ks.
(2) AUS Utility Reports, Mar 2009.
(3) Value Line Investment Survey, Electric Utility (East), Feb 28, 2009; (Central), Dec 26, 2008; (West), Feb 6, 2009.

Docket No. UE-
Exhibit PPL/203
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Capital Market Data

April 2009

PacifiCorp Oregon
Historical Capital Market Costs

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Prime Rate	8.0%	9.2%	6.9%	4.7%	4.1%	4.3%	6.2%	8.0%	8.1%	5.1%
Consumer Price Index	2.7%	3.4%	1.6%	2.5%	2.0%	3.3%	3.4%	2.6%	4.1%	-0.1%
Long-Term Treasuries	5.9%	5.9%	5.5%	5.4%	5.0%	5.1%	4.7%	5.0%	4.8%	4.3%
Moody's Avg Utility Debt	7.6%	8.1%	7.7%	7.5%	6.6%	6.2%	5.7%	6.1%	6.1%	6.7%
Moody's A Utility Debt	7.6%	8.2%	7.8%	7.4%	6.6%	6.2%	5.7%	6.1%	6.1%	6.5%

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 1999-2001 and 2007-2008; 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

PacifiCorp Oregon
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-07	5.96	4.85	1.11
Feb-07	5.90	4.82	1.08
Mar-07	5.85	4.72	1.13
Apr-07	5.97	4.87	1.10
May-07	5.99	4.90	1.09
Jun-07	6.30	5.20	1.10
Jul-07	6.25	5.11	1.14
Aug-07	6.24	4.93	1.31
Sep-07	6.18	4.79	1.39
Oct-07	6.11	4.77	1.34
Nov-07	5.97	4.52	1.45
Dec-07	6.16	4.53	1.63
Jan-08	6.02	4.33	1.69
Feb-08	6.21	4.52	1.69
Mar-08	6.21	4.39	1.82
Apr-08	6.29	4.44	1.85
May-08	6.28	4.60	1.68
Jun-08	6.38	4.69	1.69
Jul-08	6.40	4.57	1.83
Aug-08	6.37	4.50	1.87
Sep-08	6.49	4.27	2.22
Oct-08	7.56	4.17	3.39
Nov-08	7.60	4.00	3.60
Dec-08	6.52	2.87	3.65
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
3-Mo Avg	**6.40**	**3.20**	**3.21**
12-Mo Avg	**6.57**	**4.10**	**2.46**

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

Exhibit PPL/203
Hadaway/3

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

2007	A2008	E2009	Annual % Change 2007	Annual % Change A2008	Annual % Change E2009		2008 2Q	2008 3Q	2008 A4Q	E2009 1Q	E2009 2Q	E2009 3Q	E2009 4Q	E2010 1Q
						Gross Domestic Product								
$13,807.6	$14,280.7	$14,065.7	4.8	3.4	(1.5)	GDP (current dollars)	$14,294.5	$14,412.8	$14,264.6	$14,128.3	$14,011.8	$14,018.2	$14,104.7	$14,241.3
4.8	3.4	(1.5)	-	-	-	Annual rate of increase (%)	4.1	3.4	(4.1)	(3.8)	(3.3)	0.2	2.5	3.9
2.0	1.3	(2.5)	-	-	-	Annual rate of increase–real GDP (%)	2.8	(0.5)	(3.8)	(5.8)	(3.3)	0.1	2.3	2.5
2.7	2.2	1.0	-	-	-	Annual rate of increase–GDP deflator (%	1.1	3.9	(0.1)	1.7	0.0	0.1	0.2	1.4
						***Components of Real GDP**								
$8,252.8	$8,276.2	$8,181.8	2.8	0.3	(1.1)	Personal consumption expenditures	$8,341.3	$8,260.6	$8,186.9	$8,122.1	$8,130.9	$8,197.9	$8,276.3	$8,341.8
2.8	0.3	(1.1)	-	-	-	% change	1.2	(3.8)	(3.5)	(3.1)	0.4	3.3	3.9	3.2
1,242.4	1,188.3	1,109.8	4.8	(4.4)	(6.6)	Durable goods	1,228.3	1,180.1	1,107.7	1,084.6	1,083.1	1,114.4	1,157.1	1,201.9
2,392.6	2,381.9	2,310.4	2.5	(0.4)	(3.0)	Nondurable goods	2,420.7	2,376.3	2,332.8	2,292.8	2,292.7	2,314.7	2,341.4	2,363.2
4,646.2	4,714.8	4,746.8	2.6	1.5	0.7	Services	4,712.1	4,711.3	4,731.6	4,723.5	4,732.7	4,754.8	4,776.1	4,788.8
1,383.0	1,408.2	1,193.3	4.9	1.8	(15.3)	Nonresidental fixed investment	1,431.8	1,425.7	1,352.2	1,287.8	1,210.8	1,146.2	1,128.6	1,142.4
4.9	1.8	(15.3)	-	-	-	% change	2.5	(1.7)	(19.1)	(17.7)	(21.9)	(19.7)	(6.0)	5.0
1,078.9	1,047.2	893.6	1.7	(2.9)	(14.7)	Producers durable equipment	1,074.7	1,054.0	971.5	934.2	894.4	871.0	874.7	896.8
444.9	351.1	267.7	(18.1)	(21.1)	(23.7)	Residental fixed investment	361.1	345.6	323.0	291.1	262.6	255.1	261.9	270.2
(18.1)	(21.1)	(23.7)	-	-	-	% change	(13.7)	(16.0)	(23.7)	(34.0)	(33.7)	(10.9)	11.0	13.3
(2.5)	(21.1)	(88.3)	-	-	-	Net change in business inventories	(50.6)	(29.6)	6.2	(94.1)	(113.0)	(86.1)	(60.0)	(30.5)
2,012.1	2,071.0	2,119.5	2.1	2.9	2.3	Gov't purchases of goods & services	2,058.9	2,088.1	2,097.7	2,094.2	2,113.3	2,129.7	2,140.9	2,138.5
752.9	797.7	836.9	1.6	6.0	4.9	Federal	785.0	810.8	822.3	820.4	832.3	842.9	852.1	856.2
1,259.0	1,274.3	1,284.7	2.3	1.2	0.8	State & local	1,274.4	1,278.7	1,277.2	1,275.6	1,283.0	1,289.0	1,291.3	1,285.0
(546.5)	(388.2)	(305.1)	-	-	-	Net exports	(381.3)	(353.1)	(356.4)	(266.0)	(274.5)	(317.5)	(362.5)	(403.6)
1,425.9	1,518.6	1,376.3	8.4	6.5	(9.4)	Exports	1,544.7	1,556.1	1,472.8	1,424.1	1,390.4	1,353.6	1,336.9	1,339.7
1,972.4	1,906.7	1,681.4	2.2	(3.3)	(11.8)	Imports	1,926.0	1,909.1	1,829.2	1,690.1	1,664.9	1,671.1	1,699.4	1,743.4
						****Income & Profits**								
$11,663.3	$12,099.1	$12,194.4	6.1	3.7	0.8	Personal income	$12,152.2	$12,159.4	$12,124.1	$12,082.2	$12,247.0	$12,199.7	$12,248.9	$12,328.2
10,170.5	10,637.0	10,869.4	5.5	4.6	2.2	Disposable personal income	10,806.0	10,690.7	10,625.9	10,684.5	10,869.8	10,937.0	10,986.1	10,972.7
0.6	1.7	5.8	-	-	-	Savings rate (%)	2.4	1.2	2.9	4.8	6.5	6.3	5.6	4.2
1,886.3	1,613.4	1,380.9	0.7	(14.5)	(14.4)	Corporate profits before taxes	1,750.0	1,693.7	1,259.0	1,355.0	1,337.8	1,385.8	1,445.0	1,569.9
1,435.9	1,241.2	1,105.3	2.2	(13.6)	(10.9)	Corporate profits after taxes	1,343.2	1,300.1	973.6	1,086.5	1,074.0	1,109.9	1,150.9	1,220.6
66.18	31.63	32.41	(18.8)	(52.2)	2.5	‡Earnings per share (S&P 500)	51.37	45.95	31.63	24.45	19.84	18.09	32.41	34.58
						†Prices & Interest Rates								
2.9	3.8	(1.7)	-	-	-	Consumer price index	5.0	6.7	(9.2)	(3.1)	(1.8)	0.2	1.4	2.7
4.4	1.4	0.2	-	-	-	Treasury bills	1.6	1.5	0.3	0.3	0.2	0.2	0.3	0.3
4.6	3.7	3.0	-	-	-	10-yr notes	3.9	3.9	3.3	2.7	2.9	3.1	3.4	3.9
4.8	4.3	3.7	-	-	-	30-yr bonds	4.6	4.4	3.7	3.8	3.5	3.7	3.9	4.3
5.6	5.6	5.7	-	-	-	New issue rate–corporate bonds	5.6	5.7	5.8	5.9	5.4	5.5	5.8	6.3
						Other Key Indicators								
1,340.7	902.4	545.4	(26.0)	(32.7)	(39.6)	Housing starts (1,000 units SAAR)	1,025.0	875.7	656.0	510.0	496.6	544.6	630.4	721.0
16.1	13.1	10.3	(2.5)	(18.4)	(21.7)	Auto & truck sales (1,000,000 units)	14.1	12.9	10.3	9.6	9.7	10.4	11.4	12.9
4.6	5.8	8.6	-	-	-	Unemployment rate (%)	5.4	6.1	6.9	7.9	8.5	9.0	9.3	9.3
(5.6)	(4.4)	10.0	-	-	-	§U.S. dollar	(6.0)	15.7	49.5	1.8	2.3	(0.9)	(1.4)	(2.8)

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

Docket No. UE-
Exhibit PPL/204
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

GDP Growth Rates

April 2009

PacifiCorp Oregon
GDP Growth Rate Forecast

	Nominal GDP	% Change	GDP Price Deflator	% Change	CPI	% Change
1948	275.2		16.6		24.1	
1949	265.2	-3.6%	16.3	-2.0%	23.6	-1.8%
1950	313.4	18.2%	17.0	4.2%	25.0	5.8%
1951	348.0	11.0%	17.9	5.6%	26.5	6.0%
1952	371.4	6.7%	18.2	1.5%	26.7	0.9%
1953	375.9	1.2%	18.3	0.8%	26.9	0.6%
1954	389.5	3.6%	18.5	0.9%	26.8	-0.4%
1955	426.0	9.4%	19.0	2.7%	26.9	0.4%
1956	448.1	5.2%	19.6	3.3%	27.6	2.8%
1957	461.5	3.0%	20.1	2.7%	28.5	3.0%
1958	485.0	5.1%	20.7	2.6%	29.0	1.8%
1959	513.2	5.8%	20.8	0.9%	29.4	1.5%
1960	523.6	2.0%	21.1	1.5%	29.8	1.4%
1961	562.5	7.4%	21.4	1.1%	30.0	0.7%
1962	593.3	5.5%	21.7	1.3%	30.4	1.2%
1963	633.5	6.8%	22.0	1.4%	30.9	1.6%
1964	675.6	6.6%	22.3	1.5%	31.3	1.2%
1965	747.5	10.6%	22.7	2.0%	31.9	1.9%
1966	807.1	8.0%	23.5	3.5%	32.9	3.4%
1967	852.8	5.7%	24.2	3.1%	34.0	3.3%
1968	936.3	9.8%	25.4	4.6%	35.6	4.7%
1969	1004.6	7.3%	26.7	5.2%	37.7	5.9%
1970	1052.9	4.8%	28.0	5.0%	39.8	5.6%
1971	1151.7	9.4%	29.3	4.7%	41.1	3.3%
1972	1287.0	11.7%	30.7	4.5%	42.5	3.4%
1973	1432.3	11.3%	32.8	6.8%	46.3	8.9%
1974	1553.4	8.5%	36.2	10.6%	51.9	12.1%
1975	1714.6	10.4%	39.0	7.6%	55.6	7.1%
1976	1885.3	10.0%	41.1	5.5%	58.4	5.0%
1977	2111.6	12.0%	43.9	6.6%	62.3	6.7%
1978	2417.0	14.5%	47.0	7.3%	67.9	9.0%
1979	2660.5	10.1%	51.1	8.7%	76.9	13.3%
1980	2916.9	9.6%	56.1	9.7%	86.4	12.4%
1981	3196.4	9.6%	60.7	8.3%	94.1	8.9%
1982	3314.4	3.7%	63.9	5.2%	97.7	3.8%
1983	3690.4	11.3%	66.0	3.4%	101.4	3.8%
1984	4036.3	9.4%	68.4	3.6%	105.5	4.0%
1985	4321.8	7.1%	70.3	2.8%	109.5	3.8%
1986	4546.1	5.2%	71.9	2.3%	110.8	1.2%
1987	4886.3	7.5%	74.0	2.9%	115.6	4.3%
1988	5253.7	7.5%	76.7	3.7%	120.7	4.4%
1989	5584.3	6.3%	79.4	3.5%	126.3	4.6%
1990	5848.8	4.7%	82.6	4.1%	134.2	6.3%
1991	6095.8	4.2%	85.2	3.1%	138.2	3.0%
1992	6484.3	6.4%	87.0	2.1%	142.3	3.0%
1993	6800.2	4.9%	89.0	2.3%	146.3	2.8%
1994	7232.2	6.4%	91.0	2.1%	150.1	2.6%
1995	7522.5	4.0%	92.7	2.0%	153.9	2.5%
1996	8000.4	6.4%	94.5	1.9%	159.1	3.4%
1997	8471.2	5.9%	95.8	1.5%	161.8	1.7%
1998	8953.8	5.7%	96.9	1.1%	164.4	1.6%
1999	9519.5	6.3%	98.4	1.5%	168.8	2.7%
2000	9953.6	4.6%	100.7	2.3%	174.6	3.4%
2001	10226.3	2.7%	103.2	2.5%	177.4	1.6%
2002	10591.1	3.6%	104.9	1.7%	181.8	2.5%
2003	11219.5	5.9%	107.2	2.2%	185.5	2.0%
2004	11948.5	6.5%	110.7	3.2%	191.7	3.3%
2005	12696.4	6.3%	114.5	3.5%	198.2	3.4%
2006	13370.1	5.3%	117.7	2.8%	203.3	2.6%
2007	14031.2	4.9%	120.7	2.6%	211.7	4.1%
2008	14264.6	1.7%	123.0	1.8%	211.5	-0.1%
10-Year Average		4.8%		2.4%		2.6%
20-Year Average		5.1%		2.4%		2.9%
30-Year Average		6.1%		3.3%		3.9%
40-Year Average		7.1%		4.1%		4.6%
50-Year Average		7.0%		3.7%		4.1%
60-Year Average		6.9%		3.4%		3.7%
Average of Periods		6.2%		3.2%		3.6%

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

Docket No. UE-
Exhibit PPL/205
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Discounted Cash Flow Analysis

April 2009

PacifiCorp Oregon
Discounted Cash Flow Analysis
Summary Of DCF Model Results

Company	Constant Growth DCF Model Analysts' Growth Rates	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 ALLETE	10.0%	11.9%	11.4%
2 Alliant Energy Co.	11.3%	11.6%	11.9%
3 Con. Edison	8.3%	12.2%	11.5%
4 DPL Inc.	15.0%	11.6%	11.4%
5 DTE Energy Co.	11.3%	12.7%	12.6%
6 Duke Energy	12.1%	12.8%	12.4%
7 Edison Internat.	10.2%	10.2%	10.0%
8 Entergy Corp.	12.1%	10.1%	9.8%
9 FPL Group, Inc.	13.9%	10.3%	10.1%
10 IDACORP	9.6%	10.5%	9.8%
11 NSTAR	11.7%	11.0%	10.9%
12 PG&E Corp.	11.6%	10.7%	10.8%
13 Portland General	12.0%	11.7%	11.7%
14 Progress Energy	11.8%	12.7%	11.8%
15 Sempra Energy	10.8%	9.9%	10.1%
16 Southern Co.	10.1%	11.4%	11.1%
17 Vectren Corp.	11.6%	11.6%	11.2%
18 Wisconsin Energy	11.9%	9.4%	10.0%
19 Xcel Energy Inc.	12.3%	11.5%	11.1%
GROUP AVERAGE	11.4%	11.2%	11.0%
GROUP MEDIAN	11.6%	11.5%	11.1%

Source: Value Line Investment Survey, Electric Utility (East), Feb 28, 2009; (Central), Dec 26, 2008; (West), Feb 6, 2009.

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

PacifiCorp Oregon
Constant Growth DCF Model
Analysts' Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				Analysts' Estimated Growth				
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	Value Line	Zacks	Thomson	Average Growth *(Cols 4-6)*	**ROE** K=Div Yld+G *(Cols 3+7)*
1 ALLETE	30.82	1.76	5.71%	0.00%	6.50%	6.50%	4.33%	10.0%
2 Alliant Energy Co.	28.01	1.50	5.35%	6.00%	6.00%	5.95%	5.98%	11.3%
3 Con. Edison	39.21	2.36	6.02%	1.00%	3.30%	2.54%	2.28%	8.3%
4 DPL Inc.	21.51	1.16	5.39%	11.00%	10.30%	7.43%	9.58%	15.0%
5 DTE Energy Co.	33.58	2.18	6.49%	5.00%	6.00%	3.50%	4.83%	11.3%
6 Duke Energy	14.86	0.98	6.59%	7.00%	5.00%	4.45%	5.48%	12.1%
7 Edison Internat.	31.10	1.25	4.02%	6.00%	7.00%	5.49%	6.16%	10.2%
8 Entergy Corp.	77.20	3.00	3.89%	7.50%	7.80%	9.42%	8.24%	12.1%
9 FPL Group, Inc.	48.89	2.00	4.09%	10.50%	9.30%	9.62%	9.81%	13.9%
10 IDACORP	28.19	1.20	4.26%	5.00%	6.00%	5.00%	5.33%	9.6%
11 NSTAR	34.28	1.63	4.75%	7.50%	7.20%	6.00%	6.90%	11.7%
12 PG&E Corp.	37.31	1.68	4.50%	7.00%	7.10%	7.10%	7.07%	11.6%
13 Portland General	18.27	1.01	5.53%	7.00%	6.30%	6.03%	6.44%	12.0%
14 Progress Energy	38.45	2.50	6.50%	5.50%	4.80%	5.54%	5.28%	11.8%
15 Sempra Energy	42.95	1.60	3.73%	7.00%	6.50%	7.59%	7.03%	10.8%
16 Southern Co.	34.43	1.78	5.17%	4.50%	5.00%	5.36%	4.95%	10.1%
17 Vectren Corp.	24.85	1.35	5.43%	5.00%	6.40%	7.20%	6.20%	11.6%
18 Wisconsin Energy	42.68	1.35	3.16%	8.00%	9.00%	9.13%	8.71%	11.9%
19 Xcel Energy Inc.	18.15	0.97	5.34%	7.50%	6.50%	6.72%	6.91%	12.3%
GROUP AVERAGE	33.93	1.65	5.05%	6.21%	6.63%	6.35%	6.40%	11.4%
GROUP MEDIAN			5.34%					11.6%

Source: Value Line Investment Survey, Electric Utility (East), Feb 28, 2009; (Central), Dec 26, 2008; (West), Feb 6, 2009.

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

PacifiCorp Oregon
Constant Growth DCF Model
Long-Term GDP Growth

	Company	(9) Recent Price(P0)	(10) Next Year's Div(D1)	(11) Dividend Yield	(12) GDP Growth	(13) ROE K=Div Yld+G *(Cols 11+12)*
1	ALLETE	30.82	1.76	5.71%	6.20%	11.9%
2	Alliant Energy Co.	28.01	1.50	5.35%	6.20%	11.6%
3	Con. Edison	39.21	2.36	6.02%	6.20%	12.2%
4	DPL Inc.	21.51	1.16	5.39%	6.20%	11.6%
5	DTE Energy Co.	33.58	2.18	6.49%	6.20%	12.7%
6	Duke Energy	14.86	0.98	6.59%	6.20%	12.8%
7	Edison Internat.	31.10	1.25	4.02%	6.20%	10.2%
8	Entergy Corp.	77.20	3.00	3.89%	6.20%	10.1%
9	FPL Group, Inc.	48.89	2.00	4.09%	6.20%	10.3%
10	IDACORP	28.19	1.20	4.26%	6.20%	10.5%
11	NSTAR	34.28	1.63	4.75%	6.20%	11.0%
12	PG&E Corp.	37.31	1.68	4.50%	6.20%	10.7%
13	Portland General	18.27	1.01	5.53%	6.20%	11.7%
14	Progress Energy	38.45	2.50	6.50%	6.20%	12.7%
15	Sempra Energy	42.95	1.60	3.73%	6.20%	9.9%
16	Southern Co.	34.43	1.78	5.17%	6.20%	11.4%
17	Vectren Corp.	24.85	1.35	5.43%	6.20%	11.6%
18	Wisconsin Energy	42.68	1.35	3.16%	6.20%	9.4%
19	Xcel Energy Inc.	18.15	0.97	5.34%	6.20%	11.5%
	GROUP AVERAGE	33.93	1.65	5.05%	6.20%	11.2%
	GROUP MEDIAN			5.34%		11.5%

Source: Value Line Investment Survey, Electric Utility (East), Feb 28, 2009; (Central), Dec 26, 2008; (West), Feb 6, 2009.

NOTE: SEE PAGE 5 OF THIS SCHEDULE 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)
				CASH FLOWS							
Company	Next Year's Div	2012 Div	Annual Change to 2012	Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	ROE=Internal Rate of Return *(Yrs 0-150)*
1 ALLETE	1.76	1.90	0.05	-30.82	1.76	1.81	1.85	1.90	2.02	6.20%	11.4%
2 Alliant Energy Co.	1.50	1.92	0.14	-28.01	1.50	1.64	1.78	1.92	2.04	6.20%	11.9%
3 Con. Edison	2.36	2.44	0.03	-39.21	2.36	2.39	2.41	2.44	2.59	6.20%	11.5%
4 DPL Inc.	1.16	1.34	0.06	-21.51	1.16	1.22	1.28	1.34	1.42	6.20%	11.4%
5 DTE Energy Co.	2.18	2.55	0.12	-33.58	2.18	2.30	2.43	2.55	2.71	6.20%	12.6%
6 Duke Energy	0.98	1.10	0.04	-14.86	0.98	1.02	1.06	1.10	1.17	6.20%	12.4%
7 Edison Internat.	1.25	1.40	0.05	-31.10	1.25	1.30	1.35	1.40	1.49	6.20%	10.0%
8 Entergy Corp.	3.00	3.30	0.10	-77.20	3.00	3.10	3.20	3.30	3.50	6.20%	9.8%
9 FPL Group, Inc.	2.00	2.30	0.10	-48.89	2.00	2.10	2.20	2.30	2.44	6.20%	10.1%
10 IDACORP	1.20	1.20	0.00	-28.19	1.20	1.20	1.20	1.20	1.27	6.20%	9.8%
11 NSTAR	1.63	1.95	0.11	-34.28	1.63	1.74	1.84	1.95	2.07	6.20%	10.9%
12 PG&E Corp.	1.68	2.04	0.12	-37.31	1.68	1.80	1.92	2.04	2.17	6.20%	10.8%
13 Portland General	1.01	1.20	0.06	-18.27	1.01	1.07	1.14	1.20	1.27	6.20%	11.7%
14 Progress Energy	2.50	2.56	0.02	-38.45	2.50	2.52	2.54	2.56	2.72	6.20%	11.8%
15 Sempra Energy	1.60	2.00	0.13	-42.95	1.60	1.73	1.87	2.00	2.12	6.20%	10.1%
16 Southern Co.	1.78	2.00	0.07	-34.43	1.78	1.85	1.93	2.00	2.12	6.20%	11.1%
17 Vectren Corp.	1.35	1.47	0.04	-24.85	1.35	1.39	1.43	1.47	1.56	6.20%	11.2%
18 Wisconsin Energy	1.35	1.95	0.20	-42.68	1.35	1.55	1.75	1.95	2.07	6.20%	10.0%
19 Xcel Energy Inc.	0.97	1.06	0.03	-18.15	0.97	1.00	1.03	1.06	1.13	6.20%	11.1%
GROUP AVERAGE											11.0%
GROUP MEDIAN											11.1%

Source: Value Line Investment Survey, Electric Utility (East), Feb 28, 2009; (Central), Dec 26, 2008; (West), Feb 6, 2009.

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

PacifiCorp Oregon
Discounted Cash Flow Analysis
Column Descriptions

Column 1: Three-month Average Price per Share (Dec 2008-Feb 2009)

Column 2: Estimated 2009 Dividends per Share from Value Line (2010 Dividends for Value Line East Companies)

Column 3: Column 2 Divided by Column 1

Column 4: "Est'd 05-07 to 11-13" Earnings Growth Reported by Value Line ("06-08 to 12-14" for Value Line East Companies)

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 PPLxx4

Column 13: Column 11 Plus Column 12

Column 14: See Column 2

Column 15: Estimated 2012 Dividends per Share from Value Line (2013 Dividends for Value Line East Companies)

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

Column 17: See Column 1

Column 18: See Column 14

Column 19: Column 18 Plus Column 16

Column 20: Column 19 Plus Column 19

Column 21: Column 20 Plus Column 16

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

Column 23: See Column 12

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

Samuel C. Hadaway
Exhibit PPL/206

Docket No. UE-
Exhibit PPL/206
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Rick Premium Analysis (Projected Interest Rates)

April 2009

PacifiCorp Oregon

Risk Premium Analysis

(Based on Projected Interest Rates)

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

INDICATED COST OF EQUITY

PROJECTED SINGLE-A UTILITY BOND YIELD*	6.91%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.15%
INTEREST RATE DIFFERENCE	-2.24%
INTEREST RATE CHANGE COEFFICIENT	-41.34%
ADUSTMENT TO AVG RISK PREMIUM	0.92%
BASIC RISK PREMIUM	3.19%
INTEREST RATE ADJUSTMENT	0.92%
EQUITY RISK PREMIUM	4.12%
PROJECTED SINGLE-A UTILITY BOND YIELD*	6.91%
INDICATED EQUITY RETURN	**11.03%**

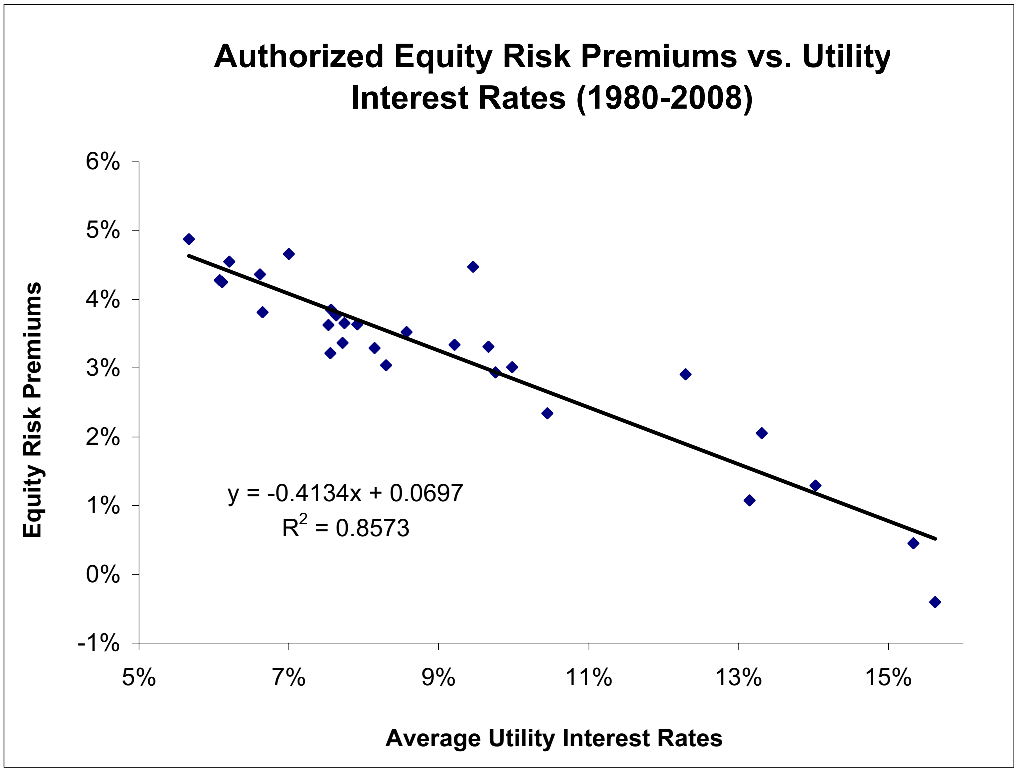
(1) Moody's Investors Service

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

*Projected single-A bond yield is 321 basis points over projected long-term Treasury bond rate of 3.7% from Exhibit PPLxx3, p. 3. The single-A spread is for 3 months ended Feb 2009 from Exhibit PPLxx3, p. 2.

PacifiCorp Oregon

Risk Premium Analysis



Docket No. UE-
Exhibit PPL/207
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Risk Premium Analysis (Current Interest Rates)

April 2009

PacifiCorp Oregon

Risk Premium Analysis

(Based on Current Interest Rates)

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

INDICATED COST OF EQUITY

CURRENT SINGLE-A UTILITY BOND YIELD*	6.40%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.15%
INTEREST RATE DIFFERENCE	-2.75%
INTEREST RATE CHANGE COEFFICIENT	-41.34%
ADUSTMENT TO AVG RISK PREMIUM	1.14%
BASIC RISK PREMIUM	3.19%
INTEREST RATE ADJUSTMENT	1.14%
EQUITY RISK PREMIUM	4.33%
CURRENT SINGLE-A UTILITY BOND YIELD*	6.40%
INDICATED EQUITY RETURN	**10.73%**

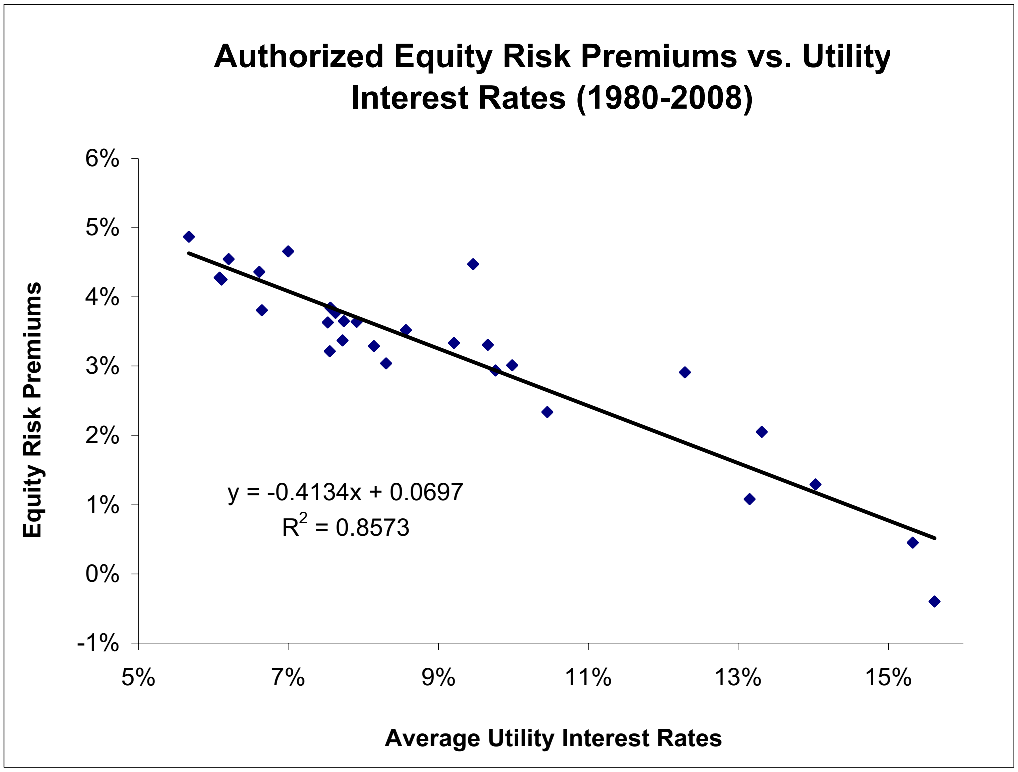
(1) Moody's Investors Service

(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 February 2009 from Exhibit PPLxx3, p. 2.

PacifiCorp Oregon

Risk Premium Analysis



Docket No. UE-
Exhibit PPL/300
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Bruce N. Williams

April 2009

Q. Please state your name, business address and present position with PacifiCorp (the 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. Briefly 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 June 1980. I also received the Chartered Financial Analyst designation upon passing the examination in September 1986. I have been employed by the Company for 23 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, pension and other investment management activities. I am also responsible for the preparation of PacifiCorp'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.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I first present a financing overview of the Company. Next, I discuss the planned amounts of common equity, debt, and preferred stock to be included in the Company's proposed capital structure. I then analyze the embedded cost of debt and preferred stock supporting PacifiCorp's electric operations in the state of Oregon as of January 1, 2010. This analysis includes the use of forward interest rates, the historical relationship of security trading patterns, and known and measurable changes to the debt and preferred stock portfolios.

Q. What time period do your analyses cover?

A. The test period in this proceeding is the twelve months ending December 31, 2010 with new rates expected to be effective on February 3, 2010. To appropriately match the Company's costs with customers' prices, the capital structure and costs of debt and preferred applied in this case are those measured at the end of the quarter prior to the effective date of the new rates. Accordingly, I have utilized December 31, 2009 as the date for determining capital structure and costs of debt and preferred stock. I determined the embedded cost of debt and preferred stock using the Company's actual costs adjusted for changes through December 31, 2009, as I later detail in this testimony.

Q. Please explain the Company's requirements to generate new capital.

A. As described in Mr. Richard P. Reiten's testimony, the Company is in the process of completing or adding significant new generation resources as well as local distribution facilities. For example, the Company is proposing to add over $2.8

billion in capital additions to its total company rate base from the historical base period level. These and future capital additions will require the Company to raise funds by issuing significant amounts of new long-term debt in the capital markets and obtaining new capital contributions from its parent company. Funds will also be made available by the continued absence of any dividends or distributions by PacifiCorp to its parent company during the period. Since the acquisition of PacifiCorp by MidAmerican Energy Holdings Company ("MEHC") in March 2006, there have been no common stock dividends or distributions, PacifiCorp has received $865 million in additional cash equity contributions from MEHC and $1.1 billion of earnings have been retained in PacifiCorp. These actions help ensure that PacifiCorp remains well-positioned to support the additional investments that have been and will continue to be made in the system.

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

A. PacifiCorp is proposing an overall cost of capital of 8.55 percent. This cost includes the Return on Equity recommendation 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	48.5%	5.98%	2.90%
Preferred Stock	0.3%	5.41%	0.02%
Common Stock Equity	51.2%	11.00%	5.63%
Total	100.0%		8.55%

Financing Overview

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

A. The Company finances the cash flow requirements of its regulated utility operations utilizing a reasonable mix of debt and equity designed to provide a competitive cost of capital and predictable capital market access.

Q. How does the Company meet its debt and preferred equity financing requirements?

A. The Company relies on a mix of first mortgage bonds, other secured debt, tax-exempt debt, unsecured debt and preferred stock to meet its long-term debt and preferred stock financing requirements.

The Company has completed the majority of its long-term financing utilizing secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit PPL/301 shows that, as of December 31, 2009 the Company is projected to have approximately $5.6 billion of first mortgage bonds outstanding, with an average cost of 6.37 percent and average remaining maturity of 19 years. 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, the Company borrows the proceeds and guarantees the repayment of the long-term debt in order to take advantage of their tax-exempt status in financings. As of December 31, 2009 the Company's tax-exempt portfolio is projected to be $738 million in principal amount with an average cost of 3.00 percent (which includes the cost of issuance and credit enhancement).

Capital Structure

Q. How did the Company determine the capital structure proposed in this proceeding?

A. The capital structure is based on the actual capital structure at December 31, 2008, which comprised 51.7 percent equity, 47.9 percent debt and 0.4 percent preferred, and then adjusted for known and measurable changes through December 31, 2009. These changes, which decrease the Company's equity to 51.2 percent and increase debt to 48.5 percent, include the recently completed issuance of new long-term debt, maturities of certain debt that was outstanding at December 31, 2008, capital contributions and retained earnings. This is the same methodology that was used in the Company's most recent general rate case in Oregon Docket UE 179.

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 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 and risk. Significant capital expenditures for new plant investment, including new renewable resources, operating and maintenance costs for new and existing utility plant assets and environmental investments are required for the Company to fulfill this obligation. Through its planning process, the Company determined the amounts of necessary new financing needed to support these activities and calculated the required equity and debt ratios required to maintain our current 'A-' credit rating for senior secured debt.

Q. Has the Company's capital structure demonstrated increased amounts of equity in the last three years?

A. Yes. Following the acquisition by MEHC the Company has received a total of $865 million of cash capital contributions from MEHC via the Company's direct parent company, PPW Holdings, LLC and has retained $1.1 billion of earnings as noted earlier in my testimony.

Q. Why is there the need for additional equity in the capital structure?

A. The Company's capital structure reflects the significant new capital investments described in this case. These new costs, coupled with the credit rating agencies' expectations for credit metrics and balance sheet strength, mean that the Company cannot finance itself solely with new debt. Additional equity is required along with improved business results and other considerations to support our current 'A-' credit rating from Standard & Poor's ("S&P"), 'A3' rating from Moody's Investors Service ("Moody's"), and 'A-'from Fitch Ratings.

Q. How does this projected capital structure compare to comparable electric utilities?

A. The projected capital structure is in-line with the comparable group that Dr. Hadaway has selected in his estimate of Return on Equity. The Value Line three to five year estimate of common equity ratio for the comparable group is 50.3 percent.

Q. Please describe the changes to the Company's levels of debt financing.

A. During the period ending December 31, 2009, the balance of the outstanding long-term debt will change through maturities, principal amortization and issuance of new securities. Based upon the long-term debt series outstanding at December 31, 2008, I have calculated the reduction to the outstanding balances for maturities, principal amortization and sinking fund requirements which are scheduled to occur during the period ending December 31, 2009. Additionally, the capital structure reflects a $1.0 billion long-term debt issuance that occurred in January 2009, the details of which I discuss later in this testimony. I then adjusted the interest rate on the $14.6 million of long-term debt that will mature during 2010 to reflect expected refinancing rates. This adjustment is consistent with the Commission practice set forth in Order No. 01-787 and was also followed in UE 179.

Q. There is a one-month lag between the end of the test period and the rate effective period in this case. Is there any material difference between measuring the cost of debt at the end of the test period or the beginning of the rate effective period?

A. No. If the cost of debt were measured as of the rate effective date of February 3, 2010, this would capture long-term debt maturities through January 2011, rather than through December 2010 as modeled in this case. Because there are no long-term maturities in January 2011, however, the timing issue is immaterial.

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 while maintaining credit ratios that support the continuance of our current 'A-' credit rating.

Q. Are PacifiCorp's stand-alone credit metrics consistent with the Company's current credit ratings?

A. No. As stated by S&P "While the…. utility's credit metrics are more consistent on a standalone basis with a 'BBB' category rating, the ratings benefit from the implicit and explicit support available to MEHC… from its parent, Berkshire Hathaway…. As a result, the ratings assigned to PacifiCorp are higher than would be warranted…." Clearly, PacifiCorp and our customers benefit from the ownership by MEHC and its parent, Berkshire Hathaway. 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. Absent ownership by MEHC and constructive regulatory treatment, PacifiCorp's credit ratings would likely suffer at least a one rating level downgrade. At the time this testimony was finalized, PacifiCorp's ratings were under review by S&P. If any changes result from this review, the Company will inform parties to this proceeding.

Q. How does maintenance of the Company's current credit rating benefit customers?

A. The credit rating given to 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. A solid credit rating directly benefits customers by reducing immediate and future borrowing costs related to the financing needed to support regulatory operations.

Q. Are there other benefits?

A. Yes. During periods of capital market disruptions, higher-rated companies are more likely to have on-going, uninterrupted access to capital. This is not always the case with lower-rated companies, which during such periods find themselves either unable to secure capital or able to secure capital only on unfavorable terms and conditions. I will discuss how PacifiCorp's current ratings have assisted it in recently accessing the market for new long-term debt at attractive levels later in my testimony.

In addition, higher-rated companies have greater access to the long-term markets for power purchases and sales. Such access provides these companies with more alternatives when attempting to meet the current and future load requirements of their customers. Finally, 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.

Impacts of Economic Crisis on PacifiCorp

Q. How has the recent liquidity or credit crisis impacted PacifiCorp?

A. Very significantly. Although the Company has been able to continue to fund its working capital and long-term needs, it has been anything but "business as usual." For example, at times during October 2008 the Company was unable to find investors for its commercial paper. Fortunately, the Company had previously arranged multi-year, committed revolving credit agreements and was able to borrow under those facilities in order to provide liquidity and daily cash needs normally met by the commercial paper markets. At the times when the commercial paper market was available, rates were significantly higher than just a few months earlier. During November 2008, the Company's commercial paper rates were at an average spread of approximately 250 basis points (2.50 percent) higher than issuances through the middle of July 2008. While recent short-term funding for the Company has modestly improved from these harsh conditions, the Company is largely limited to overnight commercial paper issuances rather than a range of maturities of up to 270 days as in prior markets.

Similar to the commercial paper market, the market for tax-exempt debt was also "frozen" for a period of time. As I discussed earlier in this testimony, the Company has arranged over $700 million of low-cost tax exempt financing. A portion of this debt is variable rate and re-prices through periodic remarketings. However, this market also was shaken by the credit crisis resulting in extremely high resets of interest rates or failed remarketings when there was insufficient investor demand. PacifiCorp chose to acquire approximately $216 million of these obligations to avoid paying rates that were unimaginable just a few months earlier. The Company recently completed the remarketing of these bonds following a change to their credit enhancements including the addition of letters of credit for the benefit of investors. Other utilities have found this market is now totally closed to them and are delaying previously scheduled tax-exempt bond offerings. Fortunately, PacifiCorp enjoys the benefits of sound credit ratings and was able to lessen the impact on customers by temporarily acquiring the bonds, arranging for these letters of credit despite extremely difficult conditions for the banks themselves and then remarketing the bonds.

Q. Was PacifiCorp able to issue new long-term debt during this period?

A. Yes. In early January 2009, the Company issued $350 million of first mortgage bonds with a ten year maturity at a coupon rate of 5.50 percent and $650 million of thirty year first mortgage bonds with a coupon of 6.00 percent.

Q. What are your observations about this long-term debt issuance?

A. First, the issuance demonstrated the importance of PacifiCorp's solid investment grade credit ratings during a period of time in which the markets have been extremely volatile. Many lower rated issuers have not been able to access the debt markets or have found the terms and conditions prohibitive. The Company's sound investment grade rating has allowed it continued access to the credit markets, although at credit spreads higher than historical levels.

Second, as noted in Dr. Hadaway's testimony, recent increases in credit spreads have impacted the Company's cost of equity and debt. His testimony includes a table that shows recent utility debt issuances and their corresponding credit spreads. While the Company's credit spread of 3.10 percent on its recent long term debt issuance is better than the range seen in recent issuances by other utilities, it is still among the highest credit spreads the Company has experienced.

Q. How do the terms of PacifiCorp's debt issuance compare to other recent utility debt issuances?

A. PacifiCorp was able to issue debt at interest rates below rates that other borrowers have achieved. For example, Nevada Power (rated Baa3/BBB) issued new debt two days following PacifiCorp and was required by investors to pay a coupon of 7.375 percent for a five-year maturity. More recently, Puget Sound Energy (rated Baa2/A-) issued new seven year debt at a spread of Treasuries plus 480.3 basis points resulting in a coupon 6.75 percent. In addition, lower rated borrowers were shut out entirely from the market. For example, Arizona Public Service Company (rated Baa2/BBB-) filed a letter with the Arizona Corporation Commission explaining that the commercial paper market is completely closed to them and, they likely could not successfully issue long-term debt. (See Exhibit PPL/302.)

Q. What do you conclude from this comparison?

A. This recent period of market volatility has underscored the critical importance to utilities of maintaining solid credit ratings. Lower-rated utilities are now paying dearly for their more tenuous credit positions because they cannot access capital or can do so only at very high prices. This confirms the importance of PacifiCorp's ongoing plan to maintain a balanced capital structure. It also highlights PacifiCorp's need for supportive and constructive treatment from its regulatory commissions.

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. They do so in order to obtain a more accurate assessment of a company's financial commitments and fixed payments. Exhibit PPL/303 is the May 12, 2003 publication by S&P detailing its view of the debt aspects of PPAs which was refined in the March 30, 2007 publication (Exhibit PPL/304).

Q. How does this impact the Company?

A. During a recent ratings review, S&P evaluated the Company's PPAs and other related long-term commitments. Approximately $450 million of additional debt and related interest expense were added to the Company's debt and coverage tests as a result of PPAs.

Q. How would the inclusion of this PPA related debt affect the Company's capital structure?

A. By including the $450 million imputed debt resulting from PPAs, the Company's capital structure would have a lower equity component as a corollary to the higher debt component.

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. 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 in the event a bond was issued to refinance a higher cost bond, 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. The 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. 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. This is the result of dividing the annual dividend rate by the per share net proceeds for each series of preferred stock. The cost 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. This 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 majority of the Company's variable rate long-term debt is in the form of tax-exempt debt. Exhibit PPL/305 shows that these securities on average had been trading at approximately 85 percent of the 30-day LIBOR (London Inter Bank Offer Rate) for the period January 2000 through December 2008. Therefore, the Company has applied a factor of 85 percent to the forward 30-day LIBOR Rate at December 31, 2009 of 1.72 percent 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 which 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 PacifiCorp.

Embedded Cost of Long-Term Debt

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

A. The cost of long-term debt is 5.98 percent, at December 31, 2009 as shown in

Exhibit PPL/301. As noted above, this includes the Company's January 2009, debt issuance. The Company does not presently expect to issue any significant new debt between the time of this filing and December 31, 2009.

Embedded Cost of Preferred Stock

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

A. Exhibit PPL/306 shows the embedded cost of preferred stock at December 31, 2009 at 5.41 percent.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Embedded Cost of Long Term Debt

April 2009

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

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	**$5,633,973,000**	**($59,191,887)**	**($32,177,777)**	**$5,542,603,335**	**$358,907,262**	**6.212%**	**6.370%**	**23.5**	**18.7**	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$14,310,270	3.260%	3.573%	28.0	11.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$7,809,876	2.131%	2.311%	27.8	8.2	5
6	**Total Pollution Control Revenue Bond**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$22,120,146**	**2.743%**	**2.996%**	**27.9**	**10.0**	6
7											7
8	**Total Cost of Long Term Debt**	**$6,372,343,000**	**($74,046,929)**	**($49,349,200)**	**$6,248,946,871**	**$381,027,408**	**5.810%**	**5.979%**	**24.1**	**17.7**	8
9											9

Exhibit PPL/301
Williams/2

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

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	19	1	$4,422,000	$412,000	$0	$0	$412,000	$100.000	7.978%	$32,869	3
4	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	2	$19,772,000	$3,590,000	$0	$0	$3,590,000	$100.000	8.493%	$304,899	4
5	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	20	2	$16,203,000	$4,247,000	$0	$0	$4,247,000	$100.000	8.797%	$373,609	5
6	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	21	3	$28,218,000	$9,301,000	$0	$0	$9,301,000	$100.000	8.734%	$812,349	6
7	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	21	3	$46,946,000	$17,918,000	$0	$0	$17,918,000	$100.000	8.294%	$1,486,119	7
8	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	22	4	$18,750,000	$8,318,000	$0	$0	$8,318,000	$100.000	8.635%	$718,259	8
9	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	5	$19,609,000	$9,585,000	$0	$0	$9,585,000	$100.000	8.470%	$811,850	9
10	**8.506%**	**Subtotal - Amortizing FMBs**			**21**	**3**		**$53,371,000**	**$0**	**$0**	**$53,371,000**		**8.506%**	**$4,539,954**	10
11															11
12	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	2	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	$98.932	7.051%	$35,255,000	12
13	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	4	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.961%	$11,922,000	13
14	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	5	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	14
15	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	22	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	15
16	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	25	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	16
17	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	25	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	17
18	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	27	$350,000,000	$350,000,000	($4,048,711)	$0	$345,951,289	$98.843	6.185%	$21,647,500	18
19	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	27	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	19
20	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	28	$600,000,000	$600,000,000	($5,873,367)	$0	$594,126,633	$99.021	6.323%	$37,938,000	20
21	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	9	$500,000,000	$500,000,000	($3,827,364)	$0	$496,172,636	$99.235	5.752%	$28,760,000	21
22	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	29	$300,000,000	$300,000,000	($3,874,418)	$0	$296,125,582	$98.709	6.448%	$19,344,000	22
23	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	9	$350,000,000	$350,000,000	($4,795,000)	$0	$345,205,000	$98.630	5.681%	$19,883,500	23
24	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	29	$650,000,000	$650,000,000	($12,285,000)	$0	$637,715,000	$98.110	6.139%	$39,903,500	24
25	6.320%	Pro Forma Series	12/31/09	12/31/39	30	30	$14,602,000	$14,602,000	($146,020)	$0	$14,455,980	$99.000	6.395%	$933,798	25
26	**6.037%**	**Subtotal - Bullet FMBs**			**23**	**20**		**$5,064,602,000**	**($54,934,666)**	**($7,263,815)**	**$5,002,403,520**		**6.157%**	**$311,825,298**	26
27															27
28	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	2	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	28
29	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.022%	$1,804,400	29
30	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	30
31	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	31
32	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	2	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	32
33	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	2	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	33
34	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	2	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	34
35	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	2	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.925%	$297,750	35
36	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	12	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	36
37	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	12	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	37
38	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	12	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	38
39	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	12	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	39
40	**8.766%**	**Subtotal - Series C MTNs**			**23**	**4**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,383,170**	40
41															41
42	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	3	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	42
43	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	13	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	43
44	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	13	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	44
45	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	45
46	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	46
47	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	13	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	47
48	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	48
49	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	49
50	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	13	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	50
51	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	13	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	51
52	**8.100%**	**Subtotal - Series E MTNs**			**29**	**12**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	52
53															53

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

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
54	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	54
55	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	55
56	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	56
57	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	57
58	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	58
59	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	59
60	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	60
61	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	61
62	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	62
63	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	63
64	**7.044%**	**Subtotal - Series F MTNs**			**30**	**14**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	64
65															65
66	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	16	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	66
67	**6.710%**	**Subtotal - Series G MTNs**			**30**	**16**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	67
68															68
69	**6.212%**	**Total First Mortgage Bonds**			**24**	**19**		**$5,633,973,000**	**($59,191,887)**	**($32,177,777)**	**$5,542,603,335**		**6.370%**	**$358,907,262**	69
70															70
71		**Pollution Control Revenue Bonds**													71
72	2.139%	Moffat 94 due May 2013	11/17/94	05/01/13	18	3	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	2.295%	$933,032	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	4	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	5	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	3.645%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	6	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	4.125%	$1,856,250	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	7	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	12	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	14	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	14	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	79
80	2.079%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	15	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	2.209%	$206,873	80
81	2.080%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	15	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	2.246%	$183,947	81
82	2.046%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	15	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	2.242%	$2,733,895	82
83	2.187%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	15	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	2.344%	$353,006	83
84	2.059%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	15	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	2.187%	$464,956	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	16	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	16	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.442%	$977,240	86
87	**3.260%**	**Subtotal - Secured PCRBs**			**28**	**12**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**3.573%**	**$14,310,270**	87
88															88
89	2.024%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	4	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	2.236%	$257,140	89
90	2.024%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	6	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	2.132%	$1,492,400	90
91	2.025%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	6	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	2.447%	$1,101,150	91
92	2.052%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	7	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	2.174%	$1,087,000	92
93	2.024%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	8	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	2.165%	$974,250	93
94	2.024%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	8	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	2.174%	$895,688	94
95	1.563%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	11	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.672%	$375,949	95
96	1.563%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	11	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.708%	$159,442	96
97	1.563%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	11	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.742%	$109,833	97
98	2.022%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	16	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	2.144%	$523,136	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	21	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	99
100	**2.131%**	**Subtotal - Unsecured PCRBs**			**28**	**8**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**2.311%**	**$7,809,876**	100
101															101
102	**2.743%**	**Total PCRB Obligations**			**28**	**10**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.996%**	**$22,120,146**	102
103															103
104	**5.810%**	**Total Long-Term Debt**			**24**	**18**		**$6,372,343,000**	**($74,046,929)**	**($49,349,200)**	**$6,248,946,871**		**5.979%**	**$381,027,408**	104
105															105

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Letter from Arizona Public Service Company
Filed with the Arizona Corporation Commission

April 2009

ORIGINAL

RECEIVED

2008 OCT 17 P 3: 28

AZ CORP COMMISSION
DOCKET CONTROL

0000089812

Exhibit/302
Williams/1

PINNACLE WEST
CAPITAL CORPORATION

LAW DEPARTMENT

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

October 17, 2008

Arizona Corporation Commission
DOCKETED
OCT 17 2008
DOCKETED BY

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

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[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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Gary Pierce
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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 27^{th} to October 1^{st} – 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

APS Revolving Lines of Credit
($K)

	Bank	Amount	% of Total
1	Bank of America	$92,857	10.3%
2	Bank of New York Mellon	80,000	8.9%
3	Citigroup	76,572	8.5%
4	JPMorgan	76,572	8.5%
5	Keybank	68,571	7.6%
6	CSFB	60,857	6.7%
7	Barclays Bank	52,857	5.9%
8	Wells Fargo	52,857	5.9%
9	UBS Warburg	52,857	5.9%
10	Union Bank	38,571	4.3%
11	Sun Trust	36,000	4.0%
12	Mizuho	28,571	3.2%
13	KBC Bank	24,000	2.7%
14	Dresdner	24,000	2.7%
15	US Bank	17,143	1.9%
16	Chang Hwa Commercial Bk	15,000	1.6%
17	BOTM	11,429	1.3%
18	Northern Trust	11,429	1.3%
19	Bank Hapoalim	10,000	1.1%
20	Subtotal	$830,143	92.3%
21	Wachovia	36,000	4.0%
22	Lehman Brothers	33,857	3.7%
23	Total	$900,000	100.0%

Bruce N. Williams
Exhibit PPL/303

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

May 12, 2003 Standard & Poor's Publication
"Buy vs. Build: Debt Aspects of Purchased-Power Agreements"

April 2009

Exhibit PPL/303
Williams/1

May 12, 2003
Vol. 12, No. 19

Standard & Poor's UTILITIES & PERSPECTIVES

GLOBAL UTILITIES RATING SERVICE

STANDARD & POOR'S

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity

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component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	**%**	**$**	**%**
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage		Adjusted pretax interest coverage	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build—i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%—10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (48 plus 11). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means. ■

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High Commodity Prices Bode Well For Stone Energy's Cash Flow

Independent oil and gas company Stone Energy Corp. (BB/Stable/—) is poised to generate strong free cash flow in 2003 as a result of very strong commodity prices recorded during the first quarter and the likelihood that they will remain higher than average for the remainder of the year. Based on Standard & Poor's Ratings Services commodity pricing assumptions for 2003, which is $24 per barrel for West Texas Intermediate crude oil and $4.00 per thousand cubic feet equivalent (mcfe) for Henry-Hub-traded natural gas, Stone should generate in excess of $300 million of operating cash flow, compared with the company's projected capital spending budget of about $240 million. Although Stone may initially use this free cash flow to pay down debt, the liberated liquidity likely will be used to fund potential acquisitions.

The ratings on Lafayette, La.-based Stone Energy reflect the challenges the company faces as a participant in the volatile, capital-intensive exploration and production segment of the oil and natural gas industry, with a short reserve life, the bulk of its assets located in high-cost regions, and somewhat aggressive financial policies. These risks are tempered by low production costs, a proven exploration staff, and a high percentage of company-operated properties.

Stone's proved reserves as of Dec. 31, 2002 were 750.8 billion cubic feet equivalent (58% gas; 24% proved undeveloped). The company's reserves are concentrated in the Gulf of Mexico and Gulf Coast (93% of Stone's total proven reserves and 95% of production), where reserves generally deplete rapidly. Stone's remaining assets are in the Rocky Mountains. Stone intends to expand these assets because of the opportunity to modestly diversify its reserve base with longer-lived properties.

Standard & Poor's expects that Stone will produce about 300 million cubic feet equivalent (mmcfe) per day in 2003, compared with 286 mmcfe per day in 2002, yielding a short reserve life (total proved) of about 7.1 years. Stone's short reserve life heightens the importance of consistent investment to maintain production and replace produced reserves, and could necessitate external financing to sustain production and maintain reserves if hydrocarbon prices fall to lower-than-normal levels.

Stone somewhat compensates for its short reserve life through its acreage position, demonstrated exploration skills, and maintenance of capital available for acquisitions. Although Stone did not fully replace reserves in 2002 (replacing 79% of production), Stone's management believes that this is an anomaly because Stone generally replaces its reserves through a combination of drilling and complimentary acquisitions. During 2002, Stone did not complete any material acquisitions. Over the past five years (1998 through 2002), Stone on average replaced 171% of its production at an average cost of $2.50 per mcfe, with 124% provided through the drillbit and the balance through acquisitions. Stone's average all-sources finding and development costs are high compared with onshore operators, because of the higher capital costs associated with working in coastal waters. However, the economics of Stone's Gulf of Mexico properties may be better than lower-cost onshore operators because of premium realized prices and the fast-producing nature of the properties. These factors also contribute to low unit cash production costs; in 2003, Stone is expected to maintain its highly competitive lease operating and general and administrative expenses of about 60 cents per mcfe and 10 cents per mcfe, respectively.

Stone's capital structure is adequate for the rating category, even after considering the incurrence of about $300 million of acquisition-related debt in 2001. As of Dec. 31, 2002, total debt-to-total capital was 43%, when compared with 22% in 2000. In 2003, improvement in debt leverage is expected from increased retained earnings. Cash flow and profitability measures in 2003 should improve markedly because of strong hydrocarbon prices. Furthermore, the company has reduced the risks to its cash flow of pricing declines through attractively priced commodity price hedging (about 30% of production). For the medium term, even in a low commodity price environment, Stone should be capable of delivering EBITDA interest coverage of more than 9x and funds from operations in excess of 50%. In 2003, assuming a NYMEX natural gas price of $24 per barrel for West Texas Intermediate crude oil and $4.00 per mcfe for Henry-Hub-traded natural gas, Stone should generate more than $300 million of operating cash flow, which should fully fund the company's projected capital spending budget of about $240 million.

As of March 10, 2003, Stone's liquidity consisted of cash balances and short-term investments of $28 million and about $161 million available on its $350 million ($300 million borrowing base) unsecured facility. These sources should provide the company with adequate near-term liquidity as the company does not intend to outspend internal cash flow and has no near-term debt maturities until December 2004, when the credit facility matures.

Full availability of Stone's revolving credit facility is likely because the company is easily outperforming its financial covenants that include a maximum consolidated debt-to-EBITDA ratio of 3.25x.

The stable outlook reflects Standard & Poor's expectations for Stone to pursue production growth funded with internally generated funds and, when possible, reduce leverage to a more appropriate level for Stone's production profile. Stone is expected to remain acquisitive, but such transactions should be financed conservatively. ■

Steven Nocar
New York (1) 212-438-7803

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Survey of State Regulators Reveals Focus on U.S. Utilities' Financial Strength

A recently completed survey of state regulators by RKS Research & Consulting on behalf of Standard & Poor's Ratings Services revealed significant shifts in regulator priorities since the previous survey of January 2001. The feedback from the interviews, which polled 47 different jurisdictions, placed financial issues as the most important consideration for regulators, followed by federal-state jurisdictional disputes, and generation and transmission resource adequacy. Other topics included reliability and power quality issues, service obligations, and subsidization of affiliate transactions. Regarding concerns over the next five to 10 years, respondents focused on jurisdictional clarity and resource adequacy, which would indicate that financial concerns are expected to dissipate in this time frame. Two years ago, the primary issues noted by regulators were considerably different: the development of distributed generation and service reliability led the list, followed by transmission issues.

The responses indicate that utilities' financial profiles matter greatly to state regulators, at least in the short term. Regulators overwhelmingly stated that utilities need to maintain strong financial profiles. In fact, regulators highlighting this concern increased threefold, and more than a third expressed extreme concern for utilities' financial health, compared with less than 10% in 2001. Along with this position was the view by almost half of the respondents that utilities had weakened during the past three years, particularly those in the Midwest and the West. Reasons cited for this included the economic downturn, bad investment decisions, holding company/affiliate transactions, and the fallout from the California and Enron Corp. crises. However, about half of the Northeastern state regulators believe that utilities have actually strengthened, reflecting the conversion of many utilities to basically lower-risk transmission and distribution companies. Not surprisingly, only half of all commissioners said they had as much confidence in the integrity of utility financial statements compared with a few years ago. Interestingly, a measurable number—17%—indicated a higher confidence level in financial statement quality; 26% have less confidence.

State regulators clearly expect to be more involved in monitoring utilities in their jurisdictions. However, while utilities' financial conditions, and more specifically, their insulation from nonregulated activities, ranked first among the most pressing issues, opinion is evenly divided regarding whether current laws provide the appropriate enabling authority for regulators to ensure that utilities are not adversely affected by unregulated affiliates.

Other issues of note include:

- Deep jurisdictional disputes with the FERC over Standard Market Design (SMD). The majority consider SMD fatally flawed, and that it will lead to wide inequities between high- and low-cost electricity regions. Respondents highlighted inflexibility, cost-shifting among states, and whether any compelling need for SMD actually exists. A majority also expressed doubt that the proposal would ever deliver the promised results.
- Broad agreement that restructuring has stalled, along with increasing support for a return to cost-of-service regulation.
- Concerns that regional transmission systems are less than fully adequate.
- A plurality that is opposed to the repeal of the Public Utility Holding Company Act, especially by those states that do not provide retail choice.

Standard & Poor's views regulators' heightened concern, and their cognizance of the fact that unregulated parents' and affiliates' business pursuits have negatively affected utilities' credit quality, as encouraging. However, the general sense that current laws and regulations limit regulators' abilities to intervene tends to neutralize the value of such recognition. Indeed, Standard & Poor's has witnessed certain states, such as Minnesota, Arizona, and Kansas, becoming engaged in overseeing the financial activities and decisions of their utilities. While utilities and their parents may remain focused on a "back-to-basics" strategy, it is not clear that over the longer term such a strategy will hold. If it fails, and in a few years the industry is again diversifying its strategy to attract higher P/E ratios, regulators may be left on the sidelines again to wonder what happened to their regulated utilities. ■

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(Ordering information for copies of the Standard & Poor's 2003 Survey of State Regulators is available from Richard Claeys, RKS-West at dclaeys@rksresearch.com or at (1) 408-867-6430.)

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Laclede Group's and Unit's Ratings Are Lowered; Outlook Stable

On May 5, Standard & Poor's Ratings Services lowered its long-term corporate credit ratings on parent The Laclede Group Inc.'s and Laclede Gas Co. to 'A' from 'A+'.

Standard & Poor's also affirmed its 'A-1' short-term corporate credit rating and commercial paper ratings on Laclede Gas. The outlook is stable.

St. Louis, Mo.-based Laclede Group has about $260 million of outstanding long-term debt.

The rating action reflects subpar financial measurements relative to former credit quality. The financial weakness can be traced primarily to several successive warmer-than-normal winters and higher debt leverage.

Notwithstanding recent financial improvement, including the refinancing of Laclede Group's $45 million bridge loan with hybrid preferred-stock securities (to which Standard & Poor's accords some equity treatment) and resolution of several regulatory issues, the company's prospective consolidated financial condition is expected to approach levels that are suitable for the revised rating.

Standard & Poor's believes that ratings stability reflects expectations for financial improvement, solid competitive standing, flexible supply position, abundant storage capacity, a stable customer base, and prospects for modest rate relief. These attributes are somewhat offset by Laclede Group's support of riskier unregulated affiliates. ■

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Sierra Pacific Power's Water Facilities Bond Rating Is Raised to 'BB'

On May 5, Standard & Poor's Ratings Services raised its rating on Sierra Pacific Power Co.'s $80 million Washoe County water facilities refunding revenue bonds to 'BB' from 'B-'.

The upgrade reflects the backing of the previously unsecured bonds by Sierra Pacific Power's general and refunding bonds as part of the current remarketing.

The tax-exempt bonds, for which Sierra Pacific Power is the obligor, mature in 2036, but are remarketed periodically to reset interest rates. The company will set rates for only one year because Sierra Pacific Power has only short-term authority to issue general and refunding bonds.

Reno, Nevada-based Sierra Pacific Power had $1.02 billion in debt outstanding as of Dec. 31, 2002. Its 'B+' corporate credit rating reflects the consolidated credit profile of Sierra Pacific Resources and its utility subsidiaries, Nevada Power Co. and Sierra Pacific Power. The rating factors in the adverse regulatory environment in Nevada; operating risk from Nevada Power's dependence on wholesale markets for over 50% of its energy requirements; and the substantially weakened financial profile resulting from the disallowance in 2002 by the Public Utility Commission of Nevada (PUCN) of $434 million in deferred-power costs for Nevada Power and $56 million for Sierra Pacific Power. The recent federal court decision denying Nevada Power's request to recover the $437 million disallowed by the PUCN did not affect ratings because Standard & Poor's had not factored into the current ratings any positive outcome from the litigation.

The negative outlook reflects the risk of an adverse ruling either by the PUCN on Nevada Power's pending deferred cost recovery case or by the court on the Enron Corp. lawsuit. Enron is demanding payment of about $300 million in marked-to-market profits on power supply contracts with Nevada Power that Enron terminated following Nevada Power's downgrade in April 2002. ■

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Empresa Electrica Guacolda Ratings Are Affirmed; Off Watch

On May 2, Standard & Poor's Ratings Services affirmed its 'BBB-' corporate credit rating on Chilean power generator Empresa Eléctrica Guacolda S.A. (Guacolda), and removed the rating from CreditWatch with negative implications. The outlook is stable. The rating was originally placed on CreditWatch on April 3, 2003 due to high refinancing risk.

The rating action follows the company's announcement that it has successfully placed $150 million in senior amortizing secured loan participation certificates with final maturity in 2013. Proceeds were mainly applied to refinance its $87 million net debt maturities on April 30, 2003, and to prepay its $48.8 outstanding debt with Mitsubishi Corp.

The new $150 million facility significantly reduces Guacolda's refinancing risk and leaves a debt structure much more in accordance with the company's cash flow projections.

Although cash reserves are low, Guacolda does not face important capital expenditures or large capital amortizations in the next two to three years. Guacolda has been applying

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excess cash flows to debt reduction in recent years—total financial debt has decreased to $192 million as of December 2002 from $215 million as of December 2001. However, Guacolda's leverage remains at high levels (62.9% as of December 2002), mainly due to the devaluation of the Chilean peso. ■

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Spanish Utilities Gas Natural, Iberdrola Ratings Are Affirmed; Off Watch

On May 6, Standard & Poor's Ratings Services affirmed its 'A+' long-term and 'A-1' short-term corporate credit ratings on Spanish utilities Gas Natural SDG S.A. and Iberdrola S.A., and removed the long-term ratings on both from CreditWatch, where they were placed on March 10, 2003. The affirmation follows the withdrawal of Gas Natural's takeover bid for Iberdrola. The outlook for both companies is stable.

Gas Natural's board announced the withdrawal of its tender offer for Iberdrola after the bid was rejected by the Spanish energy industry advisory body, Comision Nacional de Energia.

Also, Gas Natural stated that it would continue to pursue organic growth in line with its 2007 strategic plan. The utility aims to retain its roughly 70% share of the Spanish gas supply market, which is likely to experience increasing competition from electric utilities. In addition, Gas Natural targets a 10% market share in electricity supply, and plans to establish 4,800 MW of new gas-fired installed capacity by 2007. However, the utility's undiversified portfolio leaves it exposed to gas prices.

While Gas Natural's financial profile continues to provide headroom for debt-financed acquisitions, it also implies some event risk as the company may pursue larger-than-expected acquisitions, as reflected by its offer for Iberdrola.

Iberdrola, however, will continue to benefit from its strong market position, while targeting a 20% market share in gas supply. The company's strong business profile is partially offset by a considerable weakening in its financial profile caused by its ambitious 2002 growth strategy. ■

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Enel's and Subs' Ratings Are Affirmed; Off Watch, Outlook Negative

On May 2, Standard & Poor's Ratings Services affirmed its 'A+' long-term ratings on Italy's largest electric utility Enel SpA and its subsidiaries Camuzzi Gazometri SpA, Enel Investment Holding B.V., and Camuzzi Finance S.A. The ratings were removed from CreditWatch, where they were placed on March 21, 2003. The outlook is negative. The resolution of the CreditWatch listing follows Standard & Poor's review of Enel's new business plan and future strategies. At the same time, the 'A-1' short-term corporate credit ratings on Enel and Camuzzi were affirmed.

The ratings on Enel reflect its stable cash flow from regulated activities, strong position, and robust financial profile. Offsetting its credit strengths are the higher credit risks associated with the company's electricity generation operations, increasing exposure to competitive pressure in the core electricity and gas markets, and substantial investment in the telecom industry.

Enel's financial profile deteriorated in 2002 as a consequence of higher-than-expected debt. This mainly resulted from its wholly owned telecom subsidiary, Wind, not being floated. Although Enel's financial performance is forecast to recover, Standard & Poor's does not expect Enel's debt to decrease materially in the short term.

Funds from operations to net debt is expected to remain strong at more than 25% over the medium term.

Uncertainties and execution risks surrounding possible exit solutions have prolonged Enel's financial support for Wind, with a further €1 billion capital injection forecast over the next 12 months. Enel's exposure to the volatile telecom sector will shrink after it sells its interest in Wind, but Standard & Poor's does not believe that this is likely in the short term.

The negative outlook reflects the uncertainty regarding the group's telecom operations and the likelihood that Enel will have to support Wind in the short-to-medium term. In addition, the company's credit quality is expected to decline beyond the short term as market liberalization progresses and competitive pressure increases. Any debt-funded acquisitions, expansion into higher-risk activities, or a lower-than-forecast performance by the consolidated businesses could accelerate a lowering of the long-term ratings to 'A'. ■

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Petrozuata Finance Ratings Is Affirmed; Off Watch

On May 5, Standard & Poor's Ratings Services affirmed its 'B' rating on Petrozuata Finance Inc.'s $1 billion bonds and removed it from CreditWatch, where it was placed with negative implications on Dec. 10, 2002. The outlook is stable. The bonds are guaranteed by Petrolera Zuata, Petrozuata C.A.

Petrozuata is a heavy oil production and upgrading project in Venezuela that is owned by Conoco Venezuela Holding (50.1%), a subsidiary of ConocoPhillips, and PDVSA Petroleo (49.9%), a subsidiary of Petroleos de Venezuela S.A. (PDVSA).

The removal of the CreditWatch listing is due mainly to the project's ability to restart and stabilize operations and to make offshore debt payments without exposure to foreign exchange controls. The removal is further supported by the outlook for Venezuela and PDVSA, which was revised to stable on April 16, 2003, by Standard & Poor's because of the government's improving liquidity and a reduction, albeit limited, in economic and political pressures.

The Petrozuata project restarted upgrader operations in early March 2003 following the redelivery of natural gas and hydrogen feedstocks by PDVSA Gas and third parties supplied by PDVSA Gas. Petrozuata reports that its current operations are in line with 2003 business forecasts.

The stable outlook reflects Petrozuata's current production above or at pro forma rates and general expectations that the project will continue to receive sufficient feedstocks from PDVSA Gas to support production and will not be subject to foreign exchange controls. The outlook could change to negative if the project's ability to maintain steady production becomes questionable, or if the credit outlook for the Venezuela or PDVSA worsens.

The outlook could be revised to positive if the outlook on PDSVA and the government improves. ■

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Last Week's Rating Reviews

Ratings Activity: April 30 to May 7

	Action	To	From	Date
Enel SpA	Outlook revised	Negative	Watch Neg	May 2
Iberdrola S.A.	Outlook revised	Stable	Watch Neg	May 6
Laclede Group Inc.	Rating lowered	A	A+	May 5
Laclede Gas Co.	Rating lowered	A	A+	May 5
Petrozuata Finance Inc.	Outlook revised	Stable	Watch Neg	May 5

Did You Know?

World Energy Consumption and Regional Carbon Dioxide Emissions in 2001

Region	Consumption (quadrillion BTUs)	Emissions (mil. metric tons carbon equivalent)
Industrialized countries	211.5	3,179
Eastern Europe/Former Soviet Union	53.3	856
Asia	85	1,640
Middle East	20.8	354
Africa	12.4	230
Central and South America	20.9	263
Total	403.9	6,522

Source: Energy Information Administration/International Energy Outlook 2003.

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Last Week's Financing Activity

New Debt and Preferred Stock Issues, and New Shelf Registrations

April 30 to May 7

Company	Rating	Outlook	Issue registered date	Amount issued/reg (mil. $)	Coupon rate (%)	Security type	Maturity date	Price	BP spread over Treasury	Underwriter
Electric & Water										
AES Corp.	B+	Negative	May 2, 2003	600	9	Senior Secured Notes	May 15, 2015	100	496	Citigroup
Alabama Power Co.	A	Stable	May 2, 2003	250	3.125	Drawdown	May 1, 2008	—	—	Barclays Capital
Appalachian Power Co.	BBB	Stable	April 30, 2003	200	—	Unsecured Notes	—	—	—	Bank One Capital Markets
Arizona Public Service Co.	BBB	Stable	May 6, 2003	200	—	Drawdown	May 1, 2033	—	—	Lehman/Bank of America Securities
Arizona Public Service Co.	BBB	Stable	May 6, 2003	300	—	Drawdown	May 1, 2015	—	—	Lehman/Bank of America Securities
Duke Energy Corp.	A-	Negative	May 1, 2003	700	—	Drawdown	2023	—	—	Citigroup/JP Morgan
Empire District Electric Co.	BBB-	Stable	April 30, 2003	100	—	Credit Agreement	April 17, 2005	—	—	—
Entergy Arkansas Inc.	BBB+	Stable	May 2, 2003	150	5.4	First Mortgage Bonds	May 1, 2018	—	—	—
Wisconsin Electric Power Co.	A-	—	May 2, 2003	300	4.5	Drawdown	May 15, 2013	—	—	JP Morgan/BancOne Capital Markets
Wisconsin Electric Power Co.	A-	—	May 2, 2003	335	5.625	Drawdown	May 15, 2033	—	—	JP Morgan/BancOne Capital Markets
Gas										
None										
Oil & Gas										
None										
Project Finance										
None										
Telecommunications										
None										

bp—Basis point. All shelf ratings except medium-term note programs are preliminary until drawn down.

Duke Energy's $700 Million Senior Notes Are Rated 'A-'

On May 2, Standard & Poor's Ratings Services assigned its 'A-' senior unsecured debt rating to Duke Energy Corp.'s $700 million convertible senior notes due 2023. The outlook is negative.

Charlotte, N.C.-based Duke Energy had $22.5 billion in consolidated debt outstanding (including current maturities) as of Dec. 31, 2002.

The proposed note issue is a drawdown from Duke Energy's existing $1.5 billion shelf registration.

Standard & Poor's negative outlook on Duke Energy reflects the need to review the company's progress on its asset sale strategy, as well as updated financial projections, to determine the likelihood and timing of financial improvement. Duke Energy will need to improve funds from operations (FFO) interest coverage and FFO to total debt beyond 4x and 16%, respectively, to maintain current ratings.

Standard & Poor's also said that the FERC's investigations of energy traders continues to be a concern.

At the drawdown, the shelf registration had $1.3 billion available. Duke Energy plans to use the proceeds for various corporate needs, which may include the reduction of outstanding commercial paper.

The notes are senior unsecured obligations of the corporation. The noteholders can convert their holdings to common shares of Duke Energy if certain conditions are met. Given that there is no mandatory conversion, Standard & Poor's views the notes as being fully debt-like. ■

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Wisconsin Electric Power's $635 Million Debt Issue Is Rated 'A-'

On May 5, Standard & Poor's Ratings Services assigned its 'A-' rating to Wisconsin Electric Power Co.'s $635 million of senior unsecured debentures due in 2013 and 2033. Proceeds will be used to retire existing callable debt of various maturities. The outlook is stable.

Milwaukee, Wisc.-based Wisconsin Energy Corp., parent of Wisconsin Electric Power, and its other subsidiaries had

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about $3.9 billion of debt outstanding as of March 31, 2003.

Standard & Poor's stable outlook for Wisconsin Energy reflects the company's focus on its core utility business, which is expected to remain strong and provide the majority of the cash flows. However, the ratings or outlook could change due to further weakening of financial measures during the construction phase of its Power the Future (PTF) program if interest rates rise or project costs supercede original estimates.

Standard & Poor's also noted that the company is subject to refinancing risk when it will need to raise permanent financing for PTF projects, which could also adversely affect the ratings and outlook.

Wisconsin Energy's PTF program is the company's plan to build new nonregulated generation to meet Wisconsin Electric Power's expected energy demand for the next 10 years. ■

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North Carolina Eastern Municipal Power's Bonds Are Rated 'BBB'

On May 2, Standard & Poor's Ratings Services assigned its 'BBB' rating to North Carolina Eastern Municipal Power Agency's $294.1 million power system revenue bonds series 2003D-E, based on the agency's significant debt burden, relatively high wholesale power costs and resultant uncompetitive member retail rates, and credit quality implications resulting from the presence of economically depressed regions in its service territory.

These risks are mitigated by the strong take-or-pay contracts provided, which contractually obligate member cities to pay agency debt service; the financial oversight and political support provided by the Local Government Commission of North Carolina; and the limited prospects for any North Carolina deregulation.

The outlook is stable, reflecting the strength of the existing legal structure provided by the contracts and the Local Government Commission of North Carolina's oversight, the lack of deregulation, and the recently renewed supplemental agreement with Carolina Power & Light Co.

Proceeds of the bonds and certain other available money will be used to refund existing power system revenue bonds.

North Carolina Eastern's weak business profile of '6' on Standard & Poor's 10-point scale takes into account the agency's high fixed costs and the overall average credit quality of the member cities, which include the very poor economics and demographics of some of the smaller participants. Some display shrinking populations, high unemployment, and per capita income levels well below the national average. These trends heighten Standard & Poor's credit concerns.

North Carolina Eastern is a joint-action agency that provides wholesale power to 32 member cities under take-or-pay contracts. The bonds are payable from member revenues collected by the agency. ■

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Medco Energi's Proposed $200 Million Notes Are Rated 'B+'

On May 5, Standard & Poor's Ratings Services assigned its 'B+' rating to Indonesian oil and gas company P.T. Medco Energi Internasional Tbk.'s proposed senior unsecured notes issue of about $200 million. The notes are due 2010, and puttable by noteholders in 2008. The notes will be issued by subsidiary MEI Euro Finance Ltd. and will be guaranteed by Medco. The rating on the notes, therefore, reflects the corporate credit rating on Medco. Proceeds from the new debt will be used primarily to fund Medco's acquisition of petroleum assets in 2003 and its intensive exploration, development, and production program.

In addition, Medco is offering to exchange its existing $100 million 10% senior unsecured notes due March 2007 for the proposed notes due 2010. Those exchange offer notes that are tendered will form a single series with the proposed note issue, and will have the same rating.

The additional debt of about $200 million is consistent with Standard & Poor's expectations of Medco's capital structure, whereby total debt to capital could rise to 50% to 60% (from about 16% at Dec. 31, 2002) in the near-to-medium term, depending on the implementation of planned development activities and acquisition opportunities.

Medco's rating reflects the company's short proved-reserves life index of 4.8 years, which explains the company's plans to acquire producing oil blocks in 2003, in addition to developing its substantial gas reserves, to add to its proved reserves base and production volumes. With reserves declining due to the maturity of Medco's fields, the company is also expected to incur significant capital costs and face various execution risks to convert its substantial probable reserves into proved reserves.

Production and proved reserves growth remain highly dependent on gas sales contracts, or the development of

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gas infrastructure in Indonesia, to absorb the company's large uncommitted gas reserves.

Although the policy direction in Indonesia is largely positive, the full operational effects of expected changes remain to be seen.

Uncertainty in the regulatory environment will continue in the near-to-medium term. Medco does, however, enjoy some insulation from sovereign debt risks. Despite its own difficulties, the Indonesian government in recent years has not sought to impose a debt moratorium or interfere with local companies accessing the foreign exchange markets to service their foreign currency obligations. Furthermore, Medco enjoys some insulation from currency instability and weaknesses in the Indonesian banking system as its oil prices and revenues are in U.S. dollars, which are deposited mainly in offshore bank accounts.

The rating on Medco also reflects the company's favorable cost structure and production track record. The large size of Medco's operating areas, low labor costs, and proximity to oil and gas supply infrastructure contribute to its better-than-average cost structure. Lifting cost in 2002 was about $2.89 per barrel of oil equivalent (boe), compared with the global average of $4 to $5 per boe. The company's three-year rolling average finding and development costs were moderately low at $2.69 per boe. Medco also has moderate, although increasingly aggressive, debt leverage and strong credit measures. Its credit ratios will weaken in the near-to-medium term, when the company assumes greater debt to fund its acquisition of petroleum assets and drilling rigs in 2003, and its intensive drilling program.

The rating also assumes that 2003 petroleum asset acquisition costs will be between $150 million and $180 million, can immediately contribute to the company's proved reserves base, and that corresponding production volumes can be realized in a timely manner.

Securing long-term gas sales contracts would allow the company to certify its probable gas reserves into proved reserves. This could result in a modest improvement in Medco's overall credit quality, if coupled with an improving country risk environment. ■

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The following list contains Standard & Poor's Ratings, Outlooks, and Business Profiles for utilities. This list, dated May 7, 2003, reflects the most current ratings, rankings, and outlooks. It is arranged by corporate credit rating categories. Within corporate credit rating categories, issuers are grouped by Outlooks; and within Outlook categories, issuers are listed by RELATIVE STRENGTH, with the first being the strongest, and the last being the weakest.

A Standard & Poor's rating Outlook assesses the potential direction of an issuer's long-term debt rating over the intermediate to longer term. In determining a rating Outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An Outlook is not necessarily a precursor of a rating change or future CreditWatch action. "Positive" indicates that a rating may be raised; "Negative" means a rating may be lowered; "Stable" indicates that ratings are not likely to change; and "Developing" means ratings may be raised or lowered. N.M. means not meaningful.

Utility business profiles are categorized from 1 (strong) to 10 (weak). In order to determine a utility's business profile, Standard & Poor's analyzes the following qualitative business or operating characteristics typical of a utility: markets and service area economy; competitive position; fuel and power supply; operations; asset concentration; regulation; and management. Telecommunications companies have not been assigned business profiles. Issuer credit ratings, shown as long-term rating/outlook or CreditWatch/short-term rating, are local and foreign currency unless otherwise noted. A dash '—' indicates not rated. An asterisk '*' indicates that the utility was reviewed this week and its ranking position was updated.

U.S. Electric/Gas/Water Companies

Company	Corporate Credit Rating	Bus. Prof.
Baton Rouge Water Works Co. (The)	AA/Stable/—	2
Madison Gas & Electric Co.	AA/Negative/A-1+	5
Nicor Gas Co.	AA/CW-Neg/A-1+	2
Nicor Inc.	AA/CW-Neg/A-1+	3
Washington Gas Light Co.	AA-/Stable/A-1+	3
WGL Holdings Inc.	AA-/Stable/A-1+	3
Wisconsin Public Service Corp.	AA-/Stable/A-1	4
Southern California Water Co.	A+/Stable/—	3
Southern California Gas Co.	A+/Stable/A-1	2
San Diego Gas & Electric Co.	A+/Stable/A-1	5
American States Water Co.	A+/Stable/—	3
California Water Service Co.	A+/Stable/—	3
Consolidated Edison Co. of New York Inc.	A+/Stable/A-1	3
Consolidated Edison Inc.	A+/Stable/A-1	3
Orange and Rockland Utilities Inc.	A+/Stable/A-1	3
Rockland Electric Co.	A+/Stable/—	4
Otter Tail Corp.	A+/Stable/A-1	6
Questar Pipeline Co.	A+/Negative/—	3
Elizabethtown Water Co.	A+/Negative/—	3
KeySpan Energy Delivery New York	A+/Negative/—	2
KeySpan Energy Delivery Long Island	A+/Negative/—	2
Pennsylvania Suburban Water Co.	A+/CW-Neg/—	2
Central Hudson Gas & Electric Co.	A/Positive/—	3
New Jersey Natural Gas Co.	A/Positive/A-1	2
American Transmission Co.	A/Stable/A-1	2
Aquarion Co.	A/Stable/—	3
BHC Co.	A/Stable/—	2
Middlesex Water Co.	A/Stable/—	3
Colonial Pipeline Co.	A/Stable/A-1	3
Northwest Natural Gas Co.	A/Stable/A-1	3
ONEOK Inc.	A/Stable/A-1	5
Massachusetts Electric Co.	A/Stable/A-1	3
Narragansett Electric Co.	A/Stable/A-1	3
New England Power Co.	A/Stable/A-1	3
Niagara Mohawk Power Corp.	A/Stable/—	4
National Grid USA	A/Stable/A-1	3
NSTAR	A/Stable/A-1	3
Boston Edison Co.	A/Stable/A-1	3
Commonwealth Electric Co.	A/Stable/—	3
NSTAR Gas Co.	A/Stable/—	3
Cambridge Electric Light Co.	A/Stable/—	3
Buckeye Partners L.P.	A/Stable/—	4
*Laclede Gas Co.	A/Stable/A-1	3
*Laclede Group Inc.	A/Stable/—	3
MidAmerican Energy Co.	A/Stable/A-1	4
WPS Resources Corp.	A/Stable/A-1	5
Mississippi Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/—	4
Georgia Power Co.	A/Stable/A-1	4
Savannah Electric & Power Co.	A/Stable/—	4
Southern Co.	A/Stable/A-1	4
Equitable Resources Inc.	A/Stable/A-1	5
Atlantic City Sewerage Co.	A/Stable/—	3
Questar Corp.	A/Negative/A-1	5
Boston Gas Co.	A/Negative/—	3
Colonial Gas Co.	A/Negative/—	3
KeySpan Generation LLC	A/Negative/—	4
KeySpan Corp.	A/Negative/A-1	4
Florida Power & Light Co.	A/Negative/A-1	4
FPL Group Inc.	A/Negative/—	5
FPL Group Capital	A/Negative/A-1	7
Piedmont Natural Gas Co. Inc.	A/CW-Neg/—	3
IDACORP Inc.	A-/Positive/A-2	5
Idaho Power Co.	A-/Positive/A-2	4
Northern Natural Gas Co.	A-/Positive/—	3
Midwest Independent Transmission System Operator Inc.	A-/Positive/—	3
Peoples Energy Corp.	A-/Stable/A-2	4
Peoples Gas Light & Coke Co.	A-/Stable/A-2	3
North Shore Gas Co.	A-/Stable/A-2	3
Virginia Electric & Power Co.	A-/Stable/A-2	4
Wisconsin Gas Co.	A-/Stable/A-2	3
Wisconsin Electric Power Co.	A-/Stable/A-2	4
Wisconsin Natural Gas Co.	A-/Stable/—	3
Atlanta Gas Light Co.	A-/Stable/—	2
Alabama Gas Corp.	A-/Stable/—	2
Energen Corp.	A-/Stable/—	6
AGL Resources Inc.	A-/Stable/—	3
Public Service Co. of North Carolina Inc.	A-/Stable/A-1	3
South Carolina Electric & Gas Co.	A-/Stable/A-1	4
SCANA Corp.	A-/Stable/—	4
PPL Electric Utilities Corp.	A-/Stable/A-2	4
Baltimore Gas & Electric Co.	A-/Stable/A-2	3
PECO Energy Co.	A-/Stable/A-2	4
Commonwealth Edison Co.	A-/Stable/A-2	4
Exelon Generation Co. LLC	A-/Stable/A-2	8
Exelon Corp.	A-/Stable/A-2	6
Sempra Energy	A-/Stable/A-2	5
Constellation Energy Group Inc.	A-/Stable/A-2	6
Delmarva Power & Light Co.	A-/Stable/A-2	3
Union Electric Co.	A-/Stable/A-1	4
Central Illinois Public Service Co.	A-/Stable/—	3
Central Illinois Light Co.	A-/Stable /—	4
CILCORP Inc.	A-/Stable/—	4
AmerenEnergy Generating Co.	A-/Stable/—	7

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U.S. Electric/Gas/Water Companies continued

Company	Corporate Credit Rating	Bus. Prof.
Ameren Corp.	A-/Stable/A-2	5
Louisville Gas & Electric Co.	A-/Stable/A-2	4
Kentucky Utilities Co.	A-/Stable/A-2	4
LG&E Energy Corp.	A-/Stable/—	6
LG&E Capital Corp.	A-/Stable/A-2	8
AmerenEnergy Generating Co.	A-/Stable/—	7
Indiana Gas Co. Inc.	A-/Negative/—	2
Kern River Gas Transmission Co.	A-/Negative/—	4
Southern Indiana Gas & Electric Co.	A-/Negative/—	4
Vectren Utility Holdings	A-/Negative/A-2	4
Vectren Corp.	A-/Negative/—	4
PacifiCorp Holdings Inc.	A-/Negative/—	4
PacifiCorp	A-/Negative/A-2	4
Wisconsin Power & Light Co.	A-/Negative/A-2	4
Atmos Energy Corp.	A-/Negative/A-2	4
Montana-Dakota Utilities Co.	A-/Negative/—	4
MDU Resources Group Inc.	A-/Negative/A-2	6
Northern Border Pipeline Co.	A-/Negative/—	3
Northern Border Partners L.P.	A-/Negative/—	3
Duke Energy Corp.	A-/Negative/A-2	5
Duke Capital Corp.	A-/NegativeA-2	6
Texas Eastern Transmission L.P.	A-/Negative/—	4
Market Hub Partners Storage L.P.	A-/Negative/—	7
PanEnergy Corp.	A-/Negative/—	4
United Water New Jersey	A-/CW-Neg/—	3
United Waterworks	A-/CW-Neg/—	3
NOVA Gas Transmission Ltd.	A-/CW-Neg/—	2
TransCanada Pipelines Ltd.	A-/CW-Neg/—	2
South Jersey Gas Co.	BBB+/Stable/—	3
PEPCO Holdings Inc.	BBB+/Stable/A-2	4
Cascade Natural Gas Corp.	BBB+/Stable/—	3
UGI Utilities Inc.	BBB+/Stable/—	4
Kinder Morgan Energy Partners L.P.	BBB+/Stable/A-2	4
Connecticut Light & Power Co.	BBB+/Stable/—	4
Western Massachusetts Electric Co.	BBB+/Stable/—	4
Public Service Co. of New Hampshire	BBB+/Stable/—	5
Northeast Utilities	BBB+/Stable/—	5
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	4
OGE Energy Corp.	BBB+/Stable/A-2	5
Wisconsin Energy Corp.	BBB+Stable/A-2	5
Transok Inc.	BBB+/Stable/—	6
Enogex Inc.	BBB+/Stable/—	6
Consolidated Natural Gas Co.	BBB+/Stable/A-2	5
Dominion Resources Inc.	BBB+/Stable/A-2	5
Michigan Consolidated Gas Co.	BBB+/Stable/A-2	3
Detroit Edison Co.	BBB+/Stable/A-2	6
MCN Energy Enterprises Inc.	BBB+/Stable/—	8
DTE Enterprises	BBB+/Stable/—	6
DTE Energy Co.	BBB+/Stable/A-2	6
Cinergy Corp.	BBB+/Stable/A-2	5
Cincinnati Gas & Electric Co.	BBB+/Stable/—	4
PSI Energy Inc.	BBB+/Stable/—	4
National Fuel Gas Co.	BBB+/Stable/A-2	6
Union Light Heat & Power Co.	BBB+/Stable/—	4
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2	6
Maui Electric Co. Ltd.	BBB+/Stable/—	6
Hawaiian Electric Light Co. Inc.	BBB+/Stable/—	6
Potomac Electric Power Co.	BBB+/Stable/A-2	3
Conectiv	BBB+/Stable/—	4
Atlantic City Electric Co.	BBB+/Stable/A-2	3
Kaneb Pipe Line Operating Partnership L.P.	BBB+/Stable/—	5
Portland General Electric Co.	BBB+/Developing/A-2	4
Interstate Power & Light Co.	BBB+/Negative/A-2	5
Alliant Energy Corp.	BBB+/Negative/A-2	5
Alliant Energy Resources Inc.	BBB+/Negative/—	8

Company	Corporate Credit Rating	Bus. Prof.
Progress Energy Florida Inc.	BBB+/Negative/A-2	4
Progress Energy Carolinas Inc.	BBB+/Negative/A-2	5
Florida Progress Corp.	BBB+/Negative/—	5
Progress Energy Inc.	BBB+/Negative/A-2	5
Connecticut Natural Gas Corp.	BBB+/Negative/—	3
Southern Connecticut Gas Co.	BBB+/Negative/—	3
Central Maine Power Co.	BBB+/Negative/—	3
New York State Electric & Gas Corp.	BBB+/Negative/A-2	3
Energy East Corp.	BBB+/Negative/—	3
Rochester Gas & Electric Corp.	BBB+/Negative/—	5
RGS Energy Group Inc.	BBB+/Negative/—	5
Questar Market Resources Inc.	BBB+/Negative/—	8
ALLETE Inc.	BBB+/CW-Dev/A-2	6
Northern States Power Wisconsin	BBB+/CW-Dev/—	4
TEPPCO Partners L.P.	BBB/Stable/—	4
TE Products Pipeline Co. L.P.	BBB/Stable/—	4
Florida Gas Transmission Co.	BBB/Stable/—	2
NUI Utilities Inc.	BBB/Stable/—	3
Arizona Public Service Co.	BBB/Stable/A-2	4
Pinnacle West Capital Corp.	BBB/Stable/A-2	5
Kinder Morgan Inc.	BBB/Stable/A-2	5
AEP Texas Central Co. (formerly Central Power & Light)	BBB/Stable—	2
AEP Texas North Co. (formerly West Texas Utilities Co.)	BBB/Stable /—	2
AEP Resources Inc.	BBB/Stable /—	7
Appalachian Power Co.	BBB/Stable—	3
Columbus Southern Power Co.	BBB/Stable—	2
Indiana Michigan Power Co.	BBB/Stable—	4
Kentucky Power Co.	BBB/Stable—	3
Ohio Power Co.	BBB/Stable—	2
Public Service Co. of Oklahoma	BBB /Stable—	3
Southwestern Electric Power Co.	BBB/Stable/—	3
American Electric Power Co. Inc.	BBB/Stable /A-2	5
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
PSEG Power LLC	BBB/Stable/—	7
Public Service Enterprise Group Inc.	BBB/Stable/A-2	6
PSEG Energy Holdings, Inc.	BBB/Stable/—	8
Entergy Arkansas Inc.	BBB/Stable/—	6
Entergy Louisiana Inc.	BBB/Stable/—	6
Entergy Mississippi Inc.	BBB/Stable/—	7
Entergy New Orleans Inc.	BBB/Stable/—	7
Entergy Corp.	BBB/Stable/—	6
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Black Hills Power Inc.	BBB/Stable/—-	5
Black Hills Corp.	BBB/Stable/A-2	7
Potomac Capital Investment Corp.	BBB/Stable/—	7
Empire District Electric Co.	BBB/Stable/A-2	5
Great Plains Energy Inc.	BBB/Stable/—	6
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Southern Union Co.	BBB/Stable/—	4
Dayton Power & Light Co.	BBB/Stable/A-2	4
DPL Inc.	BBB/Stable/A-2	6
Centerpoint Energy Inc.	BBB/Stable/—	5
Centerpoint Energy Houston Electric LLC	BBB/Stable/—	5
Centerpoint Energy Resources Corp.	BBB/Stable/—	5
TXU U.S. Holdings	BBB/Negative/—	5
Oncor Electric Delivery Co.	BBB/Negative/—	5
TXU Energy Co. LLC	BBB/Negative/—	5
TXU Gas Co.	BBB/Negative/—	5
TXU Corp.	BBB/Negative/—	5
PacifiCorp Group Holdings Co.	BBB/Negative/—	4
Jersey Central Power & Light Co.	BBB/Negative/—	4
Pennsylvania Electric Co.	BBB/Negative/—	5

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U.S. Electric/Gas/Water Companies continued

Company	Corporate Credit Rating	Bus. Prof.
Metropolitan Edison Co.	BBB/Negative/—	5
Ohio Edison Co.	BBB/Negative/—	6
Cleveland Electric Illuminating Co.	BBB/Negative/—	6
Toledo Edison Co.	BBB/Negative/—	6
Pennsylvania Power Co.	BBB/Negative/—	6
FirstEnergy Corp.	BBB/Negative/—	6
Southwestern Energy Co.	BBB/Negative/—	8
Cleco Power LLC	BBB/Negative/A-3	5
Cleco Corp.	BBB/Negative/A-3	6
Duquesne Light Co.	BBB/Negative/A-3	4
DQE Inc.	BBB/Negative/A-3	5
Tampa Electric Co.	BBB/Negative/A-2	4
TECO Energy Inc.	BBB/Negative/A-3	5
Teco Finance Inc.	BBB/Negative/—	8
NiSource Inc.	BBB/Negative/A-2	4
Columbia Energy Group	BBB/Negative/—	4
Bay State Gas Co.	BBB/Negative/—	3
Northern Indiana Public Service Co.	BBB/Negative/—	5
Noark Pipeline Finance LLC	BBB/Negative/—	6
PPL Corp.	BBB/Negative/—	5
PPL Energy Supply LLC	BBB/Negative/A-2	5
Duke Energy Trading and Marketing LLC	BBB/Negative/—	8
Xcel Energy Inc.	BBB/CW-Dev/A-3	6
Northern States Power Co.	BBB/CW-Dev/A-3	4
Southwestern Public Service Co.	BBB/CW-Dev/A-3	4
Public Service Co. of Colorado	BBB/CW-Dev/A-3	4
Green Mountain Power Corp.	BBB-/Stable/—	7
El Paso Electric Co.	BBB-/Stable/—	6
Entergy Gulf States Inc.	BBB-/Stable/—	6
System Energy Resources Inc.	BBB-/Stable/—	7
Puget Sound Energy Inc.	BBB-/Stable/A-3	4
Washington Natural Gas Co.	BBB-/Stable/A—	5
Puget Energy Inc.	BBB-/Stable/—	5
Central Vermont Public Service Corp.	BBB-/Stable/—	6
Texas-New Mexico Power Co.	BBB-/Stable/—	5
Public Service Co. of New Mexico	BBB-/Stable/—	6
SEMCO Energy Inc.	BBB-/Negative/—	4
Southwest Gas Corp.	BBB-/Negative/—	4
AmeriGas Partners L.P.	BB+/Stable/—	7
Western Gas Resources Inc.	BB+/Stable/—	7
Avista Corp.	BB+/Stable/—	5
Kansas Gas & Electric Co.	BB+/Developing /—	6
Westar Energy Inc.	BB+/Developing/—	6
Indianapolis Power & Light Co.	BB+/Negative/—	4
IPALCO Enterprises Inc.	BB+/Negative/—	4
El Paso Energy Partners L.P.	BB+/CW-Neg/—	6
Northwestern Corp.	BB+/CW-Neg/—	6
Northwestern Energy Montana	BB+/CW-Neg/—	6
Transwestern Pipeline Co.	BB/CW-Pos/—	5
CMS Panhandle Pipeline Cos.	BB/CW-Pos/—	4

Company	Corporate Credit Rating	Bus. Prof.
Southern California Edison Co.	BB/CW-Dev/—	8
Consumers Energy Co.	BB/Negative/—	6
CMS Energy Corp.	BB/Negative/—	6
Tucson Electric Power Co.	BB/CW-Neg/—	6
Ferrellgas Partners L.P.	BB-/Stable/—	7
West Penn Power Co.	BB-/CW-Neg/—	2
Potomac Edison Co.	BB-/CW-Neg/—	2
Monongahela Power Co.	BB-/CW-Neg/—	2
Allegheny Energy Inc.	BB-/CW-Neg/—	5
Allegheny Generating Co.	BB-/CW-Neg/—	7
Allegheny Energy Supply Co. LLC	BB-/CW-Neg/—	7
Heating Oil Partners L.P.	B+/Stable/—	3
Sierra Pacific Power Co.	B+/Negative/—	5
Nevada Power Co.	B+/Negative/—	6
Sierra Pacific Resources	B+/Negative/—	5
El Paso Natural Gas Co.	B+/Negative/—	4
Tennessee Gas Pipeline Co.	B+/Negative/—	4
ANR Pipeline Co.	B+/Negative/—	4
Colorado Interstate Gas Co.	B+/Negative/—	3
El Paso CGP Co.	B+/Negative/—	6
Southern Natural Gas Co.	B+/Negative/—	4
El Paso Corp.	B+/Negative/—	6
El Paso Tennessee Pipeline Co.	B+/Negative/—	4
Transcontinental Gas Pipe Line Corp.	B+/CW-Neg/—	3
Texas Gas Transmission Corp.	B+/CW-Neg/—	4
The Williams Companies Inc.	B+/CW-Neg/—	6
Northwest Pipeline Corp.	B+/CW-Neg/—	3
Aquila Inc.	B+/CW-Neg/—	6
Aquila Merchant Services Inc.	B+/CW-Neg/—	9
Reliant Energy Mid-Atlantic Power Holdings LLC	B/CW-Dev/—	7
Reliant Resources Inc.	B/CW-Dev/—	7
Orion Power Holdings Inc.	B/CW-Dev/—	7
Illinois Power Co.	B/CW-Neg/—	6
Dynegy Holdings Inc.	B/CW-Neg/—	6
Illinova Corp.	B/CW-Neg/—	7
Dynegy Inc.	B/CW-Neg/—	7
Mirant Americas Generation Inc.	B/CW-Neg/—	7
Mirant Corp.	B/CW-Neg/—	7
Mirant Americas Energy Marketing L.P.	B/CW-Neg/—	8
Edison International	B-/Developing/—	8
PG&E Gas Transmission-Northwest	CCC/CW-Neg/—	2
PG&E Energy Trading Holdings Co.	C/CW-Neg/—	8
NRG Energy Inc.	D/—/—	9
Pacific Gas & Electric Co.	D/—/D	9

U.S. Telecommunications Companies

Company	Corporate Credit Rating
SBC Communications Inc.	AA-/CW-Neg/A-1+
BellSouth Corp.	A+/Stable/A-1
Cingular Wireless LLC	A+/Stable/A-1
Verizon Communications Inc.	A+/Stable/—
Cellco Partnership (d/b/a Verizon Wireless)	A+/Stable/—
ALLTEL Corp.	A/Negative/A-1
Telephone & Data Systems Inc.	A-/Negative/—
CenturyTel Inc.	BBB+/Stable/A-2
Intelsat Ltd.	BBB+/Stable/A-2
AT&T Corp.	BBB+/Negative/A-2

Company	Corporate Credit Rating
AT&T Wireless Services Inc.	BBB/Stable/A-2
Citizens Communications Co.	BBB/Negative/A-2
Sprint Corp.	BBB-/Stable/A-3
PanAmSat Corp.	B+/CW-Pos/—
Qwest Communications International	B-/Developing/—
Broadwing Inc.	B-/Negative/—
Williams Communications Group	D/—/—

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International Companies

Company	Corporate Credit Rating	Bus. Prof.
Europe/Middle East/Africa		
Electricite de France	AA/Negative/A-1+	4.5
E.ON AG	AA-/Stable/A-1+	N.A.
*Iberdrola S.A.	A+/Stable/A-1	4
Acea SpA	A+/Negative/A-1	3
RWE AG	A+/Negative/A-1	4.5
*ENEL SpA	A+/Negative/A-1	4.5
National Grid Co. PLC	A/Stable/A-1	3
Verbundgesellschaft	A/Stable/—	4.5
Endesa S.A.	A/Negative/A-1	5
United Utilities PLC	A-/Positive/A-2	3
South Western Electricity PLC	A-/Stable/A-2	3
PowerGen UK PLC	A-/Stable/A-1	6
Innogy PLC	A-/Negative/A-2	6
ScottishPower UK PLC	A-/Negative/A-2	3.5
CEZ AS	BBB+/Positive/—	5.5
Public Power Corp. of Greece	BBB+/Stable/—	5
WPD Holdings U.K.	BBB+/Negative/A-2	N.A.
Israel Electric Corp. Ltd.	Foreign currency	
	BBB+/Negative/—	3.5
ESKOM Holding Ltd.	Local currency	
	A-/Positive/—	5.5
	Foreign currency	
	BBB-/Positive/—	
Mosenergo (AO)	B-/Positive/—	8
British Energy PLC	SD/—/—	6
Latin America		
Comision Federal de Electricidad (CFE)	Local currency	
	BBB+/Stable/—	5
	Foreign currency	
	BBB-/Stable/—	
Enersis S.A.	BBB-/Negative/—	4.5
Companhia de Eletricidade do Rio de Janiero (CERJ)	Local currency	
	BB-/Negative/—	7
	Foreign currency	
	B+/Stable/—	
AES Gener S.A.	B/Negative/—	5.5
Empresa Electrica del Norte Grande S.A. (Edelnor S.A.)	CC/CW-Pos/—	9.5
Compania de Transporte de Energia Electrica de Alta Tension SA (Transener)	D/—/—	4.5

Company	Corporate Credit Rating	Bus. Prof.
Asia/Pacific		
Singapore Power Ltd.	AAA/Stable/—	3.5
Tokyo Electric Power Co. Inc.	AA-/Negative/A-1+	3.5
SPI PowerNet Pty Ltd.	A+/Positive/A-1	1.5
CLP Power Hong Kong Ltd.	A+/Stable/A-1	3.5
Powercor Australia LLC	A-/Stable/A-2	3.5
United Energy Ltd.	A-/CW-Neg/A-2	4.5
Korea Electric Power Corp.	Foreign currency	
	A-/Stable/A-2	5
Tenaga Nasional Berhad	BBB/Stable/—	6
TXU Electricity Ltd.	BBB/Stable/A-2	N.A.
Contact Energy Ltd.	BBB/Stable/A-2	6.5
Huaneng Power Inc.	Foreign currency	
	BBB/Stable/—	6
Electricity Generating Authority of Thailand	Local currency	
	BBB+/Stable/—	6
National Thermal Power Corp. (NTPC)	Foreign currency	
	BB/Negative/—	6
Tata Power Co. Ltd	Foreign currency	
	BB/Negative/—	5
Manila Electric Co.	Foreign currency	
	B-/Negative/—	6

Gas Credit Rankings

Company	Corporate Credit Rating	Bus. Prof.
Europe/Middle East/Africa		
Gasunie (N.V. Nederlandse)	AAA/Negative/A-1+	N.A
Gaz de France	AAA/CW-Neg/A-1+	2.5
Transco PLC	A/Stable/A-1	N.A
Centrica PLC	A/Stable/A-1	N.A.
Latin America		
Metrogas S.A.	D/—/—	6
Asia/Pacific		
Osaka Gas Co. Ltd.	AA-/Negative/A-1+	3.5
Australian Gas Light Co. (The)	A/Stable/A-1	3

Water Credit Rankings

Company	Corporate Credit Rating	Bus. Prof.
Europe/Middle East/Africa		
Thames Water PLC	A+/Negative/A-1	2.5
Suez S.A.	A-/Stable/A-2	5
Asia/Pacific		
Sydney Water Ltd.	Local currency	
	AAA/Stable/A-1+	2.5
	Foreign currency	
	AA+/Stable/A-1+	

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

March 30, 2007 Standard & Poor's Publication
"Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements"

April 2009

Exhibit PPL/304
Williams/1

STANDARD & POOR'S RatingsDirect

RESEARCH

Credit FAQ:

Imputed Debt Calculation For U.S. Utilities' Power Purchase Agreements

Publication date: 30-Mar-2007

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In November 2006, Standard & Poor's Ratings Services invited members of the U.S. electric industry and interested parties to provide us with comments on our proposal to incorporate evergreen treatment in the debt equivalents we calculate to reflect the fixed obligations created by power purchase agreements (PPAs). Evergreen treatment would, for analytical purposes, assume an extension of the life of some short- and intermediate-term PPAs, so as to achieve comparability in the financial metrics of companies with supply arrangements of varying durations.

We received comments from every sector of the power industry--utilities, independent power producers, trade organizations, consultants, investors, and regulators. Based on the comments received, we have reached a number of conclusions regarding the application of evergreen treatment to PPAs in our analysis. We have also made a number of clarifications and refinements to our rating methodology. This discussion supplements our Nov. 1, 2006 article “Request for Comments: Imputing Debt to Purchased Power Obligations,” which is available on RatingsDirect.

Frequently Asked Questions

How is evergreen treatment applied in Standard & Poor's credit analysis?

Standard & Poor's adjusts reported financial metrics to capitalize portions of the costs of PPAs. The intent of these adjustments is to capture fixed PPA obligations that have debt-like attributes because they fund the recovery of third-party power suppliers' capital investments in generation assets. These fixed obligations merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure. Evergreen treatment would extend the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

We have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs do not meaningfully correspond to long-term load serving obligations. Although evergreen treatment will be applied selectively 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.

The net present value (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.

What are the mechanics of PPA debt imputation and evergreen treatment?

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. An NPV is calculated for the stream of capacity payments associated with the outstanding contracts included in the financial statements. The notes to the financial statements report capacity payments for the succeeding five years 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 and aren't reflected in the notes to the financial statements. For this group of contracts, debt imputation will not commence until the year that energy deliveries are to begin under the anticipated contract.

How is NPV calculated?
The NPV is calculated 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 to reflect the benefits of regulatory or legislative cost recovery mechanisms (see "Request for Comments: Imputing Debt to Purchased Power Obligations," (cited above) for a discussion of risk factors).

How does evergreen treatment alter the PPA debt adjustment?
If evergreen treatment is warranted, we would extend the expiration of existing contracts and those that are slated to commence during the five-year horizon. Based on our analysis of several companies, we have determined that any evergreen extension of the tenor of existing contracts and anticipated contracts should extend those contracts to 12 years beyond the relevant forecast year.

To decide whether to apply evergreen treatment, we would start with an examination of actual capacity payments scheduled during the five-year horizon and the period represented as the thereafter period in the financial statements. 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. 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 will reflect regional differences in our analysis. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted average cost of capital and a proxy capital recovery period.

Does customer choice curb the need for evergreen treatment?
Several comments submitted to us observed that over the long term there is the potential that customers may switch to third-party providers, thereby undermining the rationale for an evergreen adjustment. We acknowledge that the introduction of customer migration would alter the long-term obligation to serve. At the same time, it must be noted that our rating methodology already addresses this concern. Customer choice typically goes hand in hand with the transformation of a utility into a pure transmission and distribution system. We have previously stated that we won't impute debt for those utilities whose role--as a result of either regulatory orders or legislation--is limited to that of a conduit between suppliers and retail customers. Therefore, utilities whose customers have retail choice aren't generally exposed to debt imputation and, in turn, we won't apply evergreen treatment to their supply obligations.

Have there been revisions to the analytical treatment of short-term PPAs?
For many years, Standard & Poor's didn't calculate debt equivalents for the fixed costs of power supply arrangements whose tenor was three years or less. We recently announced our abandonment of this exception to our debt imputation criteria. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending either the construction of new capacity or the execution of long-term PPA contracts. 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.

Are accommodations made for PPAs that are treated as leases in the financial statements?

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

Exhibit PPL/304
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that are subject to 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 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.

How is the depreciation expense related to PPAs calculated?
We noted in our November article that we now add an implied depreciation expense to funds from operations (FFO) to align the analytical treatment of PPAs with the concept of purchased power as a substitute for self-build. We observed that we calculate imputed depreciation expense in conformity with the methodology used for calculating a depreciation adjustment as an offset to debt equivalents created by leases.

The imputed depreciation expense is calculated for any given year by taking the scheduled fixed capacity payment commitment for that year and subtracting from it the implied interest expense calculated from the NPV of the stream of capacity payments associated with that year. The calculated depreciation proxy is added to FFO in the numerator as part of the calculation of both the FFO-to-interest and FFO-to-debt ratios.

What adjustments are made for tolling contracts?
We will assign a 100% risk factor when imputing debt to an unregulated energy company that has entered into a tolling agreement for a power plant's output. This is done because of the absence of a regulatory mechanism for the recovery of the fixed costs presented by the tolling arrangement.

Are transmission contracts treated differently than PPAs?
In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these transmission 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.

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Exhibit PPL/304
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Docket No. UE-
Exhibit PPL/305
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 PCRB Variable Rates

April 2009

Indicative Forward PCRB Variable Rates
For December 31, 2009

	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%
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%

Indicative Forward PCRB Variable Rates
For December 31, 2009

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
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%
Average			85%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
12/31/2009	1.72%	85%	1.46%

* Source: Bloomberg L.P. (1/5/09)

Bruce N. Williams
Exhibit PPL/306

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Embedded Cost of Preferred Stock

April 2009

PACIFICORP
Electric Operations
Cost of Preferred Stock
December 31, 2009

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.000%	126,243	$12,624,300	($98,049)	$12,526,251	99.223%	5.039%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.520%	2,065	$206,500	($9,676)	$196,824	95.314%	4.742%	$9,793	4
5	7.00% Series	(b)	None	7.000%	18,046	$1,804,600	(c)	$1,804,600	100.000%	7.000%	$126,322	5
6	6.00% Series	(b)	None	6.000%	5,930	$593,000	(c)	$593,000	100.000%	6.000%	$35,580	6
7	5.00% Series	(b)	100.00%	5.000%	41,908	$4,190,800	(c)	$4,190,800	100.000%	5.000%	$209,540	7
8	5.40% Series	(b)	101.00%	5.400%	65,959	$6,595,900	(c)	$6,595,900	100.000%	5.400%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.720%	69,890	$6,989,000	($30,349)	$6,958,651	99.566%	4.741%	$331,320	9
10	4.56% Series	Feb-65	102.34%	4.560%	84,592	$8,459,200	($49,071)	$8,410,129	99.420%	4.587%	$387,990	10
11												11
12		May-95	(d)								$67,955	12
13		Oct-95	(e)								$84,019	13
14												14
15	**Total Cost of Preferred Stock**			**5.026%**	**414,633**	**$41,463,300**	**($187,146)**	**$41,276,155**		**5.414%**	**$2,244,853**	15

(a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.
(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.
(c) Original issue expense/premium has been fully amortized or expensed.
(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.
(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.

Mark R. Tallman
Exhibit PPL/400

Docket No. UE-
Exhibit PPL/400
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark R. Tallman

April 2009

Q. Please state your name, business address and present position with PacifiCorp (the "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 Resource Acquisition.

Qualifications

Q. Briefly describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resource Acquisition since December 2007. Prior to that, I was Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 23 years in a variety of positions of increasing responsibility, including the commercial and trading organization; the Company's engineering organization; the retail distribution organization; and five years as a District Manager.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the prudence of multiple resources for which the Company is seeking cost recovery in this proceeding. These resources include the Lake Side combined cycle combustion turbine ("CCCT") resource ("Lake Side") and four wind-powered generation resources: Seven Mile

Hill II; Glenrock III; High Plains; and Three Buttes.

Q. Please briefly explain how you support the prudence of these supply-side resources in your testimony.

A. I describe the integrated resource plan ("IRP"). I explain how the Company acquired each of the resources consistent with its acknowledged IRPs and relevant MidAmerican Energy Holdings Company ("MEHC") transaction commitments. I provide a description of each resource acquired by the Company and the decision-making process that led to the acquisition. With respect to the renewable resources in this filing, I address considerations applicable to all of the resources in an overview section before addressing the resources individually.

Integrated Resource Plan

Q. Please briefly describe the IRP.

A. OAR 860-027-0400(2) defines an IRP as the utility's written plan "detailing its determination of future long-term resource needs, its analysis of the expected costs and risks of the alternatives to meet those needs, and its action plan to select the best portfolio of resources to meet those needs."

The Company uses its IRP as a strategic planning tool to ensure that the Company continues to provide reliable, least-cost service with manageable and reasonable risk to its customers. The IRP process also serves an important communications function, engaging numerous stakeholders in the planning process and soliciting their input on the key decision points leading to the Company's preferred portfolio of supply-side and demand-side resources and investment in transmission. Finally, the IRP permits the Company to develop and refine portfolio modeling and risk analysis tools, which the Company can then apply more broadly to issues such as load forecasting, resource evaluation and resource acquisitions.

Q. What is the outcome of the IRP process?

A. The result is a preferred portfolio that represents a balance of resource additions that meet future customer needs, while minimizing cost, balancing diverse stakeholder interests and addressing environmental concerns.

To follow through on the findings of the resource plan, the Company's IRP includes an action plan that is intended to inform and provide guidance for the Company's resource acquisition activities over the next few years.

The Company files its IRP with the Commission for acknowledgement. In reviewing the reasonableness of the Company's resource acquisitions, I understand that the Commission gives considerable weight to Company actions that are consistent with its acknowledged IRPs.

Q. Were the resources described in this testimony acquired consistent with the Company's acknowledged IRPs?

A. Yes. The 2003 IRP supported the need to acquire Lake Side and the 2004 and 2007 IRPs supported the need to acquire the renewable resources described in my testimony.

Q. How did the 2003 IRP address the need for new resources?

A. The Company published its 2003 IRP on January 24, 2003. The 2003 IRP concluded that the Company needed substantial new supply-side resources to meet its projected loads in 2007. Action item #2 in the 2003 IRP consisted of a long-term 570 megawatt ("MW") East system resource that would be made available in then fiscal year 2008 (beginning April 2007). Action item #2 set forth the need for acquiring the Lake Side CCCT resource.

Q. Did the Commission acknowledge the Company's 2003 IRP and action plan?

A. Yes. Order No. 03-508 (Docket LC 31) acknowledged the IRP and action plan with agreed-upon modifications.

Q. Did the Company issue a request for proposals ("RFP") as a way to acquire the 2007 resource identified in action item #2 of the 2003 IRP?

A. Yes, as I describe later in my testimony, the Company issued RFP 2003-A.

Q. How did the 2004 IRP address renewable resources?

A. The Company's 2004 IRP identified 1,400 MW of renewable resources as part of a least-cost portfolio of resources to meet the Company's growing demand over a ten-year period. The 2004 IRP included wind-powered generation resources as a proxy for all renewable resources.

Q. Did the Commission acknowledge the Company's 2004 IRP and action plan in regards to the Company's pursuit of 1,400 MW of renewable resources?

A. Yes, in Order No. 06-029 (Docket LC 39).

Q. Did the Commission order approving MEHC's acquisition of PacifiCorp include a commitment reflecting the same renewable resource acquisition target?

A. Yes. The commitment contained both short-term renewable resource acquisition goals and reaffirmed the commitment of acquiring 1,400 MW of new, cost-effective renewable resources.

Q. How did the 2007 IRP address renewable resources?

A. The 2007 IRP identified a target of 2,000 megawatts of renewable resources to be acquired by 2013. Under this plan, the Company will seek to acquire the committed 1,400 megawatts of new renewable resources by 2010, with the target of an additional 600 megawatts in its portfolio by 2013. The 2,000 megawatts of renewable resources is inclusive of the 1,400 megawatts of cost-effective renewable resources identified in the Company's 2004 IRP. While the Company used wind-powered generation for modeling purposes in the IRP process, renewable resources include other fuel sources (such as geothermal).

Q. How did the 2007 IRP address the procurement of renewable resources?

A. The 2007 IRP procurement plan recognized the challenge of acquiring the committed levels of renewable resources plus the additional targeted amount. Specifically, the 2007 IRP said:

> "*In order to fill this requirement, the company will continue to aggressively pursue the acquisition of these resources through various approaches including new request for proposals, bi-lateral negotiations, the Public Utilities Regulatory Policy Act, and self-development.*" (2007 IRP at page 229)

Q. Did the Commission acknowledge the 2007 IRP and its action plan on renewable resource acquisition?

A. Yes. Commission Order No. 08-232 (Docket LC 42) acknowledged the renewable resource acquisition in the IRP and the action plan.

Q. Has the Company aggressively pursued renewable resources via each acquisition strategy listed in the 2007 IRP?

A. Yes, the Company has acquired renewable resources via each and every acquisition strategy listed in the 2007 IRP. The Company has acquired renewable resources via new RFPs, bi-lateral negotiations, the Public Utilities Regulatory Policy Act and self development.

Q. Please describe the Company's most recent activity with respect to renewable resource RFPs to implement the 2007 IRP action plan.

A. The Company has had three recent renewable resource RFPs. First, the Company issued an RFP on January 31, 2008 for long-term renewable resources less than 100 MW[1] in generating capability that could be available by December 31, 2009. The Company termed this RFP as "RFP 2008R". Developers and other bidders could submit proposals in the form of a power purchase agreement ("PPA") or build-own-transfer agreement ("BOT"). Bids under RFP 2008R were due on March 31, 2008. As a result of RFP 2008R, the Company executed a PPA for the entire output from a 99 MW wind-powered generation project with Three Buttes Windpower LLC (Three Buttes), an entity owned by Duke Energy Corp. I provide detailed information on RFP 2008R and this renewable resource later in my testimony.

Q. Did the Company seek Oregon Commission approval to issue RFP 2008R?

A. No. The RFP was limited to resources below 100 MW in capability (or less than five years in length) to be compliant with the Commission's guidelines for

[1] The Company also considered offers for renewable resources of 100 MW or greater if the term was less than five years.

resource procurement. In January 2008, the production tax credit had not been extended past December 2008. Through implementation of its other acquisition strategies, the Company was aware that limited wind turbine generators were available in the market and that some developers were representing an ability to deliver fully developed renewable resources prior to the then-current expiration of the production tax credit. Accordingly, RFP 2008R had an expedited schedule since a compliant resource would necessarily have to be one that was fully permitted, constructed and interconnected to facilities constructed as a result of a large generator interconnection agreement and prior to December 31, 2008.

Q. Please describe the second RFP.

A. On March 4, 2008, the Company filed an application with the Oregon Commission to open a docket for approval of a RFP process targeting 500 MW of renewable resources that could be available by December 31, 2011. The Company termed this RFP as "RFP 2008R-1". On October 6, 2008, the Company issued RFP 2008R-1 to the market after receiving the Commission's approval to do so in Order No. 08-476 in Docket UM 1368. The Commission issued Order No. 08-476 approving RFP 2008R-1 on September 23, 2008.

Q. Please outline the key provisions and milestones of RFP 2008R-1.

A. Each renewable resource is limited in size to no more than 300 MW, which is the upper limit permitted by Utah Senate Bill 202[2]. The Company received bids until December 22, 2008 and is currently in the process of reviewing the information supplied by bidders.

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[2] Utah Senate Bill 202 requires the Company to issue a public solicitation of bids for a renewable energy source up to 300 MW in size each year in which it reasonably anticipates that it will need to acquire or

Q. Has the Company recently refreshed RFP 2008R-1?

A. Yes. The Company provided bidders with an opportunity to refresh their bids or for new or existing bidders to provide new proposals. The Commission approved the Amended 2008R-1 RFP in Order No. 09-017 (entered January 21, 2009). The Amended 2008R-1 constitutes the third RFP. The deadline for updated or new bids was February 27, 2009. The Company anticipates that it will continue to issue a RFP for renewable resources each year to acquire needed resources to serve customers and/or comply with renewable portfolio standard ("RPS") or emission-related laws.

Lake Side CCCT Project

Q. Please describe the size and location of Lake Side.

A. Lake Side utilizes new Siemens Westinghouse 501F machines. These combustion turbines are connected to two heat recovery steam generators and a steam turbine. Lake Side produces approximately 548 MW on a nominally rated basis. The resource is located in Vineyard, Utah.

Q. When did Lake Side become operational?

A. The resource went into service in September 2007.

Q. Have the variable costs and dispatch benefits of Lake Side been reflected in Oregon net power costs since shortly after the resource went into service?

A. Yes. As a result of the Stipulation in UE 179, the Company's net power costs have included the variable costs and dispatch benefits of Lake Side since 2007. Because Oregon rates have reflected the net power cost benefits of Lake Side without the matching fixed costs, Oregon customers have already experienced

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commence construction of a renewable energy resource. (Utah Code 54-17-502(2)(a)(i)).

significant benefit associated with this resource. Lake Side is thus already both used and useful in Oregon, notwithstanding the fact that rates do not yet reflect capital and O&M costs for the resource.

Q. On what basis did the Company determine the need for Lake Side?

A. As I described above, the 2003 IRP concluded that the Company needed substantial new supply-side resources to meet its projected 2007 loads. The Company's supply-side resource decision relative to Lake Side responded to that need.

Q. How did the Company implement this aspect of the 2003 IRP?

A. The Company issued a RFP that it termed "RFP 2003-A".

Q. Did the Commission review RFP 2003-A?

A. Yes. The Company created RFP 2003-A with the intent of being compliant with Order No. 91-1383 and filed the RFP with the Commission in Docket UM 1079. In Order No. 03-356, the Commission approved RFP 2003-A on the basis that it was "*in compliance with the competitive bidding guidelines established by Order No. 91-1383, and is consistent with PacifiCorp's filed 2003 Integrated Resource Plan.*" The Commission set two conditions for this order: (1) that the Company use an independent consultant to administer, validate, and audit the RFP process; and (2) that the Company provide a clear synopsis of the RFP process and offer a pre-bid workshop.

Q. Please describe RFP 2003-A.

A. The RFP 2003-A process used a blind bid evaluation process where bid responses were submitted to an independent evaluator, Navigant Consulting, Inc., ("Navigant"), which, in turn, assured that the responses were adequately blinded such that the bidding entity was not known to the Company. Navigant then supplied the blinded bid responses to the Company for evaluation. RFP 2003-A solicited a resource to be available during then fiscal year 2006 (beginning April 2005), a resource to be available during then fiscal year 2007 (beginning April 2007) and seasonal resources.

Q. What was Navigant's overall role?

A. Navigant's overall role was: (1) to make certain that the Company evaluated its cost-based alternatives for the 2005 and 2007 resource need in a manner that was reasonable, fair, unbiased, and comparable to the extent practicable, against other bids, and (2) to report on whether the process followed by the Company adequately met these objectives.

Q. Has the Company made available to the Commission a clear synopsis of the RFP 2003-A process?

A. Yes. The Company filed a report prepared by Navigant entitled "Navigant Consulting's Final Report on PacifiCorp's RFP 2003-A", which was dated September 8, 2004. For convenience, a copy of this report is included as Exhibit PPL/401.

Q. What resources resulted from RFP 2003-A?

A. The Currant Creek CCCT resource and the Lake Side CCCT resource.

Q. Was Navigant's role in RFP 2003-A relative to Lake Side any different than its role relative to the Currant Creek project?

A. No.

Q. Has the Commission reviewed the prudence of the Currant Creek project and is it currently in Oregon rates?

A. Yes. The Commission reviewed the prudence of the Currant Creek project in Docket UE-170, determined that the resource was prudent and, as a result, Currant Creek is in Oregon rates. See Order No. 05-1050, page 23.

Q. What conclusion did Navigant reach in its September 8, 2004 report about the RFP 2003-A process?

A. Page 48 of the Navigant report concluded that:

> "*PacifiCorp executed a fair and consistent process throughout the RFP to identify the most cost effective resources for meeting its projected supply needs. The criteria, tools, and types of personnel used were similar to other resource solicitations used by other investor owned and municipal utilities elsewhere.*"

This conclusion holds for both the Currant Creek and Lake Side resources.

Q. Did the decision to acquire Lake Side result from RFP 2003-A?

A. Yes. Upon evaluating the alternatives presented in RFP 2003-A, the Company determined that Lake Side as proposed by one of the bidders was the best alternative for the 2007 resource category in the RFP.

Q. Did Navigant agree with that decision?

A. Yes. Page 47 of the Navigant report states that:

> "*Taken in aggregate, it was apparent that the preferred transaction would be with the selected bidder due to its lower risk and its equivalent cost characteristics*".

Q. What costs related to Lake Side are reflected in the Company's revenue requirement in this filing?

A. The total Company cost for Lake Side is $338,423,481 and the O&M related to the plant is $5,520,740. The resource is reflected in the Company's net power costs calculation in the Transition Adjustment Mechanism filing for the test period in this case. Mr. R. Bryce Dalley's testimony in this case describes the revenue requirement calculations associated with the inclusion of this resource.

Q. Please describe the benefits of Lake Side to Oregon customers.

A. Lake Side benefits Oregon customers because it provides needed system capacity and associated energy, as determined by the 2003 IRP. The resource constitutes the best balance between cost and risk of the opportunities available to the Company at that time.

Q. Has the decision to construct Lake Side been reflected in rates in other states?

A. Yes. Lake Side is in rates in the states of Utah, Wyoming, Idaho and California.

Renewable Resources

Q. Please provide an overview of the renewable resources contained in this filing.

A. This filing proposes to include four new renewable resources in rates. Two of these resources were initially developed by third parties and subsequently constructed[3] by the Company (Seven Mile Hill II and High Plains). One resource (Three Buttes) was developed by a third party and will be constructed, owned and

[3] The Seven Mile Hill II resource was placed in service on December 31, 2008 whereas the High Plains resource is currently under construction.

operated by that entity. The Company will purchase the output from Three Buttes under a PPA. Finally, Glenrock III was developed and constructed by the Company on land long owned by the Company. All four of these renewable resources are located in Wyoming.

Q. Were any of these resources acquired through a Commission-approved RFP?

A. No. As a result of and consistent with Commission Order No. 08-548 in the Company's 2009 Renewable Adjustment Clause ("RAC"), Docket UE 200, I understand that the Company therefore retains the burden of producing evidence that these resources are prudent.

Q. Please provide an overview of the Company's evidence of prudence related to acquisition of these four new renewable resources.

A. First, the Company's new renewable resources are consistent with the Company's acknowledged IRPs, a fact to which I understand the Commission gives considerable weight.

Second, as detailed below, the Company's economic analysis demonstrates that each resource is cost-effective.

Third, the capital costs of the Company's new rate-based resources are all below IRP proxy costs when adjusted for the year the resource was placed in service. For example: Seven Mile Hill II went into service on December 31, 2008 at a cost of $2,345 per kilowatt ("kW"); Glenrock III went into service on January 17, 2009 at a cost of $2,235 per kW; and High Plains is expected to go into service by November 2009 at a cost of $2,479 per kW. The table below sets forth the IRP proxy costs using a range of escalation rates and shows how the Company's projects compare favorably to IRP proxy costs.

Table 1

IRP Proxy (2006$)	Wind-Powered Resource Cost Inflation	IRP Proxy (2007$)	IRP Proxy (2008$)	IRP Proxy (2009$)
$2,011/kW	10%	$2,212/kW	$2,433/kW Seven Mile Hill II = $2,345/kW	$2,677 Glenrock III = $2,235/kW High Plains = $2,479/kW
$2,011/kW	15%	$2,313/kW	$2,660/kW	$3,058
$2,011/kW	20%	$2,413/kW	$2,896/kW	$3,475

Fourth, the average capacity factor of new renewable resources reflected in my testimony is 35.8 percent (at the time of decision) and 37.4 percent based on the most recent estimates. Both of these percentages are higher than the 34.1 percent average capacity factor[4] for other Wyoming resources[5] prior to addition of these four new resources and the 35 percent capacity factor used for proxy Wyoming wind-powered generation resources in the Company's 2007 IRP.

Fifth, the Three Buttes PPA was acquired through RFP 2008R. As discussed in more detail below, the market insights provided by this competitive bidding process demonstrate the reasonableness of this PPA. Because the Company's rate-based resources are comparable to bids received in RFP 2008R, these same market insights also further demonstrate the prudence of these

[4] The average includes three contracted wind-powered generation resources in Wyoming with estimated capacity factors of 32.6 percent, 28.1 percent and 26.3 percent.

resources.

Sixth, when the Company made the decisions to acquire these resources, the Company faced an intensely competitive market for renewable resource acquisition, caused in part by the uncertain status of the production tax credit and rates being paid by California buyers that were far above the market for undifferentiated resources (non-renewable resources). At the same time, the Oregon Commission moved renewable resource acquisition to the top of its policy agenda and the Oregon Legislature was considering the aggressive new targets for renewable resource acquisition ultimately adopted in Senate Bill 838. In this environment, it was reasonable for the Company to move as expeditiously as possible to acquire new renewable resources. The prudence of the Company's renewable resource acquisition decisions should be viewed in this historically correlated context.

Q. Please describe the benefits of these resources to Oregon customers.

A. Oregon customers benefit from the Seven Mile Hill II, Glenrock III, High Plains and Three Buttes wind-powered generation resources because they represent economically quantified renewable resources. The 2004 and 2007 IRPs specify that renewable resources (using wind-powered generation resources as a proxy) should be steadily added to the system with the target of reaching 1,400 MW or more of renewable resources.

Q. How else will these renewable resources benefit Oregon customers?

A. Each of these renewable resources further benefit Oregon customers by providing

[5] Other Wyoming resources means other wind-powered generation resources owned by the Company or with which the Company has contracts.

the Company with zero incremental cost fuel sources (thus reducing commodity risk exposure), multi-shafted generation resources (thus diversifying the impact of individual generator failures) and, in the case of the owned resources, further valuable ownership and operational experience with utility scale wind-powered generation resources as well as customers having access to the terminal value associated with those assets. Each of the owned resources utilize General Electric wind turbines, thus giving PacifiCorp the option and ability to share spare parts with other General Electric based resources it owns and to synergize O&M. Further, as a result of long-term planning and the reasonable expectation that additional state and/or federal RPS laws will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years. As a result, each of the wind-powered generation resources will help comply with these RPS requirements and help reduce the Company's generation emissions.

Seven Mile Hill II

Q. Please describe the Seven Mile Hill II resource.

A. Seven Mile Hill II is a 19.5 MW resource consisting of thirteen wind turbine generators, an electrical collector system, access roads, and required communication and control facilities (metering, hardware, software, and associated communication circuits).

Q. How is energy generated by Seven Mile Hill II delivered to PacifiCorp's system?

A. Seven Mile Hill II interconnects to the Company's transmission system via facilities constructed for the Seven Mile Hill resource. These facilities include a

34.5 kV to 230 kV collector substation and a 230 kV transmission interconnection substation.

Q. Is Seven Mile Hill II metered separately from Seven Mile Hill?

A. Yes.

Q. How did the Company make the decision to move forward with the Seven Mile Hill II resource?

A. Company executives were provided with a detailed overview of the project, the contract support and counterparty guarantees for executing upon the project, the risks associated with the project, the need for the project as established by the IRP, the financial assessment of the project, and the justification of the project. Upon review of this information, the Company determined that it would proceed with acquisition of the resource. Attached as Confidential Exhibit PPL/402 is the information provided to Company executives.

Q. Has this resource been incorporated in the Company's current rates?

A. The capital costs are not currently included in rates; however, the dispatch benefits associated with the resource are being passed through to customers in the Transition Adjustment Mechanism, pursuant to the stipulation in Docket UE 199. Additionally, in accordance with the stipulation, the Company filed an application for deferred accounting on December 31, 2008 to defer the revenue requirement associated with the resource (Docket UM 1412). The Commission approved the application in Order No. 09-072.

Q. What investment related to Seven Mile Hill II is included in the revenue requirement in this filing?

A. The total company cost for Seven Mile Hill II is expected to be $45,737,658. The operations & maintenance ("O&M") cost associated with the Seven Mile Hill II resource that is associated with this application is $530,990 on a total company basis. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax, land and easement payments and other O&M expenses. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What analysis method did the Company use in the presentation provided to Company executives with respect to the Seven Mile Hill II resource?

A. The Company used the next highest alternative cost for compliance ("ACC") method.

Q. What is the ACC method?

A. The ACC method uses the Company's production cost simulation system and its associated forward price curves to generate a market-based alternative comparison of 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 renewable resources removed from the preferred portfolio. Next, other costs and benefits of the specific resource being considered are compared against the PaR model results. This comparison is in the form of a considered resource ACC value, which represents the resource cost over the life of the project[6] that yields a zero net PVRR difference with respect to the PaR model's market-based resource alternative. A negative ACC value, which is expressed on a dollars-per-megawatt-hour ("MWh") basis, indicates that the bid resource compares favorably to the undifferentiated (non-renewable resource) market-based alternative, whereas a positive ACC value indicates that the cost of the proposed resource is above the market-based alternative. The PaR model is a model used in the Company's IRP analysis process.

Q. What was the result of the ACC analysis for Seven Mile Hill II and what was the estimated capacity factor at the time the decision was made to acquire the resource?

A. The ACC for Seven Mile Hill II was estimated to be negative $10.14 per MWh, below the cost of the non-renewable resource (undifferentiated) market based alternative. The capacity factor at the time the analysis was done was estimated to be 39.3 percent.

Q. In Order No. 08-548 in the recent RAC proceeding, the Commission stated that "[t]he most recent reliable data should be used to set rates for the test period" (page 21). In light of this finding, what is the most recent capacity factor estimate for Seven Mile Hill II?

A. The most recent capacity factor estimate was provided to the Company by its consultant in a Final Build Design Estimate report dated August 14, 2008. A copy of the report is included as Confidential Exhibit PPL/403. The report estimates a

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[6] The life of the project can, and often is, longer than PPA terms. In these instances, the term of the PPA is utilized.

capacity factor of 40.3 percent for Seven Mile Hill II.

Q. What is the ACC using a 40.3 percent capacity factor?

A. Negative $14.61/MWh, further confirming the cost-effectiveness of the resource.

Q. Does the Seven Mile Hill II resource provide customers with terminal value?

A. Yes.

Glenrock III

Q. Please describe the Glenrock III resource.

A. Glenrock III is a 39 MW resource consisting of twenty-six wind turbine generators, two electrical collector systems, access roads, and required communication and control facilities (metering, hardware, software, and associated communication circuits).

Q. How is energy generated by Glenrock III delivered to PacifiCorp's system?

A. Glenrock III interconnects to the Company's transmission system via facilities constructed for the Glenrock and Rolling Hills resources. These facilities include: (i) a 34.5 kV to 230 kV collector substation, a 230 kV transmission line and a 230 kV transmission interconnection substation constructed for the Glenrock resource, and (ii) a 34.5 kV to 230 kV collector substation constructed for the Rolling Hills resource.

Q. Is Glenrock III metered separately from the Rolling Hills and Glenrock resources?

A. Yes.

Q. How did the Company make the decision to move forward with the Glenrock III resource?

A. Company executives were provided with a detailed overview of the project, the contract support and counterparty guarantees for executing upon the project, the risks associated with the project, the need for the project as established by the IRP, the financial assessment of the project, and the justification of the project. Upon review of this information, the Company determined that it would proceed with acquisition of the project. Attached as Confidential Exhibit PPL/404 is the information provided to Company executives.

Q. Has this resource been incorporated in the Company's current rates?

A. The capital costs are not currently included in rates; however, the dispatch benefits associated with the resource are being passed through to customers in the Transition Adjustment Mechanism, pursuant to the stipulation in Docket UE 199. Additionally, in accordance with the stipulation, the Company filed an application for deferred accounting on December 31, 2008 to defer the revenue requirement associated with the resource (Docket UM 1412). The Commission approved the application in Order No. 09-072.

Q. What investment related to Glenrock III is included in the revenue requirement in this filing?

A. The total company cost for the Glenrock III resource is expected to be $87,173,625. The O&M cost associated with the Glenrock III resource that is associated with this application is $803,302 on a total company basis. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and other O&M expenses. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What analysis method did the Company use in the presentation provided to Company executives with respect to the Glenrock III resource?

A. The Company used the ACC method described earlier in my testimony.

Q. What was the result of the ACC analysis for the Glenrock III resource and what was the estimated capacity factor at the time the decision was made to acquire the resource?

A. The ACC for the Glenrock III resource was estimated to be $6.26/MWh and, therefore, beneficial to customers if the cost of RPS compliance is expected to be $6.26/MWh or more above market or the value of renewable energy credits (RECs) is expected to be $6.26/MWh or higher on average over the life of the resource. The capacity factor at the time the analysis was done was estimated to be 31.0 percent.

Q. In Order No. 08-548 in the recent Renewable Adjustment Clause proceeding, the Commission stated that "[t]he most recent reliable data should be used to set rates for the test period" (page 21). In light of this finding, what is the most recent capacity factor estimate for the Glenrock III project?

A. The most recent capacity factor estimate was provided to the Company by its consultant in a Final Build Design Estimate report dated August 14, 2008. A copy of the report is included as Confidential Exhibit PPL/405. The report estimates a capacity factor of 36.4 percent for the Glenrock III.

Q. What is the ACC using a 36.4 percent capacity factor?

A. Negative $10.66/MWh, further confirming the cost-effectiveness of the resource.

Q. Does the Glenrock III resource provide customers with terminal value?

A. Yes.

Q. Please summarize the final build design energy projections for the Seven Mile Hill II and Glenrock III resources.

A. Table 2 provides a summary of the final build design energy projection estimate ("FBDE") as well as the projection at the time the decision was made to acquire the resource. The summary shows capacity factor ("CF"), MW and MWh:

Table 2

Resource	Acquisition Decision (MW)	Acquisition Decision (CF)	Acquisition Decision (MWh)	FBDE (MW)	FBDE (CF)	FBDE (MWh)
Seven Mile Hill II	19.5	39.3%	67,132	19.5	40.3%	68,840
Glenrock III	39.0	31.0%	105,908	39.0	36.4%	124,357
Total MW/MWh Average CF	**58.5**	**35.2%**	**173,041**	**58.5**	**38.4%**	**193,197**

Q. Based on the final build design estimates, is the amount of energy projected from these two resources higher or lower than originally anticipated?

A. The energy production for the combination of the two resources is expected to be approximately 20,157 MWhs per year higher than originally anticipated. This is equivalent to approximately 6.6 MW of additional wind-powered generation operating at an annual average capacity factor of 35 percent. This amount of energy also represents 503,919 MWh over the initial expected 25-year resource lives or, taking a conservative value for energy at $55.00 per MWh, an incremental nominal value of approximately $27.7 million to customers.

Q. Are there other factors that contribute to Glenrock III being economically favorable?

A. Yes. For example, one factor that makes Glenrock III a desirable resource is the Company's ability to avoid leasing costs related to the resource. Because the Company owns the land on which Glenrock III is located, third party leasing costs will be avoided. These savings are conservatively $4.8 million over the initial 25-year life of the project. Indeed, this cost avoidance is in perpetuity, which means the Company will successfully avoid more than seven times this amount over the next 100 years (more than $35.7 million).

Q. Are there other benefits that the Company conservatively excluded from the Glenrock III analysis?

A. Yes. In the case of Glenrock III, the Company did not include avoided lease payments. In addition, the Company's analysis of Glenrock III did not include the possibility that the capacity factor would increase due to the use of a conservative capacity factor. The actual capacity factor is in fact higher than the conservative estimate the Company used in its acquisition analysis.

Q. Are there qualitative factors associated with the Glenrock III resource that an alternative resource could not provide?

A. Yes. The Glenrock III resource is located adjacent to the Glenrock resource and, as such, the Company is able to better utilize certain infrastructure that was necessary for the Glenrock resource. This infrastructure includes the Windstar transmission interconnection substation, the Glenrock to Windstar 230 kV transmission line, an operations and maintenance building and land owned by the

Company previously used to support coal mining activities.

Q. You mentioned land owned by the Company previously used to support coal mining activities. Would you please elaborate?

A. The Glenrock III resource is located on property owned by the Company that includes the location of the Company's now reclaimed Dave Johnston coal mine. Mining operations took place from approximately 1958 through September of 2000. After mining operations ceased, the Company reclaimed the land pursuant to its Federal mining permit. The siting of Glenrock III at this location serves as a testimonial to environmental stewardship and continued asset utilization for the benefit of customers. This is the only instance I am aware of in the western United States that wind projects have been located at the site of a reclaimed coal mine.

High Plains

Q. Please describe the High Plains resource.

A. High Plains will be a 99 MW resource consisting of sixty-six wind turbine generators, an electrical collector system, a 34.5 kV to 230 kV collector substation, a 230 kV transmission line extension, transmission interconnection facilities, access roads, an O&M building and required communication and control facilities (metering, hardware, software, and associated communication circuits).

Q. How will energy generated by High Plains be delivered?

A. The energy produced by the High Plains resource will enter PacifiCorp's system at the Foote Creek substation. This will enable the nearly 30-mile transmission line constructed for the Foote Creek I resource (from Miners substation to Foote

Creek substation) to be more fully utilized.

Q. Where will the High Plains resource be constructed?

A. The High Plains resource will be located on a site approximately three miles east of McFadden, Wyoming.

Q. How did the Company make the decision to move forward with the High Plains resource?

A. Company executives were provided with a detailed overview of the project, the contract support and counterparty guarantees for executing upon the project, the risks associated with the project, the need for the project as established by the IRP, the financial assessment of the project, and the justification of the project. Upon review of this information, the Company determined that it would proceed with acquisition of the project. Attached as Confidential Exhibit PPL/406 is the information provided to Company executives.

Q. Has this resource been incorporated in the Company's current rates?

A. No.

Q. What investment related to the High Plains resource is included in the revenue requirement in this filing?

A. The total company cost for the High Plains resource is expected to be $245,508,239. The O&M cost associated with the High Plains resource that is associated with this application is $2,224,208 on a total company basis. This is due to an expected wind turbine-generator maintenance agreement, permitting obligations, local levy tax, land and easement payments and other O&M expenses. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What analysis method did the Company use in the presentation provided to Company executives with respect to the High Plains resource?

A. The Company used the ACC method described earlier in my testimony.

Q. What was the result of the ACC analysis for the High Plains resource and what is the estimated capacity factor?

A. The ACC for the High Plains resource ranged from a negative $10.77/MWh to a negative $1.76/MWh, therefore beneficial to customers. The range resulted from including terminal value and taking into account the avoidance of costs for turbine storage and incremental allowance for funds used during construction. The estimated capacity factor is 35.7 percent.

Q. Does the High Plains resource provide customers with terminal value?

A. Yes.

Three Buttes PPA

Q. Please describe the Three Buttes PPA.

A. The transaction is structured to purchase all of the output and RECs of a 99 MW wind-powered generation project for a term of 20 years under a PPA. The Company has the option to purchase the facility at fair market value at the conclusion of the 20-year term. The expected online date is by December 31, 2009. The project is located in Natrona and Converse counties in Wyoming. The project will utilize 66 General Electric Company 1.5 MW sle wind turbine generators. The terms and conditions included in the PPA are consistent with PPAs entered into by the Company for the output and RECs associated with other wind-powered generation projects.

Q. The Three Buttes PPA was acquired through RFP 2008R. Please describe the market response to this RFP.

A. The Company received 29 proposals from 11 different bidders.

Q. Please describe the evaluation process for RFP 2008R.

A. The Company first screened the bids on the basis of price and non price criteria. The most attractive offers were then evaluated using the Company's ACC methodology. The Company engaged in subsequent commercial negotiations with two entities.

Q. Please further explain the screening process.

A. The screening process ranked proposals on a price (70 percent) and non price (30 percent) basis. The price factor was derived using the Company's Structuring and Pricing RFP Base Model. The price factor comparison metric was an evaluation of projected net present value revenue requirement per kW-month ("Net PVRR/kW-mo"). The net PVRR component views the value of power as positive with costs taken into account as an offsetting negative. The net PVRR/kW-mo metric is the annuity value which, when applied to the nominal kW on a monthly basis and present-valued, will result in the same net PVRR as a net present value calculation. The non-price factors included conformance to the pro-forma PPA or BOT contracts; transmission availability and interconnection status; status of the development of the resource; bidder experience; and performance guarantees.

Q. Please describe the results of the negotiations.

A. The Company entered into negotiations with two of the bidders in early summer 2008. The first bidder's project was a 49.5 MW wind-powered generation project located in Wyoming. After several months of negotiations, PacifiCorp determined the counterparty was unwilling to agree to terms and conditions in the PPA that provided adequate protection to customers and that were included in other wind-powered generation PPAs negotiated by the Company. Accordingly, the Company terminated negotiations with this counterparty in late 2008. The second bidder's project was the Three Buttes transaction. PacifiCorp executed the Three Buttes PPA on March 5, 2008.

Q. How did the Company make the decision to execute the Three Buttes PPA?

A. Company executives were provided with a detailed overview of the PPA. Upon review of this information, the Company determined that it would proceed with execution of the PPA. Attached as Confidential Exhibit PPL/407 is the information provided to Company executives.

Q. What was the result of the ACC analysis for the Three Buttes PPA?

A. The ACC for the Three Buttes resource is estimated to be negative $5.72 per MWh, and therefore beneficial to customers.

Q. Does the Three Buttes resource provide customers with terminal value?

A. No.

Q. How does the cost of RFP 2008R bids compare to the costs of Seven Mile Hill II, Glenrock III and High Plains resources?

A. Confidential Exhibit PPL/408 provides a table presenting this comparison. As can be seen in Confidential Exhibit PPL/408, the Glenrock III, High Plains and Seven Mile Hill II resources rank favorably compared to the other bids from the RFP 2008R. The market insights provided by RFP 2008R support the prudence of the Three Buttes PPA and the other new renewable resources in this filing.

Q. Your testimony above indicates that customers will enjoy the benefits of terminal value associated with Seven Mile Hill II, Glenrock III and High Plains but not with Three Buttes. What is terminal value?

A. Terminal value is the value associated with the right to re-power a resource at cost when the asset reaches the end of its initial economic life. Terminal value includes all aspects of the resource, including its location, favorable land rights, the existence of or favorable location to infrastructure or other beneficial attributes.

Q. Does terminal value increase or decrease the value of a resource to customers?

A. When customers receive the benefit of terminal value then the value of the resource is increased. This means that the evaluated cost of the resource is lower. In contrast, when customers do not receive the benefit of terminal value then that value accrues to the owner of resource. This is the case with the Three Buttes PPA.

Q. Did the Company include the value of terminal value in its analysis of the Seven Mile Hill II and Glenrock III resources?

A. No, the Company conservatively excluded terminal value.

Q. Does this complete your testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/401
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman

Navigant Consulting's Final Report on RFP 2003-A, September 8, 2004

April 2009

NAVIGANT CONSULTING

PUBLIC VERSION

NAVIGANT CONSULTING'S FINAL REPORT ON PACIFICORP'S RFP 2003-A

PACIFICORP

September 8, 2004

NAVIGANT CONSULTING

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NAVIGANT CONSULTING

Executive Summary

This is the public report regarding PacifiCorp's ("PacifiCorp" or "the Company") 2003-A RFP ("RFP"). The purpose of this report is to provide a summary of the entire RFP process beginning with the review of PacifiCorp's next best alternatives ("NBA") and concluding with the review of negotiations with bidders. Navigant Consulting, Inc. ("NCI") was retained by PacifiCorp as the outside evaluator of the RFP process and was tasked with preparing this public report based on its involvement with the PacifiCorp RFP. The report provides the general public with an understanding of what went into the development of each NBA, how the screening of competitive offers was implemented, how the offer clarification and negotiation sessions with bidders were conducted, and what went into the ultimate selection of resource alternatives by PacifiCorp. The report is segmented into five primary sections that walk the reader through the following:

I. **Background of the 2003-A RFP –** highlighting the rationale and structure of the RFP, the attributes sought by bid category, the timeline of the RFP, and NCI's role as the outside evaluator;
II. **The NBA Review and Validation Process –** highlights what went into reviewing and validating the NBA's developed by PacifiCorp and the timing for completing our validation prior to PacifiCorp reviewing competitive bid information;
III. **The Bid Review and Screening Process –** describes what types of offers were received, what types of companies responded to the RFP, what took place during the course of reviewing the competitive offers submitted by bidders, and how the screening criteria were applied to identify the preliminary bidder short list;
IV. **The Offer Clarification and Negotiation Process –** explains what occurred during the course of clarifying offers with bidders, how the final short list of bidders was identified, and the duration and substance of the bidder negotiations that took place; and
V. **Conclusions and Recommendations –** observations regarding RFP specific activities, conclusions, and proposed recommendations for continuing to improve the Company's formal supply acquisition activities.

Throughout the RFP process, NCI was given unfettered access to information, models, and personnel that would facilitate the review and validation of the approach used by PacifiCorp to implement the RFP and the tools used to evaluate offers. NCI found the process used by PacifiCorp to be fair and reasonable. The first step in NCI's review was evaluating and validating the estimated costs and operating assumptions for each of the NBAs. Following this review, NCI was responsible for administering the distribution of blinded bid information to PacifiCorp and conducting a parallel review of the proposals. Once complete, PacifiCorp prepared a financial assessment of every offer that was submitted for consideration. NCI then reviewed each of the models to validate that the inputs related to each offer were properly reflected in the valuation and that the models fairly represented the value of the offers. Relying on the indicative information in the proposals, PacifiCorp identified the top bidders in each bid category with whom it was interested in holding clarifying discussions (i.e., the preliminary short list). Only these bidder's identities were released to PacifiCorp. Upon concluding clarifying discussions with bidders, the top candidates from the preliminary short list were selected for detailed negotiations. These negotiations extended over a nine-month period and concluded with the selection of a preferred resource in two of the three bid categories.

Each alternative considered by the Company was given an equal opportunity to be the resource option of choice for PacifiCorp to meet its projected supply needs. Bidders were also provided ample opportunity to put forth the best offers that they wanted PacifiCorp to consider. The analysis of the offers resulted in no super peak offers being more economic than the market-based benchmark, no peaker offers being superior to the Company's cost-based alternative, and one offer in the Baseload bid category being selected as the resource option of choice for meeting the Company's 2007 resource need.

In the course of describing the basis of the RFP process and the manner in which it was implemented, it is NCI's intent to provide its objective assessment of the process both among the specific components and for the process in its entirety. From an operational and design perspective, the RFP process developed and implemented by PacifiCorp functioned as expected. It resulted in over 100 offers from the market, a few of which were economically competitive with the Company's own internal benchmark options. It satisfied the primary criteria NCI looked for in the process: equal opportunity, analytical objectivity, reasonableness and consistency. Having met these, NCI supports the RFP process as having been managed in an effective manner with results that are readily supportable.

Although the process as a whole was sound there are some lessons learned that NCI offers to improve future solicitations, which build on the success of this current solicitation. These are offered in the form of observations and recommendations by subject matter along with a brief explanation of the basis for NCI's determination. The broad areas that NCI thought it was most important to provide its thoughts on were (1) the formulation and use of the NBAs, (2) the manner in which the RFP was developed and implemented, and (3) the economic modeling of offers and the screening and short listing process. These represent the three core dimensions of the whole RFP process beginning with the NBA and culminating with the selection of the best alternatives for meeting the Company's resource needs.

a. Next Best Alternatives (NBAs)

Recommendation #1: Encourage PacifiCorp to continue using NBAs, consisting of both cost-based and forward-market based benchmark (for the appropriate products and terms).

Rationale: The use of an NBA was an effective means of gauging the cost competitiveness of offers received from the market. Without the NBAs, PacifiCorp clearly would have been a price taker in the negotiation sessions with bidders. The NBAs were acutely necessary because of the transmission constrained and marginally liquid nature of PACE.

Recommendation #2: PacifiCorp should consider developing a component based PVRR spreadsheet for the NBA.

Rationale: This would provide a ready side-by-side benchmarking of the NBA by cost category relative to the offers received from the market and would facilitate a more efficient review process as the evaluative process evolves from beginning to end. Using a basic and simple summary page that is linked to the larger integrated model would make it much easier for PacifiCorp (and the Outside Evaluator, if they are involved) to track the impact of material changes that inevitably occur during the course of benchmarking and offer valuation. For this RFP, the absence of this information at the outset made the process of evaluating and validating the NBAs more time consuming than it needed to be, but it did not materially delay the process.

Recommendation #3: A more detailed description of the Company's self-build option should be provided to bidders during the bid development period or as a separate section of the RFP.

Rationale: comments were made in the Currant Creek proceeding and during discussions with the Baseload bid category bidders that it would have been helpful to have a more detailed description of the NBAs than what was provided. Whether this includes detailed cost information on the self-build or not is something to consider while taking into account local and regional market dynamics. The argument that bidders will only submit offers just under the perceived value of the Company's self-build is specious when they have to compete against other reputable and capable bidders. Knowing that there is an array of competitors that will be submitting offers should be incentive enough for bidders to put forth their best offer, not one that comes in just under the perceived cost or value of the self-build. Notwithstanding this recommendation, the fact that more detailed information was not provided early on in the process did not compromise the ability of bidders to submit competitive proposals in this bid category as evidenced by the vast number of bidders submitting like equipment configurations and pricing components to the NBA.

b. RFP Development and Implementation

Recommendation #4: Develop two offer summary templates to include in future RFPs – one for PPAs and one for asset sale/turnkey offers. Consider using bracketed examples of the information being sought, as a guide for respondents.

Rationale: The format of information submitted by bidders in response to the 2003-A RFP was not at all consistent, which made the process of pulling out the relevant information for preparing the valuations time consuming for PacifiCorp and NCI. Standardized templates, while not eliminating the likelihood of non-conforming responses, would still provide further information to bidders as to the exact information being sought and might result in a more efficient process.

Recommendation #5: PacifiCorp should continue to use the same channels as used before to distribute the RFP in addition to publicizing its availability on the Company's website and various media resources.

Rationale: The solicitation was sent to a broad enough audience to result in a significant response from the market with nearly 100 different offers for the resources being sought by the Company. Furthermore, a sufficient enough response was secured from the market to allow PacifiCorp to effectively evaluate supply options for meeting its forecasted load growth.

Recommendation #6: In future RFPs where future environmental risk and other risks present a material issue that PacifiCorp wants bidders to clearly state an assumption or rejection of in their proposals, include separate sections in the RFP dedicated to such topics. This would be in addition to the time devoted by PacifiCorp in the bidders workshops that PacifiCorp relied upon.

Rationale: Although clearly stated in the RFP and in the Pre-Bid Workshop materials, more than 75% of bidders chose to either ignore this issue in their proposals or did not communicate that they understood what it meant until clarifying discussions were held with bidders subsequent to the review of their proposals. Given the materiality of this issue from a risk and economics basis, it is important to raise the profile of this and other similar issues in the future RFPs.

Recommendation #7: PacifiCorp should consider developing a proposal checklist for bidders to use as a guide in completing their offers, which they include with their submittal. This checklist should be a mandatory submittal along with the proposal itself. (To be done in conjunction with Recommendation #5)

Rationale: Including a checklist would help to ensure that bidders have addressed each of the issues that PacifiCorp deems as material to their offer. This would include issues that were material to the current RFP such as the bearing of future environmental risk, the handling of operating reserves, and delivery to one of PacifiCorp's preferred points.

Recommendation #8: Whatever criteria are used in future RFPs, it should involve some scenario analysis to ensure that the scoring criteria are effective at allowing PacifiCorp to rank offers.

Rationale: The scoring criteria used in the RFP led to a situation in which the pricing criterion was rendered meaningless in the initial ranking of offers in one of the bid categories. This situation could have been avoided had the Company done some scenario testing on the criteria before the RFP was issued.

Recommendation #9: In future formal solicitations like this RFP, PacifiCorp should include credit as one of the explicit criteria used for scoring and ranking offers.

Rationale: This is a common element of solicitations issued by many other investor owned utilities across the United States. It is unusual to avoid the issue of credit in the review and ranking of offers when a Company, such as PacifiCorp, will be expected to enter into a contractual relationship that does not unduly expose it or its ratepayers to construction and development risk. It is not clear what benefit, if any, bidders with questionable credit quality or no access to credit would gain in the early stages of a bid ranking process only to be eliminated at a later stage because of inadequate credit assurances. PacifiCorp, like other companies with load obligations, are not prone to excessive risk taking. It would appear that PacifiCorp and its ratepayers cannot afford to ignore this issue in its consideration of resource options.

Recommendation #10: If credit is deemed inappropriate in the screening stage by PacifiCorp and its stakeholders, consider holding off on the formal request of credit and financial information, but provide bidders with a list of the information that they will need to have ready to submit to PacifiCorp within five days of being notified of making the Company's shortlist (ignore this recommendation if recommendation #9 is implemented).

Rationale: Since financial and credit information was not formally taken into account in the decision process of identifying the short list candidates, it seems unnecessarily burdensome to impose this information request until and unless it is necessary information to PacifiCorp in its decision to move forward with a particular bidder. In addition to recommending that credit be considered earlier in the RFP process as noted in the Final Report, the issue of credit should not only be used as a component in the screening criteria, but it should also be an important variable that bidders should be required to think through and outline in their proposals. Toward this end, additional time should be spent with bidders in pre-bid workshops to explain what PacifiCorp expects and what the bidder should be prepared to put in place in terms of credit and security to support its proposal.

Recommendation #11: In any pre-bid workshops held for future RFPs, dedicate a portion of the session(s) to explicitly directing bidders as to what PacifiCorp will be expecting from bidders in the responses with respect to their credit and financing arrangements in support of a transaction with the Company.

Rationale: Although this was requested clearly in a thorough format, PacifiCorp did not receive adequate information from the majority of bidders in the initial proposals. Spending some additional time on this topic up front may help to temper such occurrences.

Recommendation #12: In future RFPs, PacifiCorp should request all bidder information to be submitted on CD-Rom (a now-standard industry practice) in a PDF format in order to facilitate the rapid dissemination of information to the personnel within PacifiCorp responsible for reviewing it.

Rationale: This is a fairly ubiquitous technology and medium for distributing information in the industry. It would seem to make the bid review process more efficient and eliminate excessive paper waste. It also eliminates the need to make additional copies of material for other internal PacifiCorp personnel when an electronic version can be e-mailed readily.

Recommendation #13: PacifiCorp should include a section in future RFPs that addresses issues such as the cost of direct or inferred debt.

Rationale: A section in future solicitations should be dedicated to addressing some of the less obvious costs associated with different types of proposals. Here, we are referring to the issue of debt and its impact on the Company's balance sheet. This has become an increasingly common issue that has become a part of competitive bidding processes, but is not well understood by the majority of market participants. Furthermore, utilities have latitude in how they interpret the guidance that has been provided by Standard and Poors ("S&P"). If it is going to be a part of the economic valuation prepared by PacifiCorp, bidders should be made aware of how this calculation is made and what it means to the competitiveness of their offer.

Recommendation #14: For future RFPs, there should be explicit language that states who will be responsible for securing the necessary transmission to support a proposed transaction, the bidder or PacifiCorp.

Rationale: The language in the RFP left it open to either PacifiCorp or the bidder being responsible for securing the necessary transmission in support of transactions for certain delivery points. It was PacifiCorp's intention that the Company would not be responsible for securing transmission on behalf of a counterparty transaction unless it was deemed to be in the best interest of the Company. Changing this language would ensure clarity on this point with bidders.

c. Economic Modeling and Short Listing

Recommendation #15: Retain the existing analytical team, or comparable personnel, to complete future analyses for later RFPs.

Rationale: The internal PacifiCorp team used to develop the individual bidder models demonstrated a strong capability in pulling together a sophisticated tool that was an effective means of valuing a large volume of offers. Even by the end of the process, streamlined enhancements to the analytical tools were already being made by this team to ensure that the review process remains efficient in future resource solicitation reviews. Key to this will be continuation of this teams involvement or effective knowledge transfer to other personnel.

Recommendation #16: Consider using a component based PVRR (See Recommendation #2) that allows PacifiCorp to readily identify the magnitude and relative impact of modeling and assumption changes on a specific bid's valuation.

Rationale: While NCI was able to effectively review and validate the results of the economic modeling at each round of the offer review process, much time could have been saved had this been created at the beginning of the process rather than in the second round. Use of a component based PVRR analysis that compared how changes in inputs and assumptions resulted in a change in relative valuations would have made the review and validation process much quicker and efficient. As the Company moved through different rounds of offer model review (Rounds 1-4), NCI was not able to immediately identify how and why a valuation changed beyond just looking at the aggregate valuation. This simply necessitated more one-on-one sessions with the analytical team that prepared the economic models.

Recommendation #17: When using an outside evaluator (e.g., NCI), consider using economic models that do not include extraneous information, formulas, and calculations that are not relevant for the screening or economic modeling of offers in the course of the RFP.

Rationale: Notwithstanding the fact that NCI was able to complete a thorough review of the modeling tools being used by PacifiCorp to value the offers presented, the presence of irrelevant material made the process of evaluating the reasonableness of the calculations more time consuming than it needed to be in the early stages of the model validation process. Simple clean up of the models of legacy material that is not pertinent to the screening and valuation process would take care of this.

Recommendation #18: Consider adding a few weeks into the schedule for future RFPs that involve the modeling of multiple types of offers.

Rationale: The modeling and review phase was highly compressed given the volume of responses received from the market and the quick turn around that was indicated to bidders. While early indications from the "Intent to Bid" submittals suggested that a large response should be expected, it was difficult for PacifiCorp to turn them around in the original timeframe identified in the RFP due to the wide range of structures put forth. Additional flexibility in the schedule to accommodate this uncertainty in the modeling and review period would give more breathing room to the analytical team. In spite of this compressed timeframe, however, PacifiCorp and NCI were able to complete in an adequate manner their respective tasks of modeling and reviewing.

Recommendation #19: PacifiCorp should eliminate the use of two separate economic models.

Rationale: Even though NCI was able to validate the symmetry of results from the two models during our review, the process of validation was cumbersome due to the need to go back and forth and the presence of unnecessary information and calculations. NCI has used single model structures to evaluate PPAs and turnkey offers alike in other engagements and it should be the standard approach used by PacifiCorp in future resource procurement processes.

In light of these recommendations, PacifiCorp implemented an RFP that was consistent and unbiased in its treatment of each of the alternatives that it was presented with. The overall process was fair in its handling of offers and was reasonable in its dealings with bidders. The following lessons learned are provided as guides that should be taken into account in future RFPs that are issued by PacifiCorp:

» ***Include Schedule Flexibility*** – The process of reviewing, clarifying, and negotiating offers resulting from a solicitation always take longer than one thinks they will; ensure that chosen schedules have sufficient flexibility;

- ***Physical System Constraints Play a Big Role*** – The solicitation of resources in a physically constrained market creates unique circumstances that must be taken into account by both bidders and PacifiCorp due to the infrastructure requirements that are embedded in such deals;
- ***Bidders Will Ignore RFP Details*** – No matter how much standardization PacifiCorp tries to impose on the structure of responses to a solicitation, bidders will choose to submit proposals in their own preferred format and will ignore explicitly requested material information;
- ***Credit Issues are Critical*** – When PacifiCorp gets to the point of working toward a definitive agreement with a counterparty, the adequacy of credit and the collateralization of risk run paramount; as such these factors should be used within the early stages of a screening process;
- ***Use Separate Solicitations for Different Products*** – Creating separate solicitations for different product/resource types would help bidders to focus on the core components that the Company is most interested in with respect to each offer type;
- ***Use of Market and Cost-Based NBAs is Effective*** – Having a benchmark on which to fall back will continue to serve as an effective hedge against non-economic offers resulting from future solicitations and will prevent the Company from being a price taker;
- ***Internal Documentation of Analytics is Invaluable*** – Analytical documentation and consistency are perhaps the most important components of an entire RFP process for ensuring the ability of the Company to track the evolution of offer evaluation from beginning to end; and
- ***Open Communication is Vital to the Integrity of the Process*** – Open and continuous dialogue with an outside evaluator (if they are involved in future RFPs) ensures that real-time enhancements can be made in the process without waiting until issues turn into problems in later stages of an RFP process.

NAVIGANT CONSULTING

I. Background of the 2003-A RFP

The 2003-A RFP ("RFP") was issued on June 6, 2003 seeking resources to meet a portion of PacifiCorp's supply-side resource need as identified in the Company's 2003 Integrated Resource Plan ("IRP"). The focus of the RFP was on supply-side resources that would meet the Company's Eastern system resource need. In the IRP, there were a series of 28 separate action items, 3 of which were addressed by this RFP – baseload, peaker, and super peak resources needed to meet projected load growth in PacifiCorp's East control area ("PACE"). Each of these bid categories had specific attributes that PacifiCorp was looking for that was communicated to bidders in the Pre-RFP and Pre-Bid Workshops held with prospective bidders prior to the submittal date for proposals of July 22, 2003. Through the RFP, PacifiCorp was looking for resources that could meet certain operational and performance criteria consistent with its IRP identified need. At the outset of the process, PacifiCorp identified for bidders that their offers would be compared against a cost-based alternative, otherwise known as the next best alternative ("NBA").

To ensure a fair and reasonable process was used in the RFP, PacifiCorp retained NCI to validate, audit and review the NBAs, to facilitate the flow of information between bidders and PacifiCorp, and to review all of the economic modeling prepared in support of the RFP. To that end, NCI was involved in every aspect of the RFP process beginning with the Pre-Bid Workshop and the NBA review all the way through the period of negotiations with short listed bidders.

a. Rationale Behind the RFP

PacifiCorp initiated the first of its RFPs as a means of implementing the Company's Action Plan as articulated in its 2003 IRP. Over the past two years, PacifiCorp has worked with external stakeholders on developing, and then beginning the implementation of, the IRP. Throughout this process, PacifiCorp has emphasized the need to focus on several complementary goals that would meet not only the Company's own internal financial goals, but also the goals of the various stakeholders that it serves including customers, regulatory bodies, and interest groups. In initiating this process, the Company has remained focused on achieving three key outcomes: (1) a clear plan that satisfies the needs and objectives of each State; (2) a long-term, durable and balanced solution; and, (3) a more interactive, supportive, and efficient process.

Throughout the RFP, PacifiCorp has demonstrated a commitment to ensuring that the resource planning process followed a path that created a balance between projected loads and committed resources, facilitated timely decision-making regarding major resource options, enabled financial comparability of competing resource alternatives, and most importantly demonstrated reasonableness and fairness throughout the decision making process. At the center of the plan was a deliberate focus on balancing costs with risk to ensure that the optimal mix of resources would be in place for serving PacifiCorp's customers. Keeping these principles in mind, PacifiCorp successfully began the execution of its resource acquisition plans by issuing the first of its four projected RFPs. The use of an RFP was deemed as the most efficient means of identifying the depth and breadth of alternatives that could be considered for meeting the Company's growing demand. As explicitly laid out in the RFP, a series of resource portfolios were identified as the optimal mix for meeting future growth. The original sequence of RFPs was designed to move toward the development of each of these optimized portfolios. It was expected that the RFPs would yield a diversity of solutions for satisfying the Company's resource needs. Based on the volume and breadth of proposals received from the market in response to the RFP, NCI believes this goal was achieved.

b. Characteristics of the Bid Categories

In its RFP, PacifiCorp solicited proposals in three different bid categories from prospective bidders: Baseload, Peaker, and Super Peak. The minimum characteristics that PacifiCorp sought varied by bid category. In the super peak bid category, the minimum characteristics that PacifiCorp wanted to have in the resources included a start date by June 2004, a summer shaped product, and firm delivery in or to PACE. The offers in the peaking bid category were expected to offer commercial operation dates no later than June 2005, must be flexible in order to be dispatched daily, and delivered in or to PACE. Similarly, the Baseload bid category minimum characteristics called for commercial operation by June 2007 and delivery in or to PACE. (See Table A).[1]

Table A. Description of PacifiCorp's Bid Categories

	Bid Categories		
	Baseload	Peaker	Super Peak
Start of Delivery (COD)	Jun-07	Jun-05	Jun-04
Contract Duration	Up to 20 years	Up to 20 years	Up to 4 years
Size (MWs)	Up to 570	Up to 200	Up to 225
Preferred Delivery Profile	7 x 24 delivery	Daily call option	June-Sept. ('04-'07); Delivery during HE 1300-HE 2000 or daily call option
Dispatchability	Flexible	Daily Dispatch	Daily Dispatch
Point of Delivery (POD)	In or to PacifiCorp Eastern system (PACE)	In or to PacifiCorp Eastern system (PACE)	In or to PacifiCorp Eastern system (PACE)
Requested Transaction Structures	Negotiated (PPA, toll, lease, turnkey sale, equity participation, etc.)	Negotiated (PPA, toll, lease, turnkey sale, equity participation, etc.)	Negotiated (PPA, toll, lease, etc.)

i. Super Peak Bid Category

Super Peak bid category responses were those offers that were intended to meet PacifiCorp's needs during the HE 1300 - HE 2000 PPT period on either a 7X8, 6X8, or 5X8 basis for the summer months of June through September from 2004 through 2007. The resource could also be available as a daily

[1] These minimum bid characteristics are detailed in the materials presented to bidders by PacifiCorp at the June 20, 2003 RFP 2003-A Pre-Bid Conference.

call option. In this bid category, PacifiCorp was looking for a variety of attributes in addition to the months and hours of need outlined. Super peak offers preferably were to exhibit such attributes as deliverability at PacifiCorp's option, the ability to pre-schedule, delivery to PACE, and structuring under a negotiated arrangement based on a PPA, tolling agreement, or lease. In aggregate, PacifiCorp was looking for approximately 225 MW of capacity in this category, or larger if economies of scale could be demonstrated.

ii. Peaker Bid Category

Offers in this bid category were expected to meet PacifiCorp's minimum requirements of a daily dispatch and commercial operation by June 2005. Offers put in this category typically provided some form of call option structure, either hourly, intra-day, daily, day-ahead, or some other basis. Heavy load and super peak load hours were the target for this bid category. Peaker offers could be built upon a variety of physical and financial structures depending upon which party would be interested in assuming the various responsibilities and risks. In its RFP, PacifiCorp expressed an interest in considering alternatives using either one of the structures. The Company also indicated that offers of a term up to 20 years would be of interest. Proposals modeled in this category by PacifiCorp consisted of PPAs, asset purchases, and turnkey construction projects. In aggregate, PacifiCorp was looking for approximately 200 MW of capacity in this category, but advised bidders that they would entertain offers for commitments well in excess of this amount on account of its revised load forecast, which indicated an additional need for peaking resources than had originally been identified in the Company's IRP filing.[2] Furthermore, bidders proposing asset sales were encouraged to bid into the RFP.

iii. Baseload Bid Category

Baseload bid category offers solicited by PacifiCorp were expected to meet the minimum requirement outlined in the RFP (i.e., commercial operation date no later than June 2007). All of the responses modeled in this category were 7x24 offers, with some including 7x8 offers (duct-firing) embedded in their response in addition to the 7x24. With this bid category, PacifiCorp was looking for resources that could meet around the clock capacity and energy needs by June 2007 for a period of up to 20 years. PacifiCorp also requested the ability to negotiate displacement rights. Like the peaker offers received, the baseload offers in this category consisted of PPAs, asset purchases, and turnkey construction projects. In aggregate, PacifiCorp was looking for approximately 570 MW of capacity in this category, but indicated to bidders that offers in excess of this amount would be considered if economies of scope and scale could be demonstrated.

[2] See PacifiCorp's Quarterly IRP Public Input Meeting, May 19, 2003.

c. Timeline of the RFP Process

The RFP had its genesis in the Company's IRP filed in January 2003 (See Figure 1). The components of the RFP were communicated to potential bidders as early as March 21, 2003 during a Pre-RFP Bidders Workshop, where the Company walked through the sequential RFPs that were envisioned by the Company based on the IRP forecasted load and resource balance. This first RFP was intended to meet the Company's growing resource need in the Eastern portion of its system. The RFP itself was issued on June 6, 2003 and was followed two weeks later with a Pre-Bid Conference that addressed questions and issues raised by bidders after they had had an opportunity to review the actual RFP.

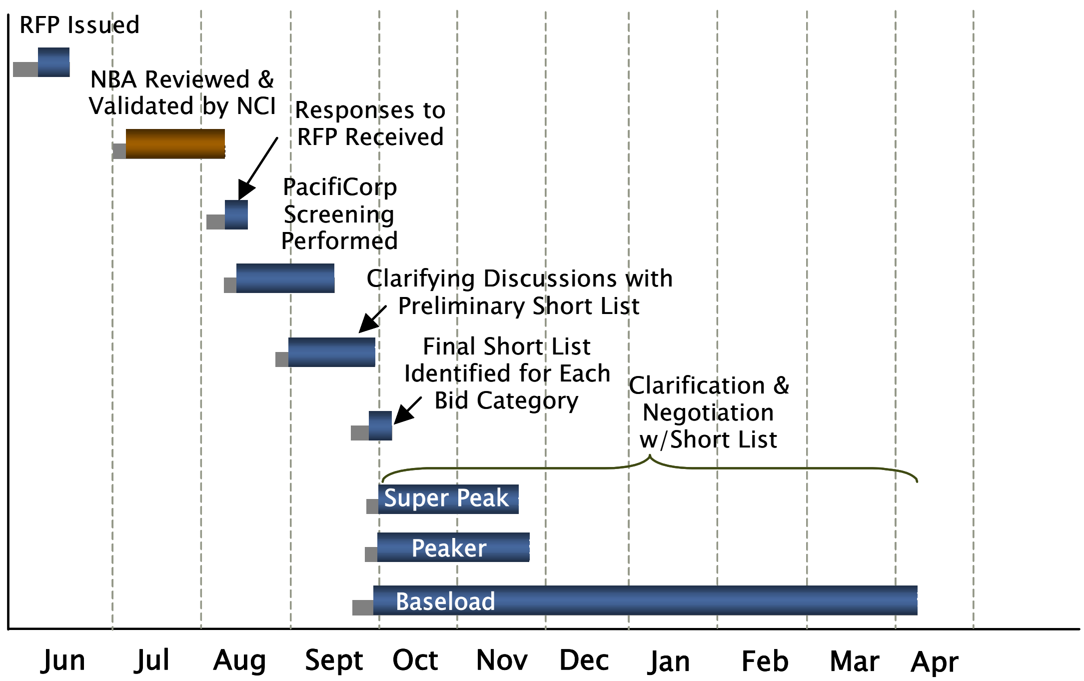

Figure 1. Timeline of the RFP Process

During this period between the issuance of the RFP and the due date for bids, NCI was engaged in a parallel task that involved the review and validation of the assumptions and valuation of PacifiCorp's NBAs. This was a critical element of the process, which occurred prior to PacifiCorp seeing any competitive bid information. NCI commenced its review of the NBA and its underlying assumptions on June 19, 2003 and concluded its review with the filing of the Review and Audit of PacifiCorp's NBA report on July 23, 2003. Although bids were received by NCI on July 22, no information, in either a blinded (e.g., technical information) or de-blinded format (e.g., credit and financial information) was forwarded to PacifiCorp until after the NBA report had been formally issued.

PacifiCorp began the process of screening the offers on July 24, 2003. This involved PacifiCorp documenting the pricing and terms associated with the respective offers, identifying the respective bid categories to which bidders were responding, assembling deal summary sheets for each of the offers, identifying missing information, and soliciting clarification from bidders via NCI in order to facilitate the completion of preliminary valuations. NCI reviewed PacifiCorp's work in this area for validation purposes. It is important to note that PacifiCorp prepared these preliminary valuations without any knowledge of who the bidder was as this remained blind to PacifiCorp until after the initial short list had been identified. The short-listed super peak bid category offers were de-blinded with NCI contacting the respective bidders on August 13, 2003. On August 21, 2003, NCI contacted the bidders making the preliminary short list for the peaking bid category. The final bid category respondents to be notified were those in the Baseload bid category. This group of respondents was de-blinded and contacted on August 22, 2003. During the subsequent three weeks, PacifiCorp and NCI held clarifying discussion sessions with each of the short listed counterparties in the respective bid categories in order to better understand the offers being presented and identify a final short list of counterparties with whom to negotiate. In follow up to questions and topics raised during these sessions, an extensive series of e-mails were exchanged among NCI, PacifiCorp and the bidders for the exclusive purpose of better understanding the terms and pricing of the offers.

Since the discussions after this point proceeded on parallel paths among each of the three bid categories, it is important to provide further granularity regarding the process of negotiation separately for each of the short lists. Once the final short lists were identified, PacifiCorp moved forward with more detailed discussions and preliminary negotiations with counterparties in the Super Peak and Baseload bid categories. In the peaker bid category, none of the offers were deemed economically superior to the respective NBA. However, since the Company needed more resources than the particular NBA would provide, it was deemed prudent by NCI and PacifiCorp to continue discussions with the short listed counterparties in the peaker bid category to ascertain whether or not an economically attractive deal could be found. It is for this reason alone that discussions with the short listed peaker bid category candidates continued beyond the middle of September. Upon further review and the subsequent comparison to the Company's incremental NBA, none of the peaker offers were found to be economically attractive relative to the NBA. As a result, discussions with these counterparties were terminated during the third week in November.

Discussions with potential counterparties in the Baseload bid category resulted in several economically attractive offers that PacifiCorp continued to clarify and negotiate through the beginning of April. At that point the preferred resource alternative was identified and discussions were concluded.

d. Navigant Consulting's Role as the Outside Evaluator

NCI's involvement in the RFP process revolved around five key tasks: (1) reviewing and validating the NBA; (2) administering the RFP on behalf of PacifiCorp; (3) reviewing PacifiCorp's proposal screening approach; (4) validating the scoring, and ranking; and (5) overseeing the negotiation process with short listed parties. The purpose of this section is to provide a brief description of each of these tasks as they were performed by NCI.

i. Review and Validation of the NBA

NCI began its involvement in the RFP process with a review of PacifiCorp's next best alternatives, or NBAs, for each of the respective bid categories. From PacifiCorp's perspective, it was important that NCI validate the NBAs prior to any bid information being reviewed by the Company. This was deemed necessary to avoid any perception that PacifiCorp would have had an opportunity to materially alter or manipulate the estimated cost components of the NBAs subsequent to the review of competitive bid information that was submitted in response to the RFP. To perform this task, NCI relied on interviews, a cost assumption review, and an assessment of the cost and economic dispatch models for the NBAs. Each step of this review and validation revealed that the NBAs were developed in a reasonable manner and that the cost assumptions themselves were consistent with the costs that would be incurred to develop the types of projects proposed by PacifiCorp.

ii. Administration of the RFP

NCI administered the entire RFP from the documentation of the notices of intent to bid through the identification of the counterparty short list for each bid category. This task began immediately following the June 20, 2003 Pre-Bid Workshop at which NCI was introduced as the primary point of contact regarding the RFP. To perform this task, NCI focused on applying lessons learned from other RFP processes to promote PacifiCorp's goals of consistency, objectivity and fairness. In administering the RFP, NCI used proven approaches for ensuring that the process adhered to the Company's (and Bidders') needs for information distribution in an objective and timely manner. As the primary conduit for information between the bidders and PacifiCorp, NCI managed all aspects of this process including, but not limited to, the following:

- » Validating the mailing list of bidders to ensure all potential bidders had been included;
- » Communicating with potential bidders to make sure they were aware of the process, schedule, response requirements, etc;
- » Ensuring that all likely bidders had received the RFP materials;
- » Addressing all questions submitted by bidders prior to the RFP response due date;
- » Issuing Bid Numbers to each bidder;
- » Soliciting the bids from the interested parties;
- » Clarifying bid information with bidders regarding their respective proposals;
- » Managing the entire Q&A process with the bidders to ensure accurate and impartial answers were provided to all and that all bidder identities were kept confidential;
- » Working with PacifiCorp to ensure that bidder questions were answered in a timely and accurate manner;
- » Reviewing all bids received;
- » "Blinding" the appropriate bid material;
- » Distributing the blinded bid material to PacifiCorp;
- » Coordinating with the Commercial and Trading Team; and
- » Coordinating with PacifiCorp Credit and PacifiCorp Legal.

iii. Review of PacifiCorp's Screening of Proposals

NCI's review of PacifiCorp's proposal screening process focused on the Company's financial evaluation of the RFP responses. NCI's objective with this task was to audit and validate that the screening of offers was done in a reasonable, consistent and fair manner across all of the proposals. In this role, NCI was involved in each step of PacifiCorp's review and valuation of the offers received to ensure that proposals were treated in a manner that identified the greatest value from each offer based on the terms presented by the bidders. NCI's functions within this task included:

» Overseeing the evaluation process employed by PacifiCorp for accuracy and fairness;
» Verifying the modeling assumptions used were consistent with the bids submitted;
» Verifying that the bid terms and conditions were accurately modeled by PacifiCorp;
» Coordinating the clarification of bids between PacifiCorp and the bidders;
» Reviewing and validating PacifiCorp's deal summary sheets;
» Ensuring that bids were assessed in the appropriate bid category that was most advantageous to their valuation; and
» Reviewing the preliminary and final valuation results developed by PacifiCorp.

iv. Validation of the Scoring and Ranking

Subsequent to the model review and validation, the next task was validating PacifiCorp's approach to the scoring and ranking of offers. NCI's approach to this task consisted of examining the results from the financial valuations and how they were rank ordered based on their score using the screening criteria (i.e., price, dispatch ability, and environmental characteristics). PacifiCorp performed the actual scoring and ranking, which was then assessed by NCI. NCI's focus was on validating that the scores were appropriate given the specific attributes of the offer and that the ranking of offers was consistent with the valuations produced from the offer modeling. Actions in this task included the following:

» Validating that the scoring criteria had been applied appropriately to each of the bids reviewed by PacifiCorp;
» Validating that the ranking was done in a manner that reflected the scores on the individual criteria and the total valuation of the offer;
» Recommending the depth of the short list with whom PacifiCorp should continue clarifying discussions;
» Reviewing and rendering an opinion on the shortlist identified; and
» Communicating with all bidders that made and did not make the short list.

v. Oversight of the Negotiation Process with Short List Parties

Once the short list had been identified and agreed upon by NCI and PacifiCorp, the process moved through a series of clarifying discussions with counterparties. NCI's involvement in these discussions was focused on ensuring that the offers, among those that were short listed, were being accurately interpreted and modeled. Additionally, if there was any flexibility, or changes, associated with the definitive offer, NCI sought to ensure that PacifiCorp captured those as a result of the dialogue with the bidders. To ensure that PacifiCorp and the bidder were interpreting terms in the same way, NCI recommended that offer summary sheets be used for the bidders to redline. Summaries from the discussions were always captured in updated offer summary sheets for each offer. Once clarified, PacifiCorp again valued the offers and derived a final short list of counterparties with whom to enter into more detailed negotiations. NCI was involved in recommending how deep to go in the list to ensure that PacifiCorp could maintain some leverage during the course of negotiation.

NCI's involvement in the negotiation process centered on the identification and chronicling of material issues associated with each offer. NCI saw its role as ensuring that PacifiCorp and the bidders engaged one another in earnest negotiations. The intent was to ensure that both bidders and PacifiCorp were negotiating with the expectation of moving toward a definitive agreement. It was NCI's focus to validate the reasons underlying the continuation, or discontinuation, of negotiations with each of the counterparties based on the respective terms and conditions of each offer. Central to this process was validation that PacifiCorp reasonably represented the risks as well as advantages associated with each offer presented by the bidders. NCI worked with PacifiCorp to ensure that bidders were provided a reasonable opportunity during the negotiation period to present the case for their offer and that the offer was treated in the same fashion as the Company's NBA in terms of offer clarification, the materiality of offer terms and conditions, risk identification, and economic valuation.

e. Modeling the Offers

PacifiCorp modeled each and every definitive offer that was presented to the Company through the RFP. PacifiCorp compared each proposal to its appropriate NBA, whether that was the cost-based alternative or the market-based alternative. Baseload and peaking proposals were compared to PacifiCorp's cost-based NBA. Each proposal that PacifiCorp received, regardless of bid type, was modeled separately. For super-peak offers, the NBA was considered to be purchases from the market, as represented by PacifiCorp's forward curve for power delivered into the eastern side of the Company's control area. For the baseload and peaking offers, PacifiCorp developed two primary analytical models to compare these types of offers to PacifiCorp's cost-based alternatives (See Table B). These two models include:

- ***Cost-based model*** is based on a PVRR analysis and was utilized to evaluate PacifiCorp's cost-based alternative as well as all proposals related to asset transfer.
- ***Market-based model*** is structured to facilitate the evaluation of power purchase agreement proposals, including fixed price contracts, fixed price options, and spread options

Table B. Valuation Models

Model	Methodology	Features	Products Evaluated
Cost-based Model	Net PVRR analysis over the life of a specific asset	Projects all estimated revenues and costs associated with the operation of the asset over its useful life	PacifiCorp's cost-based alternative and asset transfer proposals
Market-based Model	Net PVRR analysis using a mark-to-market value of the	Assesses a proposal based on the value of the proposed deal and allows for modeling of various deal	Fixed price purchases, tolling options, fixed price options

i. Cost-Based Model

The first model, for the evaluation of PacifiCorp's cost-based NBAs and all proposals for build and transfer or outright asset sales, was a PVRR model used to calculate the present value of the revenue requirement associated with a specific alternative. This model was developed by the PacifiCorp Resource Development group in its calculation of the NBAs, but had been modified by Structuring and Pricing (S&P) to allow for the determination of simulated dispatch of the asset being evaluated, including PacifiCorp's NBA. Since the incremental dispatch cost and characteristics determined the projected capacity factor of the proposal, this allowed for evaluation based on the expected market operation (i.e., the dispatch profile) as opposed to a predetermined annual capacity factor. This model was specified for each asset sale offer proposed to PacifiCorp.

As NCI performed an audit and validation of this model in its earlier report, its primary focus in this report is on the audit and validation of the modeling of the specific proposal provisions as opposed to the overall model structure, on which we have already offered comment.

ii. Market-Based Model

The second model developed for the evaluation of the proposals was based on a valuation only. The premise of the market-based model is that the value of an asset or an option is the greater of the market value over the strike price, or zero.

The market-based evaluation model was developed to accommodate a variety of different types of products for comparison against the NBA. When the word "products" is used, it refers to the different types of resources that PacifiCorp can choose from to manage its supply portfolio. Based on the type of product proffered in a proposal, PacifiCorp would select the appropriate type of calculation to use in the model. The market-based model PacifiCorp used was embedded with the internal capability for choosing the most appropriate product. There were not entirely separate models for each option. PacifiCorp had a simple switch function incorporated into the model that allowed the user to switch between the different calculations based on the defined inputs.

Based on the inputs from the individual proposals, the market-based model calculated (1) a real levelized and (2) a net present value revenue requirement (PVRR), which were then used in comparison to the PVRR for the comparable NBA. PVRRs were calculated for the wholesale (energy and capacity) portion of a specific offer. The wholesale portion included all specific costs associated with power generation, including, to the extent applicable, such items as variable and fixed O&M costs, fuel costs and gas delivery charges, and capacity payments. If transmission was not included, estimates for point-to-point service and transmission line losses to PACE were calculated specific to each offer evaluated. However, it should be noted that the transmission calculations only applied to those bids that were not delivered to or were located inside PACE.[3] The summation of these two cost components created a total PVRR for a specific offer which was then compared to the appropriate cost-based alternative PVRR on a $/MW-month basis.

Within each of the product types, the model was sufficiently detailed to capture specific operational or proposal characteristics and flexibilities.

[3] A condition precedent of the RFP was that a resource must be designated as a network resource to serve network load.

- ***Fixed price purchase option*** calculation allows for the specification of several locations, including Mona, Four Corners (345kV), Mead and Wyoming, as well as the offer profile (flat all hours, 6x16, etc.) and allowance for seasonal modeling of capacity.
- ***Fixed strike option*** allows for modeling as a call and includes the specific variable and fixed O&M costs identified in the proposal.
- ***Power/gas spread option*** (tolling) incorporates the major operational characteristics such as unit contingency, heat rate and heat rate degradation, capacity degradation, turbine type (simple versus combined cycle), variable and fixed O&M, a reference price for gas, and a fuel multiplier.

Other assumptions used in the product modeling included: forward prices for gas and electricity and inflation. Price curves for electricity and gas are based on PacifiCorp's corporate approved forward price curves. The source of the inflation rate assumption used in the modeling of bidder offers was PacifiCorp's official corporate rate.

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II. NBA Review and Validation Process

The approach used by PacifiCorp to develop the NBA went through a series of steps. As the Company moved forward with the implementation of its Integrated Resource Plan action plan, it identified its own cost-based alternative, the NBA(s), which would be used as a benchmark against other alternatives that would be presented from the market. Once the NBA(s) had been developed and reviewed by NCI, they were effectively locked down with all subsequent material changes being vetted and validated by NCI before being incorporated into subsequent financial analyses. The following walks through what went into the development of the NBA and its review and validation by NCI.

The NBA for peaking and baseload products in RFP 2003-A was a cost-based construction alternative in the event that an economic third-party alternative was not available. The scope of NCI's review included an assessment of the NBA development process, the assumptions embedded in the NBAs, and the model used to capture both one-time and on-going costs related to each NBA. NCI's objective during the course of its review was to establish a judgment regarding the following measures:

- Fairness of cost representation in the NBAs
- Viability of the NBA project options
- Reasonableness of the assumptions underlying each of the NBA options
- Soundness of the NBA expected cost modeling
- Consistency of material information included in the NBA report and what was requested of Bidders in the 2003-A RFP
- Assurance that PacifiCorp did not review any competitive information from bidders prior to the NBA being finalized.

Upon concluding its review, NCI was able to validate each of these measures concluding that the NBA options and the methodology used to develop them were reasonable and not inconsistent with other industry information. Throughout NCI's review, PacifiCorp remained cooperative and responsive to requests for information and clarification pertaining to the NBA options. As a third party objective reviewer, NCI welcomed the open nature of the NBA documentation review and validation that had to be performed. It further supported NCI's contention that the costs projected for each NBA option were derived in a transparent and logical manner. Lastly, NCI documented the fact that the NBA cost modeling was complete prior to proposal information being reviewed by PacifiCorp and established a protocol by which material changes to the NBA would require documentation by PacifiCorp along with NCI's review and audit of such changes.

a. Overview

i. Background and Objectives

NCI was retained by PacifiCorp in June 2003 to serve as an objective third party reviewer/auditor of the Company's NBA. NCI's mission was to conduct and complete a review of the NBA prior to PacifiCorp reviewing responses to its June 6, 2003 issued 2003-A RFP.[4]

The specific focus of NCI's review was to ensure that the analytical methodologies employed by the Company were both fair and reasonable. As laid out in PacifiCorp's 2003 IRP issued January 24, 2003, PacifiCorp intended to compare all competing resource alternatives, including market purchases, in the relevant market to a cost-based alternative.[5] The validation of the reasonableness of PacifiCorp's NBAs consisted of three cost-based alternatives. The scope of NCI's NBA review and audit included:

- Auditing the assumptions underlying the NBA
- Validating the reasonableness of the NBA assumptions and inputs, and
- Ensuring that the NBA model was complete prior to external bid review and that any subsequent material changes would require documentation and justification by PacifiCorp

During the course of the review, NCI took into consideration the commitments made by the Company in its IRP, but NCI did not attempt to validate the reasonableness of the conclusions within the IRP. The Action Plan and the commitment to both the Decision Processes and Procurement Program were viewed as positive steps toward implementing PacifiCorp's IRP in a fair, consistent, and methodical manner. NCI did not, however, attempt to validate the reasonableness of the Action Plan itself, the associated load forecasts, or other documented analyses supporting the Company's need for additional resources.

The premise from which NCI began its review was that the state regulatory bodies were supportive of the Company's need to acquire, or build, power supply resources over the next several years to meet what PacifiCorp refers to as "the Gap." As the Company goes through the process of evaluating different resource alternatives to fill this Gap, it is NCI's understanding that the NBAs have been developed to provide, at a minimum, a comparative cost structure against which competitive offers could be measured and evaluated. NCI's job through this first phase of the overall RFP process was to validate that the NBA options and the underlying assumptions were reasonable, that the projects were viable, and that the cost components of the NBA put forth by PacifiCorp were complete prior to their review of bid information.

Contained in the remainder of this report is a documentation of the steps NCI followed to validate the reasonableness of the NBA along with its conclusions.

[4] PacifiCorp Request for Proposals Electric Resources (RFP 2003-A), June 6, 2003.

[5] PacifiCorp Integrated Resource Plan 2003 " Assuring a Bright Future for Our Customers", January 24, 2003.

b. Approach to the Reasonableness Review

NCI's approach to validating the reasonableness of the NBA consisted of three primary steps: reviewing, auditing, and validating. To execute the analysis NCI relied on: (1) interviews with key personnel providing direct inputs to the NBA model, (2) a rigorous review of PacifiCorp's NBA model, (3) NCI's independent review of NBA work papers, and (4) external validation relying on subject matter experts within NCI with experience in assessing the development and operational costs of new capacity. Diagram 1 below illustrates NCI's NBA assessment process. During the process of review, NCI focused on determining the reasonableness of PacifiCorp's cost estimates and the overall viability of the NBA alternatives from a financial and operational perspective. In short, what NCI attempted to ascertain was whether or not PacifiCorp's NBA was a doable project that fairly represented the costs that would be incurred to bring the facility on line within the projected timeframe. While NCI did not specifically evaluate PacifiCorp's January 2003 IRP, the associated Action Plan, or its underlying assumptions for reasonableness, NCI did rely on the IRP to provide a broad understanding of what led to the Company's development plans for pursuing additional resources through a series of RFPs that it has issued and is planning to issue over the next 12 months.

i. The Interviews

NCI began its effort with a series of interviews of PacifiCorp personnel directly involved in the development of the NBA, including those that developed the model and those providing the input assumptions. The purpose of these interviews was several-fold. First, NCI wanted to understand and validate the basic process used by PacifiCorp to develop the inputs to the NBA. What NCI looked for was whether or not PacifiCorp approached the preparation of the NBA alternatives in a reasonable and disciplined manner. Second, NCI sought to determine the reasonableness of the NBA assumptions themselves and validate that they were not inconsistent with NCI's knowledge and familiarity of costs for other like projects. Third, in walking through the actual model with PacifiCorp personnel NCI wanted to validate that the NBA model was accurately representing the expected costs under those alternatives. Fourth, NCI wanted to validate that the NBA model components were consistent with what was being requested of bidders. Through the interviews, NCI was able to better understand the content of the key assumptions to validate against the information requested of bidders in the 2003-A RFP.

ii. Model Review

In order to get comfortable with the NBA, NCI also conducted a rigorous review of the NBA model provided by the Resource Development group. This was the basic model used to capture the estimated costs of each of the cost-based alternatives that the Company is considering to meet its projected supply needs over the next several years. NCI's review of the model focused on the individual calculations being done, the treatment of costs, and the interaction of cost components among one another. Conducting this review enabled NCI to establish the soundness of the model and its associated output results.

iii. Work Paper Review

In addition to the PacifiCorp interviews and model review, NCI also reviewed actual work papers used to develop the input assumptions for the NBA. NCI's guiding principle in the review was validating that the assumptions themselves were reasonable and had been appropriately reflected in the model. The work paper review was important to provide an understanding of what went into the derivation of each assumption and why costs may have departed from the work papers in the final cost modeling. This provided a valuable crosscheck against the information obtained in the interviews as well as providing another touchstone for validating the reasonableness of the expected costs embedded in the model.

iv. Subject Matter Expert Validation

Lastly, NCI leaned on subject matter experts within NCI to assist with the validation of various expected cost and performance assumptions associated with the cost-based alternatives. This included validating the content of cost assumptions having a material effect on value, confirming the reasonableness of the expected all-in-costs, and validating the expected equipment/facility performance capabilities of the proposed NBAs. Questions raised during the course of this validation dealt with the inclusion of substation expenses, the treatment of environmental costs, the impact of site location on equipment performance, the cost of a new gas lateral, and the methodology employed to develop the price forecasts for electricity and gas, among other cost-related factors, all of which NCI validated.

c. Project Viability

In addition to the review and audit of the assumptions and the modeling, NCI were also tasked with providing assurance to external constituencies that PacifiCorp was proffering a viable project that could be completed in a reasonable time frame consistent with the dates which the Company had stated the NBA could be up and running. Given the NBA information, NCI validated it against its experience with developing other like facilities. NCI also sought to understand the permitting requirements associated with the NBA options. For the purpose of the analysis, NCI assumed that these permits would be obtainable in a timely manner, given the background work PacifiCorp had already conducted.

NCI also examined site attributes, equipment selection, the preliminary design estimate and schedule, projected interconnection requirements, and the gas transportation needs related to the selected site to reinforce NCI's confidence in stating that project construction is feasible within the time frame outlined.

d. Selection and Finalization of the NBA

To preserve the objectivity of the bid review process, NCI was tasked with validating that the cost components and the allocation of costs across different categories for the NBA, and ensuring that these were finalized before PacifiCorp commenced its review and evaluation of bidder responses. This validation was necessary to establish the fact that PacifiCorp would be unable to subjectively modify individual costs or how they were allocated across different fixed and variable categories after seeing bidder offers and their respective deal structures. Any material changes subsequent to NCI's initial review of the final NBA cost model, and the issuance of this report, will require documentation by PacifiCorp along with written justification for the change. As the outside independent evaluator, NCI will continue to be responsible for reviewing documentation for any material changes made by PacifiCorp regarding the NBA valuation.

Once PacifiCorp received word from NCI that the NBAs were reasonable estimates of the costs associated with each alternative, the Company finalized, with NCI's approval, which NBAs would be used as the benchmark for each bid category. Only after this review and validation was complete did PacifiCorp have an opportunity to review any bid material. A subtle point that is important to note regarding the lockdown of the NBAs is that internally, PacifiCorp's Resource Development group developed the cost-based alternatives, which were then economically dispatched by PacifiCorp's Structuring and Pricing group to determine their value. From a valuation perspective, what that meant is that each NBA was treated just like every other alternative with costs, inputs, operating characteristics, and performance limitations that all were taken into account to derive the value of the alternative to PacifiCorp. Structuring and Pricing, the group responsible for completing the review and valuations of bidder offers, did not have a hand in determining what the inputs were for the NBA. From their perspective, the NBAs were merely other resource alternatives to be run through the economic dispatch model.

e. Summary of Review Objectives

In summary, there were six key questions NCI was intent on addressing through its audit, review and validation of the NBA.

1. NCI wanted to determine whether PacifiCorp fairly represented the expected costs associated with each of the NBA alternatives.
2. NCI sought to assess the viability of the NBA alternatives by examining the proposed engineering, procurement and construction schedules and outside the fence infrastructure needs.
3. NCI wanted to assess the reasonableness of the material assumptions presented by PacifiCorp in its NBAs.
4. NCI wanted to validate that the modeling undertaken by the Company was robust and not subject to fundamental modeling errors.
5. NCI wanted to establish whether or not the NBA and the RFP were consistent with one another in terms of material data requested of bidders and information aggregated regarding the NBAs.
6. Lastly, NCI sought to make certain that the NBA expected costs would be finalized before the Company reviewed any proposal information. Related to this point, NCI wanted to ensure that PacifiCorp would have a process in place that facilitated the documentation and justification of later changes to the cost and operational assumptions.

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III. The Bid Review and Screening Process

NCI's review of the screening process focused on the approach used by PacifiCorp to screen and evaluate the offers it received in response to the RFP. Our intent was to document the approach taken by PacifiCorp to screen and evaluate the offers obtained from the market, to provide a record of the audit, review and validation effort undertaken by NCI to assess the reasonableness of the screening review process and to provide external stakeholders with the results of NCI's findings from its review.

NCI's objective during the process of conducting the screening review was to assess and validate the following issues:

» Did PacifiCorp use a consistent and fair methodology to evaluate the proposals?
» Did PacifiCorp use analytical tools that were well suited, as well as appropriate and reasonable, for calculating valuations?
» Did PacifiCorp accurately capture proposal terms and conditions in the evaluations?
» Was the treatment of each proposal consistent during the bid review process?
» Was the scoring and ranking of proposals done in a consistent manner across all of the proposals?
» Was the bid scoring and short-list determination process transparent and consistent with the evaluation results?
» Did PacifiCorp select the most appropriate next best alternative (herein after referred to as the "NBAs") as the benchmark for each of the individual proposals (e.g., peaking bids with the peaking NBA and so on)?[6]

The accuracy and fairness in the treatment of bids was of paramount importance to NCI throughout the screening process. Bidders benefited from an objective third party administering all aspects of the screening process including assistance in the clarification of bids and ensuring proper documentation regarding the actual interpretation and modeling of proposal terms. NCI provided a check and balance that bidders were fairly treated throughout the process and that the review of proposals was completed in a manner that was reasonable, fair, unbiased and comparable ("Fair Manner").

The method NCI used to audit and review the screening process entailed a thorough assessment of each aspect of the process from reviewing and validating the breadth of outreach used by PacifiCorp to solicit competitive responses to a rigorous review of the modeling, valuation and scoring methodology used to derive the short list. Throughout the review, NCI provided direct, real-time feedback to PacifiCorp to facilitate their ability to make contemporaneous adjustments to enhance the integrity of the process.

[6] The NBAs are PacifiCorp's (1) market-based and (2) cost-based alternatives for meeting its projected supply requirements going forward. These NBAs represent the alternatives that PacifiCorp could fall back on in the absence of more economic and viable alternatives being offered by the market.

Over the two-month long screening review effort, NCI found PacifiCorp to be fair and balanced in their treatment of proposals. Where information was not provided or was unclear, every attempt was made to remedy the situation through direct communications with the bidder. Furthermore, proposals were treated in a consistent fashion to ensure that comparisons of offers of a like type were made. From NCI's perspective, this was a critical element in providing a level playing field to the bidders, allowing PacifiCorp to derive meaningful and comparative scoring information for evaluating the bids.

The screening review approach used by PacifiCorp followed a logical sequence of steps from offer identification, through valuation, scoring and bid ranking. Their approach provided a consistent framework for considering each offer. Throughout the execution of this process, PacifiCorp demonstrated a focus on ensuring that offers were subjected to a consistent and balanced review.

PacifiCorp was open and forthright in sharing its models, assumptions, and interpretation of terms. The process transparency and PacifiCorp's willingness to ensure a fair and balanced process allowed NCI to provide on-going feedback that was used to validate and incrementally enhance the screening process. NCI found this process was implemented fairly and consistently across each of the proposals received.

a. Screening Assessment

The purpose of this section is to review all of the steps that NCI went through to assess and document the screening process used by PacifiCorp. The section summarizes the background and timeline of the RFP and examines each element of the screening evaluation including the process, the models, the scoring and ranking.

i. Timeline and Steps in the Screening Process

The RFP was issued on June 6, 2003, and included a required proposal submittal date of July 22, 2003. In order to ensure the widest distribution and interest-level possible, PacifiCorp sent copies of its RFP to a distribution list of over 225 potential Respondents, established a special RFP website for the sole purpose of disseminating information about the RFP and to answer related questions, announced the issuance of the RFP in a press release, and held a Pre-RFP Bidders Workshop on March 21, 2003 and an RFP Workshop on June 20, 2003 that on a combined basis had over 100 people in attendance.

The RFP requested that Respondents intending to submit a proposal to PacifiCorp submit a Notice of Intent to Bid by June 27, 2003. NCI, on behalf of PacifiCorp, received 44 such notices. This represented approximately a 20% response rate from the initial notification that PacifiCorp made to the market.

To gauge the volume of responses that would be received from the market, at the time Bid Numbers were issued to potential respondents, NCI asked bidders to indicate whether or not they would be submitting more than one proposal that they would like PacifiCorp to consider. In cases where companies anticipated submitting multiple offers, they were issued one Bid Number to correspond with each proposal they were intending to submit. In total, NCI issued 86 separate Bid Numbers to potential bidders. This was done to blind the proposals in such a way that PacifiCorp personnel would be able to evaluate each offer on the respective merits of the proposal, without consideration for the creditworthiness and/or financing capability of the potential counterparty. While bidders submitted financial information in their proposals, this information was not forwarded on to the PacifiCorp personnel responsible for evaluating and scoring each of the proposals. This information was forwarded under separate cover to the Credit group within PacifiCorp for their independent assessment. Effectively, the proposed terms and conditions of the proposals were evaluated in parallel with the creditworthiness review. It is important to note, however, that the development of the short list was not dependent upon the creditworthiness review. Only after bidders were identified on the preliminary short list was their credit and financial strength taken into account.

On July 22, NCI received at its offices proposals from 37 companies, a response rate of nearly 85% relative to the Notices of Intent to Bid received. These 37 companies submitted 79 separate offers for PacifiCorp's consideration. While the majority of respondents followed the requested format of one bid number per proposal, several submitted their proposals with multiple offers included within one bid number. At PacifiCorp's request, NCI forwarded the blinded materials onto the Company instead of delaying the process by issuing additional bid numbers and requiring bidders to resubmit their offers under separate bid numbers. PacifiCorp then separated the indicative term sheets and pricing information from the multiple proposals into separate proposal groups requiring evaluation (See Table C). As a result, PacifiCorp ended up evaluating 94 individual proposals.[7]

Table C. Overview of RFP 2003-A Responses by Resource Type

	Baseload	Peaker	Super Peak
Number of Offers	53	28	13
MWs	18,029	5,328	992
Range of Offers	7 to 674	25 to 669	7 to 300
Period of Service	5-20 years	10-20 years	1-4.6 yrs
Basic Product Types	Fixed Price Swap; Toll; Spread Option; Fixed Strike Option; Plant Lease; Plant Purchase	Spread Option; Fixed Price Option; Toll; Asset Purchase	Spread Option; Fixed Price Swap; Fixed Strike Option

During the course of PacifiCorp's review, questions were raised regarding the interpretation of some of the terms proposed by the bidders. In such cases, PacifiCorp forwarded questions to NCI that were then put into a structured and consistent format and subsequently delivered to the respective bidder. NCI provided bidders with a twenty-four hour window within which to respond to the questions posed. In most cases, bidders submitted their responses within the agreed upon time frame and in a manner that was viewed as responsive to the question(s). However, in several

[7] MW figures are based off of summer ratings; aggregate totals include multiple counts of a single facility in the case of different terms; * A total of 103 individual offers were received, but 9 had insufficient information to allow for valuation; ** A number of offers included just equipment, and so were evaluated over the economic life of the asset; *** Four offers were contingent duct firing so they are embedded within the 53 baseload offers.

instances, there were bidders who were repeatedly asked to clarify the terms of their proposals yet continued to provide evasive responses. Without the information requested, PacifiCorp was unable to reasonably conduct a valuation of those proposals. NCI and PacifiCorp agreed that in such cases, the bidder's proposal would be dropped from further consideration.

For those proposals that PacifiCorp was able to model, the Company prepared an individual PVRR analysis for each. Consistent with the action plan laid out in the IRP, the bid categories of Baseload, Peaker, and Super Peak were used by PacifiCorp to organize the numerous offers accordingly. The starting point for each valuation was the creation of a deal summary which inventoried all of the key inputs of the offers including the size of the offer, the duration of the offer, the pricing components, points of delivery, the start dates for commercial delivery, and the performance guarantees of the offer. After this information was collected from the proposals, a PVRR model was populated with the appropriate assumptions and adjusted to reflect the exact terms proposed by the bidder. Subsequent to this valuation, PacifiCorp assigned a score to each screening criteria (pricing, dispatch ability and environmental attributes). Once the Company completed its valuation, assigned a score to the offer, and conducted an internal quality check of the accuracy of inputs, the individual models were forwarded to NCI for review. The Company also provided a consolidated summary of the blinded results for all of the offers in the respective categories.

The final step in the process was an evaluation of the ranking of each of the offers and the short list selection. Ranking of the proposals was done based on the aggregate scores received for the proposal. NCI recommended that PacifiCorp derive the short list based on three to five counterparties and two to three times the MW commitment required. For example, since the Company's Peaking NBA had a designed capability of 525 MW, the short list consisted of five counterparties with a total MW commitment of just less than 2,100 MW. This provided the Company with a breadth of counterparties and depth in each bid category that was more than adequate to meet the Company's stated resource requirements for June 2005.

Throughout the process, to preserve some leverage in negotiating with counterparties, NCI recommended that PacifiCorp proceed in discussions and negotiations simultaneously with the top counterparties in each bid category. Although PacifiCorp did have an NBA to fall back on in case negotiations did not result in a less costly and risky alternative to one of the NBAs, it was deemed necessary to ensure that counterparties were dealt with in an expeditious manner and that the time needed to negotiate a definitive agreement would be ample. Before coming to the final short list, PacifiCorp gave each of the bidders on the preliminary short list an opportunity to revise their offers in hopes that a more economic alternative would be available to customers.

ii. NCI Proposal Review

This section describes the approach taken by NCI to document and assess PacifiCorp's review and ranking of bids received in response to the 2003-A RFP. NCI's guiding principle during its review was to ensure that the treatment of proposals was done in a fair and consistent manner, such that no proposal would be granted any undue advantage over another. It was also NCI's intent to preserve a sense of reasonableness regarding the comparative review and scoring process used by PacifiCorp to evaluate, score and rank the individual proposals.

NCI's review of the overall proposal screening process can be segmented into three primary phases of review:

» Phase 1: Deal Terms
» Phase 2: Deal Modeling
» Phase 3: Deal Comparison and Ranking

Deal Term Review: In the first phase, proposal term evaluation, NCI independently prepared its own summary of the terms offered by each of the bidders. This consisted of a spreadsheet summary of all the offers by bid category, i.e., Super Peak, Peak, Baseload, and other. This spreadsheet contained such information as the capacity commitment, pricing terms, scheduling terms, facility status, point of delivery, fuel type, and availability guarantees, among other things. NCI developed this summary of proposal terms relying on its own review of the proposals submitted by bidders. Contemporaneous with the preparation of this summary, PacifiCorp developed its own deal summary. This document included the same types of information gleaned from PacifiCorp's review of the blinded proposals that was contained in NCI's document. Taking these two documents along with the proposals themselves, NCI went through each of the input assumptions identified by PacifiCorp to assess whether or not the Company had accurately and fairly represented the terms as presented by the bidders in their respective proposals. Going through this side-by-side comparison allowed NCI to identify disparities between the way NCI and PacifiCorp interpreted the terms of the proposals. As a result of this initial review, NCI prepared a summary list of questions for PacifiCorp by bid number that were in turn addressed by PacifiCorp and incorporated into their modeling of the proposals.

Deal Modeling Review: In the second phase of review, deal modeling, NCI sought to achieve two goals – ensure that the modeling being done was consistent across each of the proposals and that the proposal modeling fairly represented the terms and conditions presented in the offers from bidders. Using the finalized input material aggregated from the summaries put together by NCI and PacifiCorp, NCI proceeded with an independent review of the models that were developed by PacifiCorp to value each of the proposals presented by the bidders. At this stage of the review process, NCI's focus was on establishing whether or not there was consistency in the modeling done for each of the proposals, not on the relative scoring of those proposals to the benchmark NBA.

NCI segmented its review of the deal modeling into the three separate bid categories solicited by PacifiCorp in the RFP: Super Peak, Peak, and Baseload. Rather than deliver each of the models to NCI in a piecemeal fashion, PacifiCorp used a consolidated approach of completing the modeling for all of the proposals in a bid category and then forwarding them in aggregate. By using this approach, PacifiCorp was able to better control the consistency of modeling and assure that any modeling assumptions made in one proposal would be reflected in the rest of the proposals within each of the bid categories. This also averted any issues with loss of version control since all proposals in a category would have the same modeling structure. As the outside auditor, this approach made it more practical for ensuring consistency in the modeling and identifying differences in how one proposal was modeled relative to another given the specific terms and conditions associated with the specific proposal.

NCI conducted its modeling review examining each group of proposals individually. To complete this review, NCI followed a series of steps to achieve two specific goals – (1) validating that the terms were accurately and fairly represented in the modeling and (2) ensuring that there was consistency in how proposals of a similar type were modeled. For NCI to stand behind the integrity of the modeling process, it was important to validate that the proposals being modeled in a particular category were appropriate given the terms put forth by the bidder, i.e., validating that the proposal did not belong in a different bid category. For example, in two instances the bidders stated that they were responding to the Baseload bid category, but their offers were for commitments that would meet the June 2005 commercial on-line date. In these two cases, offers initially thought to be baseload offers were subsequently analyzed as peaking offers. Second, NCI sought to validate that PacifiCorp accurately and consistently modeled the proposal without arbitrarily advantaging or disadvantaging one proposal relative to another. Third, NCI crosschecked the modeled input assumptions with the deal summary spreadsheets prepared by both PacifiCorp and NCI as further validation that the proposed terms were input correctly. Fourth, NCI went through each model to ensure that the calculations and valuations were producing results that one would expect to see. Going through this detailed process step by step allowed us to establish confidence that PacifiCorp was approaching the proposal valuation process in a concerted, fair, and reasonable manner. Upon completing our review we found the proposals to have been fairly and reasonably modeled.

Deal Comparison and Ranking Review: In the third phase, deal comparison and ranking, NCI's focus was on the means by which PacifiCorp evaluated, compared and ranked the proposals received from the market. NCI's review consisted of an examination of the Company's approach to three key steps – selecting the most comparable NBA, comparing all of the offers in a bid category, and the subsequent ranking of the offers relative to one another. Prior to beginning this review, NCI had to ensure that PacifiCorp had received all of the information it needed to complete the valuation of the offers. Once NCI did this and was in agreement with PacifiCorp regarding the categories within which each and every bid fell, PacifiCorp could complete the task of comparing and ranking all of the offers. Although the majority of the bidders were responsive to questions posed to them during PacifiCorp's review process, it is important to reiterate that proposals that remained either vague or incomplete were left out of the comparison and ranking process, i.e., they received no valuation or score for screening purposes. This elimination occurred only after bidders received two written requests to submit information that would facilitate a valuation and failed to do so. The requests advised bidders that the information being sought was necessary for PacifiCorp to complete its valuation of their offer and that failure to provide the requested information would result in their proposal being eliminated from the process.

The first step in the comparison was choosing the appropriate NBA to use as the basis for determining the percentages to assign to the proposal for its pricing relative to the estimated costs of the benchmark NBA. If the offer was for a capacity commitment that would meet a need projected by the Company for 2007, then it was deemed to most closely resemble the baseload resource being sought by the Company. If the proposal offered a June 2005 start date, or a date close to that it was deemed as being responsive to the peaking resources needed by the Company and was therefore compared with the peaking resource NBA. Likewise, offers that were considered Super Peak bid category offers were those offering an annual or summer shaped product between 2004 and 2007. In the majority of cases, it was clear what bid category the bidder was submitting its proposal to, so it was a simple effort of choosing the right NBA. In a couple of cases where it was not readily apparent which bid category the proposal was being responsive to, PacifiCorp selected the one that would result in the higher percentage score for the proposal on the pricing component of the overall selection criteria for that proposal.

The second step in the comparison was looking at the relative comparison of the proposals in each bid category and ranking them against one another. In the case of the Baseload bid category offers, this was a straightforward process of ranking, which took into account the aggregate percentages received on the price and non-price screening criteria. However, the pricing associated with the overwhelming majority of peak and Super Peak offers ended up being far less economic than the costs associated with the NBAs.[8] Consequently, the effective score on the pricing components ended up being zero. This led to a situation in which proposals in two of the three bid categories would be ranked solely on dispatch ability and environmental attributes. Given this unexpected situation, PacifiCorp had to come up with an additional means of identifying a short list of proposals/bidders. Since pricing was being left out of the equation on the first pass using the existing screening criteria, PacifiCorp decided that it would be appropriate to secondarily rank the list by the PVRR associated with each offer. To do this, PacifiCorp took the PVRR of a proposal and calculated a relative value based on its PVRR relative to the PVRR of the related NBA on a per 100 MW-month basis. This was done by simply subtracting the PVRR of the related NBA from the PVRR of the proposal to come up with a normalized PVRR per 100 MW-month that would allow side-by-side comparisons of each of the proposals on a consistent basis. NCI found this to be a reasonable means of further ranking the offers since it was consistent with the original intent of the pricing criteria in the RFP.

The third step in the comparison involved the ranking of the offers relative to one another. The ranking of proposals was determined by both price and non-price factors in a manner that was consistent with the RFP. As expected, the Company ranked each of the proposals according to their aggregate score obtained for both price and non-price factors. To further narrow the short list, the Company then took the proposals and secondarily ranked them based on their PVRR as described above. To derive its preliminary short list, PacifiCorp worked from the top down in the resulting rankings to identify the most viable candidates with whom it would hold clarifying discussions. It is important to note that only those offers that made the preliminary short list were deblinded for PacifiCorp. All of the other offers not making this list remained blinded.

iii. Description of Resources Modeled

In its RFP, PacifiCorp solicited proposals in three different bid categories from prospective bidders: Baseload, Peaker, and Super Peak. An important step for PacifiCorp to decide before reviewing any of the bids in each of these categories was determining what to benchmark these bids against. PacifiCorp identified market and cost based options that could be used as an effective benchmark against the terms proposed by bidders. In the case of the Super Peak offers, the Company believed that the most likely alternative to potential proposals was a comparison against the forward power market (i.e., a mark-to-market). However, in the case of the other desired responses, the 575 MW baseload resource sought for 2007 and the 200 MW resource sought for 2005, the most likely

[8] This effective score of zero on the pricing criteria resulted from PacifiCorp's assumption that it would receive proposals that were less expensive than the benchmark NBA, which it did not.

alternative was the construction of these resources by the Company or the market. As a result, bids received in the baseload (e.g. coal, gas-fired generation, or other) and peaking supply categories were compared against an NBA. To ensure a fair comparison between the NBA and the proposals offered by bidders, PacifiCorp communicated effectively to each of the bidders what the timing of resources being sought was and what minimum attributes those resources possessed.

The minimum requirements that PacifiCorp sought from the proposals submitted varied by bid category. In the Super Peak category, the minimum criteria that PacifiCorp wanted to have met included a start date by June 2004, a summer shaped product, and offered firm delivery in or to the PacifiCorp East system. The offers in the peaking bid category were expected to offer commercial operation dates no later than June 2005, must be flexible in order to be dispatched daily, and delivered in or to the PacifiCorp East system. Similarly, the Baseload bid category minimum requirements called for commercial operation by June 2007 and delivery in or to the PacifiCorp East system. Before discussing how PacifiCorp went about modeling the proposals in each bid category, an overview of each bid category is provided below (See Table D).[9]

Table D. Description of PacifiCorp's Bid Categories

	BID CATEGORIES		
	Baseload	Peaker	Super Peak
Start of Delivery (COD)	June 2007	June 2005	June 2004
Contract Duration	Up to 20 Years	Up to 20 Years	Up to 4 Years
Size (MWs)	Up to 570	Up to 200	Up to 225
Preferred Delivery Attributes	7x24 Delivery	Daily Call Option	June–Sept ('04–'07); Delivery during HE 1300 – HE 2000 or Daily Call Option
Dispatchability	Flexible	Daily Dispatch	Daily Dispatch
Point of Delivery (POD)	In or to PacifiCorp Eastern System (PACE)	In or to PacifiCorp Eastern System (PACE)	In or to PacifiCorp Eastern System (PACE)

» ***Super Peak Bid Category:*** Super Peak bid category responses were those offers that were intended to meet PacifiCorp's needs during the HE 1300 - HE 2000 PPT period on either a 7X8, 6X8, or 5X8 basis for the summer months of June to September from 2004 through 2007. The resource could also be available as a daily call option. These were the first models prepared and completed by the PacifiCorp personnel responsible for the base valuations. In this bid category, PacifiCorp was looking for a variety of attributes in addition to the months and hours of need outlined. Super peak offers preferably were to exhibit such attributes as deliverability at PacifiCorp's option, the ability to pre-schedule, delivery to the Eastern PacifiCorp system, and

[9] These minimum bid requirements are detailed in the materials presented to bidders by PacifiCorp at the June 20, 2003 RFP 2003-A Pre-Bid Conference; Baseload and Peaker bid category turnkey or life of asset offers were evaluated over their estimated economic life.

structuring under a negotiated arrangement based on a PPA, tolling agreement, or lease. In aggregate, PacifiCorp was looking for approximately 225 MW of capacity in this category, or larger if economies of scale could be demonstrated.

» ***Peaker Bid Category:*** Offers in this bid category were expected to meet PacifiCorp's minimum requirements as indicated earlier (i.e., daily dispatch and commercial operation by June 2005). Offers put in this category typically provided some form of call option structure either hourly, intra-day, daily, day ahead, or some other basis. Heavy load and super peak load hours were the target for this bid category. Peaker offers could be built upon a variety of physical and financial structures depending upon which party would be interested in assuming the various responsibilities and risks. In its RFP, PacifiCorp expressed an interest in considering alternatives using either one of the structures. The Company also indicated that offers of a term up to 20 years would be of interest. Proposals modeled in this category by PacifiCorp consisted of PPAs, asset purchases, and turn-key construction projects. In aggregate, PacifiCorp was looking for approximately 200 MW of capacity in this category, but advised bidders that they would entertain offers for commitments well in excess of this amount on account of its revised load forecast suggesting an additional need for peaking resources than had originally been identified in the Company's IRP filing.[10]

» ***Baseload Bid Category:*** Baseload bid category offers solicited by PacifiCorp were expected to meet the minimum requirements outlined in the RFP (i.e., commercial operation date no later than June 2007). All of the responses modeled in this category were 7x24 offers, with some including 7x8 offers (duct-firing) with their response in addition to the 7x24. With this bid category, PacifiCorp was looking for resources that could meet around the clock capacity and energy needs by June 2007 for a period of up to 20 years. Like the peaker offers received, the baseload offers in this category consisted of PPAs, asset purchases, and turn-key construction projects. In aggregate, PacifiCorp was looking for approximately 570 MW of capacity in this category, but indicated to bidders that offers in excess of this amount would be considered if economies of scope and scale could be demonstrated.

Among these three bid categories, the offers fell into four main categories: power purchase agreements (PPAs) which include physical and/or financial tolls; turn key facility construction with sale back; facility leases; and, equipment sales. Under the PPAs, it was expected that the counterparty would be making a power sale to PacifiCorp from an existing facility, a yet to be built facility, or from an unspecified source. Offers in the turnkey category involved the bidder selling a completed project to PacifiCorp that is constructed on a bidder supplied site or a site chosen by PacifiCorp. The payment for these options was either in the form of an up front lump sum or a series of payments over a defined period of time. Facility leases were offers to construct and lease a completed facility to the Company. Lastly, a number of companies proposed equipment sales of a variety of equipment types, but they were primarily turbine generators. The sale of equipment was determined as not having a project on-line to meet the commercial on-line start dates of June 2005 and June 2007, for the Peaker and Baseload bid categories, respectively. Consequently, offers of this type were eliminated from further consideration.

[10] See PacifiCorp's Quarterly IRP Public Input Meeting, May 19, 2003.

» ***Hybrid Resource:*** Once the decision was made to move forward with the Peaking Resource NBA, a Hybrid Resource was appropriate to use against incremental resources over the Peaking Resource. In order to capture economies of scope and scale associated with constructing facilities that have a lower incremental construction cost due to shared infrastructure, PacifiCorp identified a hybrid resource option. This hybrid option consisted of the peaking NBA combined with the baseload NBA. This was developed in order to facilitate the comparison of the peaking and baseload NBAs in combination with a bidder offer. For example, use of this resource configuration allowed PacifiCorp to consider the overall economics of a peaking NBA with a baseload market offer to ensure that economies of scope or scale would not be lost in the event one of the NBAs was deemed the most economic. This approach kept with the Company's objective of securing the least cost resources on behalf of its ratepayers.

b. Responses to the Solicitation

PacifiCorp's RFP elicited a variety of responses from the market. In all, 37 different companies responded to the RFP with over 100 proposals for the Company to consider. As the Company moved through clarifying discussions with bidders, additional offers were received from short listed bidders that were exclusively hybrids of what had already been offered. This resulted in approximately a half dozen additional offers that PacifiCorp evaluated. After each and every time that a bidder clarified prices and terms associated with their respective offers, PacifiCorp prepared a revised summary of the offer along with a revised economic model of that offer. In turn these were all then reviewed by NCI for their accuracy in representing the economics of the deal and the consistency with which they were compared with PacifiCorp's NBA.

The purpose of this section is to provide an overview of all of the RFP responses including a brief description of the types of offers and their typical attributes.

c. Overview of Responses Received

PacifiCorp initially evaluated 94 specific proposals from bidders. As further discussions were held with bidders to clarify their offers, the Company received additional offers (variations of the original offer received) that it evaluated in the context of the RFP. When offer variations came into the Company for its evaluation, it is important to note that they were evaluated in the same bid category as the bidder's original offer and were subsequently ranked against PacifiCorp's NBA as well as the other proposals received in that bid category. To avoid confusion regarding the actual number of proposals reviewed by PacifiCorp, it is helpful to understand the timing of the review process and what occurred at each stage. As the Company worked through the process of evaluating the initial offers received with bidders and PacifiCorp had an opportunity to clarify what the short listed bidder was interested in and capable of providing, there were instances in which the bidders submitted revised offers for the Company to consider.

There were basically five different types of generation offers that were received from bidders: (1) turnkey offers; (2) power purchase agreements; (3) equipment sales; (4) lease arrangements; and (5) equity offers. Following is a brief description of the attributes that each type of offer included among the proposals received (See Table E).

» ***Power Purchase Agreements*** – These offers entailed the delivery of capacity and energy to PacifiCorp over a fixed period of time under a predetermined pricing structure. There was a wide variety of power purchase agreement offers made to PacifiCorp including physical and virtual tolling agreements, fixed price call options, fixed price swap, and power/coal spread options. PacifiCorp received 72 of this type of offer.

» ***Turnkey Offers*** – These offers involved proposals to design, permit and construct a facility that would be turned over to PacifiCorp at the date of commercial operation. PacifiCorp received 14 of this type of offer.

» ***Equipment Sales*** – These offers involved the sale of physical equipment, such as turbines and generators, to PacifiCorp for use at a site of PacifiCorp's choosing. PacifiCorp received 5 of this type of offer.

Table E.
Breakdown of Initial Offers by Type by Bid Category

	Super Peak	Peaker	Baseload
PPA Types			
Power/Gas Spread Option	8	17	30
Fixed Price Swap	3	--	6
Fixed Strike Option	2	--	2
Fixed Price	--	--	3
Power/Coal Spread	--	--	1
Subtotal	13	17	42
Others			
Turnkey	--	8	9
Equity	--	--	--
Equipment Sales	--	2	--
Leases	--	1	2
Subtotal	--	11	11
Total	13	28	53

» ***Lease Arrangements*** – These offers involved a fixed payment to the bidder over a set period for full dispatch rights to a facility. Lease payments would be in lieu of fixed capacity payments and other fixed charges. PacifiCorp received 3 of this type of offer.

» ***Equity Offers*** – These were proposals made by bidders offering PacifiCorp an option to purchase either a majority or minority equity stake in an existing facility or development project. While PacifiCorp did not receive any offers for an equity stake initially, as discussions evolved with the short listed bidders, the Company did end up receiving one offer for an equity stake in a partially developed facility.

i. Attributes of the Offers

In the interest of being as inclusive as possible, PacifiCorp, through its RFP, sought to attract a wide variety of offers within each bid category. To this end, PacifiCorp structured its RFP to encourage bidders to be creative in what offers they brought to the Company. PacifiCorp's interest was in allowing the market to provide the best alternatives that it could while meeting some minimal requirements. As noted in the Pre-Bid Workshop materials, there were several attributes that the

Company preferred, which were to be used by bidders as a guide for preparing their responses. The attributes that were the most important were the dates for the commencement of commercial operation and the dispatchability of the resource. Table F outlines what the requirements were by bid category. Around these two criteria, PacifiCorp received a wide array of offers including various contract durations, megawatt commitments, heat rates, delivery points, and pricing approaches (See Table F).

Table F. Bid Category Characteristics Identified in the RFP

	BID CATEGORIES		
	Baseload	Peaker	Super Peak
Start of Delivery (COD)	Jun-07	Jun-05	Jun-04
Contract Duration	Up to 20 years	Up to 20 years	Up to 4 years
Size (MWs)	Up to 570	Up to 200	Up to 225
Preferred Delivery Profile	7 x 24 delivery	Daily call option	June-Sept. ('04-'07); Delivery during HE 1300-HE 2000 or daily call option
Dispatchability	Flexible	Daily Dispatch	Daily Dispatch
Point of Delivery (POD)	In or to PacifiCorp Eastern system (PACE)	In or to PacifiCorp Eastern system (PACE)	In or to PacifiCorp Eastern system (PACE)
Requested Transaction Structures	Negotiated (PPA, toll, lease, turnkey sale, equity participation, etc.)	Negotiated (PPA, toll, lease, turnkey sale, equity participation, etc.)	Negotiated (PPA, toll, lease, etc.)

As Figure 2 illustrates, across the three bid categories, bidders submitted a wide range of offers. The figure depicts the range of megawatt commitments made by bidders and the duration of the offers. The peaker and baseload offers that extended beyond the preferred 20-year PPA period were exclusively turnkey facility construction projects that were looked at by PacifiCorp over their expected life.[11] The Super Peak bid category offers ranged in size from a few MW up to 300 MW over a one to four year period beginning June 2004. The Peaker bid category offers ranged in size from a few MW up to just over 400 MW. The term of these respective offers ranged from ten years up to the useful life of the asset, in the case of some turnkey development projects offered to the Company. The baseload offers had a similar range of five years up to the useful life of the asset. The size of the megawatt commitments ranged from a few MW to over 1,000 MW including duct firing capability.

[11] See PacifiCorp Integrated Resource Plan 2003, Appendix J, pgs. 354-358 for a detailed discussion of the methodology used in the IRP to compare projects of unequal lives.

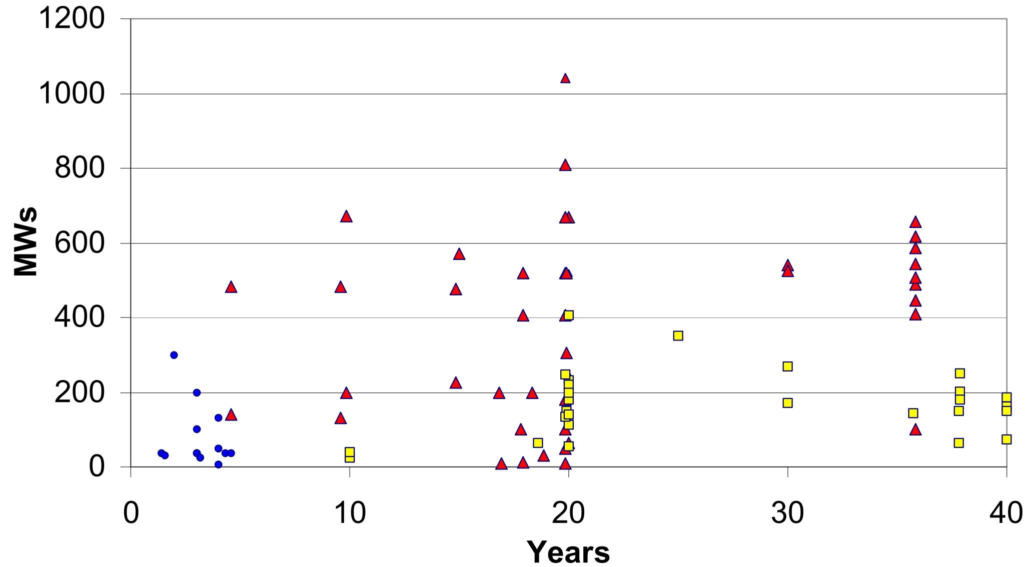

Figure 2. Distribution of the Economic Life of RFP Offers by Size and Term

The heat rates of the embedded technology in the offers also exhibited a wide range. Overall the heat rates went from a low of 6,300 Btu/kWh to close to 12,000 Btu/kWh (See Figure 3). The diversity of heat rates illustrates the wide range of available technologies and equipment configurations that PacifiCorp could tap in the market place for meeting its on-going resource needs. From PacifiCorp's perspective, a stated or guaranteed heat rate was not a determining factor in placing an offer in a particular bid category. Commercial on-line date and resource flexibility remained the two primary drivers.

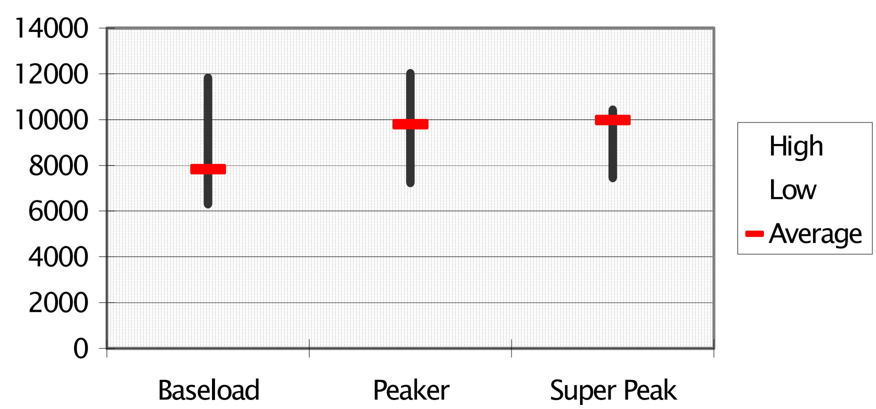

Figure 3. Range of Heat Rates Among RFP Offers

In terms of resource flexibility, bidders submitted offers across the spectrum of dispatch options. Across the three bid categories, the majority of bidders submitted offers that met PacifiCorp's preferred option of daily dispatch, however, a number of others offered day-of dispatch call option rights under their proposed terms. These respective attributes were valued in the screening process using the RFP designated criterion of dispatch that gave bids a specific weighting based on the flexibility of the resource. The optionality provided as a result of the particular resource's flexibility was not valued economically in the bid screening (See Figure 4).

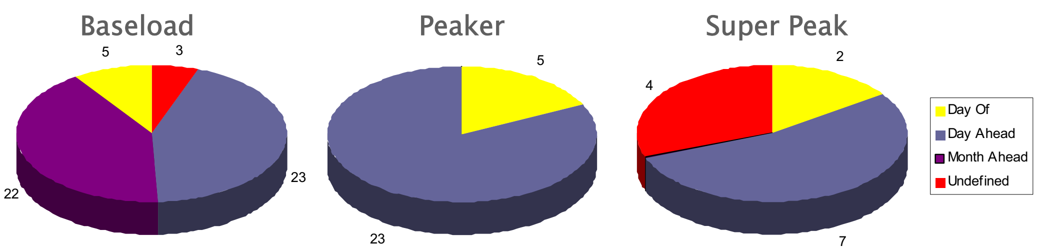

Figure 4. Dispatchability of RFP Offers

As stated in the RFP, PacifiCorp was interested in receiving offers for commercial delivery to or in PacifiCorp's Eastern transmission network interface. Delivery points of interest listed in the RFP included:

- Within PACE;
- Mona 345 kV – "MLDP" (IPP-Mona from the LADWP control area), "MDGT" (Bonanza-Mona within the PACE control area), and "PACE-Mona" (all other lines into Mona within the PACE control area);
- Gonder 230 kV;
- Glen Canyon 230 kV;
- Nevada/Utah Border (NUB) on the Sigurd-Harry Allen 345 kV; and
- Nevada with firm transmission to PACE

PacifiCorp also identified specific delivery points that would not be of interest such as Four Corners (4C), Borah, Brady, or Kinport. Although not preferred, PacifiCorp stated a willingness to consider such alternatives as long as certain infrastructure constraints and requirements were accounted for in the evaluation. As the following diagram illustrates, bidders proposed more than twenty different points of delivery (See Figure 5).

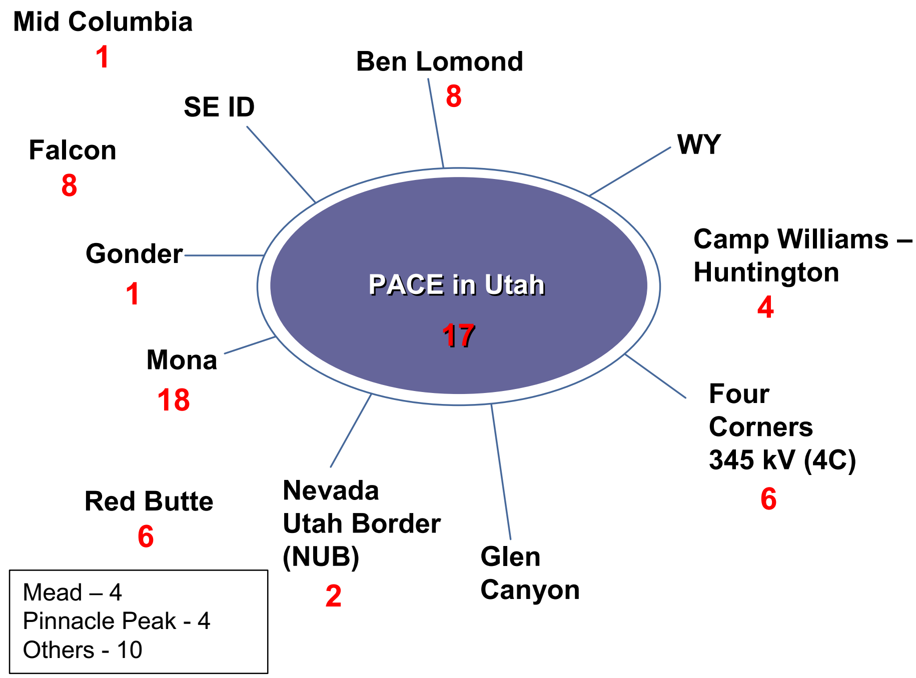

Figure 5. Bidder Proposed Points of Delivery Relative to PacifiCorp's East System

ii. Types of Entities that Responded

Across each of the three bid categories a wide variety of types of Companies responded to the RFP. PacifiCorp received proposals from thirty-seven bidders consisting of small turnkey developers, independent power producers, utility affiliate power marketers, utilities, and equipment procurement specialists. Equipment configurations ranged from modular reciprocating engine setups to large four-on-one (4X1) combined-cycle facilities.

The demonstrated experience of the respondents ranged from minimal to extensive in terms of project development and/or power sales. Some developers clearly demonstrated their experience through a breadth of domestic and international work. Others indicated they were making their first foray into power project development leveraging prior experience with equipment procurement and placement. Many were well known developers/marketers both regionally and nationally.

Since financial strength and credit quality are important elements from a financial risk perspective for PacifiCorp, it is worth pointing out the attributes of entities that responded to the RFP. Although some respondents had sufficient credit to stand behind their proposed transactions, many parties would not extend a parental guaranty and/or approached the RFP with partners in the form of private equity outfits, investment funds, bank letters of credit, and other collateral instruments in an attempt to support the proposed transactions, whether they were power purchase agreements from existing facilities or development projects with proposed off-take agreements. Some parties had not thought through this aspect of their proposal before submitting a response and, after being short-listed, had to negotiate simultaneously with external parties in order to demonstrate to PacifiCorp that they had adequate financial wherewithal to close a deal and support it on an on-going basis.

Those parties that ended up being the most successful in the negotiation process were those that were able to concisely articulate the developmental, operational, and financial components of their respective deals. Addressing risk and who would bear the responsibility for it also proved of vital importance during the negotiation process. Bidders who were either not willing to assume certain risks associated with their deal or could not get PacifiCorp comfortable that specific risks associated with the deal were manageable were not as attractive as other proposals that adequately addressed such factors. Also, as expected, those bidders that were able to offer the most attractive pricing terms over the duration of the commercial delivery period were the most valuable to PacifiCorp. Those that fell short included proposals that over priced their deals by attempting to recover all of their capital costs within the twenty year period of service without accounting for any terminal value, those that chose not to offer a specific price for asset purchase at the end of the contract period, and those that simply were more expensive for a variety of reasons than the other alternatives.

Bidders that made capacity and energy offers from small-scale projects were not broadly represented in the set of companies that responded to the solicitation. In total, only four individual offers from the nearly one hundred offers were from projects that were under 15 MWs in size. Of the thirty-seven bidders, these four offers came from just three bidders. The offers ranged in size from 7 MW up to 11 MW. Two of the projects were based on geothermal resources, one was based on the recovery of waste heat, and one was from a portfolio of distributed resources fired by oil and gas located at commercial and industrial sites within the bidders service territory. Each of the geothermal and waste heat offers were submitted as baseload resources that would be available throughout the year. The distributed resource offer was proposed as either meeting PacifiCorp's need for peaking or super peak resources. The pricing of the baseload offers were not as competitive as the pricing from other offers in this bid category. However, the super peak/peak resource category offer was attractive to PacifiCorp from a pricing perspective, but ran into difficulties in being able to establish the desired level of firmness needed by PacifiCorp to get the resource to PACE. In general, representation by small projects was low and the projects were not competitive with larger projects/offers.

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IV. The Offer Clarification and Negotiation Process

The process used to clarify offers with bidders can be segmented into two separate and distinct phases: (1) the period of initial valuation and (2) the period of clarifying short list offers. As a whole the process followed a systematic series of steps working toward the bidders with whom PacifiCorp would negotiate on a detailed basis.

a. Phase I: Initial Valuation

The initial valuation period was when PacifiCorp first received copies of the blinded proposal material from NCI in the month of July. During this time, PacifiCorp raised various questions about the material aspects of select proposals that required clarification from the bidder. PacifiCorp submitted questions to NCI who in turn forwarded those questions on to the bidder. Once responses were received from the bidders, NCI then blinded those responses by the respective bid number and forwarded them on to PacifiCorp. All attempts to resolve issues of missing or unclear information with bidders were done with the intent of understanding the definitive offer for the purpose of preparing the initial screening using the RFP designated criteria. All of the offers in each bid category went through this review. This phase concluded with the scoring and ranking of offers and the resulting identification of the short list.

b. Phase II: Offer Clarification

The phase of clarifying short list offers began once PacifiCorp had identified the top offers that it wanted to clarify with the respective bidders. This is the point at which the actual bidders of the short listed proposals were made known to PacifiCorp. Up to this point the individual bidders were still blind to PacifiCorp. These discussions were held with the bidders behind the top offers in each bid category. The number of offers clarified in this phase by bid category was as follows: six in the Super Peak category, ten in the peaker category, and twelve in the Baseload bid category. The primary purpose of these clarifying discussions was to verify the proposed terms of the offer(s), validate the substance of the offer(s), and determine whether or not the bidder had put forth their best offer(s). These were not negotiations nor were they intended as a forum for extracting concessions from bidders regarding their particular offers. Negotiations were reserved for a smaller subset of the short listed bidders after PacifiCorp obtained a better understanding of the details of the respective offers. Prior to commencing detailed negotiations, it was imperative that PacifiCorp validate the terms and conditions of the offer along with its viability.

The means used to clarify offers was structured to ensure that PacifiCorp and the bidder could come to a mutual consensus regarding the terms associated with their short listed offer(s). To facilitate this discussion, PacifiCorp used a standardized template (“Offer Summary”) to summarize all of the material items related to an offer. Prior to holding clarifying discussions with bidders, a copy of the completed offer summary was sent to the bidder for their review and redlining. The redlined document returned by the bidder was used as the basis for each clarifying discussion held. The discussions with each bidder followed a consistent path of walking through each item in the offer summary in a methodical manner to ensure that PacifiCorp understood what was definitively offered and that the bidder understood what information was being sought. In the Super Peak category, these initial clarifying discussions were held between August 14 and August 18,2003. In the peaker category, these discussions were held between August 26 and August 27, 2003. The baseload discussions took place between August 28 and August 29, 2003.

c. Scoring and Ranking the Proposals

The scoring and ranking of offers occurred prior to the clarifying discussions with the short listed bidders. All that PacifiCorp was able to rely upon was the information contained in the actual proposals as well as any material information that was solicited from bidders by PacifiCorp via NCI to facilitate their completion of the financial valuation (i.e., phase one described above). No one-on-one discussions were held with bidders prior to this point. The clarifying discussions (i.e., phase two) referenced in the above section were held after the scoring and ranking had been completed.

The scoring and ranking process used by PacifiCorp to derive the short lists relied on the three criteria used in the RFP: pricing, dispatch ability, and environmental characteristics. Each criterion was assigned an overall weighting based on a percentage, which was then used to rank each of the proposals among one another. Using the three criteria, each proposal received a specific score in each category. The combined score was then used to rank each proposal relative to one another. The criteria were uniformly applied across each of the proposals to derive their scores and relative rankings. Where questions arose about the transmission costs to impose, the flexibility of the resource, or the escalation factors to use, among other factors, PacifiCorp erred on giving the bidder the benefit of the doubt by using the option that would result in a better valuation for the proposal. However, where material differences would result, PacifiCorp sought clarification via NCI from the bidder before determining the valuation used for scoring and ranking.

Once a bid was identified as making the preliminary short list, NCI de-blinded the offer. The company submitting a bid was only made known to PacifiCorp's Commercial and Trading group if it made the short list. All others remained blinded. Also, it is important to note that other offers, submitted by the short listed bidders, which did not make the cut, were left blind. The de-blinding of proposals and subsequent acknowledgement to bidders took place by bid category. The Super Peak bid category offers were de-blinded with NCI contacting the respective bidders on August 13, 2003. On August 21, 2003, NCI contacted the bidders making the preliminary short list for the Peaking bid category. The final bid category respondents to be notified were those in the Baseload bid category. This group of respondents was contacted on August 22, 2003. Contact with bidders on these three dates included both the respondents making the preliminary short list and those that did not.

d. Determining Final Negotiating Parties

With the scoring and ranking complete and the short list identified, PacifiCorp, along with NCI, then engaged bidders directly in clarifying discussions for the purpose of determining the parties with whom PacifiCorp would enter into detailed negotiations. Based on the feedback obtained from bidders during each of the clarifying sessions, PacifiCorp updated the economic valuations for the offers. Before updating the models, PacifiCorp revised its deal summary documents and the offer summary sheet for use as the basis in updating the models. These were also used in NCI's review of the updated models to ensure that the revised information was being included in the most current valuation. Having participated in all of these clarifying discussions with bidders, NCI was able to independently validate that the offers were being accurately captured in these summary documents. NCI viewed the clarifying sessions with bidders as an opportunity to better understand what was being offered and to ensure that PacifiCorp was valuing the best deal that the bidder put forth.

Given the volume of responses, it was vital that PacifiCorp narrow the list of parties with whom it would engage in detailed negotiations. These sessions served that function by ensuring that PacifiCorp captured the bidder's best and final offer that would be used to identify the preliminary list of negotiating parties. This is also what was communicated to bidders during the clarifying sessions. To be clear, each bidder was asked to put forth their best offer that they wanted PacifiCorp to evaluate. Since offers submitted in response to the RFP were indicative, it was reasonable to expect that during clarifying discussions bidders would obtain a better understanding of what PacifiCorp was looking for and what pricing and performance terms would be looked upon more favorably during the final valuation process before moving to detailed negotiations. Indeed this is what occurred and resulted in some modified offers being submitted by the short listed bidders.

In the case of the Peaker and Super Peak bid categories, the clarifying discussions did not yield economically attractive enough offers for the company to move forward with detailed negotiations. This conclusion was arrived at after numerous discussions with the bidders in both the Super Peak and Peaker categories from mid-August through the first week in November. Initially, in the Baseload bid category, there were several offers that were more economically attractive than the NBA. Negotiations remain ongoing with a couple of these counterparties. The next section describes in more detail how the discussions with each of the short listed counterparties unfolded and which issues were most material to the proposed transaction.

e. Review and Results of Short List Discussions

The following is a review of the offers that were received from bidders that were short listed by PacifiCorp and evaluated more thoroughly in the RFP process. Each of the offers profiled and discussed in this section made the first round short list based on the RFP designated criteria. No clarifying discussions had been held directly with bidders up to this point, except for material questions that were posed to bidders through NCI that would allow PacifiCorp to complete the blinded screening and economic valuation. The intent of the short lists was to provide PacifiCorp a subset of the top candidates with whom to hold further clarifying discussions regarding the indicative information submitted in the proposals.

From this point forward, PacifiCorp's focus was on clarifying the above offers and working with the bidders to understand the material aspects of their respective offers including all of the cost components and associated risks. The relative rankings of the offers shifted as the companies clarified and explained their proposal details and as PacifiCorp revised its economic valuations based on this information. This was expected, as PacifiCorp was able to validate the definitive offers being made through direct dialogue with the bidders. At each stage of dialogue with the respective bidders, PacifiCorp prepared an updated economic valuation model that NCI reviewed for accuracy and fairness. Since NCI participated in all of these clarifying discussions with bidders along with PacifiCorp personnel, the monitoring of material changes in offer valuations was readily done.

The intent of the following sections is to provide an overview of the offers and what the outcome was of discussions with bidders in each of the bid categories.

i. Super Peak Offers

The Super Peak offers can be broken up into two classes: summer delivery products and annual delivery products. Bidders offering summer products (i.e., delivery during June through September) were responsive to the RFP and the most attractive to PacifiCorp while the annual products were less so due to the 12 month take requirements of the proposed offers. Since summer delivery is so important to PacifiCorp, the decision was made to hold discussions with all of the bidders who offered summer products. This led to discussions with five companies in the Super Peak bid category. The annual delivery offers in the Super Peak bid category were not short-listed due to their not being responsive to the RFP and their unattractive economics that were embedded in their offers. No clarifying discussions or negotiations were held with these bidders in the context of the RFP.

ii. Peaker Offers

The peaker bid category offers ran the gamut of equipment configurations, heat rates, and delivery points. Out of the 28 offers received, 10 of them were short listed for further clarification based on their ranking according to the RFP screening criteria. Initially, only two offers, were viewed as being more economic than PacifiCorp's NBA. In spite of this fact, NCI recommended to PacifiCorp that it hold clarifying discussions with three to five potential counterparties assuming the indicative economics of their offers warranted further consideration, i.e., that they were within a reasonable range of the NBA's relative economics. Clarifying discussions were then held with the five bidders behind the top ten offers. At the conclusion of these discussions, PacifiCorp prepared a revised ranking of the offers that reflected PacifiCorp's most current understanding and valuation of the offers. No offers were found to be more economically attractive than the Company's NBA.

At this point, with NCI having validated these results, PacifiCorp could have chosen to cease any further discussion with these counterparties and simply moved forward with its cost-based alternative at Currant Creek. However, the fact that (1) the Super Peak bid category offers did not look promising and (2) that the Company had issued a revised load forecast indicating a load and resource imbalance in the Eastern portion of its system in 2005 that was projected to be nearly two times as large as what had been identified in the IRP, the decision was made to continue discussions with these bidders. Building the peaker bid category NBA would not completely create a balance between projected loads and committed resources. Due to the revised load forecast, it was decided that a new NBA was needed for benchmarking purposes (since the Currant Creek peaker NBA was no longer an alternative) and that the Company would go back to the top bidders to see whether or not another opportunity to revise their offers would result in something more economic relative to the next NBA. The smaller list of counterparties was driven by the interest in having a manageable number of companies with whom the Company potentially could engage in more detailed negotiations.

PacifiCorp then prepared another NBA, which NCI validated, before reviewing revised bids from these three companies. In short, the Hybrid NBA consisted of forward market purchases for two years and an expansion at the Currant Creek site for the remaining eighteen-year period. The Hybrid NBA was used to benchmark the revised offers. Once PacifiCorp received these offers, summarized them and prepared revised economics, additional clarifying discussions were held with the bidders to ensure that the Company accurately modeled what the bidder was presenting. In addition, PacifiCorp provided feedback to the bidders about what terms and options would be most attractive to the Company. The bidders responded to this request by providing slight permutations of their offers including various terms and financing arrangements. The result of these discussions was the final ranking of offers relative to the Hybrid. Upon review of these best and final offers no offer was found to be economically superior to the Hybrid NBA. Consequently, discussions with all bidders in this bid category were ceased.

Basis for Selecting the NBA in the Peaking Resource Bid Category
PacifiCorp's Peaking NBA, the development and construction of a 525 MW gas-fired combustion turbine combined-cycle generation plant located adjacent to the Mona Substation 75 miles south of Salt Lake City, Utah, was determined to be the lowest cost resource option within the context of the RFP process. It will meet the Company's IRP identified need for a resource that is located within PacifiCorp's Eastern system. From the perspective of the RFP, this resource also met all of PacifiCorp's stated requirements, which included:

- On-line and available by June 2005;
- Daily dispatchability during heavy load and/or super peak hours; and,
- Delivery in or to PACE.

NCI not only validated the reasonableness of all the material costs associated with the NBA, but also ensured that they were appropriately reflected both in the model prepared by PacifiCorp's Resource Development group (cost-based) and the one prepared by the Commercial and Trading group (reflecting economic dispatch). This was a rigorous assessment involving the review of primary data and cost estimates as well as direct interviews with the personnel engaged in the preparation of the figures and the models. Furthermore, NCI reviewed and certified the economic analyses that were prepared for every one of the offers submitted and considered in the RFP's Peaker bid category. After the initial bid screening, in each round after bid clarification, the NBA consistently came out on top as the least cost alternative for the Company. Also, as noted earlier in this report, all of the material changes that were made to the NBA, from its initial lock down through the period of offer clarification with bidders, were reviewed and validated by NCI as being reasonable and not arbitrarily advantaging one alternative over another.

It is with this background that the decision was made to conclude discussions with the Peaker bid category bidders and proceed forward with permitting and developing the Company's cost-based alternative, the Peaking NBA at Currant Creek.

iii. Baseload Offers

The Baseload bid category yielded more than half of the proposals received in response to the RFP. PacifiCorp worked with the top bidders in this bid category to clarify their offers through a series of question and answer sessions consisting of conference calls and e-mail exchanges, which is the same process used in each of the other two bid categories. Upon the conclusion of the screening process using the RFP designated criteria, there were eleven offers that were more economic than the NBA on an indicative basis. Consistent with the other two bid categories, NCI recommended that PacifiCorp engage at least three to five counterparties in clarifying discussions. However, the decision was made jointly to hold clarifying discussions with all of the bidders whose offers were more economic than the Baseload NBA. As such, NCI deblinded nine companies' offers. This is represented in the list of twenty offers (plus the duct-fired contingent offers) that the Company clarified directly with bidders.

Once these discussions were concluded and the Company had received from bidders the necessary information to clarify the offers, PacifiCorp prepared a revised ranking that mirrored the feedback provided by the bidders. This resulted in a revised ranking. It is important to remember that at this stage, PacifiCorp did not engage the bidders in negotiation, but focused instead on clarifying the offers to ensure that there was a mutual understanding regarding the interpretation of various costs, risks, and assumptions and how they were being handled within the economic modeling. Contemporaneous with the revised list was the identification of the Peaker bid category NBA as the most economic alternative for PacifiCorp. Since the assumption was that the Company would be moving forward with its Peaking NBA at the Currant Creek site in the Peaker bid category, the Baseload NBA became the cost of marginally expanding at that site and including all of the economies of scope and scale that are afforded development at an existing site.[12] While not altering the ranking of offers, it did result in a narrowing of the short list to only three bidders presenting offers that were economically superior to the NBA. PacifiCorp began with the two more attractive offers and shortly thereafter commenced detailed discussions with the third bidder.

Basis for Selecting the Summit Power Offer

In the final economic analysis of the baseload offers, the values of two offers that were better than the NBA were within very close range of one another. Both parties clearly demonstrated their capabilities in bringing projects on-line, on time, and within budget. The key difference boiled down to an issue of schedule delay due to credit quality considerations. The winning bidder, while not having a credit rating of its own, partnered with a company that has a very strong credit rating and was willing to serve as the guarantor of the entire proposed project. As PacifiCorp considered each alternative, the question raised by PacifiCorp was which transaction posed the least cost/risk for PacifiCorp's ratepayers. The selected transaction offered the best cost/risk balance by virtue of having a lower probability of being stalled or interrupted for any reason other than force majeur events. On the other hand, the poor credit quality of the other bidder would continue to overhang the development and construction process through the greater possibility of a default that could hamper the ability to bring the proposed facility on line, on time.

[12] Not a stand-alone baseload green field resource

NCI relied on a number of factors in order to come to the above conclusions. First, NCI relied upon the actual offers submitted by the bidder and an independent validation that PacifiCorp was accurately incorporating the operational and cost assumptions of each offer into the economic valuation. Second, NCI participated in all of the clarification sessions with bidders and a majority of the negotiating sessions with bidders. Third, NCI reviewed the results of the stochastic risk analyses and the step-in scenario analyses that took into consideration various transaction and project-related risks. Under the expected case scenarios, the poor credit quality bidder offer and NBA appeared less attractive than the offer from selected bidder. Taken in aggregate, it was apparent that the preferred transaction would be with the selected bidder due to its lower risk and its equivalent cost characteristics.

Over their respective economic lives, the selected offer came out economically superior to the NBA and close with the offer from the other bidder. The credit quality and track record of Summit Power with its partner Siemens Westinghouse Power Corporation suggests that ratepayers can have a high degree of confidence that the plant will be well constructed and be operational by June 2007. Having reviewed the final Summit Power contracts, there are strong built-in provisions that mitigate a variety of development and construction risks that help to ensure that the plant will meet the agreed upon operational performance objectives as well as being available when needed. Lastly, the 12-year full requirements maintenance contract proposed by Summit Power would provide ratepayers with a known cost stream on top of receiving quality service from the actual manufacturer of the equipment for the first third of the project's life.

NAVIGANT CONSULTING

V. Conclusion

a. Summary Conclusions

PacifiCorp executed a fair and consistent process throughout the RFP to identify the most cost effective resources for meeting its projected supply needs. The criteria, tools, and types of personnel used were similar to other resource solicitations used by other investor owned and municipal utilities elsewhere. Although this was the first formal long term supply solicitation PacifiCorp has issued in two years, they clearly demonstrated the aptitude and foresight to develop a well-structured solicitation that resulted in a wide breadth of offers that were responsive to the Company's request for resources. The quality and integrity with which PacifiCorp went about the entire process is evident in a number of aspects of the process. The direct areas in which these were exhibited included, but were not limited to:

- The attention to NBA cost and assumption documentation that PacifiCorp prepared and provided to NCI for its review and validation effort;
- The series of pre-bid meetings held with bidders and other interested parties to ensure that there were multiple opportunities that bidders had to ask questions and receive timely responses about the process, its various components, and the terminology used therein;
- The level of cooperation and access given to NCI in its tasks of evaluating and validating the basic modeling tools used to economically value the numerous offers that it was presented;
- The use of standardized materials for summarizing offers that facilitated a ready dialogue between PacifiCorp and bidders regarding their offers;
- The ample time that PacifiCorp afforded bidders to provide necessary information subsequent to the bid due date to allow the Company to value its offer as well as the time given bidders after short list selection to respond to formal requests for information that enabled PacifiCorp to prepare final offer valuations;
- The Company's strict adherence to the screening criteria as the basis for selecting the short list bidders with whom to hold clarifying discussions;
- The accommodation of NCI's need to understand, review, and validate the results of the economic modeling efforts through one-on-one review sessions; and
- PacifiCorp's unwavering focus on the best interests of its ratepayers which necessitated close attention to issues of financial, regulatory and developmental risk inherent in any of the alternatives the Company was considering, including its own cost-based alternatives.

From an operational and design perspective, the RFP process developed and implemented by PacifiCorp functioned as expected. It resulted in over 100 offers from the market a few of which were economically competitive with the Company's own internal benchmark options. It satisfied the primary criteria NCI looked for in the process: equal opportunity, analytical objectivity, reasonableness and consistency. Having met these, NCI unequivocally supports the RFP process as having been managed in an effective manner with results that are fully supportable.

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/402
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL

Exhibit Accompanying Direct Testimony of Mark R. Tallman

Seven Mile Hill II Approval Document

April 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/403
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL

Exhibit Accompanying Direct Testimony of Mark R. Tallman

Seven Mile Hill II Final Build Design Estimate, August 14, 2008

April 2009

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CONFIDENTIAL
Docket No. UE-
Exhibit PPL/404
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Mark R. Tallman

Glenrock III Approval Document

April 2009

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CONFIDENTIAL
Docket No. UE-
Exhibit PPL/405
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of Mark R. Tallman

Glenrock III Final Build Design Estimate - August 14, 2008

April 2009

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Docket No. UE-
Exhibit PPL/406
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

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Exhibit Accompanying Direct Testimony of Mark R. Tallman

High Plains Approval Document (2)

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Exhibit PPL/407
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

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April 2009

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Docket No. UE-
Exhibit PPL/408
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of Mark R. Tallman

RFP 2008R Comparison

April 2009

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Stefan A. Bird
Exhibit PPL/500

Docket No. UE-
Exhibit PPL/500
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Stefan A. Bird

April 2009

Q. Please state your name, business address and present position with PacifiCorp Energy, an unincorporated division of PacifiCorp (as used herein, "PacifiCorp" or "the Company").

A. My name is Stefan A. Bird. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232. I am Senior Vice President, Commercial and Trading, for PacifiCorp Energy, a division of PacifiCorp.

Qualifications

Q. Briefly describe your educational and professional background.

A. I joined PacifiCorp Energy and assumed my current position in January 2007. Prior to that, from 2003 to 2006, I served as President of CalEnergy Generation U.S., a portfolio of qualifying facility and merchant generation assets including geothermal and natural gas-fired cogeneration projects across the United States. From 1999 to 2003, I was Vice President of acquisitions and development for MidAmerican Energy Holdings Company. From 1989 to 1997, I held multiple positions at Koch Industries, Inc., including energy trading, financial trading, acquisitions, project engineering and maintenance planning in the United States, Latin America and Europe. I hold a Bachelor of Science degree in mechanical engineering from Kansas State University.

Q. What are your responsibilities as Senior Vice President, Commercial and Trading, for PacifiCorp Energy?

A. I am responsible for all front-office and mid-office wholesale activities including dispatch of PacifiCorp's owned and contracted generation resources and making wholesale purchases and sales to balance PacifiCorp's load and resources. I am also responsible for PacifiCorp's load and revenue forecast, integrated resource plan ("IRP") and net power costs modeling. Additionally, I am responsible for acquisition of power resources for the PacifiCorp system (the "System") through negotiated power purchase agreements and the acquisition of generation resources, including through implementation of request for proposals ("RFP") processes consistent with applicable laws and guidelines.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to demonstrate that the Company's acquisition of the Chehalis Power Generating Plant (the "Plant") was prudent. More specifically, I describe: (1) the attributes of the Plant, (2) the nature and terms of the transaction to acquire the Plant; (3) the Company's need for new generation resources; (4) the Company's request and receipt of a waiver to the Competitive Bidding Guidelines (Order No. 06-446), (5) the economic analysis that demonstrates the prudence of the Company's decision to acquire the Plant and shows that it is presently used and useful; and (6) a description of the acquisition costs for the Plant.

Description of the Plant

Q. Please describe the Plant.

A. The Plant is located on a 20-acre site near the city of Chehalis in Lewis County, Washington. It is a 520 megawatt ("MW") natural gas-fired electric generation facility, consisting of a 2x1 configuration, using two General Electric 7FA dry low NOx combustion gas turbine generators. Each of the combustion turbine generators exhaust into its own heat recovery steam generator which together supply a single steam turbine generator. To augment power output during summer conditions, the Plant is equipped with an inlet fogger. The electrical energy generated by the Plant is delivered to the Napavine 230 kV substation, and is interconnected into the Bonneville Power Administration's ("BPA") transmission system at the substation. The Plant currently has a contract for station service from Public Utility District No. 1 of Lewis County. The Plant has been in service for over six years.

Q. Please describe the characteristics of the Plant.

A. Ownership of the Plant allows the Company full discretion in the dispatch of the Plant. Energy from the Plant is dispatched on a forward, day-ahead basis, with real-time optimization of the Plant's usage. This operational flexibility will provide increasing benefit to the Company as load grows, as the Company's existing flexible contracts expire, and as wind resources are added to meet existing and future renewable portfolios standards.

Structure of Transaction and Agreements

Q. Who was the prior owner of the Plant?

A. Prior to PacifiCorp's purchase, the assets of the Plant were held in a limited liability company called Chehalis Power Generating, LLC, a Delaware limited liability company (the "LLC"). The outstanding equity interests in the LLC (which are the equivalent to a corporation's stock) were, in turn, held directly by TNA Merchant Projects, Inc., a Delaware corporation ("TNA"). TNA is a wholly-owned subsidiary of Suez, S.A ("Suez"). Suez is now known as GDF

Suez S.A., an international energy group resulting from the 2008 merger of Suez and Gaz de France.

Q. Please describe the process by which the Company became aware of the availability of the Plant.

A. In late 2006, the Company entered into a confidentiality agreement for access to information about acquiring the Plant. In January 2008, Suez informed PacifiCorp that two other parties were interested in acquiring the Plant and stated that if PacifiCorp remained interested, it needed to submit an indicative bid for the Plant. PacifiCorp responded with a non-binding proposal on February 13, 2008. Based on that proposal, the Company and Suez negotiated a non-binding Confidential Memorandum of Understanding ("MOU") that was signed on February 27, 2008. Suez proceeded to develop a detailed electronic data room for due diligence, and the Company engaged a comprehensive due diligence team inclusive of internal and external expertise. Nearly 1,000 documents were subsequently reviewed and site inspections were made throughout the course of due diligence. At the same time, the Company and Suez negotiated a purchase and sale agreement ("PSA"), by and between PacifiCorp and Suez's subsidiary, TNA that was executed on April 11, 2008. The PSA provided for the transaction to close upon receipt of all required regulatory approvals and satisfaction of customary closing conditions. Closing occurred on September 15, 2008.

Q. How was the acquisition of the Plant structured?

A. The PSA provided that TNA would transfer 100 percent of the outstanding equity interest in the LLC to PacifiCorp upon closing. A copy of the PSA is attached as

Confidential Exhibit PPL/501. By acquiring the LLC's equity interests, under the terms of the PSA, PacifiCorp acquired the Plant as well as various permits, assets and liabilities associated with the Plant. On the day of closing, September 15, 2008, PacifiCorp received 100 percent of the outstanding equity interest in the LLC. PacifiCorp then immediately merged the LLC into PacifiCorp, with PacifiCorp surviving, such that the LLC ceased to exist, and all of the permits, assets and liabilities of the LLC now reside directly with PacifiCorp.

Q. What was the acquisition price for the LLC?

A. The acquisition price is detailed in Confidential Exhibit PPL/502. As further explained in my testimony, the total acquisition price includes the initial purchase price plus adjustments for the General Electric contractual services agreement, legal and consulting costs, liabilities assumed, other costs of acquisition and costs related to the Washington Energy Facility Site Evaluation Council ("WA EFSEC") ruling.

Resource Needs

Q. Please describe the Company's resource needs projected in its most recent integrated resource plan ("IRP").

A. The Company's 2007 IRP Update in Docket LC 42 identified a system deficit between the Company's projected peak capacity needs and its resources available to serve that peak demand. By 2012, that deficit, after considering energy efficiency and demand management programs, was projected to be nearly 2,400 MW.

Q. What are the primary drivers creating the resource deficit in 2012?

A. The primary drivers of the resource deficit include the expiration of 900 MW of long term power purchase agreements expiring between the summer of 2011 and 2012, combined with load growth across the PacifiCorp service area. The expiration of these contracts and the resource deficit is described in more detail in the direct testimony of Company witness Mr. Gregory N. Duvall.

Q. Does the acquisition of the Plant eliminate the need to continue to pursue additional resources?

A. No. The addition of Chehalis reduces the Company's resource need at the time of system coincident peak by 509 MW as explained by Mr. Duvall. The Company recently updated its load and resource balance forecast in the 2008 integrated resource planning process. As further explained by Mr. Duvall, after the addition of Chehalis, the peak capacity deficit in 2012 is still projected at 1,868 MW.

Q. Did the Company request a waiver to the Competitive Bidding Guidelines in Order No. 06-446 ("Guidelines") in Oregon?

A. Yes. The Company filed a waiver petition on April 1, 2008, which was docketed as UM 1374. The Guidelines allow for exemptions from the RFP process to allow a utility to take advantage of a time-limited resource opportunity that presents unique value to customers.

Q. Was Chehalis a time-limited resource opportunity that presented a unique value to customers?

A. Yes. It is the Company's experience that the time required to complete a formal RFP in accordance with the Guidelines would stretch far beyond the time limits provided in the PSA, resulting in a loss of benefits promised by the acquisition.

Q. Did the Commission retain an Independent Evaluator to evaluate the Plant?

A. Yes. Boston Pacific was hired to conduct a thorough analysis of the Company's acquisition of the Plant.

Q. What did the Independent Evaluator conclude regarding the Company's acquisition of the Plant?

A. The Oregon Independent Evaluator's Report (provided on June 18, 2008), stated:

> Boston Pacific strongly prefers choosing resources through competitive procurement and having more competitors in the market. However, our top priority is getting the best deal for ratepayers in terms of price, risk, reliability and environmental performance. Given Chehalis' obvious benefits in capacity cost, risk mitigation and given the fact that those benefits are not clearly wiped away by its disadvantages, we think that it is reasonable to grant the Company's waiver request, subject to our review of the information below. More specifically, based on what we saw in the 2012 RFP, we cannot conclude that denying the waiver, in the hope of being able to select a better offer in the upcoming RFP, is in the best interest of ratepayers.

Q Did the Oregon Independent Evaluator request additional information from the Company after the June 18, 2008 report.

A. Yes. The Oregon Independent Evaluator requested additional material concerning transmission agreements, operating and maintenance ("O&M"), gas price forecasts and an additional analysis of the transaction with the Company's Generating and Regulation Initiative Decision Tools ("GRID") model.

Q. What did the Oregon Independent Evaluator conclude after reviewing the additional information?

A. The Oregon Independent Evaluator filed a supplemental report on July 2, 2008. It concluded:

> [T]he Company's analysis does show that this is a beneficial transaction. This conclusion is reinforced when we consider that the Company's analysis does not even consider the risk reduction benefit that ratepayers receive when acquiring an operational facility versus a new-build plant.

Q. Did the Oregon Staff and Independent Evaluator recommend that the Commission approve the request for waiver of the solicitation process?

A. Yes. The Oregon Staff and the Independent Evaluator recommended the waiver be approved.

Q. Did the Commission approve the request for a waiver under Guideline 2A; "Acquisition of a Major Resource…where there is a time-limited resource opportunity of unique value to customers"?

A. Yes. On July 8, 2008, the Commission adopted Staff's recommendation, and approved the Company's petition. See Order No. 08-376.

Prudence of the Company's Decision to Acquire the Plant

Q. Was the Company's acquisition of the Plant a prudent decision?

A. Yes. The acquisition of the Plant provides a favorably-priced, flexible resource that the Company is now using to meet the resource needs for customers. The Plant satisfies a portion of the deficit identified in the 2007 IRP Update.

Q. Please identify the information, data, models and analyses used by the Company in evaluating whether to acquire the Plant.

A. The information, data, models and analyses used by the Company in its evaluation are described in detail in Mr. Duvall's testimony.

Studies performed in 2007 by Standard & Poor's and by The Brattle Group for The Edison Foundation demonstrate that the capital costs for new generation facilities increased dramatically during the preceding three years as a result of labor and materials shortages. Standard & Poor's data shows that the capital costs increased by over 50 percent.[1] Data compiled by The Brattle Group for the Edison Foundation shows that "the cumulative increase in the installation cost of new combined-cycle units from 2000 to 2006 was almost 95 percent, with much of this increase occurring in 2006."[2] A subsequent study performed by The Brattle Group noted that the Energy Information Administration (EIA) increased the assumed real capital costs of most generation technologies by 15 to 20 percent for 2008, partially accounting for construction cost increases. But, to better reflect these increases, The Brattle Group study used EPRI's July 2008 construction cost assumptions, which were more than 33% higher than EIA estimates for wind and combined cycle units.[3]

Acquisition of the Plant provided a unique opportunity for the Company to acquire a generation resource at price levels prevalent before the significant inflation of the past few years.

Q. Does the purchase of the Plant in 2008, versus waiting to acquire another resource in 2012, benefit the Company's customers?

A. Yes. This issue is addressed in Mr. Duvall's testimony. The acquisition of the Plant on the terms and conditions in the PSA reduces the Company's present

[1] Prabhu, Aneesh and Pratt, Terry A., "Increasing Construction Costs Could Hamper U.S. Utilities Plans to Build New Power Generation," Ratings Direct, Standard & Poor's (June 12, 2007) at page 2.

[2] Chupka, Marc W. and Basheda, Gregory, Rising Utility Construction Costs: Sources and Impacts, The Brattle Group for The Edison Foundation (September 2007) at 8.

[3] Chupka, Marc. W and Earle, Robert, Transforming America's Power Industry: the Investment Challenge 2010-2030, The Brattle Group for The Edison Foundation (November 2008) at 6-7.

value revenue requirement of its resource portfolio by approximately $142 million to $197 million, versus a comparable alternative resource from the 2012 RFP with an estimated cost of $1,000/kW to $1,150/kW. This analysis is now known to be conservative, given the cost of the combined cycle project short-listed in the 2012 RFP was substantially higher (which is outlined in Confidential Exhibit PPL/503) than the estimated range of costs assumed in the analysis in Mr. Duvall's testimony. The acquisition of the Plant therefore, provides economic benefit to the Company's customers and avoids the cost and schedule risks associated with permitting and construction of a new facility.

Q. Are there other benefits to acquisition of the Plant versus possible construction of a similar resource in the future?

A. Yes. An existing resource, acquisition of the Plant eliminates the risks associated with permitting and constructing a new plant and the risk of holding up to 40 percent of the costs open for up to two years after approval and execution of the contract. These risks include, but are not limited to, unanticipated costs and delays associated with permitting and construction and changes in engineering, labor and materials costs. As my foregoing answer illustrates, these risks are real and significant.

Acquisition Costs

Q. What are the elements that make up the acquisition price of the Plant?

A. The total cost of the Plant and other assets acquired to be included in rates is outlined in Confidential Exhibit PPL/502. In addition to the Plant, other assets including materials and supplies inventory and a prepaid maintenance contract were added to the initial acquisition price. The costs associated with acquiring all the above assets as of September 30, 2008 include the following:

- The initial purchase price.
- A payment to TNA at closing in the amount of $4.7 million related to the acquisition of the long-term maintenance contract. This is the amount of prepaid maintenance that TNA had paid to General Electric under the Contractual Services Agreement ("CSA") that is attributable to the period under the CSA following closing. These costs have been treated as a prepayment on the balance sheet.
- Costs for outside consultants and legal counsel associated with the acquisition of the Plant, due diligence, and related federal and state regulatory approvals for the acquisition. The total amount was $2.0 million. These costs have been capitalized as part of the cost of the Plant acquisition.
- The cost of an early termination fee of $1.8 million related to a tolling agreement contract for the Plant with Suez's merchant subsidiary, SUEZ Energy Marketing NA, Inc.
- Approximately $8.2 million in liabilities which were offset by the receipt of a working capital adjustment in the amount of $5.3 million. The difference of $2.9 million is considered an additional cost of the acquisition and consists primarily of property taxes related to the Plant.

The above costs will be allocated to plant, inventory and prepaid maintenance assets as appropriate. The Company is also required by WA EFSEC to pay a total of $1.5 million in the future for greenhouse gas mitigation in connection with the

WA EFSEC's approval of the transfer of the Site Certification Agreement ("SCA") for the Plant. Owners of generating plants in Washington are required to enter into an SCA. These amounts will be included in rate base as they are incurred.

Q. Did the Plant have an SCA prior to the Company's acquisition?

A. Yes. However, one of the regulatory approvals required for the acquisition of the Plant by the Company was approval by the WA EFSEC of the transfer of the SCA from the LLC to the Company at closing. On April 30, 2008, the Company and Suez filed a request with the WA EFSEC for approval of the transfer of the SCA and related permits. On July 8, 2008, the WA EFSEC issued its written decision approving the transfer. It provided that the Company:

> shall provide $1.5 million in funding for greenhouse gas mitigation projects. EFSEC staff and PacifiCorp representatives will work together to identify potential mitigation projects and will consult with Washington agencies …. Based on the recommendations of EFSEC staff and PacifiCorp, the Council will make final decisions selecting projects to be funded ….

The WA EFSEC also noted in its decision that:

> this CO_2 mitigation will constitute the entire mitigation obligation for the Chehalis Generating Facility. In the event that [sic] PacifiCorp requests additional amendments to the SCA in the future, the Council will not require any additional mitigation for the maximum potential CO_2 emissions associated with the existing Facility as a condition of approving any such amendment.

The Company anticipates that the mitigation projects to be funded will be identified and that the payments will be made in the near future. These costs will be capitalized as they occur in the future.

Q. Does this conclude your testimony?

A. Yes.

Stefan A. Bird
Exhibit PPL/501

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/501
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Stefan A. Bird

Chehalis Purchase and Sale Agreement

April 2009

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CONFIDENTIAL
Docket No. UE-
Exhibit PPL/502
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Stefan A. Bird

Chehalis Acquisition Price

April 2009

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Stefan A. Bird
Exhibit PPL/503

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/503
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Stefan A. Bird

Comparison of Plant Costs

April 2009

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Gregory N. Duvall
Exhibit PPL/600

Docket No. UE-
Exhibit PPL/600
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

April 2009

Q. Please state your name, business address and present position with PacifiCorp (the 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, Long Range Planning and Net Power Costs.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a degree in Mathematics from the University of Washington in 1976 and a Master of Business Administration degree from University of Portland in 1979. I was first employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). Currently, I direct the work of the integrated resource planning group, the load forecasting group, the market assessment group, and the net power cost group in the Company.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. Along with Company witness Mr. Stefan A. Bird, I present documentation to demonstrate the prudence of PacifiCorp's decision to acquire the Chehalis Power Generating Plant ("the Plant") located in Chehalis, Washington. Specifically, as the person responsible for the Company's economic analysis of the Plant acquisition, I explain how the results of that analysis demonstrate both the prudence of the acquisition and the fact that the Plant is now used and useful in Oregon.

PacifiCorp's Economic Analysis of the Plant

Q. Please identify the information, data, models and analyses used by the Company in evaluating whether to acquire the Plant.

A. The Company used data and models from its 2007 integrated resource plan ("2007 IRP"), 2007 integrated resource plan update ("2007 IRP Update") and information regarding the Plant obtained from the previous owner in analyzing whether to acquire the Plant. The Company conducted due diligence with regard to the data provided by the previous owner and concluded that the data was reasonably reliable and consistent with expectations relative to other similar facilities. The Company analyzed this data using the system optimizer and planning and risk models, which are the same models used in performing analysis for the 2007 IRP.

Q. Please describe how the Company evaluated the Plant acquisition.

A. The Company compared the cost of acquiring the Plant in 2008 to the cost of acquiring generation resources in accordance with the 2007 IRP Update. To do this, the Company first ran the system optimizer model assuming the Plant was in service beginning on October 1, 2008. The results of this system optimizer model run showed the Plant displaces front office transactions prior to 2012 and displaces a combined cycle combustion turbine beginning in 2012. This new portfolio was next analyzed using the planning and risk model through 2027. The present value revenue requirement of this new portfolio was then compared to the present value revenue requirement of the 2007 IRP Update using two estimates for the cost of the displaced combined cycle combustion turbine.

Q. Please describe the assumptions used in the studies.

A. The Company assumed the Plant was included in the resource portfolio beginning October 1, 2008, with availability after forced outages and maintenance of 92 percent. The maximum capacity was determined monthly, based on average daily temperatures and ranges from 481[1] megawatt ("MW") average in the summer to 511 MW average in the winter. Wholesale electricity and natural gas prices were based on the Company's December 31, 2007 official forward price curve. The analyses included capital cost recovery, fixed and variable operation and maintenance expense, start-up and shut-down costs, pipeline costs, sales tax and property tax.

Q. What costs were assumed for the combined cycle combustion turbine that is displaced in 2012?

A. The Company assumed the cost of a new combined cycle combustion turbine to be $1,000 to $1,150 per kilowatt in 2008 dollars. This assumption was based on a variety of factors. The primary factor was the results of the 2012 RFP, as described in the direct testimony of Mr. Bird. This assumption was also supported by the costs incurred by the Company in constructing other resources in recent years and costs included in studies performed by Standard & Poor's and

[1] The capacity contribution to the system coincident peak of the Plant was recently increased from 481 megawatts to 509 megawatts.

The Brattle Group, which are described in Mr. Bird's direct testimony.

Q. What were the results of the analysis?

A. The results of the analysis the Company performed are shown in Exhibit PPL/601. Exhibit PPL/601 shows the present value revenue requirement of the 2007 IRP Update compared to that of the 2007 IRP Update as modified to include the Plant commencing on October 1, 2008. Adding the Plant to the 2007 IRP Update reduces total variable costs by $52.1 million over the study horizon. This reduction is driven by lower overall purchased power costs offset by increased fuel and wheeling expenses and a reduction in revenue from wholesale sales.

Exhibit PPL/601 also shows the overall benefit under two views of the cost of the new facility that is displaced in 2012 by the addition of the Plant in 2008. If the cost of a new facility is assumed to be $1,000 per kW, then the total benefit of adding the Plant to the Company's portfolio in 2008 is about $142 million. Assuming the cost of a new facility is $1,150 per kW, the total benefit rises to $197 million.

In summary, this analysis demonstrates that acquisition of the Plant reduced present value revenue requirement by about $142 million to $197 million. This analysis is conservative because it does not include the benefits of avoiding the risks associated with building a new plant including, slippages in permitting, capital cost escalation and overruns, unknown terms and conditions and slippage of construction schedules. The assumptions used in the study are contained in Confidential Exhibit PPL/602 and the confidential detailed output from the IRP models is provided in my workpapers.

Q. Does the purchase of the Plant in 2008 versus waiting to acquire another resource in 2012 benefit the Company's customers?

A. Yes. The Company's analysis shows that the Company's customers are better off through acquisition of the Plant in 2008 than acquisition of a similar resource in 2012 based on market pricing and responses to the 2012 RFP.

Q. How sensitive is the foregoing analysis to changes in the price of natural gas?

A. Not very. Given the significant correlation between prices for natural gas and market prices for electricity, changes in the price of natural gas will have the same effect on the costs and benefits of any new generation resource with the characteristics of the Plant. The Company has less exposure to the volatile wholesale natural gas and electricity markets with the Plant than without the Plant. With the Plant, the Company is not exposed to either natural gas prices or electricity prices alone, but rather the Company relies on the ratio of electricity prices to natural gas prices, which is the implied spark spread, to determine the extent the Plant is economical to run. The volatility in the implied spark spread is far less than the volatility of either electricity or natural gas market prices due to the significant correlation of those two commodities. This correlation is due to natural gas-fired generation being the generation on the economic margin in the region. The Plant is anticipated to be economical to run a significant amount of time due to its low heat rate.

Q. If the Company did not acquire the Plant, what alternatives were available to meet the Company's needs?

A. As demonstrated by the 2007 IRP and the 2007 IRP Update, the Company needs to acquire substantial additional resources by 2012. The alternative to acquisition of the Plant was the addition of similar plants at higher costs or increased purchases of power on the market. The impact of these alternatives on the Company's revenue requirement would certainly be less favorable than acquisition of the Plant. This is demonstrated by the analysis in Exhibit PPL/601.

Q. Is the Plant used and useful for Oregon customers?

A. Yes. The Plant is providing low-cost power and ancillary services to meet the Company's Oregon loads. Moreover, the Plant will ultimately replace four long-term purchase power agreements in the west control area that will expire between the summer of 2011 and 2012. These four contracts currently provide 789 MW of capacity to the west control area and flexibility to provide operating reserves as well as follow changes in loads and wind generation. The largest of these, the 575 MW peak purchase contract with the Bonneville Power Administration, expires on July 31, 2011. The other three contracts are the Colockum Capacity Exchange (86 MW), the Rocky Reach purchased power contract (65 MW), and the Grant County Displacement purchased power contract (63 MW).

Q. Is there a need for a new resource in the west control area?

A. Yes. Table 9 in the Company's 2007 IRP Update identified a resource deficit in the west control area of 575 MW in 2012 without the addition of the Plant. A copy of Table 9 is provided as Exhibit PPL/603.

Q. Has the Company recently reassessed the need for resources?

A. Yes. As part of its 2008 integrated resource planning process, the Company has recently reassessed the need for resources using a load forecast prepared in

February 2009. This forecast reflects the Company's most recent view of load growth as well as potential recessionary impacts on its loads.

Q. How was the February 2009 load forecast prepared?

A. The Company created the February 2009 load forecast using a combination of statistical and end-use modeling techniques for all customers except large industrial customers. This forecast incorporated historic weather normalized load data from January 1997 through January 2009, and incorporated forecasts of economic variables from late 2008 and early 2009. Large industrial customers were forecast individually based on information provided to the Company's customer account managers by these customers.

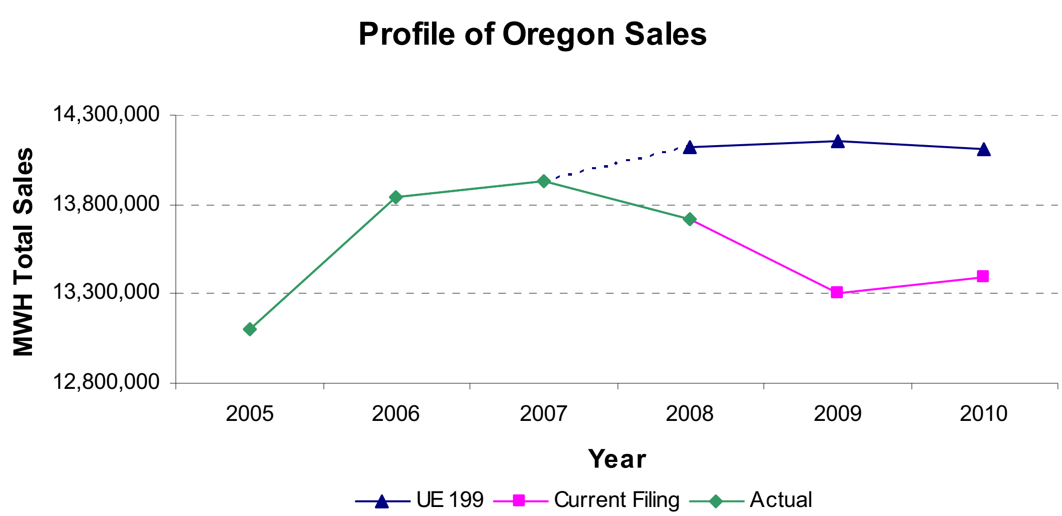
Q. Has the recent recession affected the load forecast?

A. Yes. Simply using historic data does not fully capture the effects of the current recession on the load forecast. To make this assessment, the Company reviewed the effect that the 2001-2002 recession had on loads and made a corresponding adjustment to the model driven forecast to capture load reductions reflective of the current recession.

Q. How does the February forecast compare to the last filed Oregon TAM and actual sales in 2008?

A. It is lower. Sales in 2008 started declining in the second quarter, and were down 5.3 percent in the last quarter of 2008 as compared to the last quarter of 2007. On an annual basis, 2008 sales in Oregon were about 1.5 percent below 2007 sales on a temperature adjusted basis. The declining sales in Oregon are expected to continue and are driven by the nationwide economic downturn and housing market slowdown, leading to slowdown and closures in the wood products sector. Since the previous forecast did not capture the period of economic downturn, it was important to account for the sales decline in the latest forecast. As shown in Chart 1, loads would have to increase by 3 percent from 2008 levels to achieve the levels predicted in the previous load forecast. This is impractical given the current economy. The February forecast corrects for this and predicts loads in 2010 that are 2.4 percent lower than the weather normalized 2008 loads.

Chart 1



Q. Based on this new load forecast, what is the Company's current assessment of its resource need in 2012?

A. The Company's current load and resource balance that includes the Plant in the existing portfolio is provided as Exhibit PPL/604 and shows a system need for 1,868 MW in 2012, which is nearly identical to the resource need identified in the 2007 IRP after the addition of the Plant.

Q. The 2007 IRP Update indicates that the Company doesn't need resources until 2012. Under these circumstances, why did you acquire the Plant in 2008?

A. The Company acknowledges that the load and resource balance did not show an immediate need for new resources. However, the Plant was available on a time limited basis and the analysis identified economic benefits to customers that were compelling, both short- and long-term. The alternatives were to buy the Plant in 2008 at a discount to market prices, or wait until 2012 and add a new resource at market prices. The Company's analysis accounts for the cost of purchasing the plant in 2008 rather than buying a new plant in 2012 and shows that the Company's customers are better off through acquisition of the Plant now than acquisition of a similar resource in 2012 based on market pricing and responses to the 2012 RFP.

Q. What do you conclude from the foregoing?

A. The Company's analysis demonstrates that the Company's acquisition of the Plant was a prudent decision. The Plant provides immediate and lasting benefits to its Oregon customers and is therefore used and useful. As such, I recommend that the Commission approve the Plant for inclusion in rate base as illustrated in Exhibit PPL/702 of Company witness Mr. R. Bryce Dalley.

Q. Does this conclude your direct testimony?

A. Yes.

Gregory N. Duvall
Exhibit PPL/601

Docket No. UE-
Exhibit PPL/601
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

2008-2017 Present Value Revenue Requirement Comparison

April 2009

PacifiCorp
2008-2017 Present Value Revenue Requirement Comparison
$ Millions

Description	**2007 IRP Update**	**Revised 2007 IRP Update (replace 2012 CCCT resource with 2008 Chehalis CCCT acquisition)**	**Benefit (cost) Difference**
Variable Costs			
Fuel & O&M	$15,939	$16,138	($198.7)
FOT's & Long Term Contracts	6,747	6,603	144.8
System Balancing Purchases	1,448	1,297	151.2
System Balancing Sales	(11,071)	(11,051)	(19.7)
Wheeling		25	(25.4)
Total Variable Costs	$13,064	$13,012	52.1
Case A) 2012 CCCT = $1,000/kW			
Capital and Fixed Costs	4,618	4,528	89.8
Total PVRR	$17,682	$17,540	$142.0
Case B) 2012 CCCT = $1,150/kW			
Capital and Fixed Costs	4,673	4,528	144.9
Total PVRR	$17,737	$17,540	$197.0

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/602
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Key IRP Assumptions - Chehalis

April 2009

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Docket No. UE-
Exhibit PPL/603
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

2007 Integrated Resource Plan
Update Table 9 Load and Resource Balance

April 2009

WA Docket
Greg N. Duvall
Exhibit GND 4

2007 Integrated Resource Plan Update
Table 9 – Load and Resource Capacity Balance

Planning Reserve Margin Target = 12%

Calendar Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
East										
Thermal	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	163	163	163	163	163	163	163	163	163	0
Renewable	109	109	109	109	109	109	109	105	105	105
Purchase	704	828	648	668	493	493	493	493	472	472
QF	106	106	106	106	106	106	106	106	106	105
Interruptible	212	328	328	328	328	328	328	328	328	328
East Existing Resources	7,361	7,601	7,421	7,441	7,266	7,266	7,266	7,262	7,241	7,077
Load	6,547	6,725	6,975	7,130	7,404	7,612	7,782	7,827	8,147	8,208
Sale	836	752	766	756	745	745	745	745	745	659
East Obligation	7,383	7,477	7,741	7,886	8,149	8,357	8,527	8,572	8,892	8,867
Planning reserves (12%)	756	739	792	807	860	885	905	911	951	968
Non-owned reserves	71	71	71	71	71	71	71	71	71	72
East Reserves	827	810	863	878	930	955	976	981	1,022	1,040
East Obligation + Reserves	8,210	8,287	8,604	8,764	9,079	9,312	9,503	9,553	9,914	9,907
East Position	(850)	(686)	(1,183)	(1,323)	(1,813)	(2,046)	(2,237)	(2,291)	(2,673)	(2,830)
East Reserve Margin	0%	3%	(3%)	(5%)	(10%)	(12%)	(14%)	(15%)	(18%)	(20%)
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,414	1,328	1,332	1,175	1,174	1,168	1,169	1,168	1,177
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	118	118	118	118	94	94	94	94	94	94
Purchase	800	800	800	750	112	141	107	107	107	107
QF	40	40	40	40	40	38	38	38	38	38
West Existing Resources	4,425	4,401	4,314	4,268	3,450	3,493	3,454	3,455	3,453	3,441
Load	3,228	3,343	3,302	3,316	3,341	3,409	3,457	3,531	3,444	3,550
Sale	299	299	290	290	258	258	258	158	108	108
West Obligation	3,527	3,642	3,592	3,606	3,599	3,667	3,715	3,689	3,552	3,658
Planning reserves (12%)	327	341	335	343	418	423	433	430	413	426
Non-owned reserves	7	7	7	7	7	7	7	7	7	8
West Reserves	334	348	342	349	425	430	439	436	420	434
West Obligation + Reserves	3,861	3,990	3,933	3,955	4,024	4,097	4,154	4,125	3,972	4,091
West Position	564	411	381	314	(575)	(603)	(700)	(670)	(518)	(651)
West Reserve Margin	28%	23%	23%	21%	(4%)	(4%)	(7%)	(6%)	(3%)	(6%)
System										
Total Resources	11,786	12,002	11,735	11,710	10,716	10,760	10,721	10,717	10,695	10,517
Obligation	10,910	11,119	11,333	11,492	11,748	12,024	12,242	12,261	12,444	12,525
Reserves	1,161	1,157	1,204	1,227	1,355	1,385	1,415	1,417	1,442	1,473
BP Obligation + Reserves	12,071	12,276	12,537	12,719	13,104	13,409	13,657	13,678	13,886	13,998
BP System Position	(294)	(285)	(813)	(1,020)	(2,398)	(2,664)	(2,950)	(2,975)	(3,202)	(3,495)
Reserve Margin	9%	10%	5%	3%	(8%)	(10%)	(12%)	(12%)	(14%)	(16%)

Docket No. UE-
Exhibit PPL/604
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

2008 Integrated Resource Plan Load and Resource Balance

April 2009

2008 IRP – Capacity Load and Resource Balance (12% Planning Reserve Margin)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East										
Thermal	5,983	5,998	6,025	6,066	6,066	6,078	6,079	6,087	6,088	5,863
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
QF	151	151	151	151	151	151	151	151	151	151
Interruptible	237	237	237	237	237	237	237	237	237	237
Transfers	876	952	602	-	-	-	-	-	-	-
East Existing Resources	8,636	8,572	8,284	7,553	7,563	7,584	7,592	7,589	7,600	7,386
Load (Feb 2009)	6,722	6,924	7,220	7,483	7,741	7,905	8,173	8,410	8,664	8,886
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	7,503	7,692	7,978	8,230	8,486	8,650	8,918	9,155	9,323	9,545
Planning reserves	740	782	812	862	892	910	941	971	990	1,016
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	811	852	882	933	962	981	1,012	1,042	1,061	1,086
East Obligation + Reserves	8,313	8,544	8,860	9,162	9,448	9,631	9,930	10,197	10,384	10,631
East Position	323	29	(576)	(1,609)	(1,886)	(2,047)	(2,338)	(2,607)	(2,783)	(3,245)
East Reserve Margin	16.3%	12.4%	4.8%	(7.6%)	(10.2%)	(11.7%)	(14.2%)	(16.5%)	(17.9%)	(22.0%)
West										
Thermal	2,042	2,050	2,059	2,071	2,083	2,083	2,083	2,083	2,068	2,068
Chehalis	509	509	509	509	509	509	509	509	509	509
Hydro	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
DSM	-	-	-	-	-	-	-	-	-	-
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
QF	120	120	120	120	120	120	120	120	120	120
Transfers	(878)	(953)	(603)	-	-	-	-	-	-	-
West Existing Resources	4,507	4,242	4,150	3,884	3,955	3,957	4,069	4,062	4,046	4,071
Load (Feb 2009)	3,265	3,324	3,379	3,447	3,491	3,554	3,608	3,624	3,719	3,793
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	3,764	3,814	3,669	3,705	3,749	3,812	3,766	3,732	3,827	3,901
Planning reserves	294	313	350	431	433	444	439	435	446	451
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	301	320	356	437	439	451	445	441	452	458
West Obligation + Reserves	4,065	4,134	4,025	4,143	4,188	4,262	4,211	4,173	4,279	4,359
West Position	442	109	124	(259)	(234)	(305)	(142)	(111)	(233)	(287)
West Reserve Margin	23.7%	14.9%	15.4%	5.0%	5.8%	4.0%	8.2%	9.0%	5.9%	4.6%
System										
Total Resources	13,143	12,815	12,433	11,437	11,517	11,541	11,661	11,651	11,646	11,457
Obligation	11,267	11,505	11,646	11,935	12,235	12,462	12,684	12,887	13,150	13,446
Reserves	1,112	1,172	1,239	1,370	1,402	1,432	1,457	1,483	1,513	1,544
Obligation + Reserves	12,378	12,677	12,885	13,305	13,637	13,893	14,141	14,369	14,663	14,990
System Position	765	138	(452)	(1,868)	(2,119)	(2,352)	(2,480)	(2,719)	(3,017)	(3,533)
Reserve Margin	18.8%	13.2%	8.1%	(3.6%)	(5.3%)	(6.9%)	(7.5%)	(9.1%)	(10.9%)	(14.3%)

Docket No. UE-
Exhibit PPL/700
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of R. Bryce Dalley

April 2009

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

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah, Suite 2000, Portland, Oregon, 97232. I am currently employed as Manager of 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. In addition to my formal education, 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 assumed my current position in 2008.

Q. What are your responsibilities as Manager of Revenue Requirement?

A. My primary responsibilities include the calculation and reporting of the Company's regulated earnings or 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.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified before the Oregon Public Utility Commission ("Commission") and the Washington Utilities and Transportation Commission.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

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 application. Specifically, I provide testimony on the following:

- The calculation of the $92.1 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 $789.0 million. The Company currently recovers its NPC through the Transition Adjustment Mechanism ("TAM").
- The development of the forecast test year in this case which is the twelve-months ending December 31, 2010. ("Test Period").
- 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 6.5 percent, which is far below the return on equity requested in this case and the current authorized return.
- An overview of the Company's proposal to consolidate several small deferral accounts.

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 6.5 percent during the Test Period. This return is less than the 10.00 percent ROE approved by the Commission in Docket UE 179 and is less than the 11.00 percent ROE recommended by Company witness Dr. Samuel C. Hadaway in this proceeding which produces a non-NPC revenue requirement of $789.0 million based on the Revised Protocol allocation methodology. The Company applied the Revised Protocol allocation method as approved by Commission Order No. 05-021 to calculate Oregon's results of operations. Exhibit PPL/701 provides a summary of the Company's Oregon-allocated results of operations for the Test Period.

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

A. As described above, the Company recovers its NPC through the TAM and is seeking to recover those costs as part of that mechanism. 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 removed the NPC components from the overall price change. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PPL/701. 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 embedded cost differential ("ECD"), and certain Revised Protocol allocation factors. Page 1.0 of Exhibit PPL/702 also shows the breakout of revenue requirement into the TAM and general rate case components and the resulting general rate case-related price change requested in this proceeding.

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 twelve-months ending December 31, 2010.

Q. Why did the Company choose the year ending December 31, 2010, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during which time the new rates will be in effect. Rates from this proceeding will be effective in the early part of 2010, which closely 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 net power costs filed in the TAM proceeding.

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 twelve-months ended June 30, 2008 ("Base Period"). Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing rate making adjustment was warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable and anticipated events and to include previous Commission-ordered adjustments.

Q. What is the significance of the Company's method 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 revenue and costs.

A. Revenues are adjusted for the effect of applying the current Commission-approved tariff rates to the Test Period load projection. Net power costs 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, and recovery of these costs is being sought through the TAM filing. Historical operations and maintenance ("O&M") expenses, excluding NPC, were split into labor and non-labor components. Non-labor costs were adjusted for inflation using nationally-recognized inflation indices provided by Global Insight and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs were also adjusted for contractual increases through the end of the Test Period. Specific adjustments are described in greater detail later in my testimony and exhibits where I explain the development of the Oregon results of operations.

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 which are developed specifically for electric utilities.

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. In addition, the revenue requirement developed in the case was compared to the Company's budget on a high level.

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 Generation O&M adjustment (Adjustment 4.5) which includes the cost of operating and maintaining new plants. Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production not changes in volume or processes.

In addition, the Company has included an overall reduction to O&M expenses included in this filing to align Test Period expenses with the Company's 2010 budget. This adjustment reduces Oregon revenue requirement by approximately $11 million and is described in detail later in my testimony.

Oregon Results of Operations

Q. Please describe Exhibit PPL/702.

A. Exhibit PPL/702, which was prepared under my direction, is the Company's Oregon results of operations report (the "Report"). The Base Period for the Report is the twelve-months ended June 30, 2008, which has been normalized and used to calculate the revenue requirement for the Test Period, the twelve-months ending December 31, 2010. The Report provides totals for revenue, expenses, depreciation, net power costs, 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 PPL/702 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 Revised 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).
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the year ended June 2008 and fully normalized results of operations for the Test Period by Federal Energy Regulatory Commission ("FERC") account and Revised Protocol allocation factor.
- Tabs 3 through 8 provide supporting documentation for the

- Tab 9 is a restatement of Tab 2 with the Oregon allocation based on the Modified Accord method as required pursuant to Commission Order No. 05-021.
- Tab 10 is a restatement of Tab 2 with the Oregon allocation based on the Hybrid method as required pursuant to Commission Order No. 05-021.
- Tab 11 contains the calculation of the Revised Protocol allocation factors.
- Tabs B1 through B20 contain the historical results for the twelve-month period ended June 30, 2008 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 Summary which is an overview of assumptions used to project retail revenue and a brief explanation of each additional normalization adjustment to other revenue. The numerical summary (pages 3.0.3 – 3.0.4) 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 Exhibit PPL/702, 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 Revenues (page 3.1) –** This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the twelve-months ending December 2010 based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

SO2 Emission Allowances (page 3.2) – 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 2010. This is the same methodology included in the Company's last general rate case, Docket UE 179.

Joint Use Revenues (page 3.3) – In the twelve-months ended June 2008, several entries related to joint use revenues were booked to the incorrect FERC accounts and/or locations. This adjustment corrects the accounting data to reflect proper account assignment and allocation factors.

Wheeling Revenues (page 3.4) – This adjustment records the additional revenues that the Company expects to receive over June 2008 levels for the Malin-Indian Springs contract. In addition, during the Base Period, the Company experienced various wheeling revenue transactions that are not expected to occur in the twelve-months ending December 2010. These transactions relate to various prior period adjustments and contract terminations and are removed in this adjustment.

Green Tag Revenues (page 3.5) – A market for green tags or renewable energy credits ("RECs") is developing where the tag or "green" traits of qualifying power production facilities can be detached and sold separately from the power itself. These RECs may be applied to meet renewable portfolio standards in various states. Currently, California and Oregon have renewable portfolio standards that make it advisable to use RECs for current year compliance or to bank RECs for future compliance, rather than sell them. This adjustment allocates the projected green tag sales for the twelve-months ending December 2010 to the Company's remaining jurisdictions consistent with the agreement with the Multi-State Process ("MSP") standing committee.

Clark Storage (page 3.6) – The Clark Storage & Integration Agreement was terminated in December 2007. This adjustment removes the revenue credit from the results of operations to reflect a normalized level of ancillary service revenues.

Revenue Correcting Adjustment (page 3.7) – This adjustment corrects the allocation code assignment on several revenue transactions in unadjusted results of operations.

West Valley Reserve Revenue (page 3.8) – The current GRID model for this filing includes reserves that the Company provides to the West Valley plant, which the Company no longer leases or operates. This adjustment takes the expected West Valley generation level included in the GRID model and multiplies it by the Open Access Same-time Information System ("OASIS") reserve tariff to calculate the expected revenue from the West Valley plant. This adjustment is not related to the removal of the West Valley Lease in adjustment 5.3.

Rental Income Adjustment (page 3.9) – This adjustment corrects an allocation error for sub-lease rental income, which was incorrectly assigning these revenues on a situs basis. The rental income is now being allocated on the system overhead ("SO") factor. This adjustment also annualizes the sub-lease rental income that occurred during the Base Period for a contract beginning in December 2007.

Tab 4 – O&M Adjustments

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

A. Tab 4 includes the O&M Summary followed by a numerical summary and the specific adjustments. The O&M Summary 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 4.0.4 – 4.0.6) 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 Exhibit PPL/702, 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 (page 4.1)** – This adjustment removes certain miscellaneous expenses that should have been charged below the line to nonregulated expenses.

Wage and Employee Benefits (page 4.2) – 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 these increases prospectively and adds them to operation and maintenance accounts. It also normalizes employee benefits and incentive compensation to levels the Company projects to incur for the twelve-months ending December 2010. The direct testimony of Company witness Mr. Erich Wilson provides an overview of the Company's compensation and benefit plans.

Q. Please describe how the Company computed labor costs for the Test Period.

A. As mentioned above, the Company's adjustment to labor expense is found on page 4.2, the Wage and Employee Benefit Adjustment. Labor-related costs for the Test Period are computed by adjusting salaries, incentives, benefits and costs associated with Financial Accounting Standard ("FAS") 87 (pension), FAS 106 (post retirement benefits) and FAS 112 (post employment benefits) for changes expected beyond the actual costs experienced in the Base Period. Page 4.2.2 is a numerical summary starting with actual labor costs in June 2008 and summarizing the adjustments made to project costs forward to reflect the Test Period level of expense. This summary is followed by the detailed worksheets used to adjust the labor costs forward to the Test Period.

The first step to adjust labor is to annualize salary increases that occurred during the Base Period. This was done by identifying actual wages by labor group by month along with the date each labor group received wage increases. Those increases were then applied to wages that were paid prior to the effective date. The next step is to apply the wage increases from June 2008 through December 2010 to the annualized June 2008 salaries to project the Test Period wages. The Company used union contract agreements to escalate union labor group wages, while increases for non-union and exempt employees were based on Global Insight Consumer Price Forecast increases. This calculation is detailed on pages 4.2.3 through 4.2.5.

Q. Was an adjustment made to the annual incentive plan payout?

A. Yes. An adjustment is made to increase total company incentive compensation from $30.1 million in the Base Period to $33.0 million in the Test Period as shown on page 4.2.2. The Company utilizes an incentive compensation program as part of its philosophy of delivering market competitive pay structured in a manner that benefits customers with safe, adequate and reliable electric service at a reasonable cost.

Q. Were employee pension and benefit costs adjusted in this section also?

A. Yes. Consistent with the aforementioned costs, pension expenses and other employee benefit costs were itemized starting with Base Period levels and walked forward to the Test Period. Total pension costs decrease by $13.3 million between the Base Period and the Test Period. The pension and benefit projections were provided by Mr. Wilson and are supported in his testimony.

Q. Do the pension expenses included in the Test Period reflect the recent Commission Order with respect to Docket UM 1400?

A. Yes. The Test Period pension expenses included in this filing reflect a ten-year amortization of the pension curtailment gain and the measurement date change as filed by the Company in Docket UM 1400, as approved in Commission Order No. 08-598.

Q. Were any other components of labor costs adjusted?

A. Yes. Payroll taxes were updated to capture the impact of the changes to employee salaries. This was calculated by applying the Federal Insurance Contributions Act ("FICA") tax rates to the net change in salaries and also to reflect the change in the social security cap for the Test Period.

Q. Did the Company make an adjustment for changes in workforce levels?

A. The wage and employee benefit adjustment assumes a constant level of workforce based on the historical period. However, other adjustments account for minor changes in workforce levels such as: 1) the labor savings from the reduction in the number of employees due to the Mid-American Energy Holding Company ("MEHC") transaction that is reflected in the MEHC Transition Savings adjustment (adjustment 4.3), and 2) the costs of additional compliance staffing as stated in the Compliance Department adjustment (adjustment 4.17).

Q. Please continue with the description of O&M adjustments included in Tab 4.

A. **MEHC Transition Savings (page 4.3)** – The Company eliminated many positions as a result of the MEHC transaction. These savings were made possible by the payment of Change-In-Control ("CIC") Severance. In accordance with Commission Order No. 07-211, this adjustment defers the severance cost accrued between March 21, 2006 and March 31, 2007 and amortizes it into expense on a straight-line basis over a five-year period. This adjustment also removes from the

Base Period any severance accruals and labor and overhead of employees leaving under this program.

In addition, on page 4.3.3 of Exhibit PPL/702, the Company has provided an updated cost/benefit analysis of this severance program consistent with the preliminary study distributed by the Company to the Commission and interested parties on August 1, 2007, as required by Order No. 07-211. A copy of the preliminary cost/benefit analysis has also been provided on pages 4.3.5 to 4.3.8 of Exhibit PPL/702 for comparative purposes. This analysis demonstrates that the benefits of the severance program exceeded the costs.

Irrigation Load Control (page 4.4) – Incentive payments made to Idaho customers participating in the irrigation load control program were initially system allocated in unadjusted data. This adjustment corrects that allocation and assigns these costs on a situs basis consistent with other demand side management ("DSM") programs.

Incremental Generation O&M (page 4.5) - This adjustment adds O&M expenses to the Test Period level for the Lake Side plant, Blundell bottoming cycle, Marengo wind plant, Goodnoe Hills wind plant, and Marengo II wind plant which were placed into service September 2007, December 2007, August 2007, May 2008, and June 2008 respectively. This adjustment also adds incremental operation and maintenance expenses for generating units that were not in service during the Base Period but will be in service during the Test Period.

This adjustment also includes a reduction to Oregon-allocated revenue requirement for the funding provided by the Energy Trust of Oregon ("ETO") associated with the Goodnoe Hills wind plant.

Remove Non-Recurring Entries (page 4.6) – A variety of accounting entries were made to expense accounts during the twelve-months ended June 2008 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 pages 4.6.1 and 4.6.2 of Exhibit PPL/702.

Blue Sky (page 4.7) – This adjustment removes costs associated with the Blue Sky program that were initially included in regulated results. The Blue Sky program is designed to encourage voluntary participation in the acquisition and development of renewable resources. To prevent non-participants from subsidizing the program this adjustment removes administrative and other expenses directly associated with the program.

O&M Escalation (page 4.8) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Increases are based on indices produced by Global Insight, which provides a detailed assessment of the electric market both historically and into the future. Global Insight indices are based on electric utility costs for materials and services only, which exclude labor expense, according to the Uniform System of Accounts defined by the FERC for major electric utilities and major natural gas pipeline companies. Labor-related expenses were segregated from other non-labor-related expenses to be escalated separately as described earlier in my testimony.

Global Insight's indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The Global Insight study is considered confidential; indices utilized in the Company's filing are provided in confidential Exhibit PPL/703.

Gas Swap (page 4.9) – During the twelve-months ended June 2008 several natural gas swap entries were inadvertently booked to FERC account 557. Natural gas swaps are normally charged to FERC account 547.1 and are considered to be part of net power costs. Since FERC account 557 is not a part of net power costs in the Company's filing, this adjustment removes the amounts from the Base Period to be consistent with net power cost treatment.

Grid West (page 4.10) - The write-off of the unpaid loan amount from Grid West was deferred and is accruing interest in accordance with Commission Order No. 06-483, dated August 22, 2006. In this proceeding the Company requests to begin amortization over a 3-year period on January 1, 2010. At that time the unamortized balance will be placed into rate base and will stop accruing interest.

MEHC Affiliate Management Fee (page 4.11) – This adjustment complies with the MEHC acquisition commitment 9 (Docket UM-1209) which states:

> "MEHC and PacifiCorp will hold customers harmless for increases in costs retained by PacifiCorp that were previously assigned to affiliates relating to management fees…This commitment is offsetable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case the following:
>
> > i) Corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are less than $7.3 million…"

This adjustment limits the MEHC corporate charge to PacifiCorp to $7.3 million.

Upper Beaver Hydro Sale (page 4.12) – The Company sold the Upper Beaver hydro electric facilities to Beaver City, Utah, on September 14, 2007. This adjustment removes O&M and the loss on the sale of property which both occurred during the twelve-months ended June 2008. The Upper Beaver assets were not included in the beginning rate base used to develop the test year balances.

Generation Overhaul Expense (page 4.13) – This adjustment normalizes generation overhaul expenses using a four-year average methodology. Overhaul expenses from June 2005 through June 2007 are escalated to a June 2008 level using escalation indices, and then those escalated expenses are averaged. For new generating units, which include Currant Creek, Lake Side and Chehalis, the four-year average is comprised of the overhaul expense planned for the first four years these plants are operational. The actual overhaul costs included in the Base Period are subtracted from the four-year average which results in this adjustment.

WECC Fees (page 4.14) – Since its formation, the Western Electric Coordinating Council ("WECC") has been responsible for coordinating and promoting electric system reliability. Recently, WECC's role has significantly expanded into the compliance area. This adjustment includes the increase in mandated membership WECC fees over the twelve-months ended June 2008 levels.

Preliminary Coal Plant Expense (page 4.15) – The Company was planning to build three coal units, Bridger unit 5, Hunter unit 4, and IPP unit 3. These projects were abandoned by the Company and the related expenses were written off to FERC account 557. This adjustment removes these write-offs and the associated O&M expenses from Oregon results of operations.

Memberships and Subscriptions (page 4.16) – This adjustment removes expenses in excess of Commission policy allowances as stated by the Commission Order in Docket UE 94. National and regional trade organizations are recognized at 75 percent. The Company's mandated membership in WECC is included at 100 percent.

Compliance Department (page 4.17) – As of June 18, 2007, the electricity industry has been operating under mandatory, enforceable reliability standards. Utilities and other bulk power industry participants that violate any of the standards face enforcement actions including possible sanctions of up to one million dollars per day in addition to potentially more rigorous compliance monitoring and testing requirements. In order to comply with enhanced reliability standards, the Company anticipates the addition of thirteen full-time employees along with increased program and information technology costs. These additional costs are included through this adjustment.

A&G Cost Commitment Adjustment (MEHC) (page 4.18) - Based on commitment O 12 in Docket UM-1209, the Company must reduce its administrative and general expense below $228.8 million on a total company basis, adjusted for inflation. This adjustment demonstrates the administrative and general expense included the Test Period is below the commitment level.

Captive Insurance Expense Adjustment (MEHC) (page 4.19) - This adjustment reduces the level of captive insurance expense in the Test Period to $7.4 million as agreed to by the Company as part of the MEHC transaction as stated in Docket UM 1209, commitment O 10.

Adjust Non-Power Cost O&M to 2010 Target (page 4.20) – The Company is not planning to spend more than the budgeted non-power cost O&M in the Test Period. After applying the regulatory adjustments made to Base Period O&M expenses, the Company compared the total level of non-power cost O&M expense to the total expense level included in the Company's 2010 budget. In this case, the Company's budget is approximately $40.5 million less than the level of O&M expense justified through the Company's other normalizing adjustments detailed above. As a result, this adjustment reduces total company non-power cost O&M expenses to the Company's budgeted level. The Oregon-allocated impact of this adjustment is an approximate $11.3 million reduction to the revenue requirement requested in this proceeding.

Q. Will the impact of this adjustment change if modifications are made to the Company's other non-NPC O&M normalizing adjustments?

A. Yes. This adjustment is dependent upon all the other non-NPC O&M adjustments included in this filing as shown on page 4.20.2, and will change accordingly if adjustment amounts are modified.

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 net power costs, but may or may not be addressed separately in the Company's TAM filings. Specifically, Adjustment 5.1 - Net Power Costs relates solely to NPC and recovery of these costs is being sought in the TAM proceeding rather than the general rate case. This adjustment is included in my exhibit for modeling and computational purposes only. For example, Test Period revenue requirement includes a tax credit for renewable energy generated from renewable facilities (Adjustment 7.3). This tax credit is calculated based on the generation output of these facilities as modeled in GRID (Adjustment 5.1) for the Test Period. Adjustments 5.2 through 5.5 include items that are not addressed in the Company's TAM filing. Each of these adjustments is described below.

The Net Power Cost Summary 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 Exhibit PPL/702, 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) –** The NPC adjustment presents normalized Test Period steam and hydro power generation, fuel, purchased power, wheeling expense and sales for resale based on the Company's GRID model. As I previously described, this adjustment is included in the calculation of overall revenue requirement in my exhibit for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.

West Valley Lease (page 5.2) – The Company terminated the lease for the West

Valley generating facility on May 31, 2008, and this adjustment removes the associated expense and rate base from the Base Period. This treatment is consistent with the stipulation approved in Docket UM 1209 (MEHC Transaction, Item O 8a).

James River Royalty Offset and Little Mountain (page 5.3) – 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 adjustment adds the royalty offset to FERC account 456, other electric revenue, for the Test Period.

This adjustment also normalizes the ongoing level of steam revenues related to the Little Mountain plant. Contractually, the steam revenues from Little Mountain are tied to natural gas prices. The Company's net power cost study includes the cost of running the Little Mountain plant but does not include the offsetting steam revenues. This adjustment aligns the steam revenues to the gas prices modeled in GRID.

Green Tags (page 5.4) – This adjustment removes from regulatory results the cost of RECs or green tag purchases made for the Blue Sky program.

Electric Lake Settlement (page 5.5) – Canyon Fuel Company ("CFC") owns the

Skyline mine located near Electric Lake. Electric Lake is owned by PacifiCorp and provides water for the Huntington Power Plant. The two companies have disputed the claim made by PacifiCorp that CFC's mining operations punctured the lake and caused water to flow into the Skyline mine. PacifiCorp has incurred capital costs and O&M costs to pump water from the breach into Electric Lake. The two companies negotiated a settlement and release agreement for the claims made by PacifiCorp. The settlement of costs reimburses for PacifiCorp legal expenses, other O&M and capital costs associated with the pumping and is split 71 percent O&M and 29 percent capital. The value of the settlement will be amortized over three years. This adjustment reduces rate base for the fixed cost portion of the settlement, and includes one-year of amortization for the O&M portion of the settlement. This settlement also includes a new pumping agreement.

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 Summary followed by a numerical summary and the specific adjustments. The summary 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 Exhibit PPL/702, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. How are the Company's pro forma depreciation and amortization expense for the Test Period developed in the Report?

A. The depreciation and amortization expense for the Test Period is calculated by applying functional composite depreciation and amortization rates to projected 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 6.1.17.

Q. How are the accumulated depreciation and amortization balances included in the filing calculated?

A. Accumulated depreciation and amortization balances for the Test Period are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2008 balances. An adjustment was made to the Base Period accumulated reserve balances to reflect the Commission-approved steam plant production lives. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2008 to December 31, 2010. The reserve balance calculations are detailed on pages 6.2 to 6.2.13.

Q. Please describe any additional depreciation adjustments included in the case.

A. **Hydro Decommissioning (page 6.3) –** Based on the Company's latest depreciation study approved in Docket UM 1329, an additional $19.4 million is required for the decommissioning of various hydro facilities. This adjustment includes an annual level of expense in results, and the associated adjustment to the depreciation reserve is incorporated in adjustment 6.2.

Tab 7 – Tax Adjustments

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

A. Tab 7 includes the Tax Summary followed by a numerical summary and the specific adjustments. The Tax Summary begins on page 7.0.1 with a brief overview of assumptions used. 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 Exhibit PPL/702, 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 through June 30, 2008, for known or anticipated changes in the assessed values of the Company's operating property and the corresponding affect such changes will have on property tax expense through December 31, 2010. In Confidential Exhibit PPL/704 the Company has provided a copy of the Company's property tax estimation calculations used in the development of test period property taxes included in this filing.

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 kWh generated by the plants, and the credit can be taken for the first ten years of generation from qualifying property. Under the calculation required by Internal Revenue Code Sections 45(a)(1) and 45(b)(2), the most current renewable electricity production credit rate is 2.1 cents per kilowatt hour for the electricity produced from renewable energy. This adjustment reflects this credit based on the qualifying production as modeled in GRID for the Test Period net power cost study found on page 5.1.13. This credit will be updated to reflect changes to the GRID model runs in the TAM.

This adjustment also reflects two state tax credits. The Utah State production tax credit is based on the kWh generated by the Blundell bottoming cycle, and the credit can be taken for four years from the in-service date. 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.

Q. Are the renewable energy tax credits refundable when the Company has a net tax operating loss?

A. No. The renewable energy tax credits are not refundable when the Company has zero taxable income or a net operating loss, but must be carried back one year and carried forward 20 years and utilized against the Company's net tax liability in each of those years, respectively.

Q. How would renewable energy tax credits be accounted for in a general rate case in the event the Company was not able to currently utilize the production tax credits in the year generated or in the carry back year?

A. With respect to revenue requirement, the renewable energy tax credits would be treated as a deferred tax benefit and included as a reduction to revenue requirement. An associated deferred tax asset would be included in rate base.

Q. How have the renewable energy tax credits been treated in the current general rate case?

A. The renewable energy tax credits have been included as a current tax benefit, reducing current income taxes with no corresponding rate base impacts due to the fact that the renewable energy tax credits have the ability to be utilized either in the current tax year or in the carry back tax year of the general rate case.

Q. Please continue with your description of the tax adjustments in Tab 7.

A. **Production Activities Deduction (page 7.4) -** The Domestic Production Activities Deduction is a permanent deduction for qualified production activities (including generation of electricity) in the United States. It is equal to a percentage of the lesser of a Company's taxable income or the Company's net income earned from qualified production activities. The deduction is available for tax years beginning after Dec. 31, 2004 and equals 3 percent of qualified production activities income for tax years 2005 and 2006; 6 percent for tax years 2007, 2008 and 2009; and 9 percent for tax years 2010 or later. This adjustment updates the Production Activities Deduction Schedule M for the Test Period. This adjustment will need to be further updated to reflect the final revenue requirement ordered in this case.

Pro Forma Schedule M (page 7.5) – The Base Period Schedule M items were updated for known and measurable adjustments through December 2010. Non-utility items, separate tariff items and other non-recurring items were removed from the Base Period before updating. For example, Schedule M items related to the Grid West note receivable and West Valley Lease were removed. Normalizing adjustments such as SO2 emission allowances were then added. Depreciation differences on capital additions were generated in order to bring the Schedules M items in line with the December 2010 test period. The Schedule M items were then used to develop deferred income tax expenses and balances for the Test Period.

The Company has reviewed the income tax normalization policy for AFUDC equity and has determined that an income tax flow-through policy with respect to AFUDC equity provides a more appropriate treatment for this item, as it more closely resembles a permanent item. AFUDC equity is solely a book-related item and is not an income item on a tax return. In particular, AFUDC equity is an increase to book income which reverses through a decrease in book income through book depreciation expense and never impacts taxable income. As such, the Company has computed the revenue requirement utilizing an income tax flow-through policy rather than a full normalization policy for AFUDC equity. In the event the Commission does not accept this refinement in policy, the revenue requirement will need to be increased to reflect a full normalization policy for AFUDC equity.

Deferred Income Taxes (page 7.6 & page 7.7) – The non-property-related Schedule M items were used to develop the non-property-related deferred income tax expense. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. Normalizing adjustments were added consistent with the Schedule M items. The deferred income tax expense was then used to develop the deferred tax balance for December 2010.

Q. How have current state and federal income tax expenses been calculated?

A. Current state and federal income tax expenses were calculated by applying the applicable tax rates to the taxable income calculated in the Report. State income tax expense was calculated using the state statutory tax rates applied to the jurisdictional pre-tax income. The result of accumulating those state tax expense calculations is then allocated among the jurisdictions using the Income Before Tax ("IBT") factor. Federal income tax expense is calculated using the same methodology that the Company uses in preparing its filed income tax returns. The detail supporting this calculation is contained on pages 2.18 through 2.20.

Tab 8 – Rate Base Adjustments

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

A. Tab 8 includes the Rate Base Summary followed by a numerical summary and the specific adjustments. The Rate Base Summary begins on page 8.0.1 with a brief overview of assumptions used to adjust electric plant in service and other rate base components. The numerical summary (pages 8.0.3 – 8.0.4) 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 Exhibit PPL/702, 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 included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net revenue lag days by the average daily cost of service. Net lag days in this case are based on a lead lag study recently prepared by the Company using calendar year 2007 information. A copy of this study is provided in the electronic work papers supporting this application. Based on the results of the 2007 lead lag study, the Company experiences 5.14 net revenue lag days in Oregon, requiring a cash working capital balance of $11.9 million to be included in rate base. By contrast, the Company's 2003 lead lag study resulted in 9.00 net revenue lag days in Oregon.

Trapper Mine Rate Base (page 8.2) – The Company owns a 21.4 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in account 123.1, investment in subsidiary company, which is not included as a rate base account. The normalized coal cost from Trapper Mine in net power costs includes O&M costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine net plant investment to rate base in order for the

Company to earn a return on its investment.

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 net power costs include the O&M costs of the mine but provide no return on investment.

Environmental Settlement (PERCO) (page 8.4) – In 1996, the Company received an insurance settlement of $33 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company ("PERCO"). This fund balance is amortized or reduced as PERCO expends dollars on clean-up costs. PERCO received an additional $5 million of insurance proceeds plus associated liabilities from the Company in 1998. This adjustment includes the unspent insurance proceeds in the Test Period as a reduction to rate base.

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.

Pro Forma Plant Additions (page 8.6) – To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. Company business units identified capital expenditures that will be used and useful prior to the end of the Test Period. This adjustment does not include projects that have more than $20 million (total company basis) being placed into service during 2010 or projects with in-service dates during the last few days of 2010.

Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. This adjustment is based on thirteen-month average balances for the Test Period. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described earlier in my testimony. Projects over $5 million (total company basis) are described on pages 8.6.18 through 8.6.29 of Exhibit PPL/702.

Miscellaneous Rate Base (page 8.7) – This adjustment includes three parts as described below:

- Cash is removed from rate base to avoid earning its rate of return on the balance.
- An anticipated increase in fuel stock is added due to increases in the cost of coal and the number of tons stored at each site.
- A prepaid overhaul and materials and supplies related to the Chehalis plant acquisition are added to rate base.

Plant Retirements (page 8.8) – The Company's retirement rates were applied to pro forma plant balances included in this filing. This adjustment reflects these retirements into results.

Powerdale Hydro Removal (page 8.9) – Powerdale is a hydroelectric generating facility located on the Hood River in Oregon. This facility was scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed out a major section of the flow line. The Company determined that the cost to repair this facility was not economical and that it was in the customer’s best interest to cease operation of the facility. This adjustment reflects the treatment approved by the Commission in Docket UM 1298. During 2007, the net book value (including an offset for insurance proceeds) of the assets to be retired was transferred to the unrecovered plant regulatory asset. In addition, future decommissioning costs are deferred in a regulatory asset (debit), offset by a regulatory liability (credit) reflecting the amount not spent through the Test Period. In this proceeding the Company is proposing to amortize the decommissioning regulatory asset over a three-year period beginning in January 2010. As such, one year of amortization expense is included in the Oregon revenue requirement calculation.

Goose Creek Transmission (page 8.10) – On April 1, 2008, the Company sold approximately 14 miles of transmission line, running from the Company's Goose Creek switching station and extending north to the Decker 230 kV substation near Decker, Montana. The assets sold included structures, miscellaneous support equipment, easements and rights-of-way associated with the transmission line. The sale of the transmission line resulted in the Goose Creek switching station no longer being useful to the Company. The Company is currently removing the Goose Creek switching station including all above ground facilities and leveling the site. This adjustment reduces rate base by the net book value of the assets sold. Oregon's allocated portion of the gain from the asset sale is included in the property sales balancing account and is being returned to customers through schedule 96, effective January 1, 2009. This treatment was authorized by the Commission in Order No. 07-489.

Plant Held For Future Use ("PHFU") (page 8.11) – This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Commission Order No. 01-787.

Tab 9 – Modified Accord and Tab 10 - Hybrid

Q. Please describe the information contained behind Tab 9 and Tab 10.

A. Tab 9 and Tab 10 are restatements of Tab 2 using the Modified Accord and Hybrid allocation methods respectively. The Company is providing these restated results pursuant to Commission Order No. 05-021.

Tab 11 – Allocation Factors

Q. Please describe the information contained behind Tab 11 Allocation Factors.

A. Tab 11 Allocation Factors summarizes the derivation of the jurisdictional allocation factors using the Revised Protocol allocation methodology. These factors have been developed using forecast loads consistent with the loads used in the development of Test Period revenues and net power costs.

Consolidation of Miscellaneous Deferred Accounts

Q. Please describe the Oregon Regulatory Asset & Liability Consolidation Account.

A. This account was first established in Docket UE 170. It combined six small miscellaneous deferred accounts which had previously been recovered or returned from customers through surcharges or surcredits on customer's bills. The six accounts were combined and the net balance was returned to customers as a surcredit via Schedule 95. Subsequently, as other accounts finish amortizing any remaining balance in the account is rolled over into the Oregon Regulatory Asset & Liability Consolidation Account. Schedule 95 was withdrawn when the balance in the account approached zero.

Q. What is the balance in the Oregon Regulatory Asset & Liability Consolidation Account at present?

A. At the end of February 2009, the account had a liability balance of $131,500.

Q. Please describe the Deferred Excess Net Power Costs – UE 116 Bridge Account.

A. Commission Order No. 03-637 approved a stipulation to record excess net power costs related to the UE 116 bridge period. The amounts in the account have never begun amortization and at the end of February 2009, the account had an asset balance of $163,800.

Q. Please describe the Regulatory Liability – Oregon Rate Refund Account

As part of a Settlement with the Williams Company, amounts received from the Williams Company were passed directly to customers as a credit on the customer bill during a one-month period. The account had a liability balance of $80,000 at the end of February 2009, reflecting an overpayment to customers.

Q. What is the Company proposing with respect to the balances in these three accounts?

In this proceeding, the Company proposes to combine the small balances in the

Oregon Rate Refund Account and the Deferred Excess Net Power Costs – UE 116 Bridge Account into the Oregon Regulatory Asset & Liability Consolidation Account.

Q. Will this consolidation result in any changes in rates at this time?

A. No. At some future time, when the balance in the Oregon Regulatory Asset & Liability Consolidation Account becomes significantly different from zero, the Company will propose through an Advice Letter filing to reinstate Schedule 95 and return or recover any balances to/from customers over an appropriate period of time.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/701
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Summary of the Oregon Results of Operations

April 2009

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

		(1)	(2) (3) - (1)	(3) Ref. Page 1.1	(4) **TAM**	(5) **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	252,395,751	696,945,552	949,341,303	20,571,645	92,057,256	1,061,970,204
3	Interdepartmental		-	-			-
4	Special Sales	200,753,578	963,190	201,716,768			201,716,768
5	Other Operating Revenues		42,876,105	42,876,105			42,876,105
6	Total Operating Revenues	453,149,329	740,784,847	1,193,934,176	20,571,645	92,057,256	1,306,563,077
7							
8	Operating Expenses:						
9	Steam Production	171,169,897	80,780,180	251,950,077			251,950,077
10	Nuclear Production		-	-			-
11	Hydro Production		9,911,805	9,911,805			9,911,805
12	Other Power Supply	264,996,297	10,011,575	275,007,872			275,007,872
13	Transmission	37,554,781	13,705,242	51,260,023			51,260,023
14	Distribution		70,710,593	70,710,593			70,710,593
15	Customer Accounting		31,710,902	31,710,902		598,253	32,309,156
16	Customer Service & Info		3,695,469	3,695,469			3,695,469
17	Sales		-	-			-
18	Administrative & General		57,051,637	57,051,637			57,051,637
19							
20	Total O&M Expenses	473,720,974	277,577,404	751,298,378	-		751,298,378
21							
22	Depreciation		148,046,103	148,046,103			148,046,103
23	Amortization		16,475,737	16,475,737			16,475,737
24	Taxes Other Than Income		51,964,717	51,964,717		2,605,334	54,570,050
25	Income Taxes - Federal	(6,873,192)	27,842,637	20,969,445	6,873,192	29,686,899	57,529,536
26	Income Taxes - State	(933,953)	5,404,055	4,470,103	933,953	4,033,957	9,438,012
27	Income Taxes - Def Net		17,791,779	17,791,779			17,791,779
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		(2,076,510)	(2,076,510)			(2,076,510)
30							
31	Total Operating Expenses:	465,913,829	543,025,922	1,008,939,751	7,807,145	36,924,443	1,053,671,339
32							
33	Operating Rev For Return:	(12,764,500)	197,758,925	184,994,425	12,764,500	55,132,813	252,891,738
34							
35	Rate Base:						
36	Electric Plant In Service		5,550,442,483	5,550,442,483			5,550,442,483
37	Plant Held for Future Use		(0)	(0)			(0)
38	Misc Deferred Debits		32,822,514	32,822,514			32,822,514
39	Elec Plant Acq Adj		18,568,147	18,568,147			18,568,147
40	Nuclear Fuel		-	-			-
41	Prepayments		12,200,450	12,200,450			12,200,450
42	Fuel Stock		41,007,391	41,007,391			41,007,391
43	Material & Supplies		49,318,208	49,318,208			49,318,208
44	Working Capital		12,866,739	12,866,739			12,866,739
45	Weatherization Loans		(696)	(696)			(696)
46	Misc Rate Base		1,206,251	1,206,251			1,206,251
47							
48	Total Electric Plant:	-	5,718,431,486	5,718,431,486			5,718,431,486
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(2,041,423,829)	(2,041,423,829)			(2,041,423,829)
52	Accum Prov For Amort		(141,099,147)	(141,099,147)			(141,099,147)
53	Accum Def Income Tax		(548,748,369)	(548,748,369)			(548,748,369)
54	Unamortized ITC		(4,172,305)	(4,172,305)			(4,172,305)
55	Customer Adv For Const		(3,499,244)	(3,499,244)			(3,499,244)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(21,181,866)	(21,181,866)			(21,181,866)
58							
59	Total Rate Base Deductions	-	(2,760,124,760)	(2,760,124,760)			(2,760,124,760)
60							
61	Total Rate Base:	-	2,958,306,726	2,958,306,726			2,958,306,726
62							
63	Return on Rate Base			6.253%			8.549%
64							
65	Return on Equity			6.517%			11.000%

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

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	949,341,303	112,628,901	1,061,970,204
3	Interdepartmental	-		
4	Special Sales	201,716,768		
5	Other Operating Revenues	42,876,105		
6	Total Operating Revenues	1,193,934,176		
7				
8	Operating Expenses:			
9	Steam Production	251,950,077		
10	Nuclear Production	-		
11	Hydro Production	9,911,805		
12	Other Power Supply	275,007,872		
13	Transmission	51,260,023		
14	Distribution	70,710,593		
15	Customer Accounting	31,710,902	598,253	32,309,156
16	Customer Service & Info	3,695,469		
17	Sales	-		
18	Administrative & General	57,051,637		
19				
20	Total O&M Expenses	751,298,378		
21				
22	Depreciation	148,046,103		
23	Amortization	16,475,737		
24	Taxes Other Than Income	51,964,717	2,605,334	54,570,050
25	Income Taxes - Federal	20,969,445	36,560,092	57,529,536
26	Income Taxes - State	4,470,103	4,967,909	9,438,012
27	Income Taxes - Def Net	17,791,779		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	(2,076,510)		
30				
31	Total Operating Expenses:	1,008,939,751	44,731,588	1,053,671,339
32				
33	Operating Rev For Return:	184,994,425	67,897,313	252,891,738
34				
35	Rate Base:			
36	Electric Plant In Service	5,550,442,483		
37	Plant Held for Future Use	(0)		
38	Misc Deferred Debits	32,822,514		
39	Elec Plant Acq Adj	18,568,147		
40	Nuclear Fuel	-		
41	Prepayments	12,200,450		
42	Fuel Stock	41,007,391		
43	Material & Supplies	49,318,208		
44	Working Capital	12,866,739		
45	Weatherization Loans	(696)		
46	Misc Rate Base	1,206,251		
47				
48	Total Electric Plant:	5,718,431,486	-	5,718,431,486
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(2,041,423,829)		
52	Accum Prov For Amort	(141,099,147)		
53	Accum Def Income Tax	(548,748,369)		
54	Unamortized ITC	(4,172,305)		
55	Customer Adv For Const	(3,499,244)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(21,181,866)		
58				
59	Total Rate Base Deductions	(2,760,124,760)	-	(2,760,124,760)
60				
61	Total Rate Base:	2,958,306,726	-	2,958,306,726
62				
63	Return on Rate Base	6.253%		8.549%
64				
65	Return on Equity	6.517%		11.000%
66				
67	TAX CALCULATION:			
68	Operating Revenue	228,225,751	109,425,314	337,651,065
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	85,799,770	-	85,799,770
72	Schedule "M" Additions	252,518,382	-	252,518,382
73	Schedule "M" Deductions	291,319,775	-	291,319,775
74	Income Before Tax	103,624,588	109,425,314	213,049,902
75				
76	State Income Taxes	4,470,103	4,967,909	9,438,012
77	Taxable Income	99,154,485	104,457,404	203,611,890
78				
79	Federal Income Taxes + Other	20,969,445	36,560,092	57,529,536

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

Exhibit PPL/701
Dalley/3

	Exhibit PPL/702		Exhibit PPL/702			
	Tab 2	Tab 2	Tab 3	Tab 4	Tab 5	Tab 6
	Total Company Actual Results June 2008	Oregon Allocated Actual Results June 2008	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	3,328,819,153	948,313,050	1,028,253	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	880,014,007	235,591,873	-	-	(33,875,105)	-
5 Other Operating Revenues	175,436,518	40,953,473	1,151,670	-	770,961	-
6 Total Operating Revenues	4,384,269,678	1,224,858,396	2,179,924	-	(33,104,143)	-
7						
8 Operating Expenses:						
9 Steam Production	865,024,880	221,479,375	-	7,018,680	23,452,022	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	34,323,831	9,225,176	-	693,972	-	-
12 Other Power Supply	1,316,635,416	328,614,473	72,183	1,073,585	(56,612,879)	(499,200)
13 Transmission	164,210,976	44,104,769	-	163,214	6,992,039	-
14 Distribution	218,720,171	70,365,580	(165,746)	510,759	-	-
15 Customer Accounting	93,204,369	31,796,255	-	(85,352)	-	-
16 Customer Service & Info	33,245,936	3,703,728	-	(8,258)	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	170,209,441	51,961,065	-	5,090,572	-	-
19						
20 Total O&M Expenses	2,895,575,020	761,250,421	(93,563)	14,457,171	(26,168,818)	(499,200)
21						
22 Depreciation	413,308,745	120,985,142	-	-	-	27,060,961
23 Amortization	62,472,711	15,326,015	-	-	-	493,528
24 Taxes Other Than Income	106,123,328	45,213,790	-	-	-	-
25 Income Taxes - Federal	62,041,969	39,804,467	333,832	(3,849,092)	(2,291,245)	(8,416,487)
26 Income Taxes - State	15,851,233	4,767,562	1,924,497	(640,582)	(496,997)	(1,352,535)
27 Income Taxes - Def Net	189,558,215	54,852,074	(188,314)	(937,376)	35,456	1,648,990
28 Investment Tax Credit Adj.	(3,896,956)	-	-	-	-	-
29 Misc Revenue & Expense	(6,745,817)	(1,600,705)	(39,811)	(435,994)	-	-
30						
31 Total Operating Expenses:	3,734,288,447	1,040,598,768	1,936,641	8,594,127	(28,921,603)	18,935,258
32						
33 Operating Rev For Return:	649,981,231	184,259,628	243,283	(8,594,127)	(4,182,540)	(18,935,258)
34						
35 Rate Base:						
36 Electric Plant In Service	17,064,579,403	4,861,049,864	-	-	(5,829)	-
37 Plant Held for Future Use	15,070,970	4,073,830	-	-	-	-
38 Misc Deferred Debits	190,114,990	29,310,919	-	4,580,934	(1,323,342)	-
39 Elec Plant Acq Adj	69,085,936	18,568,147	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	40,665,612	12,200,450	-	-	-	-
42 Fuel Stock	115,767,576	28,983,609	-	-	1,323,342	-
43 Material & Supplies	164,665,361	48,915,055	-	-	-	-
44 Working Capital	68,581,428	19,108,184	29,468	148,954	(362,860)	(137,569)
45 Weatherization Loans	14,588,989	(696)	-	-	-	-
46 Misc Rate Base	4,314,182	1,206,251	-	-	-	-
47						
48 Total Electric Plant:	17,747,434,447	5,023,415,613	29,468	4,729,889	(368,689)	(137,569)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(6,268,944,208)	(1,857,920,106)	-	-	796	(183,567,255)
52 Accum Prov For Amort	(400,101,953)	(119,340,193)	-	-	-	(21,758,954)
53 Accum Def Income Tax	(1,476,739,164)	(414,953,062)	1,469,319	(1,738,506)	29,897	(1,435,515)
54 Unamortized ITC	(10,292,566)	(6,725,897)	-	-	-	-
55 Customer Adv For Const	(18,763,267)	(2,682,422)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(67,068,015)	(17,634,431)	(3,871,633)	-	843,426	-
58						
59 Total Rate Base Deductions	(8,241,909,173)	(2,419,256,111)	(2,402,314)	(1,738,506)	874,120	(206,761,724)
60						
61 Total Rate Base:	9,505,525,274	2,604,159,502	(2,372,846)	2,991,382	505,431	(206,899,293)
62						
63 Return on Rate Base	6.838%	7.076%	0.016%	-0.338%	-0.162%	-0.221%
64						
65 Return on Equity	7.659%	8.123%	0.031%	-0.660%	-0.316%	-0.431%
66						
67 TAX CALCULATION:						
68 Operating Revenue		283,683,731	2,313,297	(14,021,177)	(6,935,326)	(27,055,289)
69 Other Deductions						
70 Interest (AFUDC)						
71 Interest		75,528,438	(68,820)	86,759	14,659	(6,000,700)
72 Schedule "M" Additions		236,926,771	2,576,634	-	418,027	-
73 Schedule "M" Deductions		326,587,453	2,080,448	(2,469,947)	511,453	4,345,051
74 Income Before Tax		118,494,611	2,878,303	(11,637,989)	(7,043,410)	(25,399,640)
75						
76 State Income Taxes		4,767,562	1,924,497	(640,582)	(496,997)	(1,352,535)
77 Taxable Income		113,727,050	953,806	(10,997,407)	(6,546,414)	(24,047,106)
78						
79 Federal Income Taxes + Other		39,804,467	333,832	(3,849,092)	(2,291,245)	(8,416,487)
APPROXIMATE REVISED PROTOCOL PRICE CHANGE		63,617,977	(740,281)	14,690,772	7,009,721	2,070,877

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

		Exhibit PPL/702		
		Tab 7	Tab 8	Tab 2 Oregon Allocated
		Tax Adjustments	Rate Base Adjustments	Normalized Results December 2010
1	Operating Revenues:			
2	General Business Revenues	-	-	949,341,303
3	Interdepartmental	-	-	-
4	Special Sales	-	-	201,716,768
5	Other Operating Revenues	-	-	42,876,105
6	Total Operating Revenues	-	-	1,193,934,176
7				
8	Operating Expenses:			
9	Steam Production	-	-	251,950,077
10	Nuclear Production	-	-	-
11	Hydro Production	-	(7,344)	9,911,805
12	Other Power Supply	1,883,267	476,442	275,007,872
13	Transmission	-	-	51,260,023
14	Distribution	-	-	70,710,593
15	Customer Accounting	-	-	31,710,902
16	Customer Service & Info	-	-	3,695,469
17	Sales	-	-	-
18	Administrative & General	-	-	57,051,637
19				
20	Total O&M Expenses	1,883,267	469,098	751,298,378
21				
22	Depreciation	-	-	148,046,103
23	Amortization	-	656,194	16,475,737
24	Taxes Other Than Income	6,750,927	-	51,964,717
25	Income Taxes - Federal	2,424,564	(7,036,595)	20,969,445
26	Income Taxes - State	1,291,536	(1,023,378)	4,470,103
27	Income Taxes - Def Net	(37,627,092)	8,040	17,791,779
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	(2,076,510)
30				
31	Total Operating Expenses:	(25,276,798)	(6,926,642)	1,008,939,751
32				
33	Operating Rev For Return:	25,276,798	6,926,642	184,994,425
34				
35	Rate Base:			
36	Electric Plant In Service	-	689,398,449	5,550,442,483
37	Plant Held for Future Use	-	(4,073,830)	(0)
38	Misc Deferred Debits	-	254,002	32,822,514
39	Elec Plant Acq Adj	-	-	18,568,147
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	12,200,450
42	Fuel Stock	-	10,700,440	41,007,391
43	Material & Supplies	-	403,153	49,318,208
44	Working Capital	147,399	(6,066,838)	12,866,739
45	Weatherization Loans	-	-	(696)
46	Misc Rate Base	-	-	1,206,251
47				
48	Total Electric Plant:	147,399	690,615,376	5,718,431,486
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	62,735	(2,041,423,829)
52	Accum Prov For Amort	-	-	(141,099,147)
53	Accum Def Income Tax	(131,723,043)	(397,458)	(548,748,369)
54	Unamortized ITC	2,553,593	-	(4,172,305)
55	Customer Adv For Const	-	(816,822)	(3,499,244)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	(519,229)	(21,181,866)
58				
59	Total Rate Base Deductions	(129,169,451)	(1,670,773)	(2,760,124,760)
60				
61	Total Rate Base:	(129,022,052)	688,944,603	2,958,306,726
62				
63	Return on Rate Base	1.476%	-1.593%	6.253%
64				
65	Return on Equity	2.883%	-3.112%	6.517%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(8,634,193)	(1,125,292)	228,225,751
69	Other Deductions			
70	Interest (AFUDC)			
71	Interest	(3,742,027)	19,981,460	85,799,770
72	Schedule "M" Additions	12,596,949	-	252,518,382
73	Schedule "M" Deductions	(39,755,866)	21,183	291,319,775
74	Income Before Tax	47,460,649	(21,127,935)	103,624,588
75				
76	State Income Taxes	1,291,536	(1,023,378)	4,470,103
77	Taxable Income	46,169,113	(20,104,557)	99,154,485
78				
79	Federal Income Taxes + Other	2,424,564	(7,036,595)	20,969,445
	APPROXIMATE REVISED PROTOCOL PRICE CHANGE	(60,225,317)	86,205,151	**112,628,901**

Docket No. UE-
Exhibit PPL/702
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 2010

April 2009

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/703
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 Insights Escalation Factors

April 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

R. Bryce Dalley
Exhibit PPL/704

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/704
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Property Taxes

April 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/800
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Erich D. Wilson

April 2009

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

A. My name is Erich D. Wilson. My business address is 825 N.E. Multnomah, Suite 1800, Portland, Oregon 97232. My present position is Director, Human Resources.

Qualifications

Q. Please briefly describe your education and business experience.

A. I have been employed as the Director of Human Resources since March 2006. From March 2001 to March 2006, I was the Director of Compensation for the Company. Prior to coming to the Company, I held various positions within the area of human resources (operations, benefits and staffing), but for the majority of my career I have directed the design and administration of compensation programs. I received a Bachelor's degree in Economics (Business) from the University of California at San Diego in 1992. In addition, I achieved the Certified Compensation Professional status from the American Compensation Association in 1999 and have kept this certification current through attending various educational programs and seminars.

Q. Please describe your present duties.

A. My primary responsibilities 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 related to these areas included in the test period. This overview focuses on our base pay, annual incentive, pension and healthcare 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, UE 179?

A. The current total labor costs show that the Company has done a good job keeping these costs under control. The table below shows that the total wage and benefit expense in this case for the 2010 test year is less than one percent higher than what was included in UE 179 for a 2007 test year. Moreover, on a dollars per megawatt-hour basis, wages and benefits have declined by 3.2 percent since 2007.

	Current Case Calendar Year 2010	UE 179 Calendar Year 2007	Change
Wage & Benefit Expense	$539,061,021	$534,541,770	0.8%
Total Load - MWh	58,667,781	56,307,755	4.2%
$/MWh	9.19	9.49	-3.2%

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 components in its total remuneration package as are included in the packages provided by its competitors for labor.

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. However, employees will earn less than the average remuneration when performance is less than acceptable and, conversely, will earn higher than the average remuneration when performance is exceptional.

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, we use a variety of compensation studies put out by various experts/organizations, including Hewitt & Associates, Towers Perrin, and Mercer. In addition, the Company recently acquired access to an on-line tool called MarketPay.com. MarketPay.com provides electronic access to all of the compensation studies we have traditionally used and some additional surveys, allowing us 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 our employees with incentive to perform at an above average level. 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 situation occurs, the employee will be paid less than the comparable total cash compensation in the marketplace 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: 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. Our individual employee goals start with the goals set for the Company as a whole. Each year, the Company President, in conjunction with MEHC, sets the overall goals for the Company. All of these goals focus on delivering safe and reliable electricity to our customers and providing excellent customer service. Goals include safety goals such as reducing lost time, recordable, preventable, and restricted duty incidents. Customer service related 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 the 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 serve to benefit our customers.

Q. How do the Company goals relate to individual employee goals?

A. These 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, *i.e.*, customer focus, job knowledge, planning and decision making, productivity, builds relationships and leadership. Detailed descriptions of these characteristics are attached as Exhibit PPL/801. 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 Annual Incentive Plan. The Company maintains a separate long-term incentive plan for executives that awards bonuses based on overall corporate performance, including financial performance. The Company does not seek recovery of any of the costs of the long-term incentive plan from customers. This further supports the reasonableness of the Company seeking to include the full costs of the Annual Incentive Plan in rates.

Q. Please explain the level of incentive compensation that you have included in this application?

A. This application includes a request for total Company incentive compensation based on a calendar year 2010 test period in the amount of $33.0 million. This is the total budgeted incentive compensation payout at the target incentive level for each employee participating in the incentive plan. The Oregon portion of this expense is approximately $9.7 million.

Q. What level of incentive compensation does the Company expect to pay out on a year on year basis?

A. As the Company's pay philosophy is to provide total compensation at the market average, and because target incentive compensation is set to market average, we expect that we will pay out, on a year after year basis, the target levels of incentive compensation.

Q. Does the Company recommend the full target level of incentive compensation plus base compensation be included in rates?

A. Yes, for several reasons. First, customers should fully support the cost of incentive compensation because, as I 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 our employees to pursue the goals that directly benefit our customers—safety, reliability, and customer service. This is precisely the type of prudently designed incentive plan program that provides direct benefits to customers and which customers should therefore support.

Retirement Plans

Q. Since the retirement plan changes implemented in June 2007, have there been any other changes to the plan design or benefit provided?

A. The Company regularly reviews its benefit plans. In 2008, the Company offered a choice to those that are currently participating in the cash balance retirement plan. Specifically, employees were allowed to decide whether they would prefer their retirement be determined through the cash balance formula (these employees would still be eligible for participation in the current 401(k) plan design) or through an enhanced 401(k) plan where they would receive a Company-provided fixed contribution in addition to any Company match which is based on regular participation (i.e. 65 percent on the first 6 percent of employee contribution).

Beginning in January 2008, all new hires, with the exception of those under certain collective bargaining units, were only eligible to participate in the 401(k) and are not eligible to participate in the defined benefit plan. Also, during 2008, the Company entered into collectively bargained agreements with IBEW local 659 and IBEW local 125 where the final average pay accruals under the defined benefit plan were frozen and all future retirement benefits are derived from the 401(k) plan. Lastly, as previously noted, in 2008 the Company provided a choice (defined benefit vs. 401(k)) offering to nonunion employees, of which 41 percent elected to freeze their defined benefit plan and have all future retirement benefits derived from the 401(k) plan starting January 1, 2009.

Q. Was the primary purpose for offering this choice to reduce overall pension expense?

A. No. As I have mentioned above, the labor market in our industry has become increasingly competitive and it has become harder and harder to attract and retain a qualified workforce. Accordingly, we offered this "choice benefit" as a means to retain existing employees. That said, this move is definitely consistent with our recent decisions to shift volatility/risk to the employees participating in the retirement program and away from customers.

Q. What result will this change have on retirement program costs?

A. The approach will in fact result in a pension expense reduction. This filing reflects the 41 percent of the eligible employees who opted to shift to the enhanced 401(k) plan. The impact of this expected shift is reflected in the expense reductions shown in Mr. R. Bryce Dalley's revenue requirement exhibit. As an offset, however, there will be an increased impact on the 401(k) expense as is also shown in this filing.

Q. Will customers benefit from the retirement plan changes in ways other than through a reduction in pension expense?

A. Yes. Customers will benefit from the transition to the new retirement plan because the new plan will reduce the risk facing the Company and will result in net savings to customers over time. The fundamental effect of the transition from the old defined benefit pension plan to the new 401(k) plan is that the investment risk for future retirement benefits will now be borne by the employee, instead of the Company and customers. Whereas the defined benefit plan provided a pay credit percentage with a guaranteed level of interest, that pay credit percentage is now provided to the employee in the 401(k) plan, with the employee deciding how it should be invested. This shift reduces the ongoing defined benefit expense while increasing the 401(k) expense.

Q. If the change in retirement plans will ultimately benefit customers, why does the increase in 401(k) expenses exceed the reduction in pension expenses for the test year?

A. The reduction in the pension expense for the test year is offset by the increase in the 401(k) expense as a result of the declining financial market—a factor over which the Company has no control—which would have driven increases in the pension expense whether or not the Company changed its retirement plans. An analysis of the details underlying the changes in the pension and 401(k) expense supports the Company's view that the transition will be a benefit to our customers. To assist in demonstrating this fact, the Company sought the assistance of Hewitt Associates—an actuarial firm upon whom the Company regularly relies for analysis of its retirement plans. As outlined in Exhibit PPL/803, the decision to change the retirement plan created a nearly identical pension expense when compared to the projected 2009 expenses if the plan had remained the same.

This exhibit demonstrates that if the Company had made no changes to its retirement plan, the costs would have been nearly the same. The fact is that the declining economic forecast—more than the decision to change the employee retirement benefits—is responsible for the Company's increased retirement expenses for 2009 and 2010. As the market value decreases, the Company is required to pay more into the defined benefit plan to ensure it compensates for the declining value of the financial markets.

The risk of a declining market, however, is one key reason the Company changed its retirement plan. As noted above, the changes protect customers from market volatility and future economic turmoil because they place the risk on the employee rather than the customers.

Employee Health Benefits

Q. Please describe the Company's health care benefits.

A. As with all benefits, the Company attempts to provide our employees with the same level of health care benefits that are provided by the employers with whom the Company competes for labor. In our case, this means offering employees what I would describe as market average health benefits. And of course 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 of the advice of its consultants Hewitt Associates to ensure that it is securing market competitive benefits at the best possible rate. Hewitt Associates are respected experts in their field and the Company has relied on them for many years. With the help of Hewitt Associates, the Company periodically reviews and adjusts the sharing of healthcare-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 sharply over the past several years. As a result, the Company experienced significant 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 choice into other plans, however, except for a $300 deductible plan that is offered in rural areas, these plans are set at a cost sharing of 74/26. All new hires as of January 1, 2008 have the option of selecting the high deductible plan or opting out of coverage. Exhibit PPL/802 provides market data compiled by Hewitt Associates outlining competitive healthcare sharing structures.

Q. What is the Company's rationale for sharing healthcare-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 our customers.

Q. Please explain the level of healthcare costs you have included in this application and compare that to previous fiscal year expenses.

A. There has been a significant upward trend in healthcare costs in recent years. For calendar years 2006 and 2007, actual healthcare expenses totaled $47 million and $49 million, respectively and 2008 healthcare expenses were $52.0 million. Budgeted healthcare expenses for the calendar year 2009 are $55.6 million. Consistent with this trend, the Company has included in this application healthcare expenses on a total Company basis of $59.9 million as shown in Mr. Dalley's exhibits. The Oregon allocated share of healthcare costs is $17.7 million. As can be seen from the annual expense numbers above, healthcare expenses have escalated less than 7 percent per year since the last rate case, Docket UE 179, which had a 2007 test year. This annual increase is considerably less than the 8.5 percent escalation factor authorized by the Commission in the recent rate case order for Portland General Electric.[1]

Hewitt Associates has informed the Company that current trends indicate the rates for the Company's health benefits are anticipated to increase further in 2009 by between 8 and 10 percent. Specifically, Hewitt Associates projects an 8.5 percent increase for medical benefits. In comparison, MEHC, which uses Watson Wyatt as its plan expert advisor, shows a trend for MEHC in the same range, with the actual increase expected to be 9 percent. The shifts in structure previously described pass more of the increasing expense on to employees rather than customers.

Q. The long term disability benefit expense is shown to decrease significantly in the test year. What was the reasoning for this decrease?

A. The long term disability benefits had been provided by Standard Insurance ("Standard"). Through the contract with Standard the company had agreed to a cap benefit that enabled reduced annual rates with the feature of a penalty for ending the contract. Through its normal course of assessing the competitive nature of the programs, the Company assessed its agreement and rates with Standard and determined in 2008 to change providers; this change is intended to deliver reduced rates and savings going forward. With this change the contract cancellation feature was invoked and a one time payment was made to Standard in January 2009. This payment has been removed from the benefit adjustment in Mr. Dalley's exhibits, resulting in a decrease in long-term disability expense in the test year.

[1] *See* Order No. 09-020, page 15.

Q. Does this conclude your direct testimony?

A. Yes.

Erich D. Wilson
Exhibit PPL/801

Docket No. UE-
Exhibit PPL/801
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Erich D. Wilson

Group Goal Characteristics

April 2009

Section II - Performance Factors
Weighting of Performance Factors: 30%

Section II - Performance Factors: . 1

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%

Section II - Performance Factors: . 2

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%

Section II - Performance Factors: . 3

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%

Section II - Performance Factors: . 4

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%

Section II - Performance Factors: . 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%

Section II - Performance Factors: . 6

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%

Docket No. UE-
Exhibit PPL/802
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Erich D. Wilson

Healthcare Cost Sharing

April 2009

PacifiCorp Plan Design Benchmark Data

Office Visit Copayment	PPO Average	PPO Median	POS Average	POS Median	EPO Average	EPO Median
PacifiCorp 2007 Design	$15	$15	$15	$15	$15	$15
PacifiCorp's Comparators[1]	$22	$20	$17	$18	$15	$15
Utility Industry[2]	$19	$20	$17	$18	$15	$15
All Employers[3]	$19	$20	$18	$15	$18	$20

PCP vs. Specialist Office Visit Copayment Differentials[1]	
Total PacifiCorp Comparator Companies	9
Number With Differentiated Copayment	5
Average Amount of Differentiation	$12

Utility Industry Employer Subsidy— Active Medical Plans	Overall Employer Subsidy	Employee Only Employer Subsidy	Family Employer Subsidy
All Plan Types[4]	84%	87%	83%
POS[4]	81%	86%	79%
PPO[4]	84%	87%	82%

Large Employers Employer Subsidy— Active Medical Plans	Overall Employer Subsidy	Employee Only Employer Subsidy	Family Employer Subsidy
All Plan Types[5]	80%	82%	77%
POS[5]	81%	83%	79%
PPO[5]	80%	82%	77%

[1] 2006 Salaried Benefit Index® (BI) data for companies chosen as PacifiCorp's custom comparator group in their 10/06 BI study.

[2] 2006 Salaried BI data for the utility industry.

[3] 2006 Salaried BI data for all employers in our database.

[4] Data from 19 utility industry employers included in the 2006 Hewitt Health Value Initiative™ database.

[5] Data from 345 large employers (more than 3,000 employees) included in the 2006 Hewitt Health Value Initiative™ database.

Docket No. UE-
Exhibit PPL/803
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Erich D. Wilson

Retirement Plan Changes

April 2009

PacifiCorp Retirement Plan Changes

($Millions)	Actual 2007	Actual 2008	Budget 2009	Budget 2010
Actual/Budget				
PacifiCorp Retirement Plan	$51.50	$26.20	$21.50	$24.50
401(k)	$18.50	$23.40	$44.40	$44.60
Total	$70.00	$49.60	$65.90	$69.10
Without "Management actions"				
PacifiCorp Retirement Plan	$51.50	$30.10	$35.60	$38.90
401(k)	$18.50	$19.90	$28.80	$30.30
Total	$70.00	$50.00	$64.40	$69.20
Savings	-	**$0.40**	**($1.50)**	**$0.10**

Significant Changes

2007	•Discount rate of 5.85% for first 5 months. •Discount rate of 5.70% for last 7 months. •Freeze FAP and shift Cash to Balance for Nonunion.
2008	•Discount rate of 6.30%. •New hires 401(k) only. •Change to 401(k) for Local 659. •Actual asset return.
2009	•Discount rate of 7.75%. •Choice. •Change to 401(k) for Local 125. •Asset return projected at -14%.
2010	•Discount rate of 6.30%. •Asset return projected at 7.75%.

C. Craig Paice
Exhibit PPL/900

Docket No. UE-
Exhibit PPL/900
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of C. Craig Paice

April 2009

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

A. My name is C. Craig Paice. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232, and I am currently employed as a Regulatory Consultant in the Regulation Department.

Qualifications

Q. Please briefly describe your education and business experience.

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.

Q. What are your responsibilities?

A. 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.

Q. Have you testified in previous regulatory proceedings?

A. Yes, I have previously filed testimony on behalf of the Company in the states of Washington, California, Utah, and Wyoming.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to 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 PPL/901 and explain what it shows.

A. Exhibit PPL/901 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 and Public Purposes.

No revenue requirement is shown for the Retail Service or 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, shown on Page 2 of Exhibit PPL/901, is consistent with Mr. Dalley's Exhibit PPL/701, page 1, column 6.

Q. Please identify Exhibit PPL/902 and explain what it shows.

A. Exhibit PPL/902 is the summary page from PacifiCorp's December 2010 Functionalized Oregon Results of Operations Report (the "Functionalized Oregon Results of Operations Report") and is the basis for the unbundled revenue requirement in Exhibit PPL/901. It separates the results of operations into the unbundled categories identified above. This process is described later in my testimony.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's most recent market 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 PPL/903. 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 PPL/904.

A. Exhibit PPL/904 contains a summary from PacifiCorp's State of Oregon December 2010 Marginal Cost Study (the "Marginal Cost Study"). The Marginal Cost Study is described later in my testimony.

Q. Please identify Exhibit PPL/905 and explain what it shows.

A. Page 1 of Exhibit PPL/905 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 43.16 percent of generation marginal costs and is assigned 43.16 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 PPL/905.

A. Pages 2 and 3 of Exhibit PPL/905 provide a reconciliation between Operating Revenues and Target Revenue Requirement as shown on page 1 of this exhibit, with those shown in Exhibit PPL/901 and 902. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PPL/905 accounts for all Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

Functionalization Procedures

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 PPL/906. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020.

Marginal Cost Study

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PPL/907. 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 PPL/907 contains seven summary tables followed by seventeen sections of supporting data.

Q. How does this Marginal Cost Study differ from studies the Company has previously filed?

A. This study is consistent with the Company's cost of service study presented and adopted in Docket No. UE 179, with one exception. Cost of service results have been prepared for Schedule 33 customers for informational purposes.

Q. In general, how are marginal costs calculated?

A. The 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 results 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 the marginal cost procedures is included with my workpapers.

Q. Please review the marginal cost summary tables included in Exhibit PPL/907.

A. Tables 1 and 2 of Exhibit PPL/907 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 year ending December 31, 2010 (the "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 filed Oregon avoided cost calculations.

The 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 PPL/907.

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 PPL/907.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 7 of Exhibit PPL/907 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 feeders are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Feeder Model. The feeder 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 feeder. The hypothetical feeder is constructed with seven branches of equal length using the composite line statistics and current cost estimates for the State of Oregon. Customer locations are based on actual customer distances from the substation as determined by Computer Aided Design Operations ("CADOPS"). The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated feeder model is included in Exhibit PPL/907, Marginal Cost Description of Procedures.

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 feeder 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 requirements, 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 experience of 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 testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/901
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functionalized Revenue Requirement

April 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2010 Forecast

Function		Revenue Requirement
Production		$ 635,857,496
Transmission		$ 78,906,359
Distribution		$ 281,133,021
Ancillary		$ 11,174,379
Customer Billing		$ 12,191,519
Customer Metering		$ 29,113,485
Customer Other		$ 13,593,946
Retail Service	a	$ -
Public Purposes	b	$ -
Total State of Oregon		$ 1,061,970,204

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2010 Forecast

									Consumer					Distribution Components		
		ROR	ROE	**Total**	**Production**	**Trans-mission**	**Distribution**	**Ancillary**	**Billing**	**Metering**	**Other**	**Retail Service** [a]	**Public Purposes** [b]	**Poles & Wires**	**DSM**	**Franchise Tax**
2	Functionalized Situs Revenues @ Earned	6.25%	6.52%	949,341,303	578,082,460	60,205,430	246,698,626	11,174,379	11,868,686	27,954,107	13,357,615	-	-	224,465,305	0	22,233,321
3	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
4	Total Oregon General Business Revenue			949,341,303	578,082,460	60,205,430	246,698,626	11,174,379	11,868,686	27,954,107	13,357,615	-	-	224,465,305	0	22,233,321
5																
6	Target Increase in Return	8.55%	11.00%	67,897,313	35,635,756	11,534,770	19,666,788	0	199,124	715,106	145,769			19,666,788	-	-
7																
8	Add															
9	Uncollectible Expense			598,253	306,885	99,334	182,906	0	1,715	6,158	1,255	-	-	169,365	-	13,541
10	Franchise Tax			2,534,150			2,534,150									2,534,150
11	Other Revenue Based Taxes			71,183	36,515	11,819	21,763	0	204	733	149	-	-	20,152	-	1,611
12	Inc Taxes - State			4,967,909	2,607,396	843,976	1,438,979	0	14,570	52,323	10,666	-	-	1,438,979	-	-
13	Inc Taxes - Federal			36,560,092	19,188,484	6,211,030	10,589,809	0	107,221	385,057	78,491	-	-	10,589,809	-	-
14	Total Increase Needed			112,628,901	57,775,036	18,700,929	34,434,395	0	322,833	1,159,377	236,330	-	-	31,885,093	-	2,549,303
15																
16	Total Oregon General Business Revenue @	8.55%	11.00%	1,061,970,204	635,857,496	78,906,359	281,133,021	11,174,379	12,191,519	29,113,485	13,593,946	-	-	256,350,398	0	24,782,623
17	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
18	Total Unbundled Revenue Requirement			1,061,970,204	635,857,496	78,906,359	281,133,021	11,174,379	12,191,519	29,113,485	13,593,946	-	-	256,350,398	0	24,782,623
19																
20	Rate Base			2,958,306,727	1,552,660,802	502,573,457	856,887,978	1	8,675,896	31,157,393	6,351,199			856,887,978	-	-
					52.485%	16.989%	28.965%	0.000%	0.293%	1.053%	0.215%	0.000%	0.000%	28.965%	0.000%	0.000%

Source:	
Total Column : Exhibit PPL 902	
Row 1: Exhibit PPL 902	
Row 8: Uncollectible	0.53117%
Row 9: Franchise Tax @	2.2500%
Row 10: Other Revenue Based Taxes	0.0000%
Row 11: Inc Taxes - State	4.5400%
Row 12: Inc Taxes - Federal	35.0000%
Row 19: Exhibit PPL 1002	

Notes:
a - Retail Services are conducted as unregulated activities.
b -DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

C. Craig Paice
Exhibit PPL/902

Docket No. UE-
Exhibit PPL/902
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

April 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2010 Forecast

	Description of Account Summary:	Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Other
	Operating Revenues								
1	General Business Revenues	949,341,303	578,082,460	60,205,430	246,698,626	11,174,379	11,868,686	27,954,107	13,357,615
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	201,716,768	160,439,561	41,277,207	-	-	-	-	-
5	Other Operating Revenues	42,876,105	24,676,841	20,914,345	3,829,347	(11,174,379)	4,615,083	11,815	3,053
6	Total Operating Revenues	1,193,934,176	763,198,862	122,396,981	250,527,973	0	16,483,769	27,965,923	13,360,668
8	Operating Expenses:								
9	Steam Production	251,950,077	251,950,077	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	9,911,805	9,911,805	-	-	-	-	-	-
12	Other Power Supply	275,007,872	275,007,872	-	-	-	-	-	-
13	Transmission	51,260,023	227,849	51,032,174	-	-	-	-	-
14	Distribution	70,710,593	-	-	65,959,265	-	-	4,751,328	-
15	Customer Accounts	31,710,902	3,224,181	517,074	1,058,371	0	10,456,493	10,495,642	5,959,142
16	Customer Service	3,695,469	-	-	1,198,841	-	-	-	2,496,628
17	Sales	-	-	-	-	-	-	-	-
18	Administrative & General	57,051,637	21,642,045	5,114,903	22,081,167	-	2,253,030	3,890,851	2,069,640
20	Total O & M Expenses	751,298,378	561,963,827	56,664,151	90,297,644	0	12,709,524	19,137,821	10,525,411
22	Depreciation	148,046,103	74,831,279	19,359,468	50,677,408	-	240,681	2,686,586	250,682
23	Amortization Expense	16,475,737	8,613,093	1,000,604	3,244,763	-	1,511,384	1,158,737	947,157
24	Taxes Other Than Income	51,964,717	14,766,065	4,654,270	31,716,021	0	203,106	486,747	138,507
25	Income Taxes - Federal	20,969,445	(1,950,356)	5,477,787	13,359,526	0	1,063,222	2,071,051	948,213
26	Income Taxes - State	4,470,103	1,407,118	732,047	1,785,357	0	142,088	276,774	126,719
27	Income Taxes - Def Net	17,791,779	8,931,496	3,165,701	5,397,467	-	71,227	199,073	26,815
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29	Misc Revenue & Expense	(2,076,510)	(2,457,580)	(84,921)	465,249	-	-	741	-
31	Total Operating Expenses	1,008,939,751	666,104,943	90,969,108	196,943,435	0	15,941,231	26,017,530	12,963,503
33	Operating Revenue for Return	184,994,425	97,093,919	31,427,873	53,584,538	0	542,538	1,948,393	397,165
35	Rate Base:								
36	Electric Plant in Service	5,550,442,483	2,664,952,722	902,323,027	1,837,918,800	-	34,629,709	87,905,498	22,712,727
37	Plant Held for Future Use	(0)	2,398,305	(2,398,306)	-	-	-	-	-
38	Misc Deferred Debits	32,822,514	14,423,985	12,864,540	4,143,189	-	411,163	659,863	319,774
39	Elec Plant Acq Adj	18,568,147	18,568,147	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-	-
41	Prepayments	12,200,450	5,615,243	737,959	3,635,484	-	579,637	1,043,047	589,080
42	Fuel Stock	41,007,391	41,007,391	-	-	-	-	-	-
43	Material & Supplies	49,318,208	39,617,906	3,331,576	6,152,803	-	-	215,922	-
44	Working Capital	12,866,739	7,217,990	1,148,552	3,128,564	0	382,111	638,890	350,632
45	Weatherization Loans	(696)	-	-	(696)	-	-	-	-
46	Miscellaneous Rate Base	1,206,251	1,206,251	-	-	-	-	-	-
48	Total Electric Plant	5,718,431,486	2,795,007,940	918,007,348	1,854,978,144	0	36,002,620	90,463,221	23,972,213
50	Rate Base Deductions:								
51	Accum Prov For Depr	(2,041,423,829)	(917,683,093)	(317,354,229)	(767,604,750)	-	(2,546,203)	(34,553,912)	(1,681,643)
52	Accum Prov For Amort	(141,099,147)	(43,523,799)	(5,100,653)	(42,866,832)	-	(21,822,509)	(14,783,860)	(13,001,494)
53	Accum Def Income Taxes	(548,748,369)	(263,998,753)	(90,449,542)	(181,198,496)	-	(2,253,347)	(8,626,626)	(2,221,605)
54	Unamortized ITC	(4,172,305)	(1,686,630)	(200,801)	(1,418,610)	-	(227,033)	(408,458)	(230,773)
55	Customer Adv for Const	(3,499,244)	-	(1,906,223)	(1,536,895)	-	-	(56,126)	-
56	Customer Service Deposits	-	-	-	-	-	-	-	-
57	Misc. Rate Base Deductions	(21,181,866)	(15,454,864)	(422,444)	(3,464,584)	-	(477,631)	(876,846)	(485,499)
59	Total Rate Base Deductions	(2,760,124,760)	(1,242,347,138)	(415,433,891)	(998,090,166)	-	(27,326,724)	(59,305,827)	(17,621,014)
61	Total Rate Base	2,958,306,726	1,552,660,802	502,573,457	856,887,978	1	8,675,896	31,157,393	6,351,199
63	Return on Rate Base	6.2534%	6.2534%	6.2534%	6.2534%	6.2534%	6.2534%	6.2534%	6.2534%
65	Return on Equity	6.5173%	6.5173%	6.5173%	6.5173%	6.5173%	6.5173%	6.5173%	6.5173%

Docket No. UE-
Exhibit PPL/903
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

CY 2010 Ancillary Services Revenue

April 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
CY 2010 Ancillary Services Revenue
12 Months Ended December 31, 2010 Forecast

Line	Item	Notes	Thermal Resource	Hydro Resource	Other Resource	Firm Purchases	Total Resources
1	System Resources CY 2010 (MWH)	(Note 1)	54,812,550	3,932,604	2,708,907	10,123,248	71,577,309
2	Plant allocated to Oregon based on JAM dollars	(Note 2)	26.94%	26.88%	26.83%	26.55%	
3	Oregon share of Resource Providing Service by type (MWH)	(Line 1 x Line 2)	14,765,392	1,056,961	726,754	2,688,108	19,237,216
4	Resource type % of total		76.75%	5.49%	3.78%	13.97%	100.00%
5	Oregon Retail Load, Including Losses, by resource type	(Line 4 x Line 5 Total)	11,258,368	805,916	554,138	2,049,638	14,668,059
7	FERC Tariff Ancillary Service Charges						
	Regulation and Frequency Response Service						
8	Billing Determinant (Load Energy MWH)		NA	NA	NA	NA	14,668,059
9	Charge ($/MWH)		NA	NA	NA	NA	0.1600
10	Total Cost	(Line 8 x Line 9)	NA	NA	NA	NA	$2,346,889
	Operating Reservice - Spinning Reserve Service						
11	Billing Determinant (Generated Energy in MWH)		11,258,368	805,916	554,138	2,049,638	14,668,059
12	Charge ($/MWH)		0.3730	0.2660	NA	NA	
13	Total Cost	(Line 11 x Line 12)	$4,199,371	$214,374			$4,413,745
	Operating Reservice - Supplemental Reserve Service						
14	Billing Determinant (Generated Energy in MWH)		11,258,368	805,916	554,138	2,049,638	14,668,059
15	Charge ($/MWH)		0.3730	0.2660	NA	NA	
16	Total Cost	(Line 14 x Line 15)	$4,199,371	$214,374			$4,413,745
17	Oregon Annual Ancillary Service Revenue ($ x thousands)	Line 10 + Line 13 + Line 16)					$11,174,379

Note 1 - Source :Net Power Cost Analysis

Note 2 - CY 2010 JAM Model

Total Electric Plant in Service by Plant Type ($ x Millions)	Thermal	Hydro	Other	Total
Oregon	1,443.4	173.6	760.8	2,377.8
System	5,358.4	645.9	2,835.8	8,840.0
Percent of System	26.94%	26.88%	26.83%	26.90%

2008 JAM Model - Acount 555 Purchased Power SG	Dollars
Oregon - Unadjusted	212,980,461
System	802,071,244
Percent of System	26.55%

2010 JAM Model - Production Plant	TOTAL	OTHER	OREGON
Total Steam Production Plant	5,358,373,599	3,914,936,119	1,443,437,480
Total Hydraulic Plant	645,856,753	472,270,582	173,586,171
Total Other Production Plant	2,835,812,265	2,075,011,581	760,800,684
TOTAL PRODUCTION PLANT	8,840,042,618	6,462,218,282	2,377,824,335

Docket No. UE-
Exhibit PPL/904
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

April 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2010 Forecast
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation	$148,195	$64,189	$6,127	$5,403	$14	$5,172	$9,071	$11,393	$223	$2,509	$13,014	$1,098	$7,270	$4,554	$546	$12,128	$3,590	$1,894	
2	Transmission	$150,207	$65,060	$6,210	$5,477	$14	$5,242	$9,194	$11,547	$226	$2,544	$13,191	$1,113	$7,369	$4,616	$553	$12,293	$3,638	$1,920	
3	Distribution																			
4	Poles	$42,784	$26,664	$1,960	$1,760	$4	$1,139	$1,882	$2,404	$48	$563	$2,955	$249	$1,132	$718	$0	$0	$0	$1,305	
5	Conductor	$71,273	$43,588	$3,166	$2,843	$7	$2,007	$3,317	$4,239	$83	$982	$5,152	$434	$2,174	$1,380	$0	$0	$0	$1,901	
6	Substations	$53,241	$27,798	$1,893	$1,700	$4	$1,702	$2,813	$3,595	$70	$792	$4,158	$351	$2,322	$1,473	$162	$3,814	$0	$595	
7	Subtotal: Pole, Cond, Subs	$167,297	$98,050	$7,019	$6,304	$15	$4,848	$8,011	$10,238	$201	$2,338	$12,265	$1,034	$5,628	$3,571	$162	$3,814	$0	$3,800	
8	Transformers	$5,872	$3,388	$525	$211	$0	$207	$288	$380	$0	$78	$384	$0	$287	$0	$20	$0	$0	$105	
9	Distribution subtotal	$173,169	$101,438	$7,544	$6,515	$15	$5,054	$8,300	$10,617	$201	$2,415	$12,649	$1,034	$5,915	$3,571	$182	$3,814	$0	$3,905	
10																				
11	Total Demand Related	$471,571	$230,687	$19,881	$17,395	$43	$15,468	$26,565	$33,557	$650	$7,468	$38,854	$3,245	$20,554	$12,741	$1,281	$28,235	$7,228	$7,719	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$768,041	$331,225	$35,496	$26,217	$68	$26,323	$40,974	$56,205	$1,077	$12,567	$65,716	$5,543	$36,240	$24,475	$3,311	$69,352	$23,365	$8,335	$1,552
16	Transmission Energy Related	$52,647	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,484	$1,678	$227	$4,754	$1,602	$571	$106
17	Total Energy	$820,689	$353,930	$37,929	$28,014	$73	$28,127	$43,783	$60,057	$1,151	$13,428	$70,220	$5,923	$38,724	$26,153	$3,538	$74,105	$24,967	$8,907	$1,659
18																				
19	Customer Related Marginal Cost																			
20	Poles	$62,289	$45,737	$7,081	$1,027	$4	$211	$165	$95	$3	$12	$31	$3	$1	$1	$0	$0	$0	$1,799	$6,119
21	Conductor	$22,545	$18,319	$2,835	$411	$1	$84	$67	$38	$1	$5	$12	$1	$1	$0	$0	$0	$0	$720	$48
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$12
29	Total Commitment & Billing Rel.	$248,994	$174,017	$35,358	$9,082	$48	$4,976	$4,380	$3,597	$69	$508	$1,265	$84	$477	$161	$8	$97	$89	$8,454	$6,326
30																				
31	Total Revenue @ Full MC																			
32	Generation	$916,236	$395,414	$41,623	$31,620	$82	$31,495	$50,045	$67,598	$1,300	$15,076	$78,730	$6,641	$43,510	$29,029	$3,857	$81,480	$26,955	$10,229	$1,552
33	Transmission	$202,854	$87,765	$8,643	$7,274	$19	$7,046	$12,003	$15,400	$300	$3,405	$17,696	$1,493	$9,853	$6,294	$780	$17,047	$5,240	$2,491	$106
34	Distribution	$372,038	$234,889	$37,660	$14,652	$21	$9,462	$12,200	$13,609	$205	$2,799	$13,605	$1,038	$6,161	$3,573	$186	$3,814	$0	$11,884	$6,279
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$12
38	Revenue (less Uncollectables)	$1,535,514	$753,779	$92,991	$54,465	$164	$48,458	$74,639	$97,160	$1,868	$21,362	$110,236	$9,242	$59,621	$38,993	$4,825	$102,400	$32,282	$25,045	$7,984
39																				
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$0
41	Total Revenue	$1,541,254	$758,634	$93,168	$54,490	$164	$48,571	$74,727	$97,212	$1,869	$21,404	$110,339	$9,251	$59,756	$39,055	$4,827	$102,437	$32,284	$25,079	$7,984

C. Craig Paice
Exhibit PPL/905

Docket No. UE-
Exhibit PPL/905
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Unbundled Revenue Requirement Allocation by Rate Schedule

April 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C) General Service Sch 23	(D) General Service Sch 28	(E) General Service Sch 28	(F) General Service Sch 30	(G) General Service Sch 30	(H) Large Power Service Sch 48T	(I) Large Power Service Sch 48T	(J) Large Power Service Sch 48T	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$916,236	$395,414	$73,243	$82	$149,137	$1,300	$93,805	$6,641	$47,367	$110,509	$26,955	$10,229	$1,552
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$372,038	$234,889	$52,312	$21	$35,272	$205	$16,404	$1,038	$6,347	$7,387	$0	$11,884	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,535,514	$753,779	$147,456	$164	$220,257	$1,868	$131,598	$9,242	$64,446	$141,393	$32,282	$25,045	$7,984
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.16%	7.99%	0.01%	16.28%	0.14%	10.24%	0.72%	5.17%	12.06%	2.94%	1.12%	0.17%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	63.14%	14.06%	0.01%	9.48%	0.06%	4.41%	0.28%	1.71%	1.99%	0.00%	3.19%	1.69%
18	Ancillary Service	100.00%	43.16%	7.99%	0.01%	16.28%	0.14%	10.24%	0.72%	5.17%	12.06%	2.94%	1.12%	0.17%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$264,191	$48,936	$55	$99,644	$869	$62,675	$4,437	$31,648	$73,835	$18,010	$6,835	$1,037
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$155,820	$34,703	$14	$23,398	$136	$10,882	$688	$4,211	$4,900	$0	$7,884	$4,165
30	Ancillary Services	$10,758	$4,643	$860	$1	$1,751	$15	$1,101	$78	$556	$1,298	$316	$120	$18
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$511,764	$100,095	$142	$142,788	$1,254	$84,889	$6,005	$41,462	$91,010	$20,871	$16,733	$5,397
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	89.51%	92.15%	90.70%	69.86%	87.10%	89.58%	86.43%	88.57%	86.65%	85.02%	83.38%	85.60%	64.64%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$40,169	$9,305	$43	$18,419	$131	$11,520	$687	$5,535	$13,635	$3,469	$2,409	$1,909
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	11.72%	8.52%	10.25%	43.14%	14.81%	11.64%	15.70%	12.91%	15.41%	17.62%	19.94%	16.82%	54.71%
46	(Line 41 / Line 1)													

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2010 Functionalized Revenue - Earned
($ 000)

Line No.	Description	A Generation	B Transmission	C Distribution	D Ancillary	E C Billing	F C Metering	G C Other	H DSM	I Franchise Fees	J Total
1	Earned Functional Revenue Requirement	$578,082	$60,205	$224,465	$11,174	$11,869	$27,954	$13,358	$0	22,233	$949,341
2											
3	Percent of Total	60.89%	6.34%	23.64%	1.18%	1.25%	2.94%	1.41%	0.00%	2.34%	100.00%
4											
5	Revenue From Classes Included in MC Study	$557,281	$58,039	$216,388	$10,772	$11,442	$26,948	$12,877	$0	$21,433	$915,181
6											
7	Other Revenues										
8	Partial Requirements - Sch. 47 pri										$18,498
9	Partial Requirements - Sch. 47 trn										$7,223
10	USBR Billed Revenue										$3,839
11	AGA										$2,380
12	Lighting										$2,617
13	Employee Discount										($396)
14	Total Oregon Situs Revenue										$949,341

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2010 Functionalized Revenue - Target
($ 000)

		A	B	C	D	E	F	G	H	I	J	
Line No.	**Description**	**Generation**	**Transmission**	**Distribution**	**Ancillary**	**C Billing**	**C Metering**	**C Other**	**DSM**	**Franchise Fees**	**Total**	
1	Target Functional Revenue Requirement	635,857	78,906	256,350	11,174	12,192	29,113	13,594	0	24,783	$1,061,970	
2												
3	Percent of Total	59.88%	7.43%	24.14%	1.05%	1.15%	2.74%	1.28%	0.00%	2.33%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$612,171	$75,967	$246,801	$10,758	$11,737	$28,029	$13,088	$0	$23,859	$ 1,022,411	107,229
6												
7	Other Revenues											112,629
8	Partial Requirements - Sch. 47 pri										$21,824	$3,327
9	Partial Requirements - Sch. 47 trn										$8,606	$1,383
10	USBR Billed Revenue										$3,694	-$145
11	AGA										$2,380	$0
12	Lighting										$3,485	$869
13	Employee Discount										($430)	($34)
14	Total Oregon Situs Revenue										$1,061,970	107,229

Docket No. UE-
Exhibit PPL/906
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

April 2009

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/907
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

December 2010 Marginal Cost Study for the State of Oregon

April 2009

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/1000
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of William R. Griffith

April 2009

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

A. My name is William R. Griffith. My business address is 825 NE Multnomah Avenue, Suite 2000, Portland, Oregon. My present position is Director, Pricing & Cost of Service, in the Regulation Department.

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 my present responsibilities.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified on behalf of the Company in regulatory proceedings in the states of Oregon, Utah, Wyoming, Washington, Idaho, and California.

Purpose of Testimony

Q. What are your responsibilities in this proceeding?

A. I am responsible for the design of the Company's proposed prices in this proceeding. 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 PPL/1001 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 proceeding?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's rules for Direct Access Regulation in OAR 860-038-0200. The rules indicate that rates are to be based on cost. As stated in OAR 860-038-0250(2)(b), "rates for any class of customer 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. Have you prepared an exhibit showing the estimated effects of the changes proposed in this filing?

A. Yes. Exhibit PPL/1002 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 1002-1), along with monthly billing comparisons for each of the affected delivery service rate schedules showing the net impact of the proposed prices at various usage levels assuming Cost-Based Supply Service Schedule 200. Table 1002-1 contains the effect of the price change on base rates and on net rates. Base rates show the changes on base rates before the effects of any adjustment tariffs.

The net rates in Table 1002-1 (Columns (8) and (11)) exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297). Table 1002-2 shows the calculation of the adjustments included in Table 1002-1. Table 1002-3 shows the present and proposed rates for these adjustment schedules.

Q. Please explain Table 1002-1 in Exhibit PPL/1002 in detail.

A. Table 1002-1 shows the estimated effect of the proposed price change by rate schedule for the forecast test period. The table displays the present schedule number, the proposed schedule number, the average number of customers during the test year and the megawatt-hours of energy use in Columns (2) through (5). Revenues by tariff schedule are divided into six columns—three for present revenues and three for proposed revenues. Column (6) shows annualized revenues under present base rates; Column (7) shows present revenues from current adjustment tariffs (Schedules 93, 96, 102, 203, 296, and 299); and Column (8) shows net present revenues. Present revenues include revenues from the Renewable Adjustment Clause (Schedule 203) and the recently filed Transition Adjustment Mechanism, which will be effective January 1, 2010. Column (9) shows annualized revenues under proposed base rates; Column (10) shows proposed revenues from all adjustment tariffs (Schedules 93, 96, 102, 203, 296, and 299); and Column (11) shows the net estimated revenues which would be received if the proposed prices were in effect during the entire test period as forecast. Columns (12) and (13) show the dollar and percentage changes in base rates. Columns (14) and (15) show the dollar and percentage changes comparing present net rates with net rates proposed to be in effect at the conclusion of this docket.

Q. What is the Company's rate spread objective in this case?

A. The Company's rate spread objective in this case is to minimize price impacts on our customers while sending them proper signals about the increasing costs of serving them. As a result, the Company proposes a rate spread cap where none of the general service and large general service schedules receive an overall net rate increase greater than 1.5 times the overall increase, or 13.7 percent. Also, based on the cost of service results and the present level of the Rate Mitigation Adjustment ("RMA") both of which indicate higher increases are necessary, the Company proposes that street lighting and irrigation schedules be capped at 17.5 percent, slightly under two times the overall increase. The caps that the Company is proposing strike a balance between moderating rate impacts on our customers, sending proper price signals, and not unreasonably impacting electric retail competition. As has occurred in prior cases, the Company proposes to modify the RMA in order to achieve these objectives.

Q. Please explain the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net prices across rate schedules. The RMA is designed to be revenue neutral overall, 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. It is a tariff rider included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Does the Company propose any modifications to the RMA in this case?

A. Yes. The Company proposes to modify some of the RMA rates in order to achieve the rate spread objectives in this case. For residential customers, the Company proposes no change to the current RMA rate. For the general service and large general service schedules, the Company proposes to maintain or reduce the current RMA credits or charges. RMA rates have been reduced for Schedules 23, 28 and 30, while the present RMA credit has been left unchanged for Schedule 48. In addition, the Company has proposed to increase the RMA credit for Schedule 41, Agricultural Pumping Service, in order to limit their increase at the 17.5 percent cap proposed in this case. Present and proposed RMA adjustment rates are shown in Exhibit PPL/1002, Table 1002-3.

Rate Design

Q. Please explain the process of unbundling the Company's proposed prices.

A Consistent with the method the Company implemented in UE 116, for each rate schedule, the functionalized costs developed by Mr. Paice are applied as follows: distribution, billing, metering and customer costs are included in each proposed delivery service schedule's distribution rates; the Federal Energy Regulatory Commission-regulated transmission and ancillary services are included in each proposed delivery service schedule's transmission rates; net power costs are included in new Schedule 201 which is discussed below and non-net power cost generation costs are included in Schedule 200, Cost-Based Supply Service. Forecast billing determinants and present and proposed base rates are shown in Exhibit PPL/1003.

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. However, the Company is proposing schedules that separate out net power costs from other generation costs so that in the Company's annual TAM filing, net power cost rates may be fully updated.

Q. Please explain the calculation of the proposed new Schedule 201 and Schedule 200 rates.

A. In this case, present Schedule 200 has been further unbundled into proposed Schedule 201, Net Power Costs, and Schedule 200, Cost-Based Supply Service. The rates for proposed Schedule 201 were calculated by first spreading the total Oregon-allocated net power costs shown in Company witness Mr. R. Bryce Dalley's Exhibit PPL/701 to each of the rate schedules. The allocation was based on the spread of generation revenues as shown in Mr. Paice's Exhibit PPL/905. The Company proposes to use the same rate blocks as in existing Schedule 200 for new Schedule 201. Rates have been designed for each block and are based on the same ratio as the existing Schedule 200 rates in order to collect the net power costs for each schedule. Similarly, proposed schedule 200 rates are designed to keep the same ratio between blocks and to collect the non-net power cost generation revenue.

Q. Will this change in rate design affect what each rate schedule will pay?

A. No. Each rate schedule will continue to pay its allocated generation costs as occurs today. Moreover, because we are maintaining the same ratio for rates, individual customers will see the same charges under these two separate schedules as they would have seen under a single schedule (present Schedule 200) designed to collect all generation costs. This additional unbundling simply allows rates directly collecting net power costs to be more easily revised in a TAM proceeding outside of a general rate case.

Q. Please explain the proposed rates for the Renewable Adjustment Clause ("RAC") Schedule 202.

A. The RAC is an automatic adjustment clause designed to provide timely recovery of the revenue requirement of new renewable resources and associated transmission outside of a general rate case. As indicated in Order No. 07-572 (p. 4),

> "At the time of a general rate case filing, a Utility will propose that resource costs being recovered through its RAC schedule be included in its general rates. When the resource costs are rolled into general rates, non-deferred RAC charges will be reduced to zero, until new resources are added."

In this case, resource costs currently being recovered through the RAC have been incorporated into the Company's base rates. Accordingly, the RAC Schedule 202 rates have been set to zero. Schedule 202 will remain in place for use in potential future RAC filings.

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 $1.00 per month. This will result in a Basic Charge of $8.50 per month. We believe this change will better reflect costs while minimizing customer impacts. In addition, even with this change, the Company's Basic Charge will remain in the lowest half of Basic/Minimum Charges across 23 electric utilities surveyed by the Company in Oregon.

For residential customers, as well as for all classes of customers, Supply Service schedules are proposed to reflect changes in the functionalized generation revenue requirement prepared by Mr. Paice. Residential prices contained in Cost-Based Supply Service (Schedule 200) have been modified to reflect the proposed non-net power cost generation revenue requirement change while retaining the inverted rate structure for residential customers first implemented in UE 116. The portfolio options (Schedules 210 through 213) do not require changes since they are simply 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 supply service prices, at different voltage levels, based on the cost of service results.

Q. Please explain the proposed tariffs for irrigation customers.

A. Schedule 41/741, Agricultural Pumping Service, has been modified to reflect the proposed revenue requirement and to track unit costs more closely.

Q. Has the Company proposed any changes for Schedule 33 customers?

A. No. According to Order No. 06-172, as clarified in Order No. 06-440, the Company does not propose changes for Schedule 33, Klamath Basin Irrigation and Drainage Pumping customers in this case. Present and proposed rates for these customers reflect forecasted rates which will be in effect in 2010 consistent with Order No. 06-172. The proposed rate change shown for these customers in this case is based on a) the flow through of the rate increase proposed for standard irrigation Schedule 41 to which Schedule 33 rates are targeted and b) the effect of setting the Schedule 202 RAC rate to zero. Due to the increase proposed for Schedule 41 rates in this case, the target rate for Schedule 33 will increase, causing higher rates in 2010 than would have been in place absent the general rate case. However due to setting the RAC rates to zero for all rate schedules in this case, Schedule 33 customers will see a rate decrease.

Q. What has the Company proposed for Schedule 92, Klamath Rate Reconciliation Adjustment?

A. The Company has set Schedule 92, Klamath Rate Reconciliation Adjustment, rates to zero. Schedule 92 is designed to collect or credit base revenues lost or gained by changes in Schedule 33 base rates between rate cases. As a result of resetting all rates in this general rate case, the Schedule 92 adjustment is not currently needed, nor will it be needed after the April 2010 Schedule 33 rate change occurs, as that rate change has been assumed in this case. The Company will revise Schedule 92 at such time that it is needed to offset additional Schedule 33 rate increases.

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, based on the cost of service results. 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 demand charge and a 0.1 cents per kWh time of use differential.

Q. Please explain the proposed tariffs for lighting customers.

A. For lighting (Schedules 15, 50, 51/751, 52/752, 53/753, and 54/754) the proposed revisions are designed to implement the overall functionalized base revenue requirement change.

Drainage Districts

Q. The Company was ordered in Docket UM 1304, Order No. 07-361, "to include an analysis of the effects and propriety of treating drainage districts as a separate customer class …" and to "include a draft tariff rate design…" in its next general rate case. Please discuss the Company's analysis as ordered by the Commission.

A. The Company has analyzed current customers, and based on customer name and SIC code, has identified five drainage districts with fourteen pumping accounts served by the Company in Oregon, equal to 0.002 percent of all Oregon customers. In the historic period prepared for this general rate case, these customers consumed 1,874 MWh resulting in annual revenues of $122,600, or 0.01 percent of total Oregon MWh and revenues.

As outlined in Order No. 87-402, the general legal standards for rate offerings are that "classes of customers must be based on reasonable considerations, so that customers receiving 'like and contemporaneous service under substantially similar circumstances' are placed in the same class." In addition, "volume of use" is an important factor ("permissible classification criteria").

Q. Would a separate rate classification for drainage district customers be consistent with these standards?

A, No. Some drainage district customers are seasonal customers while others are not; however, we do not believe that these customers differ in any unique way from other customers served on the Company's current general service rate schedules. Drainage district customers are customers who should be served on the same rate schedules as other customers receiving "like and contemporaneous service under substantially similar circumstances."

Q. Is volume of use a relevant factor for these customers?

A, Volume of use is relevant in that due to the small number of drainage district customers and the low level of usage, it does not support the establishment of a separate customer class for these customers. As indicated above, these customers comprise one one-hundredth of one percent (0.01%) of total Oregon revenues.

Because rates for each class of customer must be based on the costs to serve that class, designating a separate rate schedule for a very small group of customers such as drainage district customers could produce volatile changes in rates. These volatile effects could occur because changes in usage, customer characteristics, or the addition of a few new customers could produce large effects in such a small class. These customers are better served within a larger customer class where individual customer variability is cushioned.

Q. Please discuss the draft tariff rate design proposed by the Company for drainage districts.

A. As ordered by the Commission, the Company is required to present "a draft tariff rate design" in the current case. While the Company does not support this rate design, the Company believes that simple per kWh charges could apply to drainage districts only for their delivery service for loads less than 1,000 kW. Rates for Transmission and Ancillary Services, the Basic Charge and Reactive Power Charges would be equal to the Schedule 41 proposed rates for these services. Energy would be supplied under Schedule 200 and Schedule 201, or other supply options as applicable for Schedule 41 Delivery Service customers at rates equal to Schedule 41 proposed rates. All other applicable charges to Schedule 41 specified in Schedule 90 would apply to these customers.

Under this draft rate design, the remaining functionalized Distribution charges would be collected through a per kilowatt-hour rate based on voltage level. Based on proposed revenues for Schedule 41, the Distribution Energy Charges for this draft rate design are estimated to be as follows:

Secondary Distribution Energy Charge: 6.625¢ per kWh
Primary Distribution Energy Charge: 6.416¢ per kWh

We do not believe that such a rate is reasonable, however, because it will not present a clear price signal to these customers about the costs of serving them. In particular, the lack of a load size charge will discourage these customers from utilizing the Company's distribution capacity efficiently, sending improper price signals which could increase costs for other customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/1001
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

April 2009

PACIFIC POWER & LIGHT COMPANY
TARIFF INDEX

OREGON

Schedule No.

(N)

201	Net Power Costs – Supply Service Adjustment
202	Renewable Adjustment Clause – Supply Service Adjustment
203	Renewable Resource Deferral Adjustment – Supply Service Adjustment
270	Renewable Energy Rider – Optional
271	Energy Profiler Online – Optional
272	Renewable Energy Rider – Optional Bulk Purchase Option
290	Public Purpose Charge (3%)
294	Transition Adjustment
295	Transition Adjustment One-Time Multi-Year Cost of Service Opt-Out
296	Direct Access Shopping Incentive deferred Account Surcharge
297	Energy Conservation Charge
299	Rate Mitigation Adjustment
	SUPPLY SERVICE
200	Cost-Based Supply Service
210	Portfolio Time-of-Use Supply Service
211	Portfolio Renewable Usage Supply Service
212	Renewable Energy Rider - Optional
213	Portfolio Habitat Supply Service
220	Standard Offer Supply Service
230	Emergency Supply Service
247	Partial Requirements Supply Service
276R	Large General Service/Partial Requirements Service – Economic Replacement Power Rider
	DIRECT ACCESS DELIVERY SERVICE
723	General Service – Small Nonresidential – Direct Access Delivery Service
728	General Service – Large Nonresidential – 31 - 200 kW
730	General Service – Large Nonresidential – 201 - 999 kW
741	Agricultural Pumping Service
747	Large General Service, Partial Requirements Service - 1,000 kW and Over
748	Large General Service - 1,000 kW and Over
751	HPSV Street Lighting Service – Company-Owned
752	Company-owned Street Lighting Service
753	Consumer-owned Street Lighting Service
754	Recreational Field Lighting Service – Schools and Universities Restricted
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781	Direct Access Shopping Incentive Adjustment
	OTHER
33	Klamath Basin – Irrigation and Drainage Pumping
400	Special Contracts
	OTHER CHARGES
300	Charges as Defined by the Rules and Regulations
600	ESS Charges
780	Oregon Market Kick-Start Program Experimental Service

PACIFIC POWER & LIGHT COMPANY
RESIDENTIAL SERVICE
DELIVERY SERVICE

OREGON
SCHEDULE 4

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 applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, per month	$8.50	(I)
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	3.271¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.385¢	(R)

Supply Service Options

Consumer shall select Supply Service Schedule 200, 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 & LIGHT COMPANY
OUTDOOR AREA LIGHTING SERVICE
NO NEW SERVICE
DELIVERY SERVICE

OREGON
SCHEDULE 15

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 applicable adjustments as specified in Schedule 90.

Type of Luminaire	Nominal Rating	Monthly kWh	Rate Per Luminaire	
Mercury Vapor	7,000	76	$8.55	(I)
Mercury Vapor	21,000	172	$15.35	
Mercury Vapor	55,000	412	$30.21	
High Pressure Sodium	5,800	31	$12.07	
High Pressure Sodium	22,000	85	$16.33	
High Pressure Sodium	50,000	176	$25.07	(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

Supply Service shall be provided by Supply Service Schedule 200.

Special Conditions

Maintenance will be performed during regular working hours as soon as practicable after the Consumer has notified the Company of service failure.

The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

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 Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by the Consumer.

(continued)

PACIFIC POWER & LIGHT COMPANY
GENERAL SERVICE – SMALL NONRESIDENTIAL DELIVERY SERVICE

OREGON
SCHEDULE 23

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.K. 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 applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Single Phase, per month	$18.65	$18.65	(I)
Three Phase, per month	$27.85	$27.85	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$ 1.25	$ 1.25	(I)
Demand Charge, the first 15 kW of demand, per kW	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 4.36	$ 4.24	(I)
Distribution Energy Charge, per kWh	2.591¢	2.509¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.374¢	0.362¢	(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 0.9685. (R)

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 1.0325. (I)

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

A Small Nonresidential Consumer taking Delivery Service under this schedule shall specify Supply Service Schedule 200, 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 & LIGHT COMPANY
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.K. 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 applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 15.00	$ 19.00	(I)
Load Size 51-100 kW, per month	$ 28.00	$ 33.00	
Load Size 101 - 300 kW, per month	$ 66.00	$ 77.00	
Load Size > 300 kW, per month	$ 96.00	$ 110.00	
Load Size Charge			
≤50 kW, per kW load size	$ 0.95	$ 1.05	
51 - 100 kW, per kW load size	$ 0.75	$ 0.90	
101 – 300 kW, per kW Load Size	$ 0.45	$ 0.45	
> 300 kW, per kW Load Size	$ 0.30	$ 0.30	
Demand Charge, per kW	$ 2.82	$ 3.36	
Distribution Energy Charge, per kWh	0.320¢	0.057¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 1.23	$ 1.18	(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.

(continued)

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 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 0.9685. (R)

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 1.0325. (I)

Supply Service Options

A Consumer taking Delivery Service under this schedule shall specify Supply Service Schedule 200 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 written permission of the Company and where the Consumer meters and bills any of his tenants at the Company's regular tariff rate for the type of service which such tenant may actually receive.

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 & LIGHT COMPANY
GENERAL SERVICE – LARGE NONRESIDENTIAL
201 KW TO 999 KW
DELIVERY SERVICE

OREGON
SCHEDULE 30

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 applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤200 kW, per month	\$393.00	\$356.00	(I)
Load Size 201 - 300 kW, per month	\$123.00	\$116.00	
Load Size > 300 kW, per month	\$320.00	\$301.00	
Load Size Charge			
≤200 kW, per kW load size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	\$ 1.35	\$ 1.20	
> 300 kW, per kW Load Size	\$ 0.70	\$ 0.65	
Demand Charge, per kW	\$ 3.09	\$ 2.85	
Reactive Power Charge, per kvar	\$ 0.65	\$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	\$ 1.43	\$ 1.27	(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.

(continued)

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 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 0.9685. (R)

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 1.0325. (I)

Supply Service Options

A Consumer taking Delivery Service under this schedule shall specify Supply Service Schedule 200 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 written permission of the Company and where the Consumer meters and bills any of his tenants at the Company's regular tariff rate for the type of service which such tenant may actually receive.

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.

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 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 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	$ 430.00	$ 420.00	(I)
Three Phase Load Size > 300 kW	$ 1,700.00	$1,650.00	
Load Size Charge (November billing only)			
Single Phase Any Size, per kW Load Size	$ 21.00	$ 20.00	
Three Phase ≤ 50 kW, per kW Load Size	$ 21.00	$ 20.00	(I)
Three Phase 51 - 300 kW, per kW Load Size	$ 13.00	$ 13.00	
Three Phase > 300 kW, per kW Load Size	$ 8.00	$ 8.00	
Single Phase, Minimum Charge	$ 70.00	$ 70.00	(I)
Three Phase, Minimum Charge	$ 125.00	$ 120.00	
Distribution Energy Charge, per kWh	4.899¢	4.745¢	
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.439¢	0.425¢	(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.

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 0.9685. (R)

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 1.0325. (I)

Supply Service Options

A Small Nonresidential Consumer taking Delivery Service under this schedule shall specify a Supply Service Schedule 200, 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 select Supply Service Schedule 200 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.

(continued)

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS – 1,000 KW AND OVER
DELIVERY SERVICE

OREGON
SCHEDULE 47

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 applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	Secondary	Primary	Transmission	
Basic Charge				
Facility Capacity <= 4,000 kW, per month	$350.00	$350.00	$490.00	(I)(I)(I)
Facility Capacity > 4,000 kW, per month	$650.00	$630.00	$910.00	(I)(I)(I)
Facilities Charge				
<=4,000 kW, per kW Facility Capacity	$1.35	$0.70	$0.65	(R)(R)(I)
> 4,000 kW, per kW Facility Capacity	$1.25	$0.65	$0.65	(R)(R)(I)
On-Peak Demand Charge, per kW	$2.17	$2.32	$1.70	(I)(I)(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	$0.97	$1.06	$1.44	(I)(I)

(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 0.9685. (R)
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 1.0325. (I)

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 & LIGHT COMPANY
LARGE GENERAL SERVICE - 1,000 KW AND OVER
DELIVERY SERVICE

OREGON
SCHEDULE 48

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 applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Distribution Charge				
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$350.00	$350.00	$490.00	(I)(I)(I)
Facility Capacity > 4000 kW, per month	$650.00	$630.00	$910.00	(I)(I)(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$ 1.35	$ 0.70	$ 0.65	(R)(R)(I)
> 4000 kW, per kW Facility Capacity	$ 1.25	$ 0.65	$ 0.65	(R)(R)(I)
On-Peak Demand Charge, per kW	$ 2.17	$ 2.32	$ 1.70	(I)(I)(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	$ 0.55	
Transmission & Ancillary Services Charge				
Per kW of On-Peak demand	$ 1.51	$ 1.60	$ 1.98	(I)(I)(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.

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 0.9685. (R)

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 1.0325. (I)

Supply Service Options

A Consumer taking Delivery Service under this Schedule shall select Supply Service Schedule 200 or Schedule 220, as appropriate and in accordance with the Applicable section of Schedule 200 or Schedule 220.

Special Conditions

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by written permission of the Company and where the Consumer meters and bills any of his tenants at the Company's regular Tariff rate for the type of service which such tenant may actually receive.

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 & LIGHT COMPANY
MERCURY VAPOR
STREET LIGHTING SERVICE - NO NEW SERVICE
DELIVERY SERVICE

OREGON
SCHEDULE 50

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 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	$11.43	$19.73	$38.09	(I)
Vertical, per lamp	$10.48	$18.07		

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	$15.71		
On 26-foot poles, vertical, per lamp	$14.68		
On 30-foot poles, horizontal , per lamp		$24.79	
On 30-foot poles, vertical, per lamp		$23.13	
On 33-foot poles, horizontal , per lamp			$43.08

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	$15.71			
On 26-foot poles, vertical, per lamp	$14.68			
On 30-foot poles, horizontal , per lamp		$23.74		
On 30-foot poles, vertical, per lamp		$22.18		
On 33-foot poles, horizontal , per lamp			$42.02	(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 & LIGHT COMPANY
STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

OREGON
SCHEDULE 51

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 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	$ 10.19	$ 11.37	$ 13.78	$ 16.17	$ 20.79	$ 25.40
Decorative - Series 1	N/A	$ 38.65	$ 38.52	N/A	N/A	N/A
Decorative - Series 2	N/A	$ 33.15	$ 32.90	N/A	N/A	N/A

(I)

Metal Halide				
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	$ 26.95	$ 30.19	$ 29.08
Decorative - Series 1	$ 38.89	$ 41.46	N/A	N/A
Decorative - Series 2	$ 35.81	$ 35.82	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.

Supply Service Option:
A Consumer taking Delivery Service under this schedule shall specify Supply Service Schedule 200 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 & LIGHT COMPANY
STREET LIGHTING SERVICE (NO NEW SERVICE)
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

OREGON
SCHEDULE 52

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 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	8.721¢	(I)
For dusk to midnight operation, per kWh	10.484¢	(I)

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.

Supply Service Option

A Consumer taking Delivery Service under this schedule shall specify Supply Service Schedule 200 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.

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 the Company's estimated average monthly relamping and energy costs for the luminaire. The 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 the Company to Consumer.

(continued)

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 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	$ 2.53	$ 3.59	$ 5.23	$ 6.94	$ 9.39	$ 14.37

(I)

Metal Halide					
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	$ 3.18	$ 5.55	$ 7.68	$ 12.17	$ 28.91

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	8.166

(I)

(continued)

PACIFIC POWER & LIGHT COMPANY
RECREATIONAL FIELD LIGHTING
RESTRICTED
DELIVERY SERVICE

OREGON
SCHEDULE 54

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 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	9.544¢	(I)
Transmission & Ancillary Services Charge		
per kWh	0.017¢	(I)

Minimum Charge
The minimum monthly charge shall be the Basic Charge.

Supply Service Option:
A Consumer taking Delivery Service under this schedule shall specify Supply Service Schedule 200 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. The Company will supply one transformer, or transformer bank, for each athletic or recreational field; any additional transformers required shall be supplied and owned by the Consumer. All transformers owned by the Consumer must be properly fused and of such types and characteristics as conform to the Company's standards. When service is supplied to more than one transformer or transformer bank, the 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.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
LARGE GENERAL SERVICE/PARTIAL REQUIREMENTS SERVICE – ECONOMIC REPLACEMENT POWER RIDER DELIVERY SERVICE **SCHEDULE 76R**

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 applicable adjustments as specified in Schedule 90:

	Secondary	Delivery Voltage Primary	Transmission	
Transmission and Ancillary Services Charge				
per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.038	$0.041	$0.056	(I)
Daily ERP Demand Charge				
per kW of Daily ERP On- Peak Demand	$0.085	$0.090	$0.066	(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.

(continued)

PACIFIC POWER & LIGHT COMPANY
KLAMATH RATE RECONCILIATION ADJUSTMENT

OREGON
SCHEDULE 92

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.35 shall have applied an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt hour.

Schedule 4	0.000	cents	(R)
Schedule 15	0.000	cents	
Schedule 23, 723	0.000	cents	
Schedule 28, 728	0.000	cents	
Schedule 30, 730	0.000	cents	
Schedule 33	0.000	cents	
Schedule 41, 741	0.000	cents	
Schedule 47, 747	0.000	cents	
Schedule 48, 748	0.000	cents	
Schedule 50	0.000	cents	
Schedule 51, 751	0.000	cents	
Schedule 52, 752	0.000	cents	
Schedule 53, 753	0.000	cents	
Schedule 54, 754	0.000	cents	(R)

PACIFIC POWER & LIGHT COMPANY
COST-BASED
SUPPLY SERVICE

OREGON
SCHEDULE 200
Page 1

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take this service or who have elected to take service under Schedules 210, 211, 212 or 213. This service may be taken only in conjunction with the applicable Delivery Service Schedule and with other applicable Supply Service Adjustment Schedules including but not limited to Schedule 201. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-270, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T. (C)
|
(C)

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Energy Charge

The Monthly Billing shall be the Energy Charge.

Delivery Service Schedule No.			Delivery Voltage Secondary	Primary	Transmission	
4	Per kWh	0 - 500 kWh	2.351¢			(R)
		501-1000 kWh	2.786¢			|
		> 1000 kWh	3.438¢			(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).

		Secondary	Primary	Transmission	
23	First 3,000 kWh, per kWh	2.942¢	2.849¢		(R)
	All additional kWh, per kWh	2.185¢	2.116¢		|
28	First 20,000 kWh, per kWh	2.838¢	2.761¢		|
	All additional kWh, per kWh	2.761¢	2.687¢		|
30	First 20,000 kWh, per kWh	3.083¢	2.969¢		|
	All additional kWh, per kWh	2.731¢	2.650¢		|
41	Winter, first 100 kWh/kW, per kWh	4.182¢	4.050¢		|
	Winter, all additional kWh, per kWh	2.849¢	2.759¢		(R)

(continued)

Energy Charge *(continued)*

Delivery Service Schedule No.		Secondary	Primary	Transmission	
		Delivery Voltage			
41	Summer, all kWh, per kWh	2.849 ¢	2.759¢		(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.

		Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	2.813¢	2.678¢	2.569¢	(R)
	Per kWh, Off-Peak	2.763¢	2.628¢	2.519¢	(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.

		Secondary	
52	For dusk to dawn operation, per kWh	1.946¢	(R)
	For dusk to midnight operation, per kWh	1.946¢	
54	Per kWh	1.431¢	(R)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$0.73	(R)
Mercury Vapor	21,000	172	$1.65	
Mercury Vapor	55,000	412	$3.95	
High Pressure Sodium	5,800	31	$0.30	
High Pressure Sodium	22,000	85	$0.82	
High Pressure Sodium	50,000	176	$1.69	(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	$1.22	$2.77	$6.63	(R)
Vertical, per lamp	$1.22	$2.77		(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	$1.22			(R)
On 26-foot poles, vertical, per lamp	$1.22			
On 30-foot poles, horizontal , per lamp		$2.77		
On 30-foot poles, vertical, per lamp		$2.77		
On 33-foot poles, horizontal , per lamp			$6.63	(R)

(continued)

Energy Charge *(continued)*

Delivery Service Schedule No.

B. Company-owned Underground System

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
				(R)
On 26-foot poles, horizontal, per lamp	$1.22			
On 26-foot poles, vertical, per lamp	$1.22			
On 30-foot poles, horizontal ,per lamp		$2.77		
On 30-foot poles, vertical, per lamp		$2.77		
On 33-foot poles, horizontal , per lamp			$6.63	(R)

	Types of Luminaire	Nominal rating	Monthly kWh	Rate Per Luminaire	
51	High Pressure Sodium	5,800	31	$0.79	(R)(C)
	High Pressure Sodium	9,500	44	$1.12	
	High Pressure Sodium	16,000	64	$1.63	
	High Pressure Sodium	22,000	85	$2.16	
	High Pressure Sodium	27,500	115	$2.92	
	High Pressure Sodium	50,000	176	$4.47	
	Metal Halide	9,000	39	$0.99	
	Metal Halide	12,000	68	$1.73	
	Metal Halide	19,500	94	$2.39	
	Metal Halide	32,000	149	$3.79	(R)

	Types of Luminaire	Nominal rating	Monthly kWh	Rate Per Luminaire	
53	High Pressure Sodium	5,800	31	$0.26	(R)
	High Pressure Sodium	9,500	44	$0.37	
	High Pressure Sodium	16,000	64	$0.53	
	High Pressure Sodium	22,000	85	$0.71	
	High Pressure Sodium	27,500	115	$0.96	
	High Pressure Sodium	50,000	176	$1.46	
	Metal Halide	9,000	39	$0.32	
	Metal Halide	12,000	68	$0.57	
	Metal Halide	19,500	94	$0.78	
	Metal Halide	32,000	149	$1.24	
	Metal Halide	107,800	354	$2.94	
	Non-Listed Luminaire, per kWh		0.831¢		(R)

(continued)

PACIFIC POWER & LIGHT COMPANY
NET POWER COSTS
SUPPLY SERVICE ADJUSTMENT

OREGON
SCHEDULE 201
Page 1

Applicable
To all Consumers who take supply service under Schedule 200. (N)

Energy Charge
The Monthly Billing shall be the Energy Charge.

Delivery Service Schedule No.			Delivery Voltage Secondary	Primary	Transmission
4	Per kWh	0 - 500 kWh	1.754¢		
		501-1000 kWh	2.079¢		
		> 1000 kWh	2.565¢		

For Schedule 4, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	Primary	Transmission
23	First 3,000 kWh, per kWh	2.195¢	2.126¢	
	All additional kWh, per kWh	1.630¢	1.579¢	
28	First 20,000 kWh, per kWh	2.118¢	2.060¢	
	All additional kWh, per kWh	2.061¢	2.005¢	
30	First 20,000 kWh, per kWh	2.351¢	2.287¢	
	All additional kWh, per kWh	2.039¢	1.977¢	
41	Winter, first 100 kWh/kW, per kWh	3.121¢	3.023¢	
	Winter, all additional kWh, per kWh	2.127¢	2.060¢	
	Summer, all kWh, per kWh	2.127 ¢	2.060¢	

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.

		Secondary	Primary	Transmission
47/48	Per kWh On-Peak	2.102¢	2.004¢	1.923¢
	Per kWh, Off-Peak	2.052¢	1.954¢	1.873¢

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.

		Secondary	Primary	Transmission
52	For dusk to dawn operation, per kWh	1.595¢		
	For dusk to midnight operation, per kWh	1.595¢		
54	Per kWh	1.173¢		

(continued)

(N)

Energy Charge *(continued)*

(N)

Delivery Service Schedule No.

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire
Mercury Vapor	7,000	76	$1.21
Mercury Vapor	21,000	172	$2.73
Mercury Vapor	55,000	412	$6.53
High Pressure Sodium	5,800	31	$0.49
High Pressure Sodium	22,000	85	$1.35
High Pressure Sodium	50,000	176	$2.79

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	$1.00	$2.27	$5.43
Vertical, per lamp	$1.00	$2.27	

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$1.00		
On 26-foot poles, vertical, per lamp	$1.00		
On 30-foot poles, horizontal , per lamp		$2.27	
On 30-foot poles, vertical, per lamp		$2.27	
On 33-foot poles, horizontal , per lamp			$5.43

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	$1.00		
On 26-foot poles, vertical, per lamp	$1.00		
On 30-foot poles, horizontal ,per lamp		$2.27	
On 30-foot poles, vertical, per lamp		$2.27	
On 33-foot poles, horizontal , per lamp			$5.43

(continued)

(N)

(N)

Energy Charge *(continued)*

Delivery Service Schedule No.

51

Types of Luminaire	Nominal rating	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	31	$0.65
High Pressure Sodium	9,500	44	$0.92
High Pressure Sodium	16,000	64	$1.33
High Pressure Sodium	22,000	85	$1.77
High Pressure Sodium	27,500	115	$2.39
High Pressure Sodium	50,000	176	$3.66
Metal Halide	9,000	39	$0.81
Metal Halide	12,000	68	$1.42
Metal Halide	19,500	94	$1.96
Metal Halide	32,000	149	$3.10

53

Types of Luminaire	Nominal rating	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	31	$0.21
High Pressure Sodium	9,500	44	$0.30
High Pressure Sodium	16,000	64	$0.44
High Pressure Sodium	22,000	85	$0.58
High Pressure Sodium	27,500	115	$0.78
High Pressure Sodium	50,000	176	$1.20
Metal Halide	9,000	39	$0.27
Metal Halide	12,000	68	$0.46
Metal Halide	19,500	94	$0.64
Metal Halide	32,000	149	$1.02
Metal Halide	107,800	354	$2.41

Non-Listed Luminaire, per kWh 0.682¢

(N)

PACIFIC POWER & LIGHT COMPANY
RENEWABLE ADJUSTMENT CLAUSE
SUPPLY SERVICE ADJUSTMENT

OREGON
SCHEDULE 202

Purpose

This schedule recovers, between rate cases, the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

This adjustment is to recover the actual and forecasted revenue requirement associated with the prudently incurred costs of resources, including associated transmission, that are eligible under Senate Bill 838 (2007) and in service as of the date of the proposed rate change. The revenue requirement includes the actual return of and grossed up return on capital costs of the renewable energy source and associated transmission at the currently authorized rate of return, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs not captured in the Transition Adjustment Mechanism (TAM). The adjustment will also include an update on gross revenues, net revenues and total income tax expense for the calculation of “taxes authorized to be collected in rates” pursuant to OAR 860-022-0041. The revenue requirement for Oregon will be calculated using the forecasted inter-jurisdictional allocation factors based on the same 12-month period used in the TAM.

Applicable

To Residential consumers and Nonresidential consumers who take supply service under Schedule 200, 220, 230 and 247 and consumers served under Schedule 33. To Nonresidential consumers who take direct access service, other than under a multi-year cost of service opt-out option, until December 31, 2010.

Energy Charge

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

Schedule	Charge	
4	0.000 cents per kWh	(R)
15	0.000 cents per kWh	
23, 723	0.000 cents per kWh	
28, 728	0.000 cents per kWh	
30, 730	0.000 cents per kWh	
33	0.000 cents per kWh	
41, 741	0.000 cents per kWh	
47, 747	0.000 cents per kWh	
48, 748	0.000 cents per kWh	
50	0.000 cents per kWh	
51, 751	0.000 cents per kWh	
52, 752	0.000 cents per kWh	
53, 753	0.000 cents per kWh	
54, 754	0.000 cents per kWh	(R)

(continued)

Return to Cost-Based Supply Service

The Consumer's return to Cost-Based Supply Service is restricted under the provisions of Schedule 200, Cost-Based Supply Service.

Loss Adjustment Factor

The loss adjustment shall be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Transmission Delivery Voltage	1.0361	(R)
Primary Delivery Voltage	1.0595	
Secondary Delivery Voltage	1.0940	(R)

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.

PACIFIC POWER & LIGHT COMPANY
EMERGENCY
SUPPLY SERVICE

OREGON
SCHEDULE 230

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 Daily Rate

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	1.0361	(R)
Primary Delivery Voltage	1.0595	
Secondary Delivery Voltage	1.0940	(R)

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	1.0361	(R)
Primary Delivery Voltage	1.0595	
Secondary Delivery Voltage	1.0940	(R)

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	1.0361	(R)
Primary Delivery Voltage	1.0595	
Secondary Delivery Voltage	1.0940	(R)

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 & LIGHT COMPANY **OREGON**
RATE MITIGATION ADJUSTMENT **SCHEDULE 299**

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.35 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

Schedule 4	0.057	cents	
Schedule 15	1.002	cents	
Schedule 23, 723	(0.102)	cents	(R)
Schedule 28, 728	0.334	cents	
Schedule 30, 730	0.052	cents	
Schedule 41, 741	(2.671)	cents	(R)
Schedule 47, 747	(0.149)	cents	
Schedule 48, 748	(0.149)	cents	
Schedule 50	(2.846)	cents	(R)
Schedule 51, 751	(4.697)	cents	
Schedule 52, 752	(2.994)	cents	
Schedule 53, 753	(1.595)	cents	
Schedule 54, 754	(2.385)	cents	(R)

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.K. 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 applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$18.65	$18.65	(I)
Three Phase, per month	$27.85	$27.85	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 1.25	$ 1.25	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, per kW in excess of 15 kW	$ 4.36	$ 4.24	(I)
Distribution Energy Charge, per kWh	2.591¢	2.509¢	(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.

(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 Company's demand meter for the 15-minute period of 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 0.9685. (R)

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 1.0325. (I)

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.

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.

(continued)

PACIFIC POWER & LIGHT COMPANY
GENERAL SERVICE – LARGE NONRESIDENTIAL
31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 728

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.K. 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 applicable adjustments as specified in Schedule 90.

Distribution Charge	Delivery Voltage		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 15.00	$ 19.00	(I)
Load Size 51-100 kW, per month	$ 28.00	$ 33.00	
Load Size 101 - 300 kW, per month	$ 66.00	$ 77.00	
Load Size > 300 kW, per month	$ 96.00	$ 110.00	
Load Size Charge			
≤ 50 kW, per kW load size	$ 0.95	$ 1.05	
51-100 kW, per kW load size	$ 0.75	$ 0.90	
101 – 300 kW, per kW Load Size	$ 0.45	$ 0.45	
> 300 kW, per kW Load Size	$ 0.30	$ 0.30	
Demand Charge, per kW	$ 2.82	$ 3.36	
Distribution Energy Charge, per kWh	0.320¢	0.057¢	(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.

(continued)

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 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 0.9685. (R)

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 1.0325. (I)

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 written permission of Company and where Consumer meters and bills any of his tenants at Company's regular tariff rate for the type of service which such tenant may actually receive.

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.

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 applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$393.00	$356.00	(I)
Load Size 201 - 300 kW, per month	$123.00	$116.00	|
Load Size > 300 kW, per month	$320.00	$301.00	(I)
Load Size Charge			
≤ 200 kW, per kW load size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.35	$ 1.20	(I)
> 300 kW, per kW Load Size	$ 0.70	$ 0.65	
Demand Charge, per kW	$ 3.09	$ 2.85	(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.

(continued)

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.

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 0.9685. (R)

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 1.0325. (I)

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 written permission of Company and where Consumer meters and bills any of his tenants at Company's regular tariff rate for the type of service which such tenant may actually receive.

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 & LIGHT COMPANY
AGRICULTURAL PUMPING SERVICE
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 741

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 1,000kW 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 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 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	$ 430.00	$ 420.00	(I)
Three Phase Load Size > 300 kW	$1,700.00	$1,650.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW	$ 21.00	$ 20.00	(I)
Three Phase 51 - 300 kW, per kW	$ 13.00	$ 13.00	|
Three Phase > 300 kW, per kW	$ 8.00	$ 8.00	|
Single Phase, Minimum Charge	$ 70.00	$ 70.00	(I)
Three Phase, Minimum Charge	$ 125.00	$ 120.00	(I)
Distribution Energy Charge, per kWh	4.899¢	4.745¢	(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.

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 0.9685. (R)

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 1.0325. (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.

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.

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 applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	Secondary	Primary	Transmission	
Basic Charge				
Facility Capacity <= 4,000 kW, per month	$350.00	$350.00	$490.00	(I) (I) (I)
Facility Capacity > 4,000 kW, per month	$650.00	$630.00	$910.00	(I) (I)
Facilities Charge				
<=4,000 kW, per kW Facility Capacity	$1.35	$0.70	$0.65	(R) (R)
> 4,000 kW, per kW Facility Capacity	$1.25	$0.65	$0.65	(R) (R)
On-Peak Demand Charge, per kW	$2.17	$2.32	$1.70	(I) (I) (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 0.9685. (R)
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 1.0325. (I)

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.

Supplemental Reserves

In addition to the Supplemental Reserves provided for the Consumer's Baseline Demand, Supplemental Reserves provide Electricity within the first ten minutes after a Consumer's demand rises above Baseline Demand.

(continued)

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE - 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 748

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 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 applicable adjustments as specified in Schedule 90.

Distribution Charge	Delivery Voltage			
	Secondary	Primary	Transmission	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$350.00	$350.00	$490.00	(I) (I) (I)
Facility Capacity > 4000 kW, per month	$650.00	$630.00	$910.00	(I) (I)
Facilities Charge				
≤ 4000 kW, per kW, Facility Capacity	$ 1.35	$ 0.70	$ 0.65	(R) (R)
> 4000 kW, per kW, Facility Capacity	$ 1.25	$ 0.65	$ 0.65	(R) (R)
On-Peak Demand Charge, per kW	$ 2.17	$ 2.32	$ 1.70	(I) (I) (I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	$ 0.55	

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 0.9685. (R)

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 1.0325. (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.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by written permission of Company and where Consumer meters and bills any of his tenants at Company's regular Tariff rate for the type of service which such tenant may actually receive.

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 & LIGHT COMPANY
STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

OREGON
SCHEDULE 751

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 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	$ 10.18	$ 11.36	$ 13.76	$ 16.15	$ 20.76	$ 25.35	(I)
Decorative - Series 1	N/A	$ 38.64	$ 38.50	N/A	N/A	N/A	|
Decorative - Series 2	N/A	$ 33.14	$ 32.88	N/A	N/A	N/A	(I)

Metal Halide					
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	$ 26.93	$ 30.16	$ 29.04	(I)
Decorative - Series 1	$ 38.88	$ 41.44	N/A	N/A	|
Decorative - Series 2	$ 35.80	$ 35.80	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.

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 & LIGHT COMPANY
STREET LIGHTING SERVICE (NO NEW SERVICE)
COMPANY-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 752

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 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	8.698¢	(I)
For dusk to midnight operation, per kWh	10.456¢	(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.

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.

PACIFIC POWER & LIGHT COMPANY
STREET LIGHTING SERVICE
CONSUMER-OWNED SYSTEM
DELIVERY SERVICE

OREGON
SCHEDULE 753

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 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	$ 2.53	$ 3.59	$ 5.22	$ 6.93	$ 9.38	$ 14.36	(I)

Metal Halide						
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	$ 3.18	$ 5.55	$ 7.67	$ 12.16	$ 28.88	(I)

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	8.158	(I)

(continued)

PACIFIC POWER & LIGHT COMPANY
RECREATIONAL FIELD LIGHTING
RESTRICTED
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 754

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 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	9.544¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

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.

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 applicable adjustments as specified in Schedule 90:

		Delivery Voltage		
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERP On- Peak Demand	$0.085	$0.090	$0.066	(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)

William R. Griffith
Exhibit PPL/1002

Docket No. UE-
Exhibit PPL/1002
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 the Proposed Rates

April 2009

Table 1002-1

PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates[1]	Present Revenues ($000) Adders[2]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[2]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[3]	Change Net Rates ($000)	Change Net Rates %[3]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	478,485	5,435,846	$480,272	$18,970	$499,242	$511,766	$18,970	$530,736	$31,494	6.6%	$31,494	6.3%	1
2	**Total Residential**			478,485	5,435,846	$480,272	$18,970	$499,242	$511,766	$18,970	$530,736	$31,494	6.6%	$31,494	6.3%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,055	1,013,941	$92,533	($2,688)	$89,845	$100,239	$1,946	$102,185	$7,706	8.3%	$12,340	13.7%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,101	2,045,065	$128,740	$14,255	$142,995	$144,038	$12,885	$156,923	$15,298	11.9%	$13,928	9.7%	4
5	Gen. Svc. 201 - 999 kW	30	30	853	1,378,646	$80,816	$6,369	$87,185	$90,897	$4,770	$95,667	$10,081	12.5%	$8,482	9.7%	5
6	Large General Service >= 1,000 kW	48	48	215	2,643,901	$134,528	$3,542	$138,070	$153,341	$3,542	$156,883	$18,813	14.1%	$18,813	13.7%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	571,965	$26,523	$767	$27,290	$30,431	$767	$31,198	$3,908	14.1%	$3,908	13.7%	7
8	Agricultural Pumping Service	41	41	6,108	136,792	$14,539	($3,071)	$11,468	$16,732	($3,252)	$13,480	$2,193	15.1%	$2,012	17.5%	8
9	Agricultural Pumping - Other	33	33	2,062	118,046	$3,839	$344	$4,183	$3,694	$344	$4,038	($145)	-3.8%	($145)	-3.5%	9
10	**Total Commercial & Industrial**			93,401	7,908,356	$481,518	$19,518	$501,036	$539,372	$21,002	$560,374	$57,854	12.0%	$59,338	11.8%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,404	10,466	$1,321	$132	$1,453	$1,467	$132	$1,599	$146	11.1%	$146	10.1%	11
12	Street Lighting Service	50	50	287	10,738	$1,179	$124	$1,303	$1,811	($280)	$1,531	$632	53.6%	$228	17.5%	12
13	Street Lighting Service HPS	51	51	686	16,085	$2,847	$270	$3,117	$4,377	($714)	$3,663	$1,530	53.7%	$546	17.5%	13
14	Street Lighting Service	52	52	79	1,186	$135	$14	$149	$208	($33)	$175	$73	54.1%	$26	17.5%	14
15	Street Lighting Service	53	53	250	9,316	$593	$75	$668	$913	($128)	$785	$320	54.0%	$117	17.5%	15
16	Recreational Field Lighting	54	54	105	816	$71	$6	$77	$108	($17)	$91	$37	52.1%	$14	18.2%	16
17	**Total Public Street Lighting**			8,811	48,607	$6,146	$621	$6,767	$8,884	($1,040)	$7,844	$2,738	44.6%	$1,077	15.9%	17
18	**Total Sales to Ultimate Consumers**			580,697	13,392,809	$967,936	$39,109	$1,007,045	$1,060,022	$38,932	$1,098,954	$92,086	9.5%	$91,909	9.1%	18
19	**Employee Discount**				18,481	($404)	($16)	($420)	($430)	($16)	($446)	($26)		($26)		19
20	**Total Sales with Employee Discount**			580,697	13,392,809	$967,532	$39,093	$1,006,625	$1,059,592	$38,916	$1,098,508	$92,060	9.5%	$91,883	9.1%	20
21	AGA Revenue					$2,380		$2,380	$2,380		$2,380	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			580,697	13,392,809	$969,912	$39,093	$1,009,005	$1,061,972	$38,916	$1,100,888	$92,060	9.5%	$91,883	9.1%	22

[1] Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.
[2] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[3] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Table 1002-2
PACIFIC POWER & LIGHT COMPANY
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 (000)	Prop. Sales 96 (000)	Interv. Fndg. 97 (000)	Tax Adj 102 (000)	RAC Defer. 203 (000)	Shop. Inctv. 296 (000)	RMA 299 (000) PRE	RMA 299 (000) PRO	Total (000) PRE	Total (000) PRO
	Residential												
1	Residential	4	4	$381	($544)	$0	$10,817	$5,218	$0	$3,098	$3,098	$18,970	$18,970
2	**Total Residential**												
	Commercial & Industrial												
3	Gen. Svc. < 31 kW	23	23	$71	($101)	$0	$2,017	$993	$0	($5,668)	($1,034)	($2,688)	$1,946
4	Gen. Svc. 31 - 200 kW	28	28	$144	($205)	$0	$4,070	$1,963	$82	$8,201	$6,831	$14,255	$12,885
5	Gen. Svc. 201 - 999 kW	30	30	$96	($138)	$0	$2,744	$1,296	$55	$2,316	$717	$6,369	$4,770
6	Large General Service >= 1,000 kW	48	48	$185	($264)	$0	$5,261	$2,300	$0	($3,940)	($3,940)	$3,542	$3,542
7	Partial Req. Svc. >= 1,000 kW	47	47	$40	($57)	$0	$1,138	$498	$0	($852)	($852)	$767	$767
8	Agricultural Pumping Service	41	41	$10	($14)	$0	$272	$131	$3	($3,473)	($3,654)	($3,071)	($3,252)
9	Agricultural Pumping - Other	33	33	$8	($12)	$0	$235	$113	$0	$0	$0	$344	$344
10	**Total Commercial & Industrial**			$554	($791)	$0	$15,737	$7,294	$140	($3,416)	($1,932)	$19,518	$21,002
	Lighting												
11	Outdoor Area Lighting Service	15	15	$1	($1)	$0	$22	$5	$0	$105	$105	$132	$132
12	Street Lighting Service	50	50	$1	($1)	$0	$21	$5	$0	$98	($306)	$124	($280)
13	Street Lighting Service HPS	51	51	$1	($2)	$0	$32	$11	$0	$228	($756)	$270	($714)
14	Street Lighting Service	52	52	$0	$0	$0	$2	$1	$0	$11	($36)	$14	($33)
15	Street Lighting Service	53	53	$1	($1)	$0	$19	$2	$0	$54	($149)	$75	($128)
16	Recreational Field Lighting	54	54	$0	$0	$0	$2	$0	$0	$4	($19)	$6	($17)
17	**Total Public Street Lighting**			$4	($5)	$0	$98	$24	$0	$500	($1,161)	$621	($1,040)
18	**Total**			$939	($1,340)	$0	$26,652	$12,536	$140	$182	$5	$39,109	$38,932
19	**Employee Discount**			$0	$0	$0	($9)	($4)	$0	($3)	($3)	($16)	($16)
20	**Total Sales with Employee Discount**			$939	($1,340)	$0	$26,643	$12,532	$140	$179	$2	$39,093	$38,916

Table 1002-3
PACIFIC POWER & LIGHT COMPANY
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 ¢/kWh	Prop. Sales 96 ¢/kWh	Interv. Fndg. 97 ¢/kWh	Tax Adj 102 ¢/kWh	RAC Defer. 203 ¢/kWh	Shop. Inctv. 296 ¢/kWh	RMA 299 ¢/kWh	RMA 299 ¢/kWh
										PRE	PRO
	Residential										
1	Residential	4	4	0.007	(0.010)	0.000	0.199	0.096	0.000	0.057	0.057
	Commercial & Industrial										
2	Gen. Svc. < 31 kW	23	23	0.007	(0.010)	0.000	0.199	0.098	0.000	(0.559)	(0.102)
3	Gen. Svc. 31 - 200 kW	28	28	0.007	(0.010)	0.000	0.199	0.096	0.004	0.401	0.334
4	Gen. Svc. 201 - 999 kW	30	30	0.007	(0.010)	0.000	0.199	0.094	0.004	0.168	0.052
5	Large General Service >= 1,000 kW	48	48	0.007	(0.010)	0.000	0.199	0.087	0.000	(0.149)	(0.149)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.007	(0.010)	0.000	0.199	0.087	0.000	(0.149)	(0.149)
7	Agricultural Pumping Service	41	41	0.007	(0.010)	0.000	0.199	0.096	0.004	(2.539)	(2.671)
8	Agricultural Pumping - Other	33	33	0.007	(0.010)	0.000	0.199	0.096	0.000	0.000	0.000
	Lighting										
9	Outdoor Area Lighting Service	15	15	0.007	(0.010)	0.000	0.199	0.053	0.000	1.002	1.002
10	Street Lighting Service	50	50	0.007	(0.010)	0.000	0.199	0.044	0.000	0.908	(2.846)
11	Street Lighting Service HPS	51	51	0.007	(0.010)	0.000	0.199	0.069	0.000	1.416	(4.697)
12	Street Lighting Service	52	52	0.007	(0.010)	0.000	0.199	0.053	0.000	0.920	(2.994)
13	Street Lighting Service	53	53	0.007	(0.010)	0.000	0.199	0.023	0.000	0.580	(1.595)
14	Recreational Field Lighting	54	54	0.007	(0.010)	0.000	0.199	0.039	0.000	0.539	(2.385)

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price**	GRC Proposed Price	Difference	Difference
100	$15.93	$17.34	$1.41	8.85%
200	$23.63	$25.41	$1.78	7.53%
300	$31.33	$33.49	$2.16	6.89%
400	$39.04	$41.58	$2.54	6.51%
500	$46.74	$49.65	$2.91	6.23%
600	$55.11	$58.51	$3.40	6.17%
700	$63.48	$67.37	$3.89	6.13%
800	$71.86	$76.24	$4.38	6.10%
900	$80.22	$85.10	$4.88	6.08%
950	**$84.42**	**$89.54**	**$5.12**	**6.06%**
1,000	$88.61	$93.96	$5.35	6.04%
1,100	$97.99	$104.00	$6.01	6.13%
1,200	$107.36	$114.03	$6.67	6.21%
1,300	$116.75	$124.06	$7.31	6.26%
1,400	$126.13	$134.10	$7.97	6.32%
1,500	$135.50	$144.13	$8.63	6.37%
1,600	$144.87	$154.16	$9.29	6.41%
2,000	$182.40	$194.30	$11.90	6.52%
3,000	$276.19	$294.65	$18.46	6.68%
4,000	$369.98	$394.99	$25.01	6.76%
5,000	$463.77	$495.33	$31.56	6.81%

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

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price**		GRC Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$55	$63	$63	$72	13.82%	14.07%
	750	$74	$82	$84	$94	13.64%	13.84%
	1,000	$93	$102	$106	$115	13.53%	13.70%
	1,500	$132	$140	$149	$159	13.40%	13.54%
10	1,000	$93	$102	$106	$115	13.53%	13.70%
	2,000	$170	$178	$193	$202	13.34%	13.45%
	3,000	$247	$255	$280	$289	13.26%	13.34%
	4,000	$312	$320	$353	$362	13.19%	13.26%
20	4,000	$337	$345	$382	$391	13.34%	13.40%
	6,000	$466	$474	$528	$537	13.23%	13.27%
	8,000	$596	$604	$674	$684	13.16%	13.20%
	10,000	$725	$733	$820	$830	13.12%	13.15%
30	9,000	$711	$719	$805	$815	13.28%	13.31%
	12,000	$905	$913	$1,025	$1,034	13.21%	13.23%
	15,000	$1,099	$1,108	$1,244	$1,253	13.16%	13.18%
	18,000	$1,294	$1,302	$1,463	$1,473	13.12%	13.14%
31	9,300	$735	$743	$833	$842	13.29%	13.31%
	12,400	$936	$944	$1,060	$1,069	13.21%	13.23%
	15,500	$1,137	$1,145	$1,286	$1,296	13.16%	13.18%
	18,600	$1,338	$1,346	$1,513	$1,523	13.13%	13.14%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

kW		Monthly Billing*				Percent Difference	
		Present Price**		GRC Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$54	$62	$61	$71	13.46%	13.75%
	750	$73	$81	$82	$92	13.22%	13.48%
	1,000	$91	$100	$103	$113	13.09%	13.31%
	1,500	$129	$137	$145	$155	12.93%	13.09%
10	1,000	$91	$100	$103	$113	13.09%	13.31%
	2,000	$166	$174	$187	$197	12.85%	12.98%
	3,000	$241	$249	$272	$281	12.75%	12.85%
	4,000	$304	$312	$343	$352	12.67%	12.75%
20	4,000	$329	$337	$371	$380	12.86%	12.93%
	6,000	$455	$463	$513	$522	12.72%	12.77%
	8,000	$581	$589	$655	$664	12.64%	12.69%
	10,000	$707	$716	$797	$806	12.59%	12.63%
30	9,000	$693	$702	$782	$792	12.79%	12.82%
	12,000	$883	$891	$995	$1,004	12.70%	12.73%
	15,000	$1,072	$1,080	$1,208	$1,217	12.64%	12.66%
	18,000	$1,262	$1,270	$1,421	$1,430	12.60%	12.62%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
15	4,500	$338	$372	10.00%
	7,500	$512	$558	9.01%
	10,500	$685	$744	8.53%
31	9,300	$685	$752	9.71%
	15,500	$1,044	$1,136	8.81%
	21,700	$1,401	$1,518	8.36%
40	12,000	$881	$965	9.65%
	20,000	$1,344	$1,461	8.77%
	28,000	$1,797	$1,946	8.29%
60	18,000	$1,316	$1,442	9.57%
	30,000	$1,999	$2,172	8.66%
	42,000	$2,679	$2,899	8.20%
80	24,000	$1,742	$1,907	9.47%
	40,000	$2,650	$2,877	8.58%
	56,000	$3,557	$3,847	8.14%
100	30,000	$2,166	$2,369	9.40%
	50,000	$3,301	$3,582	8.53%
	70,000	$4,435	$4,794	8.10%
200	60,000	$4,265	$4,660	9.25%
	100,000	$6,535	$7,085	8.42%
	140,000	$8,804	$9,510	8.02%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	GRC Proposed Price	Difference
15	4,500	$341	$367	7.59%
	7,500	$505	$540	6.91%
	10,500	$670	$714	6.57%
31	9,300	$686	$737	7.30%
	15,500	$1,027	$1,096	6.71%
	21,700	$1,365	$1,452	6.40%
40	12,000	$881	$945	7.24%
	20,000	$1,320	$1,408	6.66%
	28,000	$1,750	$1,861	6.32%
60	18,000	$1,316	$1,412	7.30%
	30,000	$1,963	$2,094	6.65%
	42,000	$2,608	$2,773	6.31%
80	24,000	$1,741	$1,867	7.22%
	40,000	$2,601	$2,772	6.57%
	56,000	$3,461	$3,677	6.25%
100	30,000	$2,163	$2,318	7.16%
	50,000	$3,238	$3,450	6.53%
	70,000	$4,313	$4,581	6.22%
200	60,000	$4,242	$4,528	6.75%
	100,000	$6,392	$6,791	6.25%
	140,000	$8,541	$9,054	6.00%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

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

kW Load Size	kWh	Monthly Billing* Present Price**	Monthly Billing* GRC Proposed Price	Percent Difference
100	30,000	$2,359	$2,621	11.13%
	50,000	$3,363	$3,697	9.93%
	70,000	$4,368	$4,773	9.28%
200	60,000	$4,264	$4,701	10.24%
	100,000	$6,273	$6,853	9.24%
	140,000	$8,283	$9,005	8.72%
300	90,000	$6,283	$6,920	10.13%
	150,000	$9,297	$10,148	9.15%
	210,000	$12,311	$13,376	8.66%
400	120,000	$8,239	$9,074	10.13%
	200,000	$12,258	$13,378	9.14%
	280,000	$16,276	$17,682	8.64%
500	150,000	$10,201	$11,225	10.04%
	250,000	$15,224	$16,606	9.07%
	350,000	$20,247	$21,986	8.59%
600	180,000	$12,163	$13,377	9.98%
	300,000	$18,191	$19,834	9.03%
	420,000	$24,219	$26,290	8.55%
800	240,000	$16,088	$17,681	9.90%
	400,000	$24,125	$26,290	8.97%
	560,000	$32,162	$34,898	8.51%
1000	300,000	$20,012	$21,984	9.86%
	500,000	$30,058	$32,745	8.94%
	700,000	$40,104	$43,506	8.48%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

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

kW Load Size	kWh	Monthly Billing* Present Price**	GRC Proposed Price	Percent Difference
100	30,000	$2,312	$2,491	7.72%
	50,000	$3,298	$3,537	7.25%
	70,000	$4,284	$4,584	6.99%
200	60,000	$4,181	$4,485	7.28%
	100,000	$6,153	$6,578	6.91%
	140,000	$8,125	$8,671	6.73%
300	90,000	$6,157	$6,603	7.24%
	150,000	$9,115	$9,743	6.88%
	210,000	$12,074	$12,883	6.70%
400	120,000	$8,093	$8,685	7.32%
	200,000	$12,037	$12,871	6.93%
	280,000	$15,981	$17,058	6.74%
500	150,000	$10,018	$10,746	7.27%
	250,000	$14,948	$15,979	6.90%
	350,000	$19,878	$21,212	6.71%
600	180,000	$11,943	$12,807	7.24%
	300,000	$17,859	$19,087	6.87%
	420,000	$23,776	$25,367	6.69%
800	240,000	$15,793	$16,930	7.20%
	400,000	$23,682	$25,303	6.85%
	560,000	$31,570	$33,676	6.67%
1000	300,000	$19,643	$21,052	7.17%
	500,000	$29,504	$31,519	6.83%
	700,000	$39,365	$41,985	6.66%

* Net rate including Schedules 91, 290 and 297.

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			GRC Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill**	December-March Monthly Bill**	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$202	$221	$185	$238	$262	$216	18.26%	18.50%	16.67%
	5,000	$336	$356	$185	$397	$421	$216	18.26%	18.41%	16.67%
	7,000	$470	$490	$185	$556	$580	$216	18.26%	18.37%	16.67%
Three Phase										
20	6,000	$403	$443	$371	$477	$525	$433	18.26%	18.51%	16.67%
	10,000	$672	$711	$371	$795	$842	$433	18.26%	18.41%	16.67%
	14,000	$941	$980	$371	$1,112	$1,160	$433	18.26%	18.37%	16.67%
100	30,000	$2,016	$2,215	$1,504	$2,384	$2,624	$1,782	18.26%	18.50%	18.49%
	50,000	$3,359	$3,559	$1,504	$3,973	$4,214	$1,782	18.26%	18.40%	18.49%
	70,000	$4,703	$4,904	$1,504	$5,562	$5,804	$1,782	18.26%	18.36%	18.49%
300	90,000	$6,046	$6,644	$3,770	$7,151	$7,873	$4,460	18.26%	18.50%	18.31%
	150,000	$10,077	$10,678	$3,770	$11,918	$12,643	$4,460	18.26%	18.40%	18.31%
	210,000	$14,108	$14,711	$3,770	$16,685	$17,412	$4,460	18.26%	18.36%	18.31%

* Net rate including Schedules 91, 98, 290 and 297.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			GRC Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill**	December-March Monthly Bill**	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$194	$214	$185	$228	$252	$206	17.42%	17.70%	11.11%
	5,000	$324	$343	$185	$381	$404	$206	17.42%	17.59%	11.11%
	7,000	$454	$473	$185	$533	$556	$206	17.42%	17.54%	11.11%
Three Phase										
20	6,000	$389	$427	$371	$457	$503	$412	17.42%	17.70%	11.11%
	10,000	$648	$687	$371	$761	$807	$412	17.42%	17.59%	11.11%
	14,000	$907	$946	$371	$1,065	$1,112	$412	17.42%	17.54%	11.11%
100	30,000	$1,944	$2,138	$1,494	$2,283	$2,516	$1,772	17.42%	17.69%	18.62%
	50,000	$3,241	$3,435	$1,494	$3,805	$4,039	$1,772	17.42%	17.58%	18.62%
	70,000	$4,537	$4,732	$1,494	$5,327	$5,562	$1,772	17.42%	17.53%	18.62%
300	90,000	$5,833	$6,415	$3,760	$6,849	$7,549	$4,450	17.42%	17.69%	18.36%
	150,000	$9,722	$10,306	$3,760	$11,415	$12,118	$4,450	17.42%	17.58%	18.36%
	210,000	$13,611	$14,197	$3,760	$15,982	$16,687	$4,450	17.42%	17.53%	18.36%

* Net rate including Schedules 91, 98, 290 and 297.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

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

kW Load Size	kWh	Monthly Billing Present Price**	Monthly Billing GRC Proposed Price	Percent Difference
1,000	300,000	$18,971	$21,350	12.54%
	500,000	$28,268	$31,888	12.81%
	700,000	$37,565	$42,427	12.94%
2,000	600,000	$37,623	$42,339	12.53%
	1,000,000	$55,657	$62,856	12.94%
	1,400,000	$73,826	$83,510	13.12%
4,000	1,200,000	$74,155	$83,545	12.66%
	2,000,000	$110,494	$124,852	12.99%
	2,800,000	$146,832	$166,159	13.16%
6,000	1,800,000	$110,175	$124,578	13.07%
	3,000,000	$164,682	$186,539	13.27%
	4,200,000	$219,190	$248,500	13.37%

Notes:

On-Peak kWh	64.01%
Off-Peak kWh	35.99%

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

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price**	Monthly Billing: GRC Proposed Price	Percent Difference
1,000	300,000	$17,645	$20,197	14.46%
	500,000	$26,566	$30,248	13.86%
	700,000	$35,487	$40,300	13.56%
2,000	600,000	$35,012	$40,033	14.34%
	1,000,000	$52,294	$59,576	13.93%
	1,400,000	$69,711	$79,255	13.69%
4,000	1,200,000	$68,975	$78,933	14.44%
	2,000,000	$103,810	$118,291	13.95%
	2,800,000	$138,644	$157,650	13.71%
6,000	1,800,000	$102,980	$117,948	14.53%
	3,000,000	$155,233	$176,986	14.01%
	4,200,000	$207,485	$236,024	13.75%

Notes:

On-Peak kWh	60.53%
Off-Peak kWh	39.47%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.
**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price**	Monthly Billing: GRC Proposed Price	Percent Difference
1,000	300,000	$16,384	$19,441	18.66%
	500,000	$24,952	$29,092	16.59%
	700,000	$33,519	$38,743	15.59%
2,000	600,000	$32,500	$38,378	18.08%
	1,000,000	$49,075	$57,120	16.39%
	1,400,000	$65,786	$75,998	15.52%
4,000	1,200,000	$63,961	$75,478	18.01%
	2,000,000	$97,383	$113,234	16.28%
	2,800,000	$130,804	$150,990	15.43%
6,000	1,800,000	$95,784	$113,148	18.13%
	3,000,000	$145,917	$169,782	16.36%
	4,200,000	$196,049	$226,416	15.49%

Notes:

On-Peak kWh	56.04%
Off-Peak kWh	43.96%

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

**Includes the effects of the Transition Adjustment Mechanism for January 1, 2010 as filed March 30, 2009.

Docket No. UE-
Exhibit PPL/1003
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Billing Determinants

April 2009

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price	Present Rates Effective 3/31/09 Dollars	Proposed Price	Proposed Dollars
Schedule No. 4						
Residential Service						
Transmission & Ancillary Services Charge						
per kWh	5,435,845,633	kWh	0.394 ¢	$21,417,232	0.385 ¢	$20,928,006
Distribution Charge						
Basic Charge, per month	5,741,820	bill	$7.50	$43,063,650	$8.50	$48,805,470
Three Phase Demand Charge, per kW demand	17,328	kW	$2.20	$38,122	$2.20	$38,122
Three Phase Minimum Demand Charge, per month	1,556	bill	$3.80	$5,913	$3.80	$5,913
Distribution Energy Charge, per kWh	5,435,845,633	kWh	3.115 ¢	$169,326,591	3.271 ¢	$177,806,511
Energy Charge						
Schedule 200						
First Block kWh	2,374,190,522	kWh	3.521 ¢	$83,595,248	2.351 ¢	$55,817,219
Second Block kWh	1,499,989,488	kWh	4.173 ¢	$62,594,561	2.786 ¢	$41,789,707
Third Block kWh	1,561,665,624	kWh	5.149 ¢	$80,410,163	3.438 ¢	$53,690,064
Schedule 201						
First Block kWh	2,374,190,522	kWh			1.754 ¢	$41,643,302
Second Block kWh	1,499,989,488	kWh			2.079 ¢	$31,184,781
Third Block kWh	1,561,665,624	kWh			2.565 ¢	$40,056,723
Subtotal				$460,451,480		$511,765,818
Renewable Adjustment Clause, per kWh	5,435,845,633	kWh	0.223 ¢	$12,121,936	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	5,435,845,633	kWh	(0.018) ¢	($978,452)	0.000 ¢	$0
Total	5,435,845,633	kWh		$471,594,964		$511,765,818
					Change	$40,170,854
Schedule No. 4 - Employee Discount						
Residential Service						
Transmission & Ancillary Services Charge						
per kWh	18,481,059	kWh	0.394 ¢	$72,815	0.385 ¢	$71,152
Distribution Charge						
Basic Charge, per month	14,361	bill	$7.50	$107,708	$8.50	$122,069
Three Phase Demand Charge, per kW demand	82	kW	$2.20	$180	$2.20	$180
Three Phase Minimum Demand Charge, per month	12	bill	$3.80	$46	$3.80	$46
Distribution Energy Charge, per kWh	18,481,059	kWh	3.115 ¢	$575,685	3.271 ¢	$604,515
Energy Charge						
Schedule 200						
First Block kWh	6,715,105	kWh	3.521 ¢	$236,439	2.351 ¢	$157,872
Second Block kWh	5,192,652	kWh	4.173 ¢	$216,689	2.786 ¢	$144,667
Third Block kWh	6,573,302	kWh	5.149 ¢	$338,459	3.438 ¢	$225,990
Schedule 201						
First Block kWh	6,715,105	kWh			1.754 ¢	$117,783
Second Block kWh	5,192,652	kWh			2.079 ¢	$107,955
Third Block kWh	6,573,302	kWh			2.565 ¢	$168,605
Subtotal				$1,548,021		$1,720,834
Renewable Adjustment Clause, per kWh	18,481,059	kWh	0.223 ¢	$41,213	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	18,481,059	kWh	(0.018) ¢	($3,327)	0.000 ¢	$0
Total	18,481,059	kWh		$1,585,907		$1,720,834
Total Employee Discount				($396,477)		($430,209)

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 23/723								
General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,012,788,782	kWh	0.455	¢	$4,608,189	0.374	¢	$3,787,830
Distribution Charge								
Basic Charge								
Single Phase, per month	695,056	bill	$16.15		$11,225,154	$18.65		$12,962,794
Three Phase, per month	193,187	bill	$24.10		$4,655,807	$27.85		$5,380,258
Load Size Charge								
≤ 15 kW		kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	767,514	kW	$1.10		$844,265	$1.25		$959,393
Demand Charge, the first 15 kW of demand		kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	419,716	kW	$3.77		$1,582,329	$4.36		$1,829,962
Reactive Power Charge, per kvar	54,155	kvar	65.00	¢	$35,201	65.00	¢	$35,201
Distribution Energy Charge, per kWh	1,012,788,782	kWh	2.252	¢	$22,808,003	2.591	¢	$26,241,357
Energy Charge								
Schedule 200								
1st 3,000 kWh, per kWh	778,802,018	kWh	4.502	¢	$35,061,667	2.942	¢	$22,912,355
All additional kWh, per kWh	233,986,764	kWh	3.343	¢	$7,822,178	2.185	¢	$5,112,611
Schedule 201								
1st 3,000 kWh, per kWh	778,802,018	kWh				2.195	¢	$17,094,704
All additional kWh, per kWh	233,986,764	kWh				1.630	¢	$3,813,984
Subtotal					$88,642,793			$100,130,449
Renewable Adjustment Clause, per kWh	1,012,788,782	kWh	0.229	¢	$2,319,286	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,012,788,782	kWh	(0.017)	¢	($172,174)	0.000	¢	$0
Total	1,012,788,782	kWh			$90,789,905			$100,130,449
						Change		$9,340,544

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 23/723								
General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,151,715	kWh	0.442	¢	$5,091	0.362	¢	$4,169
Distribution Charge								
Basic Charge								
Single Phase, per month	228	bill	$16.15		$3,682	$18.65		$4,252
Three Phase, per month	190	bill	$24.10		$4,579	$27.85		$5,292
Load Size Charge								
≤ 15 kW		kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	2,989	kW	$1.10		$3,288	$1.25		$3,736
Demand Charge, the first 15 kW of demand		kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	2,440	kW	$3.67		$8,955	$4.24		$10,346
Reactive Power Charge, per kvar	3,872	kvar	60.00	¢	$2,323	60.00	¢	$2,323
Distribution Energy Charge, per kWh	1,151,715	kWh	2.190	¢	$25,223	2.509	¢	$28,897
Energy Charge								
Schedule 200								
1st 3,000 kWh, per kWh	535,677	kWh	4.386	¢	$23,495	2.849	¢	$15,261
All additional kWh, per kWh	616,038	kWh	3.259	¢	$20,077	2.116	¢	$13,035
Schedule 201								
1st 3,000 kWh, per kWh	535,677	kWh				2.126	¢	$11,388
All additional kWh, per kWh	616,038	kWh				1.579	¢	$9,727
Subtotal					$96,713			$108,426
Renewable Adjustment Clause, per kWh	1,151,715	kWh	0.229	¢	$2,637	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,151,715	kWh	(0.017)	¢	($196)	0.000	¢	$0
Total	1,151,715	kWh			$99,154			$108,426
						Change		$9,272

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 28/728								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,689,074	kW	$1.25		$8,361,343	$1.23		$8,227,561
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	55,594	bill	$12.00		$667,128	$15.00		$833,910
Load Size 51-100 kW, per month	41,613	bill	$22.00		$915,486	$28.00		$1,165,164
Load Size 101-300 kW, per month	22,978	bill	$52.00		$1,194,856	$66.00		$1,516,548
Load Size > 300 kW, per month	422	bill	$75.00		$31,650	$96.00		$40,512
Load Size Charge								
≤ 50 kW	2,060,865	kW	$0.75		$1,545,649	$0.95		$1,957,822
51-100 kW, per kW	2,821,071	kW	$0.60		$1,692,643	$0.75		$2,115,803
101-300 kW, per kW	3,340,661	kW	$0.35		$1,169,231	$0.45		$1,503,297
>300 kW, per kW	183,259	kW	$0.25		$45,815	$0.30		$54,978
Demand Charge, per kW	6,689,074	kW	$2.21		$14,782,854	$2.82		$18,863,189
Reactive Power Charge, per kvar	562,858	kvar	65.00	¢	$365,858	65.00	¢	$365,858
Distribution Energy Charge, per kWh	2,026,816,182	kWh	0.259	¢	$5,249,454	0.320	¢	$6,485,812
Energy Charge								
Schedule 200								
1st 20,000 kWh, per kWh	1,433,359,115	kWh	4.182	¢	$59,943,078	2.838	¢	$40,678,732
All additional kWh, per kWh	593,457,067	kWh	4.069	¢	$24,147,768	2.761	¢	$16,385,350
Schedule 201								
1st 20,000 kWh, per kWh	1,433,359,115	kWh				2.118	¢	$30,358,546
All additional kWh, per kWh	593,457,067	kWh				2.061	¢	$12,231,150
Subtotal					$120,112,813			$142,784,232
Renewable Adjustment Clause, per kWh	2,026,816,182	kWh	0.224	¢	$4,540,068	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	2,026,816,182	kWh	(0.014)	¢	($283,754)	0.000	¢	$0
Total	2,026,816,182	kWh			$124,369,127			$142,784,232
						Change		$18,415,105

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 28/728								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	60,958	kW	$1.23		$74,978	$1.18		$71,930
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	59	bill	$16.00		$944	$19.00		$1,121
Load Size 51-100 kW, per month	174	bill	$28.00		$4,872	$33.00		$5,742
Load Size 101-300 kW, per month	356	bill	$66.00		$23,496	$77.00		$27,412
Load Size > 300 kW, per month	14	bill	$94.00		$1,316	$110.00		$1,540
Load Size Charge								
≤ 50 kW	2,153	kW	$0.90		$1,938	$1.05		$2,261
51-100 kW, per kW	12,408	kW	$0.75		$9,306	$0.90		$11,167
101-300 kW, per kW	58,741	kW	$0.40		$23,496	$0.45		$26,433
>300 kW, per kW	6,724	kW	$0.25		$1,681	$0.30		$2,017
Demand Charge, per kW	60,958	kW	$2.87		$174,949	$3.36		$204,819
Reactive Power Charge, per kvar	34,625	kvar	60.00	¢	$20,775	60.00	¢	$20,775
Distribution Energy Charge, per kWh	18,249,203	kWh	0.044	¢	$8,030	0.057	¢	$10,402
Energy Charge								
Schedule 200								
1st 20,000 kWh, per kWh	9,486,985	kWh	4.104	¢	$389,346	2.761	¢	$261,936
All additional kWh, per kWh	8,762,218	kWh	3.994	¢	$349,963	2.687	¢	$235,441
Schedule 201								
1st 20,000 kWh, per kWh	9,486,985	kWh				2.060	¢	$195,432
All additional kWh, per kWh	8,762,218	kWh				2.005	¢	$175,682
Subtotal					$1,085,090			$1,254,110
Renewable Adjustment Clause, per kWh	18,249,203	kWh	0.224	¢	$40,878	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	18,249,203	kWh	(0.014)	¢	($2,555)	0.000	¢	$0
Total	18,249,203	kWh			$1,123,413			$1,254,110
						Change		$130,697

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 30/730								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,534,295	kW	$1.38		$4,877,327	$1.43		$5,054,042
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	155	bill	$319.00		$49,342	$393.00		$60,788
Load Size 201-300 kW, per month	2,716	bill	$99.00		$268,849	$123.00		$334,024
Load Size > 300 kW, per month	6,740	bill	$258.00		$1,738,822	$320.00		$2,156,679
Load Size Charge								
≤ 200 kW	14,627	kW	No Charge			No Charge		
201-300 kW, per kW	714,392	kW	$1.10		$785,831	$1.35		$964,429
>300 kW, per kW	3,411,992	kW	$0.55		$1,876,596	$0.70		$2,388,394
Demand Charge, per kW	3,534,295	kW	$2.49		$8,800,395	$3.09		$10,920,972
Reactive Power Charge, per kvar	713,631	kvar	65.00	¢	$463,860	65.00	¢	$463,860
Energy Charge								
Schedule 200								
1st 20,000 kWh, per kWh	190,869,386	kWh	4.552	¢	$8,688,374	3.083	¢	$5,884,503
All additional kWh, per kWh	1,093,845,348	kWh	3.947	¢	$43,174,076	2.731	¢	$29,872,916
Schedule 201								
1st 20,000 kWh, per kWh	190,869,386	kWh				2.351	¢	$4,487,339
All additional kWh, per kWh	1,093,845,348	kWh				2.039	¢	$22,303,507
Subtotal					$70,723,472			$84,891,453
Renewable Adjustment Clause, per kWh	1,284,714,734	kWh	0.218	¢	$2,800,678	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,284,714,734	kWh	(0.012)	¢	($154,166)	0.000	¢	$0
Total	1,284,714,734	kWh			$73,369,984			$84,891,453
						Change		$11,521,469
Schedule No. 30/730								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	279,833	kW	$1.32		$369,380	$1.27		$355,388
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	bill	$310.00		$0	$356.00		$0.00
Load Size 201-300 kW, per month	106	bill	$100.00		$10,597	$116.00		$12,293.00
Load Size > 300 kW, per month	520	bill	$260.00		$135,223	$301.00		$156,546.00
Load Size Charge								
≤ 200 kW	0	kW	No Charge			No Charge		
201-300 kW, per kW	27,640	kW	$1.05		$29,022	$1.20		$33,168
>300 kW, per kW	314,299	kW	$0.55		$172,864	$0.65		$204,294
Demand Charge, per kW	279,833	kW	$2.46		$688,389	$2.85		$797,524
Reactive Power Charge, per kvar	35,084	kvar	60.00	¢	$21,050	60.00	¢	$21,050
Energy Charge								
Schedule 200								
1st 20,000 kWh, per kWh	12,465,248	kWh	4.461	¢	$556,075	2.969	¢	$370,093
All additional kWh, per kWh	81,466,178	kWh	3.857	¢	$3,142,150	2.650	¢	$2,158,854
Schedule 201								
1st 20,000 kWh, per kWh	12,465,248	kWh				2.287	¢	$285,080
All additional kWh, per kWh	81,466,178	kWh				1.977	¢	$1,610,586
Subtotal					$5,124,750			$6,004,876
Renewable Adjustment Clause, per kWh	93,931,426	kWh	0.218	¢	$204,771	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	93,931,426	kWh	(0.012)	¢	($11,272)	0.000	¢	$0
Total	93,931,426	kWh			$5,318,249			$6,004,876
						Change		$686,627

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Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 33								
Klamath Irrigation and Drainage Pumping								
Total Customers	2,062							
Charges								
Off-Project (Rate Code 35)	52,080,607	kWh	3.016	¢	$1,570,751	3.123	¢	$1,626,477
On-Project (Rate Code 40)	62,373,687	kWh	2.757	¢	$1,719,643	2.855	¢	$1,780,769
U.S. Government (Rate Code 33TX)	3,592,093	kWh						
U.S. Gov - On Peak	1,437,815	kWh	2.560	¢	$36,808	2.652	¢	$38,131
U.S. Gov - Off Peak	2,154,278	kWh	2.037	¢	$43,883	2.037	¢	$43,883
Minimum Charges Off-Project					$6,529			$6,529
Minimum Charges On-Project					$197,821			$197,821
Subtotal	118,046,387	kWh			$3,575,435			$3,693,610
Renewable Adjustment Clause, per kWh	118,046,387	kWh	0.223	¢	$263,243	0.000	¢	$0
Total	118,046,387	kWh			$3,838,678			$3,693,610
Note: Rates reflect estimated rate changes through 2010.						Change		($145,068)

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Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 41/741								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	134,221,373	kWh	0.427	¢	$573,125	0.439	¢	$589,232
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, or Single Phase Any Size	5,637	bill	No Charge			No Charge		
Three Phase Load Size 51 - 300 kW, per month	453	bill	$360.00		$163,080	$430.00		$194,790
Three Phase Load Size > 300 kW, per month	13	bill	$1,420.00		$18,460	$1,700.00		$22,100
Total Customers	6,103	bill						
Load Size Charge								
Single Phase Any Size, Three Phase ≤ 50 kW	74,733	kW	$18.00		$1,345,194	$21.00		$1,569,393
Three Phase 51-300 kW, per kW	39,848	kW	$11.00		$438,328	$13.00		$518,024
Three Phase > 300 kW, kW	6,641	kW	$7.00		$46,487	$8.00		$53,128
Single Phase, Minimum Charge	838	bill	$60.00		$50,280	$70.00		$58,660
Three Phase, Minimum Charge	1,139	bill	$105.00		$119,595	$125.00		$142,375
Distribution Energy Charge, per kWh	134,221,373	kWh	4.088	¢	$5,486,970	4.899	¢	$6,575,505
Reactive Power Charge, per kvar	27,433	kvar	65.00	¢	$17,831	65.00	¢	$17,831
Energy Charge								
Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	1,363,670	kWh	6.035	¢	$82,297	4.182	¢	$57,029
Winter, All additional kWh, per kWh	1,466,167	kWh	4.112	¢	$60,289	2.849	¢	$41,771
Summer, All kWh, per kWh	131,391,536	kWh	4.112	¢	$5,402,820	2.849	¢	$3,743,345
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	1,363,670	kWh				3.121	¢	$42,560
Winter, All additional kWh, per kWh	1,466,167	kWh				2.127	¢	$31,185
Summer, All kWh, per kWh	131,391,536	kWh				2.127	¢	$2,794,698
Subtotal					$13,804,756			$16,451,626
Renewable Adjustment Clause, per kWh	134,221,373	kWh	0.223	¢	$299,314	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	134,221,373	kWh	(0.017)	¢	($22,818)	0.000	¢	$0
Total	134,221,373	kWh			$14,081,252			$16,451,626
						Change		$2,370,374
Schedule No. 41/741								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	2,570,507	kWh	0.415	¢	$10,668	0.425	¢	$10,925
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, or Single Phase Any Size	3	bill	No Charge			No Charge		
Three Phase Load Size 51 - 300 kW, per month	0	bill	$350.00		$0	$420.00		$0
Three Phase Load Size > 300 kW, per month	2	bill	$1,380.00		$2,760	$1,650.00		$3,300
Total Customers	5	bill						
Load Size Charge								
Single Phase Any Size, Three Phase ≤ 50 kW	46	kW	$18.00		$828	$20.00		$920
Three Phase 51-300 kW, per kW	0	kW	$11.00		$0	$13.00		$0
Three Phase > 300 kW, kW	2,169	kW	$7.00		$15,183	$8.00		$17,352
Single Phase, Minimum Charge	0	bill	$60.00		$0	$70.00		$0
Three Phase, Minimum Charge	1	bill	$100.00		$100	$120.00		$120
Distribution Energy Charge, per kWh	2,570,507	kWh	3.975	¢	$102,178	4.745	¢	$121,971
Reactive Power Charge, per kvar	3,066	kvar	60.00	¢	$1,840	60.00	¢	$1,840
Energy Charge								
Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	10,613	kWh	5.877	¢	$624	4.050	¢	$430
Winter, All additional kWh, per kWh	61,869	kWh	4.007	¢	$2,479	2.759	¢	$1,707
Summer, All kWh, per kWh	2,498,025	kWh	4.007	¢	$100,096	2.759	¢	$68,921
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	10,613	kWh				3.023	¢	$321
Winter, All additional kWh, per kWh	61,869	kWh				2.060	¢	$1,275
Summer, All kWh, per kWh	2,498,025	kWh				2.060	¢	$51,459
Subtotal					$236,756			$280,541
Renewable Adjustment Clause, per kWh	2,570,507	kWh	0.223	¢	$5,732	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	2,570,507	kWh	(0.017)	¢	($437)	0.000	¢	$0
Total	2,570,507	kWh			$242,051			$280,541
						Change		$38,490

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Schedule No. 47/747						
Large General Service - Partial Requirement (Primary)						
Transmission & Ancillary Services Charge						
per kW of on-peak demand	629,550	kW	$1.05	$661,028	$1.06	$667,323
credit per kW of on-peak demand	0	kW	($1.05)	$0	($1.06)	$0
Distribution Charge						
Basic Charge						
Load Size ≤ 4,000 kW, per month	0	bill	$270.00	$0	$350.00	$0
Load Size > 4,000 kW, per month	36	bill	$480.00	$17,280	$630.00	$22,680
Load Size/Facility Charge						
Load Size ≤ 4,000 kW, per kW	0	kW	$0.85	$0	$0.70	$0
Load Size > 4,000 kW, per kW	655,984	kW	$0.80	$524,787	$0.65	$426,390
Demand Charge, per kW of on-peak demand	629,550	kW	$1.43	$900,257	$2.32	$1,460,556
Reactive Power Charge, per kvar	22,941	kvar	60.00 ¢	$13,765	60.00 ¢	$13,765
Reactive Hours, per kvarh	4,083,071	kvarh	0.080 ¢	$3,266	0.080 ¢	$3,266
Reserves Charges						
Spinning Reserves, per kW of Facility	655,984	kW	$0.27	$177,116	$0.27	$177,116
Supplemental Reserves, per kW of Facility	655,984	kW	$0.27	$177,116	$0.27	$177,116
Spinning Reserves Credit, per kW of Facility	520,704	kW	($0.27)	($140,590)	($0.27)	($140,590)
Supplemental Reserves Credit, per kW of Facility	520,704	kW	($0.27)	($140,590)	($0.27)	($140,590)
Energy Charge						
Schedule 200						
On-Peak, per on-peak kWh	232,517,250	kWh	3.797 ¢	$8,828,680	2.678 ¢	$6,226,812
Off-Peak, per off-peak kWh	179,422,218	kWh	3.697 ¢	$6,633,239	2.628 ¢	$4,715,216
Schedule 201						
On-Peak, per on-peak kWh	232,517,250	kWh			2.004 ¢	$4,659,646
Off-Peak, per off-peak kWh	179,422,218	kWh			1.954 ¢	$3,505,910
Unscheduled Energy, per kWh	832,620	kWh	*5.970 ¢*	$49,709	*5.970 ¢*	$49,709
Subtotal				$17,705,063		$21,824,325
Renewable Adjustment Clause, per kWh	412,772,088	kWh	0.203 ¢	$837,927	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	412,772,088	kWh	(0.011) ¢	($45,405)	0.000 ¢	$0
Total	412,772,088	kWh		$18,497,585		$21,824,325
					Change	$3,326,740
Schedule No. 47/747						
Large General Service - Partial Requirement (Transmission)						
Transmission & Ancillary Services Charge						
per kW of on-peak demand	291,068	kW	$1.40	$407,495	$1.44	$419,138
credit per kW of on-peak demand	0	kW	($1.40)	$0	($1.44)	$0
Distribution Charge						
Basic Charge						
Load Size ≤ 4,000 kW, per month	24	bill	$260.00	$6,240	$490.00	$11,760
Load Size > 4,000 kW, per month	24	bill	$480.00	$11,520	$910.00	$21,840
Load Size/Facility Charge						
Load Size ≤ 4,000 kW, per kW	35,910	kW	$0.45	$16,160	$0.65	$23,342
Load Size > 4,000 kW, per kW	330,471	kW	$0.45	$148,712	$0.65	$214,806
Demand Charge, per kW of on-peak demand	291,068	kW	$0.78	$227,033	$1.70	$494,816
Reactive Power Charge, per kvar	43,402	kvar	55.00 ¢	$23,871	55.00 ¢	$23,871
Reactive Hours, per kvarh	977,033	kvarh	0.08 ¢	$782	0.08 ¢	$782
Reserves Charges						
Spinning Reserves, per kW of Facility	366,381	kW	$0.27	$98,923	$0.27	$98,923
Supplemental Reserves, per kW of Facility	366,381	kW	$0.27	$98,923	$0.27	$98,923
Spinning Reserves Credit, per kW of Facility	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW of Facility	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge						
Schedule 200						
On-Peak, per on-peak kWh	88,587,292	kWh	3.630 ¢	$3,215,719	2.569 ¢	$2,275,808
Off-Peak, per off-peak kWh	64,575,860	kWh	3.530 ¢	$2,279,528	2.519 ¢	$1,626,666
Schedule 201						
On-Peak, per on-peak kWh	88,587,292	kWh			1.923 ¢	$1,703,534
Off-Peak, per off-peak kWh	64,575,860	kWh			1.873 ¢	$1,209,506
Unscheduled Energy, per kWh	6,030,044	kWh	*6.347 ¢*	$382,701	*6.347 ¢*	$382,701
Subtotal				$6,917,607		$8,606,416
Renewable Adjustment Clause, per kWh	159,193,196	kWh	0.203 ¢	$323,162	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	159,193,196	kWh	(0.011) ¢	($17,511)	0.000 ¢	$0
Total	159,193,196	kWh		$7,223,258		$8,606,416
					Change	$1,383,158

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Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	kW	$0.038		$0	$0.038		$0
Primary	0	kW	$0.041		$0	$0.041		$0
Transmission	0	kW	$0.055		$0	$0.056		$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	kW	$0.051		$0	$0.085		$0
Primary	0	kW	$0.056		$0	$0.090		$0
Transmission	0	kW	$0.030		$0	$0.066		$0
Schedule No. 48/748								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,680,446	kW	$1.51		$2,537,473	$1.51		$2,537,473
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	1,466	bill	$310.00		$454,460	$350.00		$513,100
Load Size > 4,000 kW, per month	12	bill	$580.00		$6,960	$650.00		$7,800
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	1,931,585	kW	$1.75		$3,380,274	$1.35		$2,607,640
Load Size > 4,000 kW, per kW	130,868	kW	$1.60		$209,389	$1.25		$163,585
Demand Charge, per kW of on-peak demand	1,680,446	kW	$1.31		$2,201,384	$2.17		$3,646,568
Reactive Power Charge, per kvar	486,931	kvar	65.00	¢	$316,505	65.00	¢	$316,505
Energy Charge								
Schedule 200								
On-Peak, per on-peak kWh	415,357,613	kWh	3.976	¢	$16,514,619	2.813	¢	$11,684,010
Off-Peak, per off-peak kWh	233,733,537	kWh	3.876	¢	$9,059,512	2.763	¢	$6,458,058
Schedule 201								
On-Peak, per on-peak kWh	415,357,613	kWh				2.102	¢	$8,730,817
Off-Peak, per off-peak kWh	233,733,537	kWh				2.052	¢	$4,796,212
Subtotal					$34,680,576			$41,461,768
Renewable Adjustment Clause, per kWh	649,091,150	kWh	0.203	¢	$1,317,655	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	649,091,150	kWh	-0.011	¢	($71,400)	0.000	¢	$0
Total	649,091,150	kWh			$35,926,831			$41,461,768
						Change		$5,534,937
Schedule No. 48/748								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,454,326	kW	$1.59		$5,492,378	$1.60		$5,526,922
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	673	bill	$270.00		$181,710	$350.00		$235,550
Load Size > 4,000 kW, per month	400	bill	$480.00		$192,000	$630.00		$252,000
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	1,185,743	kW	$0.85		$1,007,882	$0.70		$830,020
Load Size > 4,000 kW, per kW	2,859,392	kW	$0.80		$2,287,514	$0.65		$1,858,605
Demand Charge, per kW of on-peak demand	3,454,326	kW	$1.43		$4,939,686	$2.32		$8,014,036
Reactive Power Charge, per kvar	800,170	kvar	60.00	¢	$480,102	60.00	¢	$480,102
Energy Charge								
Schedule 200								
On-Peak, per on-peak kWh	962,377,337	kWh	3.797	¢	$36,541,467	2.678	¢	$25,772,465
Off-Peak, per off-peak kWh	627,543,923	kWh	3.697	¢	$23,200,299	2.628	¢	$16,491,854
Schedule 201								
On-Peak, per on-peak kWh	962,377,337	kWh				2.004	¢	$19,286,042
Off-Peak, per off-peak kWh	627,543,923	kWh				1.954	¢	$12,262,208
Subtotal					$74,323,038			$91,009,804
Renewable Adjustment Clause, per kWh	1,589,921,260	kWh	0.203	¢	$3,227,540	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,589,921,260	kWh	-0.011	¢	($174,891)	0.000	¢	$0
Total	1,589,921,260	kWh			$77,375,687			$91,009,804
						Change		$13,634,117

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Schedule No. 48/748								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	619,494	kW	$1.94		$1,201,818	$1.98		$1,226,598
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	0	bill	$260.00		$0	$490.00		$0
Load Size > 4,000 kW, per month	23	bill	$480.00		$11,040	$910.00		$20,930
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	0	kW	$0.45		$0	$0.65		$0
Load Size > 4,000 kW, per kW	753,152	kW	$0.45		$338,918	$0.65		$489,549
Demand Charge, per kW of on-peak demand	619,494	kW	$0.78		$483,205	$1.70		$1,053,140
Reactive Power Charge, per kvar	127,183	kvar	55.00	¢	$69,951	55.00	¢	$69,951
Energy Charge								
Schedule 200								
On-Peak, per on-peak kWh	226,903,748	kWh	3.630	¢	$8,236,606	2.569	¢	$5,829,157
Off-Peak, per off-peak kWh	177,985,113	kWh	3.530	¢	$6,282,874	2.519	¢	$4,483,445
Schedule 201								
On-Peak, per on-peak kWh	226,903,748	kWh				1.923	¢	$4,363,359
Off-Peak, per off-peak kWh	177,985,113	kWh				1.873	¢	$3,333,661
Subtotal					$16,624,412			$20,869,790
Renewable Adjustment Clause, per kWh	404,888,861	kWh	0.203	¢	$821,924	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	404,888,861	kWh	-0.011	¢	($44,538)	0.000	¢	$0
Total	404,888,861	kWh			$17,401,798			$20,869,790
						Change		$3,467,992
Schedule No. 15								
Outdoor Area Lighting Service								
No. of Customers	7,404							
Transmission & Ancillary Services Charge								
per kWh	10,467,219	kWh	0.015	¢	$1,570	0.017	¢	$1,779
Distribution Charge								
Distribution Charge, per kWh	10,467,219	kWh	10.129	¢	$1,062,234	11.451	¢	$1,198,590
Energy Charge								
Sch 200, per kWh	10,467,219	kWh	2.276	¢	$238,234	0.959	¢	$100,381
Sch 201 TAM, per kWh	10,467,219	kWh				1.586	¢	$166,010
Subtotal					$1,302,038			$1,466,760
Renewable Adjustment Clause, per kWh	10,467,219	kWh	0.123	¢	$12,875	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	10,467,219	kWh	-0.028	¢	($2,931)	0.000	¢	$0
Total	10,467,219	kWh			$1,311,982			$1,466,760
						Change		$154,778
Schedule No. 50								
Mercury Vapor Street Lighting Service								
No. of Customers	287							
Transmission & Ancillary Services Charge								
per kWh	10,738,031	kWh	0.013	¢	$1,396	0.020	¢	$2,148
Distribution Charge								
Distribution Charge, per kWh	10,738,031	kWh	8.919	¢	$957,702	15.237	¢	$1,494,518
Energy Charge								
Sch 200, per kWh	10,738,031	kWh	1.893	¢	$203,271	1.610	¢	$172,882
Sch 201 TAM, per kWh	10,738,031	kWh				1.319	¢	$141,635
Subtotal					$1,162,369			$1,811,183
Renewable Adjustment Clause, per kWh	10,738,031	kWh	0.102	¢	$10,953	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	10,738,031	kWh	-0.025	¢	($2,685)	0.000	¢	$0
Total	10,738,031	kWh			$1,170,637			$1,811,183
						Change		$640,546

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 51/751								
High Pressure Sodium Vapor Street Lighting Service								
No. of Customers	686							
Transmission & Ancillary Services Charge								
per kWh	16,084,697	kWh	0.019	¢	$3,056	0.029	¢	$4,665
Distribution Charge								
Distribution Charge, per kWh	16,084,697	kWh	14.457	¢	$2,325,307	24.641	¢	$3,628,550
Energy Charge								
Sch 200, per kWh	16,084,697	kWh	2.988	¢	$480,611	2.541	¢	$408,712
Sch 201 TAM, per kWh	16,084,697	kWh				2.082	¢	$334,883
Subtotal					$2,808,974			$4,376,811
Renewable Adjustment Clause, per kWh	16,084,697	kWh	0.161	¢	$25,896	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	16,084,697	kWh	-0.038	¢	($6,112)	0.000	¢	$0
Total	16,084,697	kWh			$2,828,758			$4,376,811
						Change		$1,548,052
Schedule No. 52/752								
Company-Owned Street Lighting Service								
No. of Customers	79							
Transmission & Ancillary Services Charge								
per kWh	1,185,726	kWh	0.015	¢	$178	0.023	¢	$273
Distribution Charge								
Distribution Charge, per kWh	1,185,726	kWh	8.913	¢	$105,671	15.533	¢	$165,265
Energy Charge								
Sch 200, per kWh	1,185,726	kWh	2.289	¢	$27,141	1.946	¢	$23,074
Sch 201 TAM, per kWh	1,185,726	kWh				1.595	¢	$18,912
Subtotal					$132,990			$207,525
Renewable Adjustment Clause, per kWh	1,185,726	kWh	0.124	¢	$1,470	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,185,726	kWh	-0.027	¢	($320)	0.000	¢	$0
Total	1,185,726	kWh			$134,140			$207,525
						Change		$73,385
Schedule No. 53/753								
Customer-Owned Street Lighting Service								
No. of Customers	250							
Transmission & Ancillary Services Charge								
per kWh	9,316,113	kWh	0.005	¢	$466	0.008	¢	$745
Distribution Charge								
Distribution Charge, per kWh	9,316,113	kWh	5.355	¢	$495,092	8.962	¢	$771,408
Energy Charge								
Sch 200, per kWh	9,316,113	kWh	0.978	¢	$91,112	0.831	¢	$77,417
Sch 201 TAM, per kWh	9,316,113	kWh				0.682	¢	$63,536
Subtotal					$586,670			$913,106
Renewable Adjustment Clause, per kWh	9,316,113	kWh	0.053	¢	$4,938	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	9,316,113	kWh	-0.015	¢	($1,397)	0.000	¢	$0
Total	9,316,113	kWh			$590,211			$913,106
						Change		$322,896
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	815,719	kWh	0.011	¢	$90	0.017	¢	$139
Distribution Charge								
Basic Charge, Single Phase, per month	865	bill	$6.00		$5,190	$6.00		$5,190
Basic Charge, Three Phase, per month	397	bill	$9.00		$3,573	$9.00		$3,573
Distribution Energy Charge, per kWh	815,719	kWh	5.716	¢	$46,626	9.544	¢	$77,852
Energy Charge								
Sch 200, per kWh	815,719	kWh	1.683	¢	$13,729	1.431	¢	$11,673
Sch 201 TAM, per kWh	815,719	kWh				1.173	¢	$9,568
Subtotal					$69,208			$107,995
Renewable Adjustment Clause, per kWh	815,719	kWh	0.091	¢	$742	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	815,719	kWh	-0.018	¢	($147)	0.000	¢	$0
Total	815,719	kWh			$69,803			$107,995
						Change		$38,192
TOTAL OREGON	13,392,810,002				$947,357,466			$1,060,020,623
Employee Discount					($396,477)			($430,209)
TOTAL OREGON					$946,960,989			$1,059,590,414