PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 1, 2008

VIA ELECTRONIC FILING
& OVERNIGHT DELIVERY

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

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: Advice Filing 08-007
PacifiCorp's 2009 Renewable Adjustment Clause
Schedule 202 – Renewable Adjustment Clause

PacifiCorp (dba Pacific Power) submits for filing an original and five copies of Renewable Adjustment Clause - Schedule 202. The Company is requesting an effective date of January 1, 2009 for these tariff sheets. PacifiCorp makes this filing concurrently with the filing of its Transition Adjustment Mechanism (TAM), Schedule 200, Cost-Based Supply Service.

PacifiCorp waives paper service in this docket and requests that communications on this filing be addressed to the parties identified in subsection (E) herein.

A. Description of Filing

In Order No. 07-572, the Commission approved a Renewable Adjustment Clause (RAC) for PacifiCorp, pursuant to Senate Bill 838 (SB 838), enacted on June 6, 2007. The Commission directed PacifiCorp to file Schedule 202, to be effective January 1, 2008. In Advice 07-027, PacifiCorp filed Schedule 202 in compliance with Order No. 07-572.

Schedule 202 provides that the Company file Schedule 202 by April 1 of each year, beginning in 2008, as necessary, for proposed charges relating to new eligible renewable resources and associated transmission and for updating charges already included in the schedule. This filing complies with the process contemplated by Order 07-572 and Schedule 202.

This tariff filing is supported by testimony and exhibits from Company witnesses addressing policy issues raised by the RAC, a description of the Company's new renewable resources and their cost-effectiveness, the total revenue requirement impact of the resources and pricing.

B. Inapplicability of OAR 860-038-0001(4)

OAR 860-038-0001(4) requires new resources to be reflected in rates at market, not cost, and precludes their inclusion in rate base. To date, the Commission has waived application of this rule with respect to new resources. Section 13 of SB 838 specifically allows recovery of all costs associated with eligible resources. Accordingly, SB 838 appears to have superseded OAR 860-

038-0001(4) with respect to renewable resources. As such, PacifiCorp has not sought a waiver of the rule in this case, notwithstanding the fact that the RAC proposes recovery of rate base investment at cost.

C. Proposed Procedural Schedule

In the Stipulation approved in Order No, 07-572, the Commission approved the parties' agreement that the RAC would follow a schedule designed to produce a Commission order by November 1. This is the same general schedule used for the Company's TAM. The Company is filing its 2009 TAM concurrently with this RAC filing. For efficiency, PacifiCorp suggests adoption of the same procedural schedule in both dockets. PacifiCorp proposes adoption of a schedule in both cases similar to that followed in previous TAM dockets. A proposed procedural schedule is described as follows:

RAC Filed	April 1
Prehearing Conference	April 25
Staff and Intervenor Testimony Due	June 25
Settlement Conference	July 9
Rebuttal Testimony Due	July 30
Hearing	August 13
Target Commission Decision	October 16
RAC Update Filing (if needed)	December 1
Effective Date for New Rates	January 1, 2009

To allow for the parties to conduct their review of the filing within this schedule, the Company requests the scheduling of a prehearing conference in this docket as soon as practicable and suggests April 25. Also, the Company will be filing a motion for protective order shortly to expedite discovery in this docket.

D. Tariff Sheets

First Revision of Sheet No. 202-1	Schedule 202	Renewable Adjustment Clause
First Revision of Sheet No. 202-2	Schedule 202	Renewable Adjustment Clause

E. Correspondence

It is respectfully requested that all communications on this filing be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Ste. 2000
Portland, OR 97232
oregondockets@pacificorp.com

Katherine A. McDowell
McDowell & Rackner PC
520 SW 6th Ave, Ste 830
Portland, OR 97204
Katherine@mcd-law.com

Ryan Flynn
Legal Counsel
825 NE Multnomah Street, Ste 1800
Portland, OR 97232
Ryan.flynn@pacificorp.com

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

By e-mail (preferred):	datarequest@pacificorp.com
By fax:	(503) 813-6060
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

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 in Docket UM 1330, as indicated on the attached certificate of service.

Very truly yours,

Andrea L Kelly / JS

Andrea L. Kelly
Vice President, Regulation
Enclosures

cc: UM 1330 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 1st day of April, 2008, I caused to be served, via E-Mail and Overnight Delivery (to those parties who have not waived paper service), a true and correct copy of PacifiCorp's Advice 08-007 - 2009 Renewable Adjustment Clause to the following:

SERVICE LIST
UM-1330

Lowrey R. Brown (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
lowrey@oregonbuc.org

Robert Jenks (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
bob@oregoncub.org

Jason Eisdorfer (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
jason@oregoncub.org

Melinda J. Davison (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
mail@dvclaw.com

Lisa F. Rackner
McDowell & Rackner PC
520 SW Sixth Ave, Suite 830
Portland, OR 97204
Lisa@mcd-law.com

Michael T. Weirich (C)
Assistant Attorney General
Regulated Utility & Business Section
1162 Court St, NE
Salem, OR 97301-4096
michael.t.weirich@doj.state.or.us

John W. Stephens (W)
Esler Stephens & Buckley
888 SW Fifth Ave, Suite 700
Portland, OR 97204-2021
stephens@eslerstephens.com

Cece L. Coleman (C)
Portland General Electric
121 SW Salmon St.
Portland, OR 97204
Cece.coleman@pgn.com

Patrick Hager (C)
Portland General Electric
121 SW Salmon St. 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

Natalie Hocken (W)
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
Natalie.hocken@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Judy Johnson
Oregon Public Utility Commission
P.O.Box 2148
Salem, OR 97308-2148
Judy.johnson@state.or.us

Ann English Gravatt (W)
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
Ann@rnp.org

Jesse Jenkins
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
jesse@rnp.org

Randall J. Falkenberg (C)
PMB 362
8343 Roswell Road
Sandy Springs, GA 30350
consultrfi@aol.com

Ariel Son

Ariel Son
Coordinator, Administrative Services

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

2009 RENEWABLE ADJUSTMENT CLAUSE (RAC)

Direct Testimony and Exhibits

April 2008

Case UE-
Exhibit PPL/100
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Andrea L. Kelly

POLICY

April 2008

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power & Light Company (the Company).

A. My name is Andrea L. Kelly. My business address is 825 NE Multnomah St., Suite 2000, Portland, OR 97232. I am employed by PacifiCorp as Vice President of Regulation.

Qualifications

Q. Briefly describe your education and business experience.

A. I hold a Bachelor's degree in Economics from the University of Vermont and an MBA in Environmental and Natural Resource Management from the University of Washington. After graduate school, I joined the Staff of the Washington Utilities and Transportation Commission. In 1995, I became employed by PacifiCorp as a Senior Pricing Analyst in the Regulation Department and advanced through positions of increasing responsibility. From 1999 to 2005, I led major strategic projects at PacifiCorp including the Multi-State Process (MSP) and the regulatory approvals for the MidAmerican-PacifiCorp transaction. In March 2006, I was appointed Vice President of Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have appeared as a witness on behalf of PacifiCorp in the states of Oregon, Idaho, Utah, Washington and Wyoming. In addition, I sponsored testimony in various proceedings as a member of the Washington Commission Staff.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Summarize the Company's 2009 Renewable Adjustment Clause (RAC) filing,
- Provide an overview of Senate Bill 838, the Oregon Renewable Energy Act (SB 838) and the provisions that relate to the RAC filing,
- Describe how the Company's RAC filing complies with the all-party Stipulation and Commission Order from Docket UM 1330, adopting the design of the RAC and approving implementing tariffs,
- Provide a brief overview of the 713 MWs of new cost-effective renewable generating resources that have been acquired by the Company since its last general rate case or are expected to be acquired by December 31, 2008, and are included for cost recovery in the RAC,
- Discuss the significant net power cost benefits provided by these renewable resources as reflected in the Company's 2009 Transition Adjustment Mechanism (TAM) filing[1],
- Explain the benefits that customers will realize in future years as the fixed costs of new renewable resources decline as a result of capturing the increased accumulated depreciation of the resources, and
- Introduce the Company's other witnesses in this proceeding.

Summary of PacifiCorp's 2009 RAC Filing

Q. Please summarize the Company's RAC filing.

A. The Company is submitting the RAC filing in compliance with the Stipulation and the Commission's order in Docket UM 1330. The RAC is an automatic

[1] The Company's TAM filing is being filed with the Commission concurrently with the RAC filing under separate cover.

adjustment clause that allows PacifiCorp to recover the revenue requirement between rate cases for new renewable resources and associated transmission that are eligible under SB 838. As discussed below, pursuant to the Commission's order, the Company's RAC filing is due each April 1.

Q. What is included in the filing?

A. This filing includes proposed charges for tariff Schedule 202, Renewable Adjustment Clause, the form and terms of which the parties to the Stipulation agreed to support and the Commission previously approved. The proposed charges reflect prices designed to recover the revenue requirement for calendar year 2009 of new renewable resources eligible under SB 838, which are not otherwise reflected in base rates. The filing also includes testimony and exhibits from several witnesses in support of the proposed revenue requirement increase.

Q. What is the estimated revenue requirement to be collected from Oregon customers through Schedule 202 for calendar year 2009?

A. The Company's revenue requirement to be recovered from Oregon customers through Schedule 202 in calendar year 2009 is $39.0 million. As explained in Ms. Ridenour's testimony, this would result in an overall increase to net rates of approximately 4.2 percent.

Overview of SB 838

Q. What is SB 838?

A. SB 838 is the Oregon Renewable Energy Act, which was enacted on June 6, 2007. This law establishes a Renewable Portfolio Standard (RPS) for electricity, which requires large, Oregon electric utilities to meet 25 percent of their Oregon load by 2025 with electricity generated by eligible renewable resources. This target is phased-in starting with 5 percent of load served by renewables in 2011, 15 percent in 2015, and 20 percent in 2020.

Section 13 of SB 838 provides that "all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company." Further, Section 13 required the Commission to establish an automatic adjustment clause, or another method, that allows timely recovery of prudently-incurred costs, by January 1, 2008. The Commission adopted the RAC for PacifiCorp and Portland General Electric (PGE) in the UM 1330 proceeding to implement this provision of the Act.

Q. Before you discuss the UM 1330 proceeding, are there any other provisions of SB 838 that may become relevant to the resources contained in this filing?

A. Yes. Section 12 of SB 838 relates to cost protections for customers and will eventually be applied to the resources that the Company is proposing to include in the RAC. Section 12(1) provides:

> Electric utilities are not required to comply with a renewable resource standard during a *compliance* year to the extent that the *incremental* cost of compliance, the costs of unbundled renewable energy certificates and the cost of alternative compliance payments....exceeds four percent of the utility's annual revenue requirement for the compliance year. (Emphasis added.)

The first compliance year for SB 838 is 2011. Section 12(4) defines the incremental cost of compliance as the difference between the levelized annual delivered cost of qualifying electricity and the levelized annual delivered cost of an equivalent amount of reasonably available non-qualifying electricity. The Commission is currently in the process of creating the rules to implement this and other provisions of SB 838. As discussed in Mr. Tallman's testimony, the renewable resources that are included in the RAC filing are cost-effective and prudently acquired when compared against reasonably-available non-qualifying electricity. The final determination in this regard related to these specific resources will need to be made after the Commission has adopted its final implementation rules.

Compliance with Docket UM 1330

Q. Please explain how the RAC was developed in the UM 1330 proceeding?

A. In UM 1330, both PGE and PacifiCorp filed proposed mechanisms to implement Section 13 of SB 838. Through the course of numerous settlement discussions, the parties of Commission Staff, the Citizens' Utility Board (CUB), the Industrial Customers of Northwest Utilities (ICNU), PGE and PacifiCorp, developed a comprehensive Stipulation to implement Section 13 and the RAC. The Stipulation, approved by the Commission in Order No. 07-572, detailed the scope, applicability, and procedural elements for the future RAC filings, among other things. The Commission also approved present Schedule 202.

Q. Briefly describe how the RAC works.

A. Unless superseded by filing a general rate case, the Company is required to file on April 1 each year new charges for Schedule 202 that (1) recover the revenue requirement of new renewable resources eligible under SB 838 (including associated transmission) and (2) update the revenue requirement for renewable resources already included in the RAC. Consistent with the TAM, which sets net power costs, the new resources must be expected to be in service as of the date of the proposed rate change, which is January 1 of the subsequent year. The parties to the Stipulation agreed that if a resource is not included in the RAC, then it should likewise not be included in the TAM.

The revenue requirement is based on a forecast for the following year and uses allocation factors consistent with the TAM. Once a resource is incorporated into the RAC, the Company will annually file to update all costs and inter-jurisdictional allocation factors for the following year's test period. At the time of a general rate case, the resources being recovered through the RAC will be rolled into general rates.

If the final costs of a resource cannot be verified by the final round of testimony in the proceeding because it is not yet in service (but expected to be by December 31), then the company will make an updated filing by December 1 to reflect the actual resource costs, or forecasted costs where appropriate. If actual costs cannot be verified until after December 1, the company may use deferred accounting for the differences between projected and actual costs.

Overview of the Company's New Renewable Generation Resources

Q. What new renewable generation resources are included in this RAC filing?

A. The RAC includes 713 MW of new renewable generation resources, which have come into service since September 2006 or are expected to be in service prior to January 1, 2009: the wind facilities of Leaning Juniper (September 2006), Marengo I (August 2007) and Marengo II (August 2008), Goodnoe Hills (June 2008), Glenrock (December 2008), Rolling Hills (December 2008), Seven Mile Hill (December 2008), and the Blundell Bottoming Cycle geothermal resource

(December 2007). Leaning Juniper, Marengo I and Blundell are already in service and customers are currently receiving the benefit of the near zero-cost energy for these facilities through the 2008 TAM. Additional information for each of these resources in provided in the Direct Testimony of Mark R. Tallman.

Q. Are these resources eligible under SB 838?

A. Yes. The wind resources are eligible pursuant to Section 4(1)(a). The Blundell geothermal resource is eligible pursuant to Section 4(1)(d). All of the resources became or will become operational on or after January 1, 1995, as required by Section 3(1). As such, their Oregon-allocated output will be used to comply with the requirements of SB 838.

Q. Will the RAC filing augment the TAM to allow recovery of the revenue requirement of these resources not included in net power costs?

A. Yes. The Company's TAM does not provide for recovery of the revenue requirement for generation resources unrelated to net power costs. For example, while Leaning Juniper went into service in 2006, the Stipulation in the Company's last general rate case, UE 179, specifically precluded the Company from seeking recovery of the capital costs until September 2007, which was the end of an agreed-upon stay-out period. In addition to the renewable resources of Leaning Juniper, Marengo and Blundell, the Company has also placed into service the 525 MW Lake Side combined cycle combustion plant since the last general rate case. The fixed costs of Lake Side will not be reflected in rates until approved in a general rate case.

Q. Does the Company have any plans to file a general rate case in Oregon during calendar year 2008?

A. No. The Company does, however, anticipate filing a general rate case in 2009 for rates effective January 1, 2010.

Net Power Costs Benefits of New Renewables

Q. Please explain the significant net power costs benefits provided by these renewable resources in the TAM.

A. The near-zero variable cost energy for the new renewable generation resources reduces the overall amount of net power costs because it offsets the need to make market purchases or run higher-cost generation in the GRID model. In the 2008 TAM, the inclusion of Leaning Juniper, Marengo and Blundell reduced total company net power costs by approximately $42 million. For the 2009 TAM, the inclusion of the 713 MW of renewable generation resources reduces the total company net power costs by approximately $121 million. The Oregon-allocated share of this reduction is approximately $31 million, offsetting 80 percent of the RAC revenue requirement. Given that additions to ratebase carry higher early year costs due to the "lumpiness" of investment, this comparison helps to demonstrate the significant net power cost benefits provided by these resources.

Q. Will Oregon customers realize additional benefits in the future related to these renewable resources?

A. Yes. The RAC mechanism requires the Company to update the revenue requirement each year for resources included in the RAC. As such, customers receive the benefit of reduced rate base due to depreciation each year. For instance, it is estimated that the revenue requirement related to rate base for the resources included in the 2009 RAC filing will be approximately $17 million less in the 2010 RAC filing, on a total company basis. In addition, it is reasonable to expect that market prices will continue to rise over the life of the asset. Mr. Tallman's testimony provides additional details on the benefits to customers of these renewable resources.

Introduction of Witnesses

Q. Please list the Company witnesses and provide a brief explanation of the witnesses' testimony.

A. The other Company witnesses filing direct testimony are:

Mark R. Tallman, Vice President of Renewable Resource Acquisition, describes the new renewable resources that the Company is seeking recovery for in this proceeding.

R. Bryce Dalley, Manager of Revenue Requirement, presents the revenue requirement calculation and the allocation methodology and factors used in this filing.

Judith M. Ridenour, Senior Analyst, Pricing & Cost of Service, presents the Company's proposed Schedule 202 and provides a comparison of existing and estimated customer rates.

Q. Does this conclude your direct testimony?

A. Yes.

Case UE-
Exhibit PPL/200
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark R. Tallman

RENEWABLE RESOURCES

April 2008

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power & Light Company (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 22 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 renewable resources that the Company is seeking cost recovery for in this proceeding. These renewable resources are the: Leaning Juniper 1; Marengo; Goodnoe Hills; Marengo II; Seven Mile Hill; Glenrock; and Rolling Hills wind resources as well as the Blundell Bottoming Cycle geothermal resource.

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) and how that strategic tool is utilized to assist the Company in identifying and quantifying the need and timing of new supply-side resources. I also provide an overview of the relevant MidAmerican Energy Holdings Company (MEHC) transaction commitments. I conclude with a description of each renewable resource acquired by the Company and the decision-making process that led to the acquisition.

Integrated Resource Plan

Q. Please briefly describe the IRP.

A. The IRP is a strategic planning tool that presents a framework of future actions to ensure PacifiCorp continues to provide reliable, least-cost service with manageable and reasonable risk to its customers. Each IRP builds on PacifiCorp's prior resource planning efforts and reflects continuous significant advancements in portfolio modeling and risk analysis.

Q. What is the main purpose of the IRP?

A. The main purpose of the IRP is to serve as a strategic roadmap to assist the Company in determining and implementing the Company's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, input received from stakeholders, corporate business goals, other potential external influences, and applicable MEHC transaction commitments related to IRP activities (such as adding new renewable resources to the Company's portfolio).

As a strategic business planning tool, the IRP supports informed decision-making on resource acquisition by providing an analytical framework for assessing alternative resource tradeoffs. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to the Company's preferred portfolio of supply-side and demand-side resources and investment in transmission.

The emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures, as opposed to the optimal plan for some expected view of the future. The modeling is intended to inform and support rather than overshadow the expert judgment of the Company's decision-makers. The preferred portfolio is not meant to be a static planning product, but rather is expected to evolve as part of the ongoing planning process as new information and circumstances become available. As a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views. As the owner of the IRP, the Company is uniquely positioned to determine the resource plan that best accomplishes IRP objectives on a system-wide basis, thereby meeting customer, community and investor obligations collectively.

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, PacifiCorp'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.

Q. How did the 2004 IRP address renewable resources in Docket LC 39?

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 resources as a proxy for all renewable resources, which are part of a prudent and balanced resource mix. The 2004 IRP characterized wind energy as having only minor impacts on the environment and producing no air pollutants or greenhouse gasses (page 94 of PacifiCorp's 2004 IRP). Action item 1 in the plan was to continue to aggressively pursue cost-effective renewable resources through current and future requests for proposals (RFP) and pursuant to an overall resource procurement strategy.

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. Order No. 06-029 acknowledged Action Item 1.

Q. Did the Company utilize a RFP as a way to acquire renewable resources identified in the 2004 IRP?

A. Yes. The Company's RFP, designated RFP 2003-B, was issued in February 2004 for the purpose of acquiring renewable resources and recommended the acquisition of up to 1,100 MW of renewable resources. Following the acquisition of PacifiCorp by MEHC, PacifiCorp amended RFP 2003-B by allowing previous bidders to update their proposals and invite new bidders to participate.

Q. How did the 2007 IRP address renewable resources in Docket LC 42?

A. The 2007 IRP identifies a target of 2,000 megawatts of renewable resources to be acquired by 2013. Under this plan, the company will seek to acquire 1,400 megawatts of new renewable resources by 2010, with 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 for modeling purposes in the IRP process, renewable generation includes other fuel sources (such as geothermal).

Q. Has the Commission acknowledged the 2007 IRP and its action plan on renewable resource acquisition?

A. The Commission has not yet issued its final order on the Company's 2007 IRP. However, in the Commission Staff Report on the IRP, dated December 14, 2008, the Staff recommended that the Commission acknowledge the Company's 2007 IRP action plan item to acquire 2,000 MW of renewable resources by 2013.

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

A. The Company is implementing two renewable resource RFPs in 2008. On January 31, 2008, PacifiCorp issued an RFP for long-term renewable resources less than 100 MW in generating capability, or alternatively for a term less than five years if greater than 100 MW in generating capability, that will be in operation prior to December 31, 2009. Developers may submit proposals in the form of a power purchase agreement or build-own-transfer agreement. The

Company will not have a benchmark or other Company owned alternative in this process. The deadline for bids was March 31, 2008. The Company expects to efficiently complete evaluations and announce a short list soon thereafter. Final agreements with project developers are targeted by June 30, 2008.

On March 4, 2008, the Company filed an application with the Oregon Commission to open a docket for approval of a RFP process targeting system-wide renewable resources up to 500 MW that will be in operation prior to December 31, 2011. Each renewable resource is limited in size to no more than 300 MW, which is the upper limit permitted by Utah Senate Bill 202[1]. The Company is currently in the process of soliciting for independent evaluators for the RFP and is targeting to file the draft RFP in early April. As a part of this RFP, the Company is proposing a form and process that will allow the Company to re-issue the solicitation in subsequent time periods to call for new bidders or updated bids on an as-needed basis. This ability to periodically re-issue the solicitation is important to the Company and customers so as to provide needed flexibility in the procurement of renewable resources. The Company anticipates that it will re-issue the renewable RFP at least each year in order to acquire needed resources to serve customers and comply with RPS laws.

MEHC Transaction Commitments

Q. Please provide an overview of the MEHC transaction commitments related to the acquisition of renewable resources.

A. As part of the regulatory approvals related to the acquisition of PacifiCorp,

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

MEHC and PacifiCorp committed to:

- Bring at least 100 MW of cost-effective wind resources in service within one year of the close of the transaction;
- Have 400 MW of cost-effective new renewable resources in PacifiCorp's generation portfolio by December 31, 2007, and
- Reaffirm PacifiCorp's commitment to acquire 1,400 MW of cost-effective new renewable resources.

The resources described below have been acquired consistent with these commitments.

Analysis Methodologies

Q. Please generally describe the analysis methodologies the Company utilized to evaluate the economic effectiveness of the wind resources that your testimony addresses.

A. The Company used two analysis methods depending on when a wind resource was evaluated. The first method is a present value revenue requirements differential method ("PVRR(d)") and the second is a next highest alternative cost for compliance ("ACC") method.

Q. Which wind resources were analyzed using the PVRR(d) method?

A. Leaning Juniper 1, Marengo, Marengo II, and Seven Mile Hill.

Q. Which renewable resources were analyzed using the ACC method?

A. Glenrock and Rolling Hills.

Q. How was the Goodnoe Hills project analyzed?

A. The Goodnoe Hills project was analyzed using the PVRR(d) method but the results were expressed so as to be consistent with the way the ACC method expresses results.

Q. Please describe the PVRR(d) method.

A. The PVRR(d) method utilizes production cost modeling based on the Company's GRID model or a forward price curve. The forward price curve (FPC) was used if, based on the location of the resource, the GRID model could reasonably be expected to balance against a FPC market. Where GRID is used, the Company first runs GRID to obtain a baseline reference. GRID is then run a second time with the renewable resource added at zero cost. The result is market-based energy costs avoided as a result of adding the renewable resource to the GRID resource set. The PVRR(d) approach uses the Company's FPC as an input and generates a market-based alternative comparison of the resource. The PVRR(d) approach then compares other costs and benefits of the specific resource being considered against the GRID model results, or a FPC, and represents the resource in terms of a project-specific benefit to customers on a net present value basis over the life of the project as compared to an alternative. The alternative in this case was the GRID model results or a FPC. A negative result denotes a financial benefit to customers whereas a positive result indicates that customers may be better off to pursue an alternative other than the resource.

Q. Was there an assumption for renewable energy credit (REC) value included in the PVRR(d) method?

A. Yes. The PVRR(d) method included a REC value assumption of $5.00 per megawatt-hour for a period of five (5) years. The REC assumption was consistent with the REC assumption used in the IRP.

Q. Please describe the ACC method.

A. The ACC method utilizes production cost modeling based on the IRP Planning and Risk ("PaR") model. The PaR model uses the Company's FPC as an input and the ACC method also generates a market-based alternative comparison of the resource. In determining the alternative, the Company first runs the PaR model utilizing the then-current IRP preferred portfolio or, if applicable, the IRP preferred portfolio as modified by the Company's then-current business plan. The PaR model was then run a second time with the uncommitted renewable resources from the preferred portfolio removed. The result is market-based energy costs incurred as a result of no longer adding renewable resources to the IRP portfolio. The ACC approach then compares other costs and benefits of the specific resource being considered against the PaR model results and represents the resource in terms of a project-specific ACC over the life of the project necessary to result in a zero net present value revenue requirement difference. The alternative in this case was the PaR model results. The ACC method represents its results on a dollars per megawatt-hour (MWh) basis whereas the PVRR(d) method represents its results on the basis of dollars.

Q. Is a REC value used in the ACC method?

A. No.

Q. What does a negative ACC denote and what does a positive ACC denote?

A. A negative ACC denotes a case where the resource compares favorably to the PaR model results without any consideration to REC values and/or the next highest alternative cost for compliance. A positive value denotes a case where the project-specific ACC can be compared against current or potential future penalties for not complying with the RPS requirements in Oregon, which is described in Ms. Kelly's testimony, and/or with the RPS requirements in other states, or a potential future federal RPS law or laws.

Q. What is the cost for non-compliance under the RPS laws in the Company's service area?

A. In Washington, the potential penalty is equal to $50 adjusted for inflation for each MWh the Company fails to include as an adequate level of energy from renewable resources in its portfolio. In California, the California Public Utilities Commission has the discretion to administer potential penalties of five (5) cents per kWh (or $50 per MWh), up to $25 million per year, if the Company fails to meet procurement targets for renewable energy. In Oregon, the penalty is not defined by the law; Senate Bill 838 states that the Commission may impose a penalty against the Company in an amount determined by the Commission if the Company fails to comply with the standard.

Q. Why did the Company start using the ACC method for analyzing renewable resources?

A. The Company started using the ACC method for three reasons: (1) we understood from our stakeholders that they desired an IRP-based analytical methodology for renewable resource evaluation; (2) the Company was implementing the IRP preferred portfolio of resources; and (3) RPS requirements had been passed in Washington, California and, subsequently, in Oregon. Additionally, Utah Senate

Bill 202 sets forth energy resource and carbon emission reduction initiatives.

Q. Please generally describe the analysis methodologies the Company utilized to evaluate the Blundell Bottoming Cycle geothermal resource.

A. The method used to analyze the Blundell Bottoming Cycle resource was based on a FPC but without any REC value assumption.

Leaning Juniper 1

Q. Please describe the size and location of the Leaning Juniper 1 resource.

A. Leaning Juniper 1 is a 100.5 MW wind energy generation facility, consisting of 67 General Electric 1.5 MW (model SLE) 60 hertz wind turbine generators located about three miles southwest of Arlington, Oregon. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets and all output and all interconnection rights up to the project's 100.5 MW capability. The turbines have 80 meter tubular towers and a 77 meter rotor diameter. The project includes above-ground and underground electric cable, fiber optic communication cable, approximately 20 miles of turbine access roads, two permanent meteorological towers, one collector substation, one supervisory control and data acquisition system, and one operation and maintenance building. Ongoing operations, warranty, and general maintenance services are being performed by Leaning Juniper 1 Wind Power LLC (a PPM Energy, Inc. affiliate), under a negotiated two-year contract.

Q. How is energy generated by Leaning Juniper 1 delivered?

A. The energy generated by the project is delivered to the project's substation, which connects to the Jones Canyon substation that was built by the Bonneville

Power Administration (BPA), then to BPA's transmission system. Energy from the project is then transmitted across BPA's transmission system for delivery into PacifiCorp's system.

Q. Please describe the benefits of this resource to Oregon customers.

A. Oregon customers benefit from this resource as it represents the only resource made available to the Company via RFP 2003-B that could economically meet a commercial operation date in 2006. The 2003 and subsequent IRPs specify that renewable resources (using wind resources as a proxy) steadily be added to the system with the target of reaching 1,400 MW or more of renewable resources. Leaning Juniper 1 represents such a resource. In addition, Leaning Juniper 1 was economical when compared against resources identified via RFP 2003-B for renewable resources that could become commercial during 2007.

Q. How else does the Leaning Juniper 1 resource benefit Oregon customers?

A. The Leaning Juniper 1 resource further benefits Oregon customers by providing the Company with a zero incremental cost fuel source (thus reducing commodity risk exposure in the Transition Adjustment Mechanism (TAM)), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and valuable ownership and operational experience with utility scale wind projects. Leaning Juniper 1 is the first wind resource that PacifiCorp has acquired on an ownership basis since the construction of the Foote Creek 1 wind resource at Foote Creek rim in Wyoming. The Leaning Juniper 1 project utilizes General Electric Company wind turbines, thus giving PacifiCorp valuable experience with this particular manufacturer. As a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years. PacifiCorp currently has a number of power purchase and service agreements associated with wind projects in its portfolio and it is important that the Company diversify to include owned renewable resources. Leaning Juniper 1 is providing the Company with valuable experience to enable the evolution of those activities as well as valuable experience with a General Electric Company turbine-based wind project.

Q. How did the Company make the decision to move forward with the Leaning Juniper 1 project?

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 due to the results of RFP 2003-B. Upon review of this information, the Company determined that it would proceed with acquisition of the project.

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

A. Since January 2007, Leaning Juniper has been included in the Company's net power costs in the TAM. The Company's current rates do not provide for recovery of the revenue requirement that is unrelated to net power costs.

Q. What investment related to the Leaning Juniper 1 project is included in the revenue requirement in this filing?

A. The Company has included $175.7 million, total company, for the Leaning

Juniper 1 plant in this application. The total company O&M cost associated with the Leaning Juniper 1 resource is $3.4 million for this application. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land and easement payments.

The Leaning Juniper 1 plant was placed in service September 14, 2006. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PVRR(d) method of analysis that was presented to Company executives with respect to the Leaning Juniper 1 resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Marengo

Q. Please describe the size and location of the Marengo resource.

A. Marengo is a 140.4 MW wind energy generation facility, consisting of seventy-eight Vestas 1.8 MW wind turbine generators located near Dayton, Washington. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and all interconnection rights. The Vestas turbines located at the Marengo site have eighty meter rotor diameter and sixty-seven meter tubular towers. The project includes above-ground and underground electric cable; fiber optic communication cable; turbine access roads; two permanent meteorological towers; one collector substation; a transmission line extension; one supervisory control and data acquisition system; and one operation and maintenance building. Ongoing operations, warranty, and general maintenance services will initially be performed by Vestas American Wind Technology, Inc., for a period that extends for more than four years.

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

A. The electrical energy generated by the Marengo wind project is delivered to the project substation and stepped up from 34.5kV to 230kV and delivered into PacifiCorp's transmission system on the North Lewiston-to-Walla Walla 230kV transmission line via a 230 kV transmission line extension and new transmission switching station (the Talbot switching station). As such, no third-party transmission expense is anticipated (*i.e.,* no Bonneville Power Administration (BPA) point-to-point wheeling expenses) to deliver project energy to the Company's system. The Marengo wind resource is interconnected to the Company's west control area.

Q. Please describe the benefits of this resource to Oregon customers.

A. The Marengo resource benefits Oregon customers in several ways. It is a cost-effective addition to the Company's portfolio that is consistent with the preferred portfolios resulting from PacifiCorp's last three IRP cycles. Marengo will also provide the Company and its customers with a long-term resource to comply with requirements of Oregon's RPS. In addition, the Marengo resource provides our customers with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. Marengo is the second wind resource that PacifiCorp has acquired on an ownership basis since the construction of the Foote Creek 1 wind resource at Foote Creek rim in Wyoming. The Marengo project utilizes Vestas wind turbines, thus giving PacifiCorp valuable experience with this particular manufacturer. As a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years. In light of these emerging requirements, PacifiCorp currently has a number of power purchase agreements and service agreements for wind projects in its portfolio and it is important that the Company diversify to include owned renewable resources.

Q. How did the Company make the decision to move forward with the Marengo project?

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 due to the results of RFP 2003-B. Upon review of this information, the Company determined that it would proceed with acquisition of the project.

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

A. Since January 2008, Marengo has been included in the Company's net power costs in the TAM. The Company's current rates do not provide for recovery of the revenue requirement that is unrelated to net power costs.

Q. What investment related to the Marengo project is included in the revenue requirement in this filing?

A. The total company cost for the Marengo project was $246.1 million. The O&M

cost associated with the Marengo resource that is associated with this application is $4.9 million on a total company basis. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land and easement payments.

The Marengo plant was placed in service August 4, 2007. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PVRR(d) method of analysis that was presented to Company executives with respect to the Marengo resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Goodnoe Hills

Q. Please describe the size and location of the Goodnoe Hills resource.

A. The Goodnoe Hills resource is a wind resource located near Goldendale, Washington. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and 94 MW of interconnection rights with the BPA. Ongoing operations, warranty, and general maintenance services will be performed by the wind turbine supplier (REpower System AG) for the first two years and then by enXco Service Corporation for the following eight years. The Goodnoe Hills wind project consists of a 94 MW wind energy generation facility utilizing forty-seven REpower System AG 2.0 MW (model MM92) sixty hertz wind turbine generators. The turbines have a 92.5 meter rotor diameter and eighty meter tubular towers. The project includes above-ground and underground electric cable; fiber optic communication cable, turbine access roads; permanent meteorological towers; a supervisory control and data acquisition system; a collector substation and one operation and maintenance building.

Q. How is energy generated by Goodnoe Hills delivered to PacifiCorp's system?

A. The energy generated by the project will be delivered to a 34.5/230 kilovolt substation which connects to the Rock Creek substation built by BPA. The energy is then delivered to BPA's transmission system for transmission across BPA's system for delivery into the Company's system.

Q. Please describe the benefits of this resource to Oregon customers.

A. The Goodnoe Hills resource benefits Oregon customers in several ways. It is a cost-effective addition to the Company's portfolio that is consistent with the preferred portfolios resulting from PacifiCorp's last three IRP cycles. Goodnoe Hills will also provide the Company and its customers with a long-term resource to comply with requirements of Oregon's RPS. In addition, the Goodnoe Hills resource provides our customers with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. The Goodnoe Hills project utilizes REpower wind turbines, thus giving PacifiCorp valuable experience with this particular manufacturer who is establishing a sales and maintenance operation in Oregon. The combination of the turbine supplier and operational expertise held by the project developer enabled the Company to negotiate a long-term operation and maintenance agreement for the entire project. This benefited customers as it is an economical way to operate a project that is located outside of PacifiCorp's historical service territory. Further, as a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years. PacifiCorp currently has a number of power purchase agreements and service agreements for wind projects in its portfolio and it is important that the Company diversify to include owned renewable resources. Goodnoe Hills will provide the Company with further experience in owning wind resources and enable the evolution of those activities in other locations.

Q. How did the Company make the decision to move forward with the Goodnoe Hills project?

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.

Q. What investment related to the Goodnoe Hills project is included in the revenue requirement?

A. The Company has forecasted $196.6 million, total company, for the Goodnoe Hills project. The O&M cost associated with the Goodnoe Hills resource is forecasted at $3.2 million total company. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land

and easement payments.

The Goodnoe Hills project is expected to be operational by June 2008. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PRVV(d) method of analysis that was presented to Company executives with respect to the Goodnoe Hills resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Marengo II

Q. Please describe the size and location of the Marengo II resource.

A. The Marengo II project is a 70.2 MW wind energy generation facility, consisting of 39 Vestas 1.8 MW wind turbine generators located near the Marengo wind project outside of Dayton, Washington. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and all interconnection rights. The Vestas turbines located at the Marengo II site have 67 meter tubular towers and an 80 meter rotor diameter. The project includes above-ground and underground electric cable; fiber optic communication cable; turbine access roads; a permanent meteorological tower; one collector substation; a transmission line extension; and one supervisory control and data acquisition system. Ongoing operations, warranty and general maintenance services will initially be performed by Vestas American Wind Technology, Inc. for a period of four years.

Q. How will energy generated by Marengo II be delivered?

A. The electrical energy generated by the Marengo II wind project will be delivered to the project substation and stepped up from 34.5kV to 230kV and delivered into

PacifiCorp's Talbot switching station via the 230 kV transmission line extension constructed as part of the Marengo wind project. Similar to the Marengo project, the Marengo II wind project will not incur third-party transmission expense to deliver to PacifiCorp's system.

Q. Are the benefits of Marengo II similar to those you have identified associated with the original Marengo Wind Project?

A. Yes, with this project being a renewable resource that can economically meet a commercial operation date during 2008.

Q. How did the Company make the decision to move forward with the Marengo II project?

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.

Q. What investment related to the Marengo II project is included in the revenue requirement?

A. The Company has projected the total company cost of Marengo II to be $135.8 million. The total company forecasted O&M cost associated with the Marengo II resource is $2.3 million. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land easement payments. The Marengo II project is expected to be operational by August 2008. Mr.

Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PVRR(d) method of analysis that was presented to Company executives with respect to the Marengo II resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Seven Mile Hill

Q. Please describe the size and location of the Seven Mile Hill resource.

A. The Seven Mile Hill resource is a wind resource located in Carbon County, Wyoming. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and all interconnection rights with PacifiCorp Transmission. Ongoing operations, warranty, and general maintenance services will be performed by PacifiCorp or a third party. The Seven Mile Hill wind project consists of a 99 MW wind energy generation facility utilizing 66 General Electric 1.5 MW wind turbine generators. The turbines have 80 meter towers and a 77 meter rotor diameter. The project includes underground electric cable; fiber optic communication cable; turbine access roads; permanent meteorological towers; a supervisory control and data acquisition system; a collector substation; and one operation and maintenance building.

Q. How will energy generated by Seven Mile Hill be delivered?

A. The energy generated by the project will be delivered to a 34.5/230 kilovolt substation which will connect to PacifiCorp's transmission system via an adjacent 230 kilovolt interconnection substation. The energy is then delivered to PacifiCorp's transmission system on the Miners to Dave Johnston 230kV transmission line.

Q. Please describe the benefits of this resource to Oregon customers.

A. Oregon customers benefit from this resource as it represents an economic renewable resource. The 2004 and 2007 IRPs specify that renewable resources (using wind resources as a proxy) be steadily added to the system with the target of reaching 1,400 MWs or more of renewable resources. Seven Mile Hill represents such a resource.

Q. How else will the Seven Mile Hill resource benefit Oregon customers?

A. The Seven Mile Hill resource further benefits Oregon customers by providing the Company with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. The Seven Mile Hill project utilizes General Electric wind turbines, thus giving PacifiCorp the option and ability to share spare parts with other General Electric based wind projects. Further, as a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years.

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

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.

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

A. The Company has forecasted $201.4 million, total company, for the Seven Mile Hill project. The O&M cost associated with the Seven Mile Hill resource is forecasted at $3.6 million, total company. This is due to expected wind turbine-generator maintenance costs, permitting obligations, local levy tax and land and easement payments. The Seven Mile Hill project is expected to be operational by the end of December 2008. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PVRR(d) method of analysis presented to Compny executives with respect to the Seven Mile Hill resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Glenrock

Q. Please describe the size and location of the Glenrock resource.

A. The Glenrock wind project is a wind resource located in Converse County, Wyoming. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and all interconnection rights with PacifiCorp Transmission. Ongoing operations, warranty and general maintenance services will be performed by PacifiCorp or a third party. The Glenrock wind project consists of a 99 MW wind energy generation facility utilizing 66 General Electric 1.5 MW wind turbine generators. The turbines have 80 meter tubular towers and a 77 meter rotor diameter. The project includes above-ground and underground electric cable; fiber optic communication cable; turbine access roads, permanent meteorological towers; a supervisory control and data acquisition system; and operations/maintenance structures at the site.

Q. Please describe other attributes associated with the site on which the Glenrock wind project is being constructed?

A. The Glenrock wind project is located on property owned by the Company that includes the location of the former Dave Johnston Coal Mine. Strip mining of the area began in 1958 and ceased in September 2000. Since then, the Company has worked closely with the Wyoming Department of Environmental Quality (WDEQ) to reclaim the mined area. The area that was mined is re-contoured and now supports vegetation and animal life native to Wyoming. The Company will continue to work closely with WDEQ to assure that construction of the Glenrock wind project on PacifiCorp's property is in compliance with any WDEQ requirements related to that portion of the wind project site for which coal mining activities took place.

Q. How will energy generated by Glenrock be delivered?

A. The energy generated by the Glenrock project will be delivered to a 34.5/230 kilovolt substation which will connect to PacifiCorp's transmission system via a 13-mile 230 kilovolt transmission line extension and a new transmission interconnection substation located between the Glenrock mine and the Dave Johnston power plant.

Q. Please describe the benefits of this resource to Oregon customers.

A. Oregon customers benefit from this resource as it represents an economic renewable resource. The 2004 and 2007 IRPs specify that renewable resources (using wind resources as a proxy) be steadily added to the system with the target of reaching 1,400 MWs or more of renewable resources. Glenrock represents such a resource.

Q. How else will the Glenrock resource benefit Oregon customers?

A. The Glenrock resource further benefits Oregon customers by providing the Company with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. The Glenrock project utilizes General Electric Company wind turbines, thus giving PacifiCorp the opportunity to use valuable experience from other General Electric based projects and spare parts optimization. General Electric is the largest manufacturer of wind turbines in the United States. Further, as a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years.

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

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.

Q. What investment related to the Glenrock project is included in the revenue requirement?

A. The Company has forecasted total company costs of $210.3 million for the Glenrock project. The total company O&M cost associated with the Glenrock resource is $4.4 million. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land royalties and easements. The Glenrock project is expected to be operational by the end of December 2008. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the ACC method of analysis that was presented to Company executives with respect to the Glenrock resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Rolling Hills

Q. Please describe the size and location of the Rolling Hills resource.

A. The Rolling Hills wind project is a wind resource located in Converse County, Wyoming on the same site that the Glenrock wind project is located on. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and all interconnection rights with PacifiCorp Transmission. Ongoing operations, warranty, and general maintenance services will be performed by PacifiCorp or a third party. The Rolling Hills wind project consists of a 99 MW wind energy generation facility utilizing 66 General Electric 1.5 MW wind turbine generators. The turbines have 80 meter tubular towers and a 77 meter rotor diameter. The project includes above-ground and underground electric cable; fiber optic communication cable; turbine access roads; permanent meteorological towers; and a supervisory control and data acquisition system.

Q. How will energy generated by Rolling Hills be delivered?

A. The energy generated by the Rolling Hills project will be delivered to a 34.5/230 kilovolt substation which will connect to PacifiCorp's transmission system via the same 13-mile 230 kilovolt transmission line extension and a transmission interconnection substation being constructed for the Glenrock Wind project.

Q. Please describe the benefits of this resource to Oregon customers.

A. Oregon customers benefit from this resource as it represents an economic renewable resource. The 2004 and 2007 IRPs specify that renewable resources (using wind resources as a proxy) be steadily added to the system with the target of reaching 1,400 MWs or more of renewable resources. Rolling Hills represents such a resource.

Q. How else will the Rolling Hills resource benefit Oregon customers?

A. The Rolling Hills resource further benefits Oregon customers by providing the Company with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. The Rolling Hills project utilizes

General Electric Company wind turbines, thus giving PacifiCorp more opportunities to gain synergies with other General Electric Company wind turbine based wind projects. Further, as a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years.

Q. How did the Company make the decision to move forward with the Rolling Hills project?

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.

Q. What investment related to the Rolling Hills project is included in the revenue requirement?

A. The Company has forecasted $206.5 million, total company, for the Rolling Hills project. The total company O&M cost associated with the Glenrock resource is forecasted at $3.9 million. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land royalties and easements. The Rolling Hills project is expected to be operational by the end of December 2008. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the ACC method of analysis that was presented to Company executives with respect to the Rolling Hills resource?

A. The response to this question is included in confidential Exhibit PPL/202.

<u>Blundell Bottoming Cycle</u>

Q. Please describe the size and location of the Blundell Bottoming Cycle resource.

A. The Blundell Bottoming Cycle resource is a separate facility at the Blundell plant, located near Milford, Utah. Exhibit PPL/201 shows a map of the plant location. The bottoming cycle generates a nominal 11 MW of electrical energy using latent heat in the geothermal brine.

Q. Please provide additional detail about the Blundell Bottoming Cycle resource.

A. The Blundell Plant, which was developed and constructed in the 1980's, utilizes a single-flash process to generate electrical power from liquid-dominated geothermal brine. The original plant was designed to utilize the heat energy in the geothermal brine, flashing the brine to steam and using it in a conventional steam turbine generator. The brine is flashed to steam, passed through a steam turbine generator, condensed back to liquid and then re-injected back into the underground geothermal reservoir at approximately 340^{o}F. The bottoming cycle uses the latent heat in the geothermal brine to drive a second turbine generator. Rather than re-injecting the 340^{o}F brine back into the underground geothermal reservoir, it flows through a conventional tube and shell heat exchanger and is used to vaporize pentane as the motive fluid. The pentane vapor drives the second turbine generator which produces the nominal 11 MW. The pentane is condensed back to liquid with an air-cooled condenser. The brine is re-injected back into the geothermal reservoir at approximately 190^{o}F.

Q. How will energy generated by the Blundell Bottoming Cycle resource be delivered?

A. Energy generated by the Blundell Bottoming Cycle will be delivered directly to the Company's existing transmission system at the 46kV level.

Q. Please describe the benefits of this resource to Oregon customers.

A. Oregon customers benefit from this resource as it represents a high capacity factor renewable resource that can economically meet a commercial operation date during 2007. The 2004 and 2007 IRPs specify that renewable resources be steadily added to the system with the target of reaching 1,400 MWs or more of renewable resources prior to 2015. The Blundell Bottoming Cycle project represents such a resource.

Q. How else will the Blundell Bottoming Cycle resource benefit Oregon customers?

A. This resource is predicated on enhancing the overall efficiency of an existing generation plant. PacifiCorp routinely makes these assessments in search for projects that can take advantage of existing infrastructure. In this instance, the project takes advantage of existing generation and transmission infrastructure. As such, no material transmission system investments had to be made to accept the electrical output.

Q. How did the Company make the decision to move forward with the Blundell Bottoming Cycle resource?

A. The Company's board of directors was provided with a detailed overview of the project; the plan for executing upon the project; the risks associated with the project; the need for the project; the financial assessment of the project; the fueling strategy; and the justification of the project. Upon review of this information, the Company's board of directors deliberated and subsequently voted to proceed with the project.

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

A. Since January 2008, the Blundell Bottoming Cycle has been included in the Company's net power costs in the TAM. The Company's current rates do not provide for recovery of the revenue requirement that is unrelated to net power costs.

Q. What investment related to the Blundell Bottoming Cycle resource is included in the revenue requirement in this filing?

A. The Company has included $23.2 million for the Blundell Bottoming Cycle resource on a total company basis. The total company O&M cost associated with the Blundell Bottoming Cycle resource is $540,000. The Blundell Bottoming Cycle resource was placed in service on December 1, 2007. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the FPC based analysis that was presented to the Company's Board with respect to the Blundell Bottoming Cycle resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Conclusion

Q. Please summarize your conclusions.

A. The supply-side renewable resources (Leaning Juniper 1, Marengo, Goodnoe Hills, Marengo II, Seven Mile Hill, Glenrock, Rolling Hills, and the Blundell bottoming cycle project) with in-service dates prior to December 31, 2008 have been included in the Company's RAC filing. These projects represent significant investments the Company is making on behalf of its customers to meet their energy needs and compliance obligation with respect to renewable resource portfolio standards on a prudent and cost-effective basis. Customers will receive the benefit of the output of these facilities and, therefore, the costs associated with the facilities should be included in rates. The Company has been prudent in securing these facilities for the benefit of its Oregon customers and should be granted full cost recovery.

Q. Does this conclude your direct testimony?

A. Yes.

Case UE-
Exhibit PPL/201
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman

LOCATIONS OF NEW RESOURCES

April 2008


Leaning Juniper 1
100.5 MW
Washington
Oregon
Yakima
Yakama Indian Reservation
Klickitat
Benton
Franklin
Umatilla
Morrow
Gilliam
Sherman
Wasco
Richland
Benton City
Pasco
Columbia
Grandview
Mabton
Prosser
Umatilla National Wildlife Refuge
Irrigon
Umatilla Chemical Depot (Closed)
Stanfield
Boardman Naval Bombing Range
Klickitat
Goldendale
Columbia River Gorge National Scenic Area
Wishram
Rufus
The Dalles
Wasco
Moro
Dufur
Grass Valley
Tygh Valley
Lower John Day Wilderness Study Area
Ione
Lexington
Heppner
Condon
15 km
10 mi
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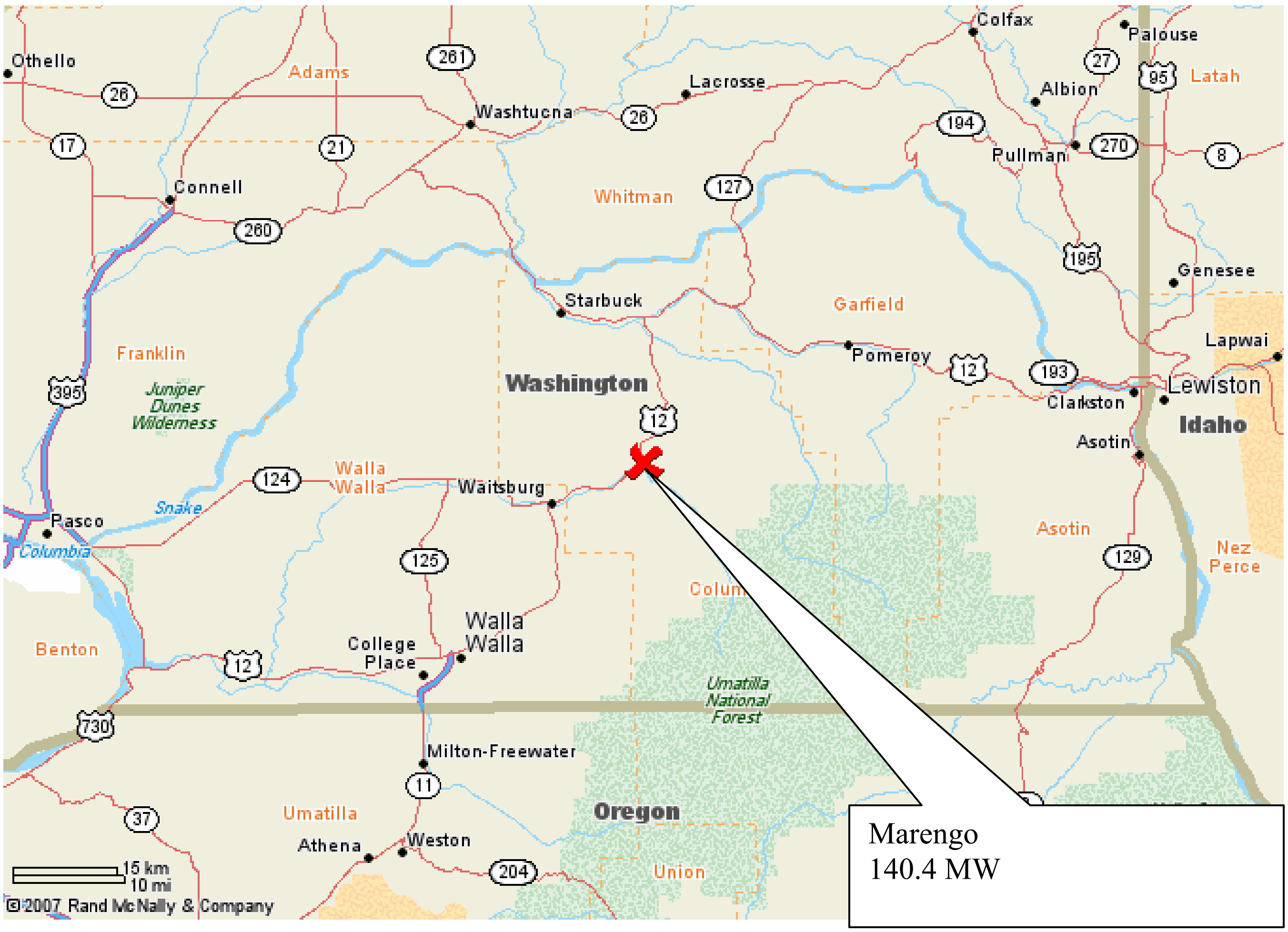
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Juniper Dunes Wilderness
Washington
Pomeroy
Clarkston
Lewiston
Lapwai
Idaho
Asotin
Walla Walla
Waitsburg
Snake
Pasco
Columbia
Benton
College Place
Walla Walla
Colum
Umatilla National Forest
Nez Perce
Milton-Freewater
Oregon
Umatilla
Athena
Weston
Union
15 km
10 mi
©2007 Rand McNally & Company
Marengo
140.4 MW


Goodnoe Hills
94 MW
Washington
Oregon
Toppenish
Zillah
Granger
Sunnyside
Grandview
Mabton
Prosser
Benton
Yakima
Yakama Indian Reservation
Toppenish National Wildlife Refuge
Lewis
Gifford Pinchot National Forest
Skamania
Conboy Lake National Wildlife Refuge
Klickitat
Columbia
Arlington
White Salmon
Hood River
Carson
Cascade Locks
Columbia River Gorge National Scenic Area
Wishram
The Dalles
Wasco
Multnomah
Parkdale
Mount Hood National Forest
Clackamas
Dufur
Moro
Sherman
Grass Valley
Tygh Valley
Lower John Day Wilderness Study Area
Gilliam
Morrow
Ione
Lexington
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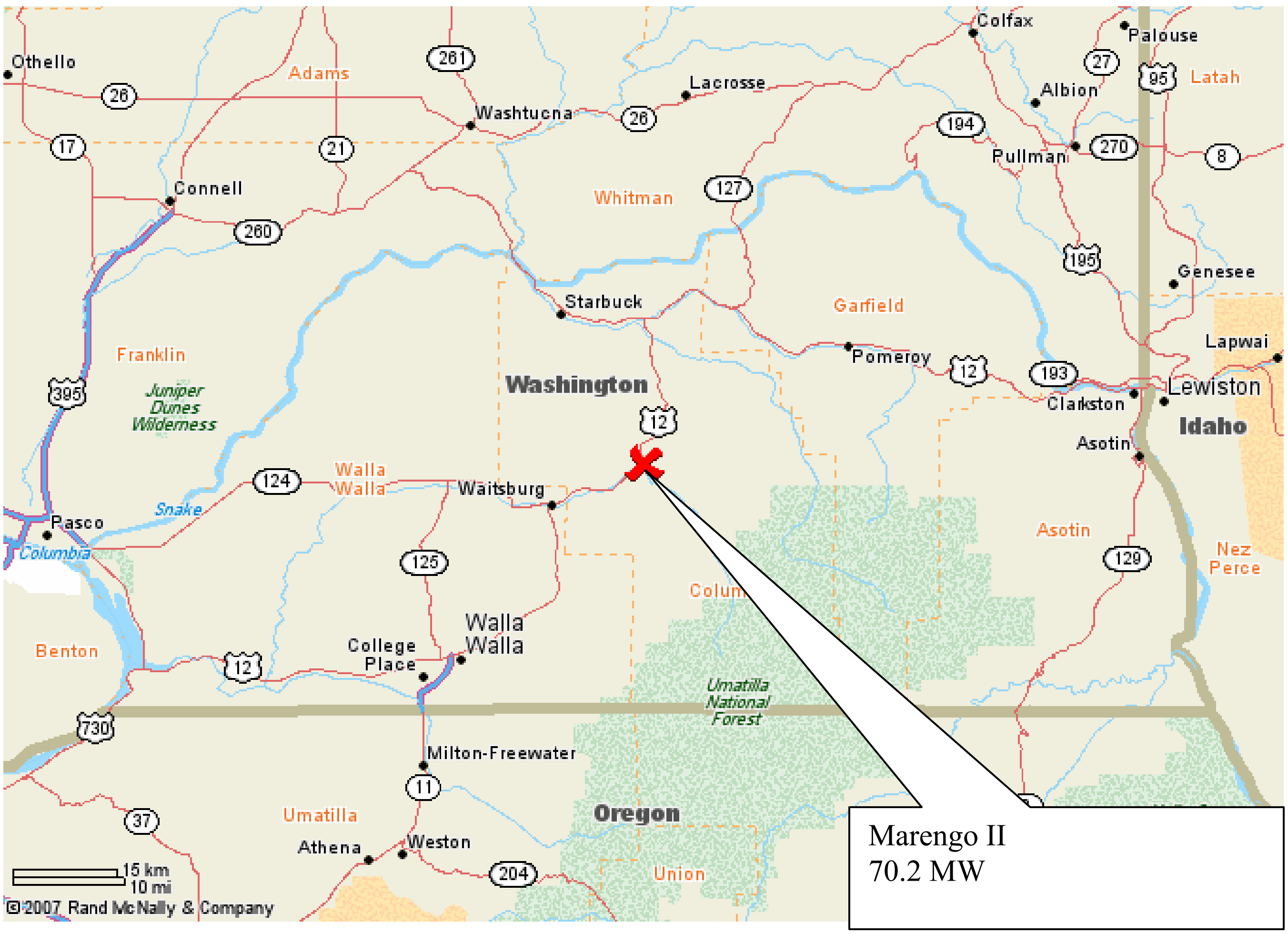
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70.2 MW
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Adams
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Starbuck
Garfield
Genesee
Lapwai
Franklin
Juniper
Dunes
Wilderness
Washington
Pomeroy
Clarkston
Lewiston
Idaho
Asotin
Walla
Walla
Waitsburg
Snake
Pasco
Columbia
Colum
Nez
Perce
Benton
College
Place
Walla
Walla
Umatilla
National
Forest
Milton-Freewater
Oregon
Umatilla
Athena
Weston
Union
15 km
10 mi
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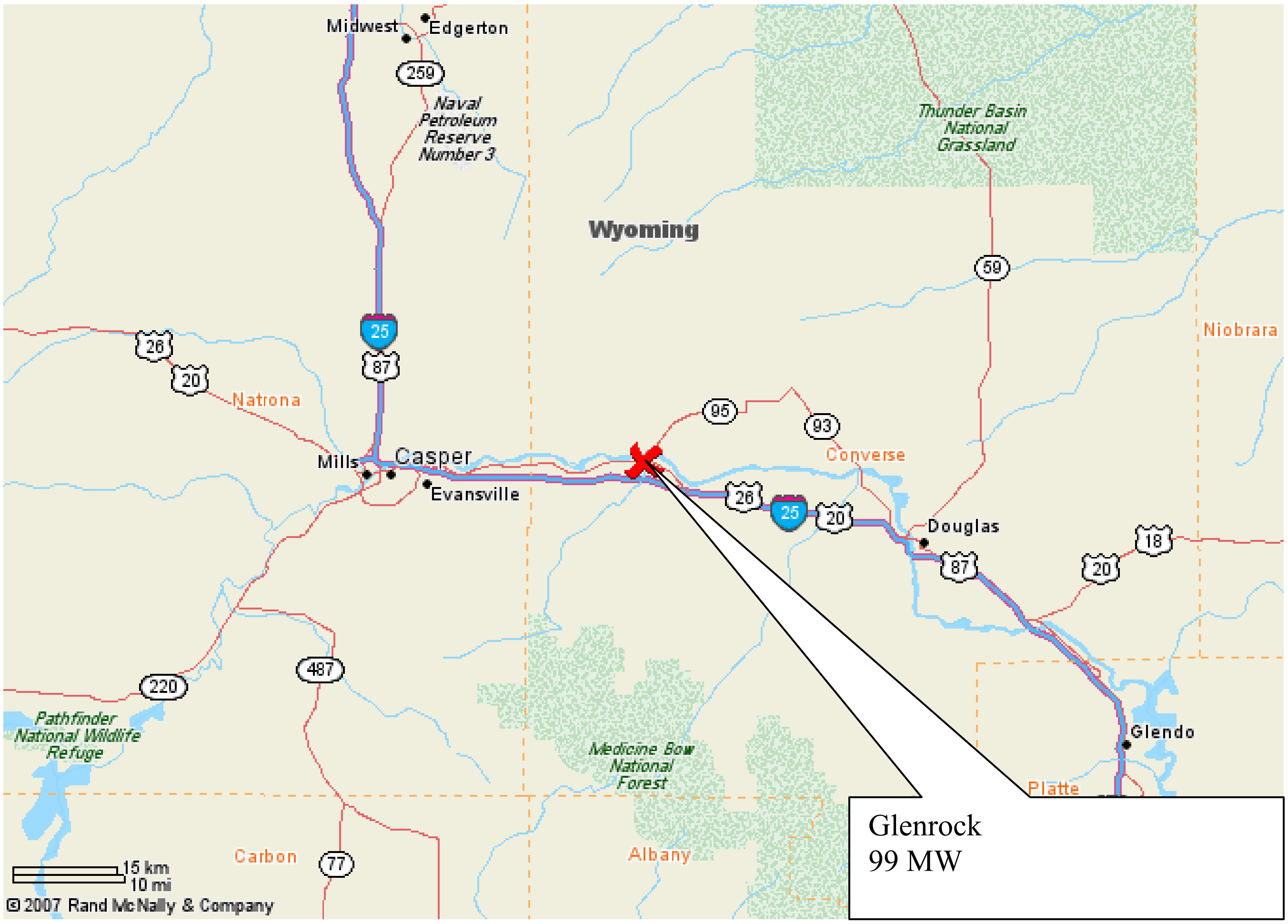
PPL/201
Tallman/5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Edgerton
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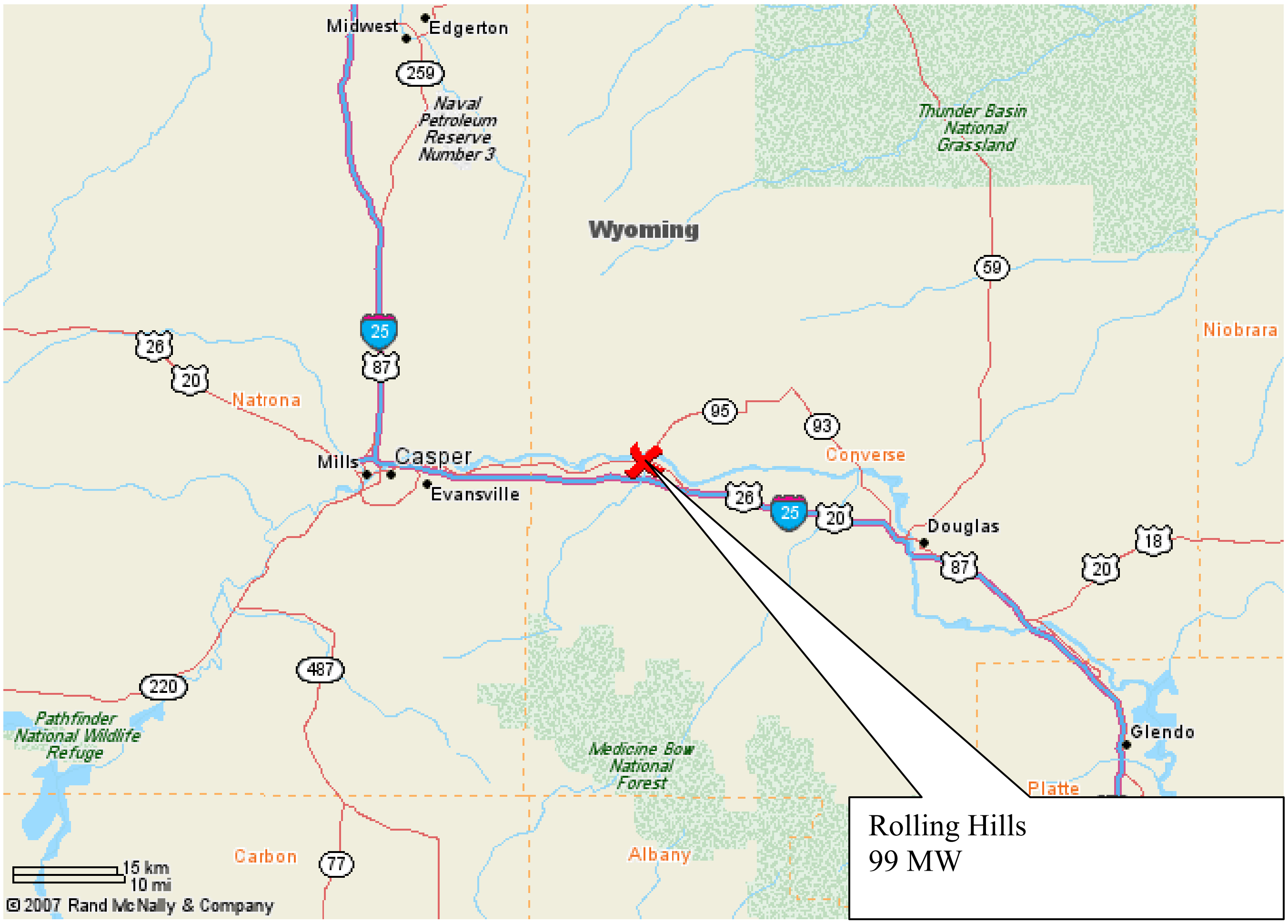
Thunder Basin National Grassland
Wyoming
Niobrara
Natrona
Mills
Casper
Evansville
Converse
Douglas
Glendo
Platte
Pathfinder National Wildlife Refuge
Medicine Bow National Forest
Carbon
Albany
15 km
10 mi
© 2007 Rand McNally & Company
Glenrock
99 MW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Edgerton
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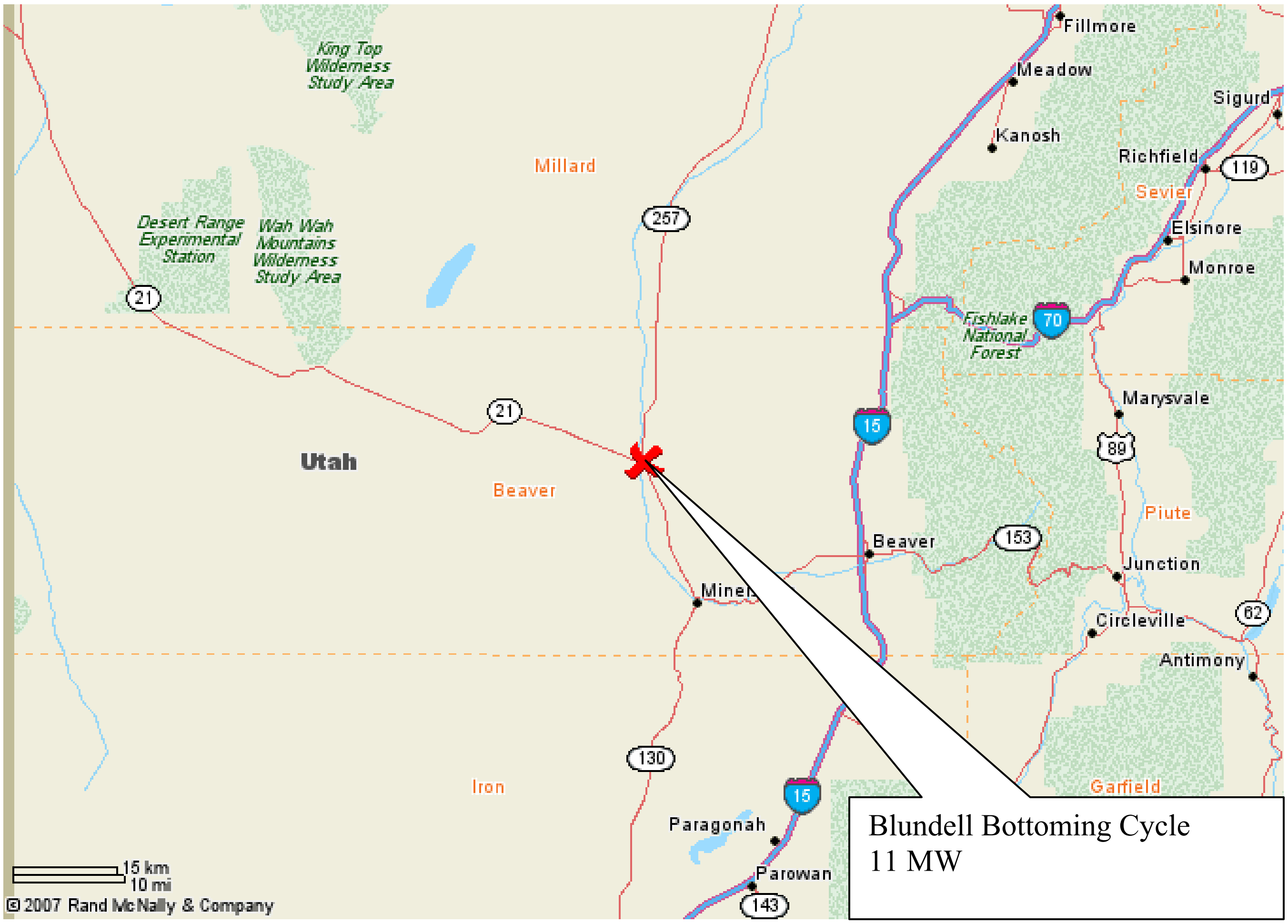
Naval Petroleum Reserve Number 3
Thunder Basin National Grassland
Wyoming
59
Niobrara
25
87
26
20
Natrona
95
93
Converse
Mills
Casper
Evansville
26
25
20
Douglas
18
87
20
220
487
Pathfinder National Wildlife Refuge
Medicine Bow National Forest
Glendo
Platte
Carbon
77
Albany
15 km
10 mi
© 2007 Rand McNally & Company
Rolling Hills
99 MW


King Top Wilderness Study Area
Fillmore
Meadow
Sigurd
Kanosh
Richfield
119
Millard
Sevier
257
Desert Range Experimental Station
Wah Wah Mountains Wilderness Study Area
Elsinore
Monroe
21
Fishlake National Forest
70
21
Marysvale
15
89
Utah
Beaver
Piute
Beaver
153
Junction
Minersville
62
Circleville
Antimony
130
15
Iron
Garfield
Paragonah
Parowan
143
15 km
10 mi
© 2007 Rand McNally & Company
Blundell Bottoming Cycle
11 MW

Case UE-
CONFIDENTIAL
Exhibit PPL/202
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Direct Testimony of Mark R. Tallman

ANALYSIS OF METHODOLOGY RESULTS

April 2008

CONFIDENTIAL EXHIBIT PPL/202
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

Case UE-
Exhibit PPL/300
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of R. Bryce Dalley

REVENUE REQUIREMENT

April 2008

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power & Light Company (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 education and business experience.

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 at PacifiCorp?

A. My primary responsibilities include the calculation and reporting of the Company's revenue requirement, assuring that the applicable inter-jurisdictional cost allocation methodologies are correctly applied, and providing the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses the calculation of the $39.0 million revenue increase requested in the Company's Renewable Adjustment Clause (RAC) filing. In support of this calculation, I will also discuss the allocation methodology and factors used by the Company in this filing.

Q. Please describe Exhibit PPL/301.

A. Exhibit PPL/301 is a summary of the 2009 revenue requirement associated with renewable resources that are currently in service, or projected to be in service prior to January 1, 2009. This exhibit shows the total company revenue requirement associated with each renewable resource included in the Company's filing and the Oregon allocated revenue requirement of $39.0 million.

Q. Are the renewable resources included in this filing consistent with the renewable resources included in the Company's 2009 Transition Adjustment Mechanism (TAM) filing?

A. Yes. This filing includes the same renewable resources that are reflected in the Company's 2009 TAM filing[1]. Including the same resources in this filing ensures a proper matching of the costs and benefits associated with these resources.

Q. What cost components are included in the calculation of the revenue requirement?

A. The revenue requirement calculation in this filing includes cost components outlined in section 6(b) of the all-party Stipulation and Commission Order from Docket UM 1330, which states:

> The revenue requirement as described in this Section 6(b) includes:
> - The return of and grossed up return on capital costs of the renewable energy source and associated transmission at the Utility's currently authorized rate of return;
> - Forecasted operation and maintenance costs;
> - Forecasted property taxes;

[1] The Company's 2009 TAM filing is being filed with the Commission concurrently with the RAC under separate cover.

- Forecasted energy tax credits; and
- Other forecasted costs and cost offsets authorized by Section 13(3) of SB 838 not captured in the Utility's annual power cost update.

Revenue Requirement Components

Q. Please describe the development of each cost component included in the revenue requirement calculation shown in Exhibit PPL/301.

A. Each cost component included in the revenue requirement calculation in Exhibit PPL/301 is discussed below.

Return Of and Grossed Up Return On Capital Costs (Rate Base)

The return on capital costs included in this filing is calculated by multiplying the projected 2009 net rate base balance for each resource by the Commission-authorized weighted cost of capital (grossed up for income taxes) described in Docket UE 179, the Company's last general rate case. Projected net rate base was developed by taking gross plant balances less accumulated depreciation and accumulated deferred income taxes. All aspects of rate base included in this filing were calculated using a beginning/ending average rate base methodology for calendar year 2009. In conjunction with the accumulated depreciation included as a reduction to rate base, the associated annual depreciation expense for each resource has been included in the revenue requirement calculation.

Forecasted Operation and Maintenance Costs

The operation and maintenance costs included for each resource in this filing are based on the Company's latest forecast of expenses that will be incurred during calendar year 2009.

Forecasted Property Taxes

With the exception of the Leaning Juniper resource, property taxes have been calculated by computing Oregon allocated property taxes as a percentage of Oregon-allocated net rate base from Docket UE 179 and multiplying that percentage by the 2009 projected net rate base balance of each resource in this filing.

The Leaning Juniper resource is located within an enterprise zone which entitles it to a three-year exemption from property taxes (2007-2008, 2008-2009, 2009-2010 tax years). However, the Company is required to pay Gilliam County an in-lieu-of fee of $100,000 per year during the exemption's three-year period. This fee has been included in this filing in place of property tax for this resource.

Forecasted Energy Tax Credits

The Company is eligible for a federal income tax credit as a result of placing renewable generating resources in service. The tax credit is based on the generation of the plants, and the credit can be taken for ten years on qualifying property. Under the calculation prescribed by Internal Revenue Service (IRS) Code Section 45(b)(2), the most current renewable electricity production rate is 2.0 cents per kilowatt hour of electricity produced. All of the renewable resources included in this filing qualify for this credit. To quantify the credit included in this filing, 2.0 cents has been multiplied by the kilowatt hours of production for each resource as dispatched by the GRID study included in the Company's TAM filing.

In addition to the federal energy tax credit, two state tax credits have been reflected in this filing - the Oregon Business Energy Tax Credit (BETC) and the Utah Renewable Energy Systems Tax credit. The BETC is applicable to the Leaning Juniper resource for a total credit of $3.5 million amortized over five years, equaling $500,000 in 2009. The Utah Renewable Energy Systems Tax credit is applicable to the Blundell bottoming cycle resource and is calculated by multiplying the kilowatt hours of production, as dispatched by the GRID study included in the Company's TAM filing, by 0.35 percent. Both the federal tax credit and the two state credits are multiplied by the appropriate gross-up factor to arrive at the revenue requirement shown in Exhibit PPL/301.

Other Forecasted Costs

Forecasted franchise taxes and uncollectible expenses have also been included in this filing. These values were determined by multiplying the revenue requirement of each resource by the uncollectible expense percentage and franchise tax rate included in Docket UE 179**.**

Oregon Allocation

Q. How is the revenue requirement associated with the resources in this filing allocated to Oregon?

A. The Oregon-allocated revenue requirement has been calculated using the Revised Protocol allocation methodology. By applying the appropriate Revised Protocol allocation factor to the total company cost components, the Oregon allocation of revenue requirement has been developed.

Q. Specifically, which allocation factors are applied to the total company costs?

A. With the exception of property taxes, cost components included in this filing are allocated using the System Generation (SG) factor. This factor is calculated using a weighted average of Oregon's percentage of total company energy and demand requirements. The SG factor has been updated in this filing to reflect the 2009 load forecast for both energy and demand. The load forecast used in the calculation of the SG factor in this filing is also used in the determination of net variable power costs included in the Company's TAM filing.

Q. How have property taxes been allocated to Oregon in this filing?

A. According to the Revised Protocol allocation methodology, property taxes are allocated using the Gross Plant System (GPS) factor. This factor is developed by dividing Oregon allocated gross plant by total company gross plant. An update to this factor is available only when all components of gross plant are considered. Because only a small subset of total company gross plant balances is considered in this filing, the GPS factor included in Docket UE 179 has been used to allocate the applicable property taxes to Oregon.

Q. Will the revenue requirement for resources not yet in service be updated in this proceeding?

A. Yes. As provided for in the all-party Stipulation and Commission Order from Docket UM 1330, the Company will update the revenue requirement in either the final round of testimony or in the Company's December 1 filing update for the resources included in this filing that are still under construction. The update will reflect the actual costs of the resources, or forecasted costs where appropriate, and any changes to other cost components.

Q. Please describe Exhibit PPL/302.

A. The Stipulation and Commission Order in Docket UM 1330 requires that the Company provide an update to 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. Exhibit PPL/302 complies with this provision and reflects the impact of revenue and the associated income tax expense changes since Docket UE 179, including the Company's 2008 TAM (Docket UE 191), and the current RAC and TAM filings.

Q. Does this conclude your direct testimony?

A. Yes.

Case UE-
Exhibit PPL/301
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

REVENUE REQUIREMENT

April 2008

Pacific Power
Oregon
Renewable Adjustment Clause
Total Revenue Requirement

CY 2009

	Leaning Juniper	**Marengo**	**Blundell Bottoming Cycle**	**Goodnoe Hills**	**Marengo II**	**Glenrock**	**Seven Mile Hill**	**Rolling Hills**	**Total**	**Factor**	**Factor %**	**Oregon Allocated**
Electric Plant In Service	175,714,195	246,087,156	23,237,159	196,642,063	135,784,147	210,292,077	201,359,265	206,460,230	1,395,576,291	SG	26.4114%	368,591,655
Depreciation Reserve	(20,044,173)	(18,408,667)	(1,186,054)	(8,193,419)	(4,752,445)	(4,556,328)	(4,362,784)	(4,473,305)	(65,977,176)	SG	26.4114%	(17,425,516)
Accumulated DIT Balance	(43,695,706)	(50,543,529)	(4,982,221)	(23,756,462)	(16,747,719)	(27,001,688)	(25,854,707)	(26,509,676)	(219,091,708)	SG	26.4114%	(57,865,253)
Net Rate Base	111,974,316	177,134,959	17,068,884	164,692,182	114,283,983	178,734,060	171,141,773	175,477,249	1,110,507,407			293,300,886
	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%			11.26%
Pre-Tax Return on Rate Base	12,604,367	19,939,162	1,921,356	18,538,543	12,864,354	20,119,164	19,264,540	19,752,562	125,004,047			33,015,356
Operation & Maintenance	3,351,019	4,866,477	540,000	3,195,887	2,321,109	4,395,966	3,551,906	3,862,750	26,085,114	SG	26.4114%	6,889,452
Depreciation	7,028,568	9,843,486	729,879	7,865,683	5,431,366	8,411,683	8,054,371	8,258,409	55,623,444	SG	26.4114%	14,690,947
Property Taxes	100,000	1,547,245	149,094	1,438,559	998,252	1,561,213	1,494,895	1,532,765	8,822,023	GPS	28.4419%	2,509,155
Federal Renewable Energy Tax Credit	(9,903,548)	(12,783,479)	(2,833,194)	(9,033,001)	(6,391,739)	(10,763,254)	(11,647,576)	(8,610,991)	(71,966,781)	SG	26.4114%	(19,007,456)
Oregon/Utah State Energy Tax Credits	(523,780)	-	(322,276)	-	-	-	-	-	(846,055)	SG	26.4114%	(223,455)
Rev. Reqt. Before Franchise Tax & Bad Debt	12,656,626	23,412,891	184,859	22,005,671	15,223,341	23,724,772	20,718,136	24,795,495	142,721,792			37,873,998
Franchise Taxes	305,298	564,756	4,459	530,812	367,211	572,280	499,755	598,107	3,442,678			913,582
Bad Debt Expense	85,003	157,244	1,242	147,792	102,242	159,338	139,145	166,529	958,535			254,366
Total Revenue Requirement	**13,046,927**	**24,134,891**	**190,559**	**22,684,275**	**15,692,794**	**24,456,390**	**21,357,036**	**25,560,131**	**147,123,005**			**39,041,946**

Case UE-
Exhibit PPL/302
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

UPDATE TO REVENUE AND TAXES PURSUANT TO OAR 860-022-0041

April 2008

Pacific Power
Oregon
Renewable Adjustment Clause
Total Revenue Requirement
($ 000's)

	CY 2007 UE-179 Unadjusted	UE-191 TAM	2009 RAC	2009 TAM	Total
Operating Revenues:					
General Business Revenues	890,034	22,422	39,042	41,161	992,658
Interdepartmental	-	-	-	-	-
Special Sales	278,958	-	-	-	278,958
Other Operating Revenues	35,635	-	-	-	35,635
Total Operating Revenues (Gross Revenues)	**1,204,627**	**22,422**	**39,042**	**41,161**	**1,307,251**
Operating Expenses:					
O & M Expenses	754,387	22,422	7,144	41,161	825,113
Depreciation/Amortization	139,978	-	14,691	-	154,669
Taxes Other Than Income	46,996	-	3,423	-	50,419
Income Taxes - Federal	**64,398**	**-**	**(38,431)**	**-**	**25,967**
Income Taxes - State	**9,002**	**-**	**(3,843)**	**-**	**5,159**
Income Taxes - Def Net	**5,252**	**-**	**32,125**	**-**	**37,377**
Misc Revenue & Expense	(3,168)	-	-	-	(3,168)
Total Operating Expenses	1,016,845	22,422	15,109	41,161	1,095,537
Operating Revenue for Return (Net Revenues)	**187,782**	**-**	**23,933**	**-**	**211,715**
Total Rate Base	2,301,339	-	293,301	-	2,594,640

Case UE-
Exhibit PPL/400
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

PRICING AND TARIFFS

April 2008

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power & Light Company (the Company).

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah St., Suite 2000, Portland, Oregon 97232. My present position is Senior Analyst, Pricing & Cost of Service, in the Regulation Department.

Qualifications

Q. Briefly describe your education and business experience.

A. I hold a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the Regulation Department in October 2000. I assumed my present responsibilities in May 2001.

Q. Please describe your current duties.

A. I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six state service territory, including those contained in the Company's last Oregon General Rate Case, Docket UE 179.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified for the Company in regulatory proceedings in Oregon and California.

Purpose of Testimony

Q. What are your responsibilities in this proceeding?

A. I will present the Company's proposed Renewable Adjustment Clause (RAC) prices and proposed tariffs. I will also provide a comparison of present and proposed customer rates.

Price Change and Tariffs

Q. How does the Company propose to collect the price change from customers?

A. Consistent with Order 07-572 in the RAC Docket UM 1330, the Company proposes to allocate the revenue change across customer classes on the basis of an equal percent of generation revenue as calculated using present Schedule 200, Cost Based Supply Service rates and the forecasted energy from the Company's most recent general rate case, UE 179. The revenue change will be applied on a cents per kilowatt-hour basis to each applicable rate schedule through Supply Service Adjustment Schedule 202, Renewable Adjustment Clause.

Q. Have you prepared an exhibit showing the calculation of the proposed rate changes?

A. Yes. Exhibit PPL/401 shows the calculation of the proposed change to Schedule 202 rates. Columns 1 and 2 list the Delivery Service schedules. Column 3 shows the forecast kilowatt-hours from UE 179 upon which present rates are based. Column 4 shows the present Schedule 200 Cost-Based Supply Service revenues as approved in the Company's last TAM filing effective January 1, 2008; column 4 excludes Delivery Service revenues. Column 5 calculates the revenue change by Delivery Service schedule. Column 6 translates the revenue change into a cents per kilowatt-hour charge.

Q. Please describe Exhibit PPL/402.

A. Exhibit PPL/402 contains the revised Schedule 202, Renewable Adjustment Clause. This contains the proposed cents per kilowatt-hour charges applicable to each Delivery Service schedule calculated in Exhibit PPL/401 Column 6, along with some minor formatting adjustments.

Comparison of Present and Proposed Customer Rates

Q. What are the overall effects of the changes proposed in this filing?

A. The overall proposed increase to rates is 4.2 percent on a net basis. Exhibit PPL/403 shows the estimated effect of the Company's proposed prices by Delivery Service schedule both base and net of applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Have you prepared an exhibit which shows a comparison of present and proposed customer rates?

A. Yes. Exhibit PPL/404 contains monthly billing comparisons for various size customers on each of the main residential, commercial and industrial Delivery Service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. What is the estimated monthly impact to an average size residential customer using 1,000 kilowatt-hours?

A. The estimated monthly impact to a residential customer using 1,000 kilowatt-hours is $3.03.

Q. Does this conclude your direct testimony?

A. Yes.

PPL/401
Ridenour Exhibit

Case UE-
Exhibit PPL/401
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

DEVELOPMENT OF RAC ADJUSTMENTS FOR JANUARY 1, 2009

April 2008

PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF RAC ADJUSTMENT FOR JANUARY 1, 2009
FORECAST 12 MONTHS ENDED DECEMBER 31, 2007

Line No.	Description	Sch No.	kWh	Sch 200 Present Revenue	RAC Adjustment Revenue	RAC Adjustment Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6)
						(5)/(3)
	Residential					
1	Residential	4	5,423,447,855	$220,453,212	$15,965,501	0.294
2	**Total Residential**		5,423,447,855	$220,453,212	$15,965,501	
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,156,146,030	$48,204,878	$3,491,058	0.302
4	Gen. Svc. 31 - 200 kW	28	2,076,346,691	$84,718,823	$6,135,445	0.295
5	Gen. Svc. 201 - 999 kW	30	1,332,132,861	$52,818,281	$3,825,167	0.287
6	Large General Service >= 1,000 kW	48	3,116,065,292	$115,674,985	$8,377,329	0.269
7	Partial Req. Svc. >= 1,000 kW	47	208,767,290	$7,633,718	$552,844	0.269
8	Agricultural Pumping Service	41	108,189,038	$4,401,683	$318,775	0.295
9	Klamath Basin Irrigation[1]	33	106,791,778		$315,036	0.295
10	**Total Commercial & Industrial**		7,997,647,202	$313,452,368	$23,015,654	
	Lighting					
11	Outdoor Area Lighting Service	15	11,554,534	$258,675	$18,734	0.162
12	Street Lighting Service	50	11,406,000	$212,366	$15,380	0.135
13	Street Lighting Service HPS	51	15,574,917	$457,778	$33,153	0.213
14	Street Lighting Service	52	1,827,840	$41,173	$2,982	0.163
15	Street Lighting Service	53	8,459,069	$81,405	$5,895	0.070
16	Recreational Field Lighting	54	836,416	$13,855	$1,003	0.120
17	**Total Public Street Lighting**		49,658,776	$1,065,252	$77,147	
18	**Total Sales to Ultimate Consumers**		13,470,753,833	$534,970,832	$39,058,302	
19	**Employee Discount**			($225,855)	($16,357)	
20	**Total Sales with Employee Discount**		13,470,753,833	$534,744,977	$39,041,946	

[1] Schedule 33 rate set equal to Schedule 41 rate.

Case UE-
Exhibit PPL/402
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

TARIFF SCHEDULE 202

April 2008

PACIFIC POWER & LIGHT COMPANY
RENEWABLE ADJUSTMENT CLAUSE
SUPPLY SERVICE ADJUSTMENT

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	0.294 cents per kWh	(I)
15	0.162 cents per kWh	
23, 723	0.302 cents per kWh	
28, 728	0.295 cents per kWh	
30, 730	0.287 cents per kWh	
33	0.295 cents per kWh	
41, 741	0.295 cents per kWh	
47, 747	0.269 cents per kWh	
48, 748	0.269 cents per kWh	
50	0.135 cents per kWh	
51, 751	0.213 cents per kWh	
52, 752	0.163 cents per kWh	
53, 753	0.070 cents per kWh	
54, 754	0.120 cents per kWh	(I)

(continued)

Special Conditions

1. The Company will file this schedule by April 1 of each year, as necessary, for proposed charges relating to new eligible resources and updating all charges already included on this schedule.

2. The Company will make an update filing within eight (8) months of the date of the initial filing, or by December 1, to reflect then-current, prudently-incurred actual resource costs or forecasted costs where appropriate, if the cost elements of an eligible resource cannot be verified as of the date of the final round of testimony in the proceeding initiated April 1. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed charges before the January 1 effective date. The Company will be allowed to defer for later commission review and incorporation into rates the cost differences between the projected costs in the record and the updated prudently incurred cost elements if (a) such cost elements are higher than the projected costs in the record or (b) if actual capital costs cannot be verified until after December 1.

3. Costs recovered in this schedule will be allocated across customer classes using the applicable forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kilowatt-hour to each applicable rate schedule.

PPL/403
Ridenour Exhibit

Case UE-
Exhibit PPL/403
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

ESTIMATED EFFECTS OF PROPOSED PRICE CHANGE TO SCHEDULE 202

April 2008

PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED RAC PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2007

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	467,946	5,423,448	$452,922	$5,056	$457,978	$468,888	$5,056	$473,944	$15,966	3.5%	$15,966	3.5%	1
2	**Total Residential**		467,946	5,423,448	$452,922	$5,056	$457,978	$468,888	$5,056	$473,944	$15,966	3.5%	$15,966	3.5%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	70,185	1,156,146	$97,229	($5,862)	$91,367	$100,720	($5,862)	$94,858	$3,491	3.6%	$3,491	3.8%	3
4	Gen. Svc. 31 - 200 kW	28	9,623	2,076,347	$121,509	$11,026	$132,535	$127,645	$11,026	$138,670	$6,135	5.1%	$6,135	4.6%	4
5	Gen. Svc. 201 - 999 kW	30	797	1,332,133	$72,779	$3,971	$76,750	$76,604	$3,971	$80,575	$3,825	5.3%	$3,825	5.0%	5
6	Large General Service >= 1,000 kW	48	222	3,116,066	$144,641	($829)	$143,812	$153,019	($829)	$152,190	$8,377	5.8%	$8,377	5.8%	6
7	Partial Req. Svc. >= 1,000 kW	47	8	208,767	$10,232	($55)	$10,177	$10,785	($55)	$10,730	$553	5.8%	$553	5.8%	7
8	Agricultural Pumping Service	41	6,240	108,189	$11,277	($2,635)	$8,642	$11,595	($2,635)	$8,960	$319	2.8%	$319	3.7%	8
9	Agricultural Pumping - Other	33	2,117	106,792	$1,543	$4	$1,547	$1,858	$4	$1,862	$315	20.4%	$315	20.4%	9
10	**Total Commercial & Industrial**		89,192	8,104,440	$459,210	$5,620	$464,830	$482,226	$5,620	$487,846	$23,016	5.0%	$23,016	5.0%	10
	Lighting														
11	Outdoor Area Lighting Service	15	7,718	11,556	$1,415	$122	$1,537	$1,434	$122	$1,555	$19	1.3%	$19	1.2%	11
12	Street Lighting Service	50	317	11,406	$1,222	$110	$1,332	$1,237	$110	$1,347	$15	1.3%	$15	1.2%	12
13	Street Lighting Service HPS	51	660	15,575	$2,682	$229	$2,911	$2,715	$229	$2,944	$33	1.2%	$33	1.1%	13
14	Street Lighting Service	52	112	1,828	$219	$18	$237	$222	$18	$240	$3	1.4%	$3	1.3%	14
15	Street Lighting Service	53	229	8,459	$528	$54	$582	$534	$54	$588	$6	1.1%	$6	1.0%	15
16	Recreational Field Lighting	54	98	836	$70	$5	$75	$71	$5	$76	$1	1.4%	$1	1.3%	16
17	**Total Public Street Lighting**		9,134	49,660	$6,136	$537	$6,673	$6,213	$537	$6,750	$77	1.3%	$77	1.2%	17
18	**Total Sales to Ultimate Consumers**		566,272	13,577,548	$918,268	$11,214	$929,482	$957,326	$11,214	$968,540	$39,058	4.3%	$39,058	4.2%	18
19	**Employee Discount**			21,641	($447)	($3)	($450)	($464)	($3)	($467)	($16)		($16)		19
20	**Total Sales with Employee Discount**		566,272	13,577,548	$917,821	$11,211	$929,031	$956,862	$11,211	$968,073	$39,042	4.3%	$39,042	4.2%	20
21	AGA Revenue				$1,554		$1,554	$1,554		$1,554	$0		$0		21
22	**Total Sales with Employee Discount and AGA**		566,272	13,577,548	$919,375	$11,211	$930,585	$958,416	$11,211	$969,627	$39,042	4.3%	$39,042	4.2%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Schedule 91), Public Purpose Charge (Schedule 290) and Energy Conservation Charge (Schedule 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Case UE-
Exhibit PPL/404
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

MONTHLY BILLING COMPARISONS

April 2008

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 4 + Supply Service Schedule 200
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$15.59	$15.89	$0.30	1.92%
200	$22.94	$23.55	$0.61	2.66%
300	$30.30	$31.21	$0.91	3.00%
400	$37.65	$38.87	$1.22	3.24%
500	$45.01	$46.53	$1.52	3.38%
600	$53.03	$54.85	$1.82	3.43%
700	$61.07	$63.18	$2.11	3.46%
800	$69.09	$71.52	$2.43	3.52%
900	$77.12	$79.85	$2.73	3.54%
1,000	$85.15	$88.18	$3.03	3.56%
1,100	$94.18	$97.52	$3.34	3.55%
1,200	$103.22	$106.86	$3.64	3.53%
1,300	$112.25	$116.19	$3.94	3.51%
1,400	$121.29	$125.53	$4.24	3.50%
1,500	$130.32	$134.86	$4.54	3.48%
1,600	$139.34	$144.19	$4.85	3.48%
2,000	$175.48	$181.54	$6.06	3.45%
3,000	$265.82	$274.90	$9.08	3.42%
4,000	$356.16	$368.27	$12.11	3.40%
5,000	$446.49	$461.63	$15.14	3.39%

* Net rate including Schedules 91, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

RAC

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$51	$60	$53	$61	3.03%	2.62%
	750	$69	$77	$71	$79	3.38%	3.02%
	1,000	$86	$94	$89	$98	3.62%	3.29%
	1,500	$121	$129	$126	$134	3.86%	3.61%
10	1,000	$86	$94	$89	$98	3.62%	3.29%
	2,000	$156	$164	$162	$170	3.99%	3.79%
	3,000	$226	$234	$235	$243	4.14%	3.99%
	4,000	$283	$292	$296	$304	4.39%	4.27%
20	4,000	$308	$317	$321	$329	4.03%	3.93%
	6,000	$424	$432	$443	$451	4.40%	4.32%
	8,000	$539	$547	$564	$572	4.61%	4.55%
	10,000	$655	$663	$686	$694	4.75%	4.69%
30	9,000	$647	$655	$675	$683	4.32%	4.27%
	12,000	$820	$829	$858	$866	4.55%	4.51%
	15,000	$994	$1,002	$1,040	$1,048	4.70%	4.66%
	18,000	$1,167	$1,175	$1,223	$1,231	4.80%	4.77%
31	9,300	$670	$678	$698	$707	4.32%	4.27%
	12,400	$848	$857	$887	$895	4.55%	4.50%
	15,500	$1,027	$1,036	$1,076	$1,084	4.69%	4.66%
	18,600	$1,206	$1,215	$1,264	$1,272	4.80%	4.76%

* Net rate including Schedules 91, 290 and 297.

RAC

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent Difference	
kW		Present Price		Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$50	$59	$52	$60	3.09%	2.64%
	750	$67	$76	$70	$78	3.47%	3.10%
	1,000	$84	$93	$87	$96	3.69%	3.36%
	1,500	$118	$126	$123	$131	3.95%	3.70%
10	1,000	$84	$93	$87	$96	3.69%	3.36%
	2,000	$152	$160	$158	$166	4.09%	3.88%
	3,000	$220	$228	$229	$237	4.25%	4.09%
	4,000	$276	$284	$288	$296	4.51%	4.38%
20	4,000	$300	$309	$313	$321	4.14%	4.03%
	6,000	$413	$421	$431	$439	4.52%	4.44%
	8,000	$525	$533	$550	$558	4.74%	4.67%
	10,000	$637	$645	$668	$676	4.88%	4.82%
30	9,000	$630	$638	$658	$666	4.44%	4.39%
	12,000	$798	$806	$836	$844	4.68%	4.63%
	15,000	$966	$975	$1,013	$1,021	4.83%	4.79%
	18,000	$1,135	$1,143	$1,191	$1,199	4.93%	4.90%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$310	$324	4.41%
	7,500	$465	$488	4.90%
	10,500	$620	$652	5.14%
31	9,300	$627	$656	4.50%
	15,500	$948	$995	4.97%
	21,700	$1,266	$1,332	5.21%
40	12,000	$806	$842	4.52%
	20,000	$1,219	$1,280	4.98%
	28,000	$1,624	$1,709	5.24%
60	18,000	$1,204	$1,259	4.54%
	30,000	$1,812	$1,904	5.03%
	42,000	$2,419	$2,546	5.28%
80	24,000	$1,593	$1,666	4.58%
	40,000	$2,401	$2,523	5.06%
	56,000	$3,209	$3,380	5.30%
100	30,000	$1,980	$2,071	4.60%
	50,000	$2,990	$3,142	5.08%
	70,000	$4,000	$4,213	5.32%
200	60,000	$3,893	$4,075	4.68%
	100,000	$5,913	$6,217	5.14%
	140,000	$7,934	$8,360	5.36%

* Net rate including Schedules 91, 290 and 297.

RAC

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$313	$326	4.37%
	7,500	$459	$481	4.97%
	10,500	$605	$637	5.28%
31	9,300	$629	$657	4.49%
	15,500	$930	$978	5.06%
	21,700	$1,230	$1,296	5.36%
40	12,000	$806	$843	4.52%
	20,000	$1,196	$1,257	5.08%
	28,000	$1,576	$1,661	5.40%
60	18,000	$1,205	$1,259	4.54%
	30,000	$1,777	$1,868	5.13%
	42,000	$2,348	$2,475	5.44%
80	24,000	$1,592	$1,665	4.58%
	40,000	$2,352	$2,474	5.17%
	56,000	$3,113	$3,283	5.47%
100	30,000	$1,977	$2,068	4.61%
	50,000	$2,928	$3,079	5.19%
	70,000	$3,878	$4,091	5.48%
200	60,000	$3,869	$4,052	4.71%
	100,000	$5,771	$6,075	5.27%
	140,000	$7,672	$8,097	5.54%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$2,176	$2,265	4.07%
	50,000	$3,060	$3,207	4.83%
	70,000	$3,943	$4,150	5.25%
200	60,000	$3,900	$4,077	4.55%
	100,000	$5,666	$5,961	5.22%
	140,000	$7,432	$7,846	5.57%
300	90,000	$5,736	$6,002	4.64%
	150,000	$8,385	$8,829	5.29%
	210,000	$11,035	$11,655	5.63%
400	120,000	$7,510	$7,865	4.72%
	200,000	$11,042	$11,633	5.35%
	280,000	$14,574	$15,402	5.68%
500	150,000	$9,290	$9,733	4.77%
	250,000	$13,705	$14,444	5.39%
	350,000	$18,120	$19,155	5.71%
600	180,000	$11,070	$11,602	4.81%
	300,000	$16,368	$17,255	5.42%
	420,000	$21,666	$22,908	5.73%
800	240,000	$14,629	$15,339	4.85%
	400,000	$21,694	$22,876	5.45%
	560,000	$28,759	$30,414	5.76%
1000	300,000	$18,189	$19,076	4.88%
	500,000	$27,020	$28,498	5.47%
	700,000	$35,851	$37,920	5.77%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$2,130	$2,219	4.16%
	50,000	$2,994	$3,142	4.94%
	70,000	$3,859	$4,066	5.36%
200	60,000	$3,816	$3,993	4.65%
	100,000	$5,545	$5,841	5.33%
	140,000	$7,274	$7,688	5.69%
300	90,000	$5,610	$5,876	4.74%
	150,000	$8,204	$8,647	5.40%
	210,000	$10,798	$11,418	5.75%
400	120,000	$7,363	$7,718	4.82%
	200,000	$10,822	$11,413	5.46%
	280,000	$14,280	$15,107	5.80%
500	150,000	$9,106	$9,550	4.87%
	250,000	$13,429	$14,168	5.50%
	350,000	$17,752	$18,786	5.83%
600	180,000	$10,849	$11,381	4.90%
	300,000	$16,036	$16,923	5.53%
	420,000	$21,223	$22,465	5.85%
800	240,000	$14,335	$15,044	4.95%
	400,000	$21,251	$22,433	5.56%
	560,000	$28,167	$29,823	5.88%
1000	300,000	$17,820	$18,707	4.98%
	500,000	$26,465	$27,944	5.58%
	700,000	$35,111	$37,180	5.89%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$192	$212	$185	$201	$221	$185	4.75%	4.30%	0.00%
	5,000	$320	$340	$185	$335	$355	$185	4.75%	4.47%	0.00%
	7,000	$448	$467	$185	$469	$489	$185	4.75%	4.55%	0.00%
Three Phase										
20	6,000	$384	$423	$371	$402	$442	$371	4.75%	4.31%	0.00%
	10,000	$639	$679	$371	$670	$709	$371	4.75%	4.48%	0.00%
	14,000	$895	$935	$371	$938	$977	$371	4.75%	4.55%	0.00%
100	30,000	$1,918	$2,140	$1,504	$2,009	$2,232	$1,504	4.75%	4.26%	0.00%
	50,000	$3,197	$3,435	$1,504	$3,349	$3,587	$1,504	4.75%	4.42%	0.00%
	70,000	$4,476	$4,730	$1,504	$4,689	$4,943	$1,504	4.75%	4.50%	0.00%
300	90,000	$5,755	$6,421	$3,770	$6,028	$6,695	$3,770	4.75%	4.26%	0.00%
	150,000	$9,591	$10,306	$3,770	$10,047	$10,762	$3,770	4.75%	4.42%	0.00%
	210,000	$13,428	$14,191	$3,770	$14,066	$14,829	$3,770	4.75%	4.50%	0.00%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$185	$204	$185	$194	$213	$185	4.94%	4.47%	0.00%
	5,000	$308	$327	$185	$323	$342	$185	4.93%	4.64%	0.00%
	7,000	$431	$450	$185	$452	$472	$185	4.93%	4.72%	0.00%
Three Phase										
20	6,000	$369	$408	$371	$388	$426	$371	4.94%	4.47%	0.00%
	10,000	$616	$654	$371	$646	$685	$371	4.94%	4.64%	0.00%
	14,000	$862	$901	$371	$905	$943	$371	4.93%	4.72%	0.00%
100	30,000	$1,847	$2,064	$1,494	$1,938	$2,155	$1,494	4.93%	4.42%	0.00%
	50,000	$3,079	$3,311	$1,494	$3,231	$3,463	$1,494	4.93%	4.59%	0.00%
	70,000	$4,310	$4,559	$1,494	$4,523	$4,772	$1,494	4.93%	4.67%	0.00%
300	90,000	$5,542	$6,192	$3,760	$5,815	$6,465	$3,760	4.93%	4.42%	0.00%
	150,000	$9,236	$9,934	$3,760	$9,692	$10,390	$3,760	4.93%	4.59%	0.00%
	210,000	$12,931	$13,677	$3,760	$13,569	$14,315	$3,760	4.93%	4.67%	0.00%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$17,239	$18,070	4.82%
	500,000	$25,380	$26,765	5.46%
	700,000	$33,521	$35,461	5.79%
2,000	600,000	$34,158	$35,820	4.87%
	1,000,000	$49,881	$52,651	5.55%
	1,400,000	$65,740	$69,619	5.90%
4,000	1,200,000	$67,224	$70,549	4.95%
	2,000,000	$98,942	$104,483	5.60%
	2,800,000	$130,660	$138,418	5.94%
6,000	1,800,000	$99,778	$104,765	5.00%
	3,000,000	$147,355	$155,667	5.64%
	4,200,000	$194,931	$206,568	5.97%

Notes:

On-Peak kWh	61.24%
Off-Peak kWh	38.76%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$15,923	$16,754	5.22%
	500,000	$23,696	$25,081	5.85%
	700,000	$31,469	$33,408	6.16%
2,000	600,000	$31,568	$33,231	5.27%
	1,000,000	$46,554	$49,324	5.95%
	1,400,000	$61,675	$65,554	6.29%
4,000	1,200,000	$62,087	$65,412	5.36%
	2,000,000	$92,329	$97,871	6.00%
	2,800,000	$122,572	$130,330	6.33%
6,000	1,800,000	$92,648	$97,636	5.38%
	3,000,000	$138,012	$146,325	6.02%
	4,200,000	$183,377	$195,014	6.35%

Notes:

On-Peak kWh	61.24%
Off-Peak kWh	38.76%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

RAC

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$14,660	$15,491	5.67%
	500,000	$22,078	$23,463	6.27%
	700,000	$29,496	$31,435	6.58%
2,000	600,000	$29,052	$30,714	5.72%
	1,000,000	$43,328	$46,098	6.39%
	1,400,000	$57,740	$61,618	6.72%
4,000	1,200,000	$57,064	$60,389	5.83%
	2,000,000	$85,887	$91,429	6.45%
	2,800,000	$114,711	$122,469	6.76%
6,000	1,800,000	$85,438	$90,426	5.84%
	3,000,000	$128,674	$136,986	6.46%
	4,200,000	$171,910	$183,546	6.77%

Notes:

On-Peak kWh	56.02%
Off-Peak kWh	43.98%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.