ORDER NO. 05-1050

ENTERED 09/28/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

In the Matter of	)	
	)	
PACIFIC POWER & LIGHT COMPANY	)	ORDER
(dba PacifiCorp)	)	
	)	
Request for a General Rate Increase in the	)	
Company's Oregon Annual Revenues.	)	

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SUMMARY

In this order, the Commission approves new rate schedules for PacifiCorp. The allowed revenue requirement increase is approximately $25.9 million, or 3.17 percent. This is a reduction of $76.1 million from PacifiCorp's initial request of approximately $102.0 million. The specific rate changes will take effect on October 4, 2005.

The Commission determined that the provisions of SB 408 apply to this rate case, and authorized a $16.07 million adjustment to PacifiCorp's tax expense. The Commission further adopted numerous stipulations agreed to by various parties in this proceeding. One of these stipulations authorizes a change in billing so that customers will not be billed at a higher rate due to a variance in the monthly billing cycle. Finally, the Commission is approving PacifiCorp's transition adjustment mechanism.

INTRODUCTION

Procedural Background

On November 12, 2004, Pacific Power and Light (PacifiCorp) filed Advice No. 04-018, an application for a general rate increase of approximately $102.024 million, or 12.5 percent, in Oregon revenues. PacifiCorp asked for the new rates to take effect on December 12, 2004.

On December 7, 2004, the Commission found good and sufficient cause to investigate the propriety and reasonableness of the tariff sheets pursuant to ORS 757.210 and 757.215. The Commission ordered the rates to be suspended for nine months from December 12, 2004. The initial suspension period expired on September 11, 2005. PacifiCorp subsequently extended the suspension period through October 3, 2005.

Conferences

On December 7, 2004, a prehearing conference was held in Salem, Oregon, to identify parties and interested persons, and to adopt a procedural schedule. The following entities either had party status or participated in the proceeding: Portland General Electric (PGE), Oregon Department of Energy (ODOE), Fred Meyer Stores and Quality Food Centers, Divisions of Kroger Company, Inc. (Fred Meyer), Citizens' Utility Board (CUB), Industrial Customers of Northwest Utilities (ICNU), Community Action Directors of Oregon, Oregon Energy Coordinators Association, Utility Reform Project, Nancy Newell, Klamath Off-Project Water Users, Inc., Klamath Water Users Association, WaterWatch of Oregon, Oregon Natural Resources Council and Commission Staff (Staff) .

During the course of these proceedings, a new docket (UE 171) was opened to address issues about the future rates of irrigators in the Klamath Basin. That docket was later closed by the Commission (Order No. 05-726). Further proceedings regarding Klamath Basin irrigators' rate issues were remanded to this docket. Due to the remand, a bifurcated proceeding was necessary. All general rate issues, excluding Klamath Basin irrigator issues, are being resolved in this order. As discussed below, the current Schedule 33 will be used for interim rates until the Klamath Basin irrigator issues are addressed and resolved in a separate order.

Public Comment Meetings

The general public was given an opportunity to attend open houses to learn about and make comment on PacifiCorp's application. These open houses were held in Bend on February 28, 2005; Portland on March 9, 2005; Klamath Falls on March 15, 2005; and Medford on March 16, 2005.

Evidentiary Hearings

Hearings were held in Salem, Oregon, on July 20 and 21, 2005. During those proceedings, the following appearances were entered:

Katherine McDowell and Marcus Wood, attorneys, represented PacifiCorp.

Jason Eisdorfer, attorney, represented CUB.

Melinda Davison and Irion Sanger, attorneys, represented ICNU.

Michael Kurtz, attorney, represented Fred Meyer Stores.

Jason Jones and David Hatton, attorneys, represented Staff.

Briefing and Oral Arguments

Prehearing briefs were filed by PacifiCorp, ICNU, Klamath Water Users Association, CUB, Staff and Fred Meyer Stores on July 13 and 14, 2005. Posthearing opening and reply briefs were filed by PacifiCorp, ICNU, CUB and Staff on August 4 and 11, 2005, respectively.

Oral argument was held before the Commission on August 15, 2005. PacifiCorp, ICNU, CUB and Staff participated in the oral argument.

Stipulations

Five stipulations were filed during the course of these proceedings. The subject matter and signatories of the stipulations are identified below. The contents of each stipulation are discussed in further detail in this order, below at 4.

On May 4, 2005, a partial stipulation was filed that addressed some revenue requirement issues. If adopted, the stipulation would reduce PacifiCorp's revenue requirement by approximately $31 million. This stipulation, which was supported by the joint testimony of Paul Wrigley (PacifiCorp), Ed Durrenberger (Staff), Bob Jenks (CUB), Randall Falkenberg (ICNU) and Kevin Higgins (Fred Meyer), is attached as Appendix A.

On May 6, 2005, a Partial Requirements and Economic Replacement Power Tariffs stipulation was filed, which addressed issues involving PacifiCorp's tariff schedules for standby electric service for consumers supplying all or part of their load by self-generation. This stipulation, which was supported by the joint testimony of William Griffith (PacifiCorp), Lisa Schwartz (Staff) and Kathryn Iverson (ICNU), is attached as Appendix B.

On June 29, 2005, a second partial stipulation was filed addressing some additional revenue requirement issues. If adopted, this stipulation would further reduce PacifiCorp's revenue requirement by $2.44 million. The stipulation, which was supported by the joint testimony of Paul Wrigley (PacifiCorp), Ed Durrenberger (Staff), Bob Jenks (CUB), James Selecky (ICNU), and Kevin Higgins (Fred Meyer), is attached as Appendix C.

Also on June 29, 2005, a third partial stipulation was filed by PacifiCorp and Staff to address other revenue requirement issues. If adopted, this stipulation would increase PacifiCorp's revenue requirement by approximately $2.49 million. The stipulation, which was supported by the joint testimony of Mark Widmer (PacifiCorp) and Bill Wordley (Staff), is attached as Appendix D.

On July 29, 2005, the fourth partial stipulation was filed addressing additional revenue requirement issues, capital structure and cost of capital. If adopted, this stipulation would reduce PacifiCorp's proposed revenue requirement increase to approximately $52.5 million. The stipulation, which was supported by the joint testimony of Laura Beane (PacifiCorp), Ed Durrenberger (Staff), Bob Jenks (CUB), James Selecky (ICNU), and Kevin Higgins (Fred Meyer), is attached as Appendix E.

The stipulations and supporting testimony were entered into the record as evidence pursuant to OAR 860-014-0085(1).

Based on the record in these proceedings, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Applicable Law

In a rate case, the Commission's function involves two primary steps. First, we determine the amount of revenue an entity, such as PacifiCorp, is entitled to receive. The utility's revenue requirement is determined on the basis of the utility's costs. Second, we allocate the burden of paying the revenue requirement among the utility's customer classes and design rates for each class.[1]

In the revenue requirement phase of a rate case, the Commission must determine for a specified test year: (1) the gross utility revenues; (2) the utility's reasonable operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which utility stockholders are reasonably entitled.[2] Once these components are known, the Commission is then able to set utility rates that are at fair, just and reasonable levels.

STIPULATED ISSUES

Various parties submitted five stipulations throughout the course of these proceedings. One stipulation addresses issues regarding partial requirements consumers, three stipulations solely address revenue requirement issues, and the final stipulation addresses cost of capital, rate spread and rate design and revenue requirement issues. There was also an agreement regarding interim rates for the Klamath Basin irrigators. For purposes of our discussion, we divide the stipulations and agreement into three groups: (1) Partial Requirements Stipulation; (2) Revenue Requirement, Cost of Service and Rate Design Stipulations; and (3) Klamath Basin Irrigators' Interim Rate Proposal.

1. Partial Requirements Stipulation

On May 6, 2005, PacifiCorp filed a stipulation regarding partial requirements and economic replacement power tariffs (Schedules 47, 247, 747, 76R, 276R and 776R), which was signed by Staff, ODOE, ICNU, and PacifiCorp.

Partial requirements consumers regularly provide all or part of their load by self-generation. The tariffs embodied in Schedules 47, 747 and 247 more closely reflect the cost of providing standby service to these partial requirements consumers. The proposed economic replacement tariffs (Schedules 76R, 276R and 776 R) provide partial requirements consumers an opportunity to purchase energy from PacifiCorp or an energy service supplier (ESS) that replaces all or some of the power that could be self-generated, particularly when the consumer decides that purchased energy is economically beneficial. Current Schedule 47 partial requirements consumers, of which there are seven, will have to enter into new partial requirements service agreements.

The proposed Schedule 247 uses PowerDex Hourly as the market index to be used for determining unscheduled energy charges. *See* Partial Requirement Stipulation, Exhibit B at 2. ICNU does not agree with the use of PowerDex Hourly for determining unscheduled energy charges, but did agree not to file testimony or take any

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[1] *See, e.g.., American Can Co. v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[2] *See Pacific Northwest Bell Tel. Co. v. Sabin,* 21 Or App 200, 205 n.4, *rev den* (1975).

action to oppose use of the PowerDex Hourly index. ICNU supports Commission approval of the stipulation as presented.

Several of the charges in the six rate schedules reflect the revenue requirement as originally filed by PacifiCorp. These include: 1) Schedule 47 – Distribution, Reserves, and Transmission and Ancillary Service Charges; 2) Schedule 747 – Distribution and Reserves Charges; 3) Schedule 76R – Transmission and Ancillary Services and Daily ERP Demand Charges; and 4) Schedule 776R – Daily ERP Demand Charge. Once a final revenue requirement is established, PacifiCorp will file compliance tariffs to reflect changes in revenue requirement.

Commission Resolution

Having reviewed the partial requirements and economic replacement power tariffs stipulation and supporting testimony, we find the proposed tariffs to be fair and reasonable, subject to our review of the compliance tariffs as required by this order. The stipulation set forth in Appendix B is adopted.

2. Revenue Requirement, Cost of Service and Rate Design Stipulations

While the remaining four stipulations have numerous agreements involving revenue requirement, they also contain agreements about other contested matters. We summarize the contents and discuss our resolution of each stipulation. While we reserve our discussion about most of the disputed issues for later in this order, some disputed issues are resolved during our discussion of the stipulation. To make our holdings as clear as possible, we will indicate whether we adopt, or do not adopt, each stipulation in this portion of the order.

A. Partial Stipulation filed May 4, 2005

PacifiCorp, Staff, CUB, ICNU and Fred Meyer entered into this stipulation, the effect of which reduced PacifiCorp's proposed revenue requirement increase by approximately $31 million. The adjusted revenue requirement increase, based on this stipulation, is approximately $71 million.[3]

The parties agreed to the following:

1. Annual Net Power Costs will be set at approximately $785 million on a Total Company basis, subject to adjustments based on the resolution of Net Power Costs not resolved by this stipulation.

2. PacifiCorp will commit necessary resources to evaluate stochastic modeling of Net Power Costs for possible incorporation into rates. The analysis will consider volatility of hydro generation, electricity

[3] $8.00 million will be incorporated into PacifiCorp's RVM, if approved.

and natural gas prices, system load and forced outages, along with the correlations among these variables. With Staff input, PacifiCorp will develop a plan to complete the stochastic modeling. Quarterly public workshops will be held to report progress made and receive input from interested persons.

3. Line losses in the load forecast will be updated, resulting in a reduction in the filed revenue requirement of $9.16 million. The revenue requirement will also be updated based on the new allocation factors resulting from the changes in PacifiCorp's load forecast.

4. PacifiCorp will not take an operating deduction for the Oregon Commission fee, resulting in a $0.138 million revenue requirement reduction.

5. The annual net cost for employee incentive programs for the 2006 test year will be set at $35.6 million on a Total Company basis. This adjustment ties PacifiCorp's total compensation to market, rather than to financial performance. PacifiCorp's Long Term Incentive Compensation is completely excluded. These adjustments result in a $5.5 million revenue requirement reduction.

6. Non-labor administrative and general costs are reduced by $6.123 million.

7. Due to growth in revenue accounts 450, 451, 454 and 465, a $2.2 million revenue requirement reduction will be taken.

8. The impact of nonrecurring coal costs associated with Bridger will be computed by amortizing the difference between actual 2004 costs and forecasted 2006 costs over a three-year period, with PacifiCorp recovering a return on the unamortized balance. This process results in a $2.4 million revenue requirement reduction.

9. PacifiCorp's federal and state income expense will be adjusted based upon the final weighted average cost of debt.

10. The production activity deduction methodology proposed by PacifiCorp will be used. The actual amount of the deduction will be based upon the final revenue requirement authorized by this order. If the Internal Revenue Service approves the production activity methodology proposed by the Edison Electric Institute (EEI), PacifiCorp reserves the right to file for deferred accounting treatment for the difference between the PacifiCorp and EEI methodologies.

11. Several adjustments will increase PacifiCorp's revenue requirement by $2.54 million. These are:

    $1.3 million – DITBAL allocation
    $0.992 million – Hermiston and Gadsby allocation factor corrections
    $0.250 million – Little Mountain and WSCC membership costs

12. The Cost-Based Supply Service Energy Charges in Schedule 200 will have equal tailblock charges applicable for Schedules 28 and 30.

13. Change the graveyard market caps for the Transition Adjustment calculation depending on the assumed amount of direct access load.

The parties listed the outstanding issues to be resolved during the proceedings. They agreed to support adoption of the stipulation, stating that the adjustments, along with the revenue requirement levels resulting from adjustments, are fair and reasonable.

Commission Resolution

This stipulation attempts to resolve numerous revenue requirement issues, and results in an approximate $31 million decrease in PacifiCorp's filed revenue requirement. PacifiCorp, Staff, CUB, ICNU and Fred Meyer believe these adjustments are supported by the evidence and are fair and reasonable. We agree. The stipulation set forth in Appendix A is adopted.

B. Second Partial Stipulation filed June 29, 2005

PacifiCorp, Staff, CUB, ICNU, and Fred Meyer entered into this stipulation. The parties agreed to reduce PacifiCorp's filed revenue requirement for full-time employee benefits by $2.44 million. This reduction reflects a change in base data and escalation rates for medical benefits and workers compensation, as well as amortization of external system development costs associated with Other Salary Overhead over two years.

The parties further stated that the adjustments, along with the revenue requirement level resulting from the adjustments, are fair and reasonable and recommended that the stipulation be adopted.

Commission Resolution

This stipulation addresses employee benefits. It results in a $2.44 million revenue requirement reduction, and allows PacifiCorp to amortize some development costs involving Other Salary Overhead over two years. PacifiCorp, Staff, CUB, ICNU and Fred Meyer believe these adjustments are supported by the evidence and are fair and reasonable. We agree. The stipulation set forth in Appendix C is adopted.

C. Third Partial Stipulation filed June 29, 2005

PacifiCorp and Staff entered into this stipulation, the effect of which increased PacifiCorp's proposed revenue requirement by $2.49 million. The settlement contains various matters:

RVM - If RVM is implemented, adoption of this stipulation would result in a decrease from PacifiCorp's original proposed revenue requirement for RVM on January 1, 2006. Further, if RVM is implemented as proposed by PacifiCorp, Staff and PacifiCorp agreed that the RVM power costs should be set at $800.5 million, prior to the inclusion of RVM updates. The actual change to the revenue requirement will be determined by the November 15, 2005, final GRID power cost model run. This final GRID run will include all the adjustments proposed by PacifiCorp in its testimony (PPL/Widmer; 604-606 and 607-608) except for the Deferred Maintenance, Thermal Ramping, Station Service, and Planned Outages adjustments.

Fuel Handling Charge – PacifiCorp and Staff agreed that the revenue requirement should be corrected to include a fuel handling charge, resulting in a $2.49 million revenue requirement increase.

Other Matters – Staff agreed to the following:

1. Support waiver of OAR 860-038-0080(1)(b) as to West Valley Lease, the Gadsby CTs and Currant Creek projects.

2. Accept PacifiCorp's level of plant forced outages.

3. Support treatment of four qualifying facilities as "new" under the terms of the Revised Protocol.

4. Will not raise any issue about any "mismatch" between a September 12, 2005, base rate change effective date[4] and the calendar year 2006 test period.

Staff and PacifiCorp stated that the adjustments, along with the revenue requirement level resulting from the adjustments, are fair and reasonable and recommended that the stipulation be adopted.

[4] This date has been changed to October 4, 2005.

Commission Resolution

This stipulation, entered into by PacifiCorp and Staff, provides for a $2.49 million revenue requirement increase due to an incorrect fuel handling charge. In June 2005, PacifiCorp increased its original filed fuel handling charge by approximately $2.5 million to correct an error. *See* PPL/1600, Wrigley/4. According to Paul Wrigley, Manager of Revenue Requirement, when PacifiCorp prepared the results of operations exhibit (PPL 801) for this proceeding, the fuel handling costs were erroneously removed. PPL/1600, Wrigley/2.

ICNU recommends that we reject PacifiCorp's fuel handling adjustment because it establishes a poor precedent to allow a utility to include additional costs in the middle of a rate case, and because PacifiCorp has not established that the costs are reasonable. ICNU also finds it "suspicious" that PacifiCorp identified its error at the same time it agreed to make an offsetting $2 million power cost adjustment related to the Camas facility.

While the timing may be "suspicious," nevertheless it was an error on PacifiCorp's part to exclude the fuel handling costs. The costs are not additional expenses, but expenses inadvertently omitted by PacifiCorp. ICNU had sufficient time to respond to PacifiCorp's correction. Further, Staff reviewed the expense, agreed that an error had occurred, and recommended that the expense be included in revenue requirement so that test year 2006 can accurately reflect PacifiCorp's costs. We agree with Staff and PacifiCorp that the fuel handling charge should be corrected.

The stipulation also sets forth an agreement between Staff and PacifiCorp about the appropriate number for RVM power costs. As discussed later in this order, we adopt PacifiCorp's Transition Adjustment Mechanism (TAM) proposal. Our discussion will explain why we believe that the TAM proposal is appropriate. Therefore, we find that this stipulation set forth in Appendix D is fair and reasonable, and we adopt it in its entirety.

D. Fourth Partial Stipulation filed July 29, 2005

PacifiCorp, Staff, ICNU, CUB and Fred Meyer entered into this stipulation regarding cost of capital and specific revenue requirement adjustments. The effect of this stipulation is a $23.4 million reduction in PacifiCorp's proposed revenue requirement of $75.9 million, resulting in an approximate $52.5 million total revenue requirement increase.

Capital Structure, Cost of Capital and Rate of Return - The signatories agreed to the cost of capital, capital structure and rate of return (8.057 percent) as shown in the following chart:

Capital Component	**Percent**	**Cost**	**Weighted Cost**
Long Term Debt	51.34%	6.288%	3.228%
Preferred Stock	1.10%	6.590%	0.073%
Common Equity	47.56%	10.000%	4.756%
Total	100.00%		8.057%

Rate Spread/Rate Design - The signatories also agreed to a rate spread methodology,[5] with an understanding that none of the major rate schedules will receive more than 1.5 times the net increase, unless such computation is less than two percentage points above the net increase. In that instance, the cap on any major rate schedule net increase shall be the sum of the net increase plus two percentage points. However, Schedule 48 (Large General Service) will not increase more than 1.45 times the net increase. Finally, Residential Schedule 4 will not have a Rate Mitigation Adjustment (RMA) surcharge or surcredit, while Schedule 48 may have a surcredit but no surcharge. Other rate schedules may have RMA surcharges or surcredits if needed to implement the rate spread methodology.

As for rate design, the signatories agreed to implement time of day demand and energy pricing on an experimental basis for Schedules 48/200. This experiment will continue until PacifiCorp's next general rate case. PacifiCorp will complete a study within 12 months that analyzes the wholesale cost differences between on-peak and off-peak rate differentials. PacifiCorp will also collect data to analyze the effectiveness of this program, including analysis of the ability of Schedule 48 customers to change usage patterns. Finally, Schedule 28/200 tailblock equalization "shall be as described in PPL Exhibit 1204, Griffith/6-7 and Staff Exhibit 900, Breen/15." Stipulation at 6.

The signatories agreed to adopt CUB's proposed bill proration method, which prorates residential bills based on the number of billing days in the meter read cycle.[6] The proration provides a more equitable treatment of kWh allocation, so that customers with a longer billing cycle, particularly in the winter months, will not be penalized. The signatories further agreed that any consumer complaints that relate to the

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[5] The stipulation states:

> Except for the modification indicated, the Parties agree that the rate spread methodology as shown in PPL Exhibit 1210, Griffith/1 is the appropriate rate spread methodology to employ in setting rates in UE 170.

PPL Exhibit 1210, Griffith/1 is an Excel spreadsheet. While the formula is embedded in the spreadsheet, the spreadsheet itself does not explain the methodology used to generate the numbers shown on the spreadsheet.

[6] This essentially implements daily blocks for all bills.

correct application of the bill proration proposal for residential customers will not be counted against PacifiCorp's consumer complaint metrics.

Finally, the signatories agreed that rate changes due to the order in this docket will go into effect October 4, 2005. PacifiCorp previously submitted a letter extending the suspension period through October 3, 2005.

Pension Expense - PacifiCorp will adjust its pension expense to reflect the $52.5 million revenue requirement increase in light of the cost of capital agreement. This permits PacifiCorp to recover its full FAS 87 pension expense.

The parties agreed that the following issues were excluded from the fourth partial stipulation:

For Staff, ICNU and CUB – tax adjustments.

For ICNU and CUB – RVM proposal and RVM power cost adjustments.

For ICNU – fuel handling correction; allocation treatment of certain qualifying facilities; prudence of West Valley Lease, the Gadsby CTs and Currant Creek projects; UM 995 deferral period outages; waiver of OAR 860-038-0080(1)(b); treatment of costs related to development of RTO; and Third Partial Stipulation issues, including a GRID model outage and heat rate update adjustment.

The parties agreed that the stipulated adjustments, and the revenue requirement level resulting from application of the adjustments, are fair and reasonable and recommended that the stipulation be adopted.

Commission Resolution

This stipulation also was supported by PacifiCorp, Staff, CUB, ICNU and Fred Meyer. As we previously stated, the effect of this stipulation would reduce the revenue requirement increase to approximately $52.5 million.[7] While not all parties agree on each of the specific capital components set forth in the table, above at 10, they do agree that the cost of capital resolution results in a reasonable overall revenue requirement.

The parties also agreed to rate spread and rate design, as well as to an October 4, 2005, effective date for the rate changes. Finally, the parties accepted CUB's proposal for prorating bills. This proposal ensures that customers won't be charged at a higher rate simply because one billing cycle was longer than another billing cycle, causing the customer to be billed at a higher block rate due to usage.

[7] This amount will change based on our decision in this order on the matters the parties were unable to resolve.

The signatories believe these adjustments are supported by the evidence and are fair and reasonable. We agree. The stipulation set forth in Appendix E is adopted.

3. Klamath Basin Irrigators' Interim Rate Proposal

In its rate filing, PacifiCorp sought to change rates paid by irrigators in the Klamath Basin. That issue has been removed from this portion of the proceeding, and will be resolved by separate order. However, we've been asked to adopt a proposal to allow the current rates to serve as interim rates until the Klamath Basin irrigator rates are resolved. We address this proposal under stipulated issues.

For almost 50 years, PacifiCorp served irrigators located in the Klamath Basin under historic contracts that provide rates below PacifiCorp's general tariff schedules. Irrigators located within the federally-designated boundaries of the Klamath Project (On-Project Irrigators) buy power from PacifiCorp at rates established pursuant to a contract between PacifiCorp's predecessor, the California-Oregon Power Company (Copco), and the United States Bureau of Reclamation. This contract (On-Project Contract) expires by its terms in April 2006. The Klamath Basin irrigators located outside the boundaries of the Klamath Reclamation Project (Off-Project Irrigators) buy power from PacifiCorp pursuant to a separate contract between Copco and an association representing irrigation customers. This second contract (Off-Project Contract) was executed April 30, 1956, but contains no express termination date.

As part of its general rate filing in this docket, PacifiCorp proposed to move both the On-Project and Off-Project irrigators to standard tariff rates concurrent with the expiration of the On-Project Contract. The Commission opened a separate docket, UE 171, to separately address PacifiCorp's proposal, but later remanded the issue back to this proceeding. *See* Order No. 05-726.

Organizations representing the irrigation customers and other interested parties agree that the rate for Klamath Basin irrigation customers need not be completed prior to the suspension date for this general rate proceeding, but should be resolved prior to the expiration date of the 1956 on-project contract. *See,* ALJ Ruling issued June 30, 2005. To accomplish this, the parties suggest that the Commission use the current historic contract rates, set forth in Schedule 33, as interim rates for these irrigation customers when setting PacifiCorp's revenue requirement in the general rate proceeding. The parties further agreed that, once a Commission decision is made regarding the rates for the Klamath Basin irrigators, PacifiCorp should spread any revenue requirement impact of that decision to other customer classes through an adjustment to its rate spread/rate design.

Commission Resolution

Under the unique circumstances presented in this proceeding with the expiration of the On-Project contract in 2006, the test year for this rate proceeding, we agree with and adopt the parties' proposal. The current historic contract rates, set forth in PacifiCorp's Schedule 33, will be adopted as interim rates for these irrigation customers for purposes of setting PacifiCorp's revenue requirement in this proceeding. Once a decision is made regarding the rates for the Klamath Basin irrigators, we will direct PacifiCorp to spread any revenue requirement impact arising from that decision to other customer classes through a revenue-neutral adjustment to its rate spread/rate designs.

CONTESTED ISSUES

Having addressed the five filed stipulations, we turn to the remaining contested issues in this case: treatment of taxes; RVM and power cost adjustments; prudence of West Valley Lease, Gadsby CTs and Currant Creek projects; waiver of OAR 860-038-0080(1)(b); treatment of costs related to development of a Regional Transmission Organization (RTO); UM 995 deferral period outages; and allocation treatment of certain qualifying facilities under the Revised Protocol.

1. Taxes

The issue of how to address income taxes as part of the revenue requirement was an area of fundamental disagreement between PacifiCorp on one side and Staff and intervenors on the other. To a lesser degree, Staff and intervenors disagreed among themselves as to the appropriate way to handle this issue. We first provide a background and factual findings for the present dispute and then discuss the various positions of the parties. Next, we discuss legal parameters to our decision, including the overlay, if any, of recently enacted SB 408. Finally, we set forth our decision as to how taxes will be addressed in this docket.

Background and Factual Findings

A utility's federal and state income taxes are allowed as operating expenses for ratemaking purposes. To calculate these taxes, the Commission has historically used a stand-alone methodology. "Under the 'stand-alone' method, ratemaking tax expense is calculated based on the items of income and expense included in the regulated utility's revenue requirement calculation." Staff/1000, Conway-Johnson /2. This method looks only to the regulated revenues and operating costs of the utility itself, without regard to the utility's unregulated activities or the operations and actions of its parent and other affiliated companies.

Recently, the Commission's use of the stand-alone methodology has come under criticism due to the potential mismatch between monies collected from ratepayers to pay taxes and the actual amount of taxes paid to the taxing authorities. Because tax laws allow a utility's corporate holding company to file consolidated tax returns reflecting its full span of operations, losses in some operations can offset profits in others. Thus, consolidated tax reporting may result in amounts collected for taxes in a utility's rates to exceed the taxes the parent company actually pays.

In response to these concerns, the 2005 Oregon Legislative Assembly passed SB 408. This bill requires utilities to file certain utility tax information with this Commission. After reviewing this information and upon making specific findings, the Commission must direct the utility to implement an automatic adjustment clause to ensure that ratepayers are not charged more tax than the utility or its affiliated group pays to units of government that is properly attributed to the regulated operations of the utility. Although SB 408 contained an emergency clause, making the bill effective upon the Governor's signature, which occurred on September 2, 2005, the automatic adjustment clause applies only to taxes paid to units of government and collected from ratepayers on or after January 1, 2006.

The controversy relating to utility taxes affects PacifiCorp, which was purchased by ScottishPower in 1999. *See*, Order No. 99-616. Shortly after the purchase, ScottishPower created PacifiCorp Holdings, Inc. (PHI) to serve as a non-operating, direct, wholly owned subsidiary. PHI was capitalized with an intercompany acquisition-related loan, which is a loan on PHI's books, rather than PacifiCorp's. PHI then used that loan to acquire ScottishPower's shares of PacifiCorp's. The interest that PHI pays to ScottishPower is deductible on PHI's consolidated income tax returns (filed on behalf of PacifiCorp and other PHI affiliates). The effect of this deduction is to eliminate or substantially reduce the consolidated group's taxable income, resulting in PacifiCorp collecting more money from ratepayers than the consolidated group pays in taxes to governmental units. CUB/100, Jenks/5.

<u>Parties' Positions</u>

Both CUB and ICNU recommend abandonment of the stand-alone methodology, with each party proposing slightly different tax adjustments utilizing the interest deduction at PHI.[8] CUB allocates the $160.31 million interest expense deduction using PacifiCorp's proportionate share of gross profits to PHI (91.5 percent). CUB adjusts this system-wide figure to determine Oregon's jurisdictional share (28.8 percent), and then calculates the tax deduction using the 35 percent federal tax rate. CUB contends that its methodology, which results in an adjustment of $14.83 million, is an attempt to make a better forecast of PacifiCorp's tax liability in test year 2006. CUB asserts that the adjustment is reasonable. It notes that, although PacifiCorp is the primary asset of PHI, and PacifiCorp's rates are the main source of income to pay the PHI debt, its customers are not the primary recipients of the consolidated tax deductions that come from the interest payments on that debt.

ICNU allocates the $160.31 million interest expense adjustment using the percentage of PHI assets related to PacifiCorp's activities (94.72 percent). Like CUB, ICNU similarly adjusts this amount to determine the Oregon jurisdictional share based on percentage of rate base, but then uses the Oregon composite tax rate of 37.95 percent to

[8] Although CUB and ICNU both claim their adjustments are consistent with the stand-alone methodology, the fact that their adjustments are based on the actions of PacifiCorp's parent company necessarily implies the rejection of this historically used methodology.

calculate its proposed $16.64 million tax adjustment. ICNU contends the Commission should adopt this adjustment to reduce PacifiCorp's revenue requirement and eliminate the amount of "phantom taxes" being assessed by PacifiCorp that will never be paid to taxing authorities. ICNU adds that PHI will retain the tax benefit of its corporate structure, while little or no taxes will be paid on PacifiCorp's income.

ICNU also asserts that newly enacted SB 408 applies to this proceeding. Specifically, ICNU cites Section 2 (1)(f) and Section 5:

> Utility rates that include amounts for taxes should reflect the taxes that are paid to units of government to be considered fair, just and reasonable.
>
> ORS 757.210 is amended to read:
>
> * * *
> The commission may not authorize a rate or schedule of rates that is not fair, just and reasonable.

ICNU argues that the Commission must, in this order, consider the taxes paid to units of government when establishing rates.

Staff continues to support a stand-alone methodology for calculating taxes, with one significant change. Staff contends that the Commission can consider tax benefits at the holding company level, in this case, at PHI, if the Commission determines that including the benefits in rates meets the benefits/burdens test outlined in *City of Charlottesville, Virginia v. FERC*, 294 U.S. App. C.C. 236, 774 F.2d 1205 (1985). This test is applied when a stand-alone methodology is used. Simply stated, it provides:

> The benefits of consolidated tax savings are given to ratepayers (by reducing the jurisdictional affiliate's tax allowance) if they bore the burden of paying the deductible expenses that generated the savings. *Id.* at 1208.

Staff did not allocate any of the PHI tax benefit to customers. Instead, it treated the PHI load and attendant tax benefits as events that would reduce PacifiCorp's cost of debt. Staff found it necessary to make some assumptions to estimate the effect of PHI's debt on PacifiCorp's cost of borrowing. Using its assumptions, Staff estimates that PacifiCorp's ratings could be as much as one full rating higher (BBB to A) if the PHI debt did not exist. Staff states this lower rating results in an approximate increase in all-in costs of 53 basis points. PacifiCorp issued $1.9 billion in debt between 2000 and June 2005, which accounts for 47 percent of PacifiCorp's total debt. Using the revenue requirement model in this docket with the 53 basis points and the 47 percent ratio, Staff calculates this change is worth approximately $4.6 million annually. Therefore, Staff recommends that PacifiCorp's tax expense be reduced by $4.6 million to reflect the burden customers are bearing due to PHI's debt.

PacifiCorp argues that the Commission's long-standing practice of treating taxes on a stand-alone basis should be maintained and upheld as the practice has been consistently used in prior rate cases and is codified in the Commission's own rules. [9] It strenuously asserts that any change to that policy in this docket would be inappropriate, and possibly illegal.

PacifiCorp claims that none of the parties questioned the accuracy of its stand-alone tax expense, but rather proposed adjustments based upon the tax liability of its parent, PHI. These adjustments are tax "savings" which result from PHI's interest payments on the debt used to finance ScottishPower's acquisition of PacifiCorp. According to PacifiCorp, the three proposed adjustments are contrary to the Commission's obligation to prevent cross-subsidization of regulated and unregulated activities. *See*, Order No. 03-691.

Even if the Commission determines that adjustments to the revenue requirement for taxes are permissible, the application of the benefits/burden standard does not show that ratepayers have had the burden of paying the deductible expenses that generated the savings. Therefore, according to PacifiCorp, since there is no burden, but actually a benefit, no adjustment should be made to PacifiCorp's revenue requirement under any benefits/burdens approach.

Commission Discussion and Resolution

SB 408 and its application to this proceeding - The issue of tax treatment for utilities was debated in the legislature and in the media. The legislative result was SB 408, which was a response to the reaction caused by the inclusion of earmarked taxes in rates and the fact that, in some cases, the utility (or the affiliate that pays taxes on behalf of the utility) does not deliver all of the earmarked taxes to tax authorities.

This bill, which has only recently been enacted, is complex. At the time of signing the bill, Governor Kulongoski noted that many "difficult questions about the impact and implementation of SB 408 [were left] to the Oregon Public Utility Commission."[10] We share the Governor's observations, and have opened a permanent

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[9] PacifiCorp is referring to OAR 860-027-0048. The relevant sections are:

> (4) The energy utility shall use the following cost allocation methods when transferring assets or supplies or providing or receiving services involving its affiliates:
>
> * * *
>
> (h) Income taxes shall be calculated for the energy utility on a standalone basis for both ratemaking purposes and regulatory reporting. When income taxes are determined on a consolidated basis, the energy utility shall record income tax expense as if it were determined for the energy utility separately for all time periods.

[10] We take official notice of the letter from Theodore R. Kulongoski, Governor to Honorable Bill Bradbury, Secretary of State, dated September 2, 2005.

rulemaking docket (AR 499) to address the many uncertainties of the interpretation and application of SB 408.

In the meantime, ICNU has raised the issue of whether SB 408 applies to this proceeding. It argues that it does, and we agree. The plain language of Section 6 of SB 408 declares that "this 2005 Act takes effect on its passage." While certain portions of the bill cannot be implemented until a later date[11], other sections of the bill can be implemented immediately.[12]

In Section 5 of the bill, the legislature specifically added language to ORS 757.210(1). First, the word "fair" was added to the utilities' burden and Commission's determination. This word, in and of itself, may not be significant. While we are to assume that language which modifies a statute intends to change existing law, there is nothing in the legislative history to indicate the intent of the legislature when it added this word. *See, Jones v. General Motors Corp.*, 325 Or. 404, 414 at Fn 6, 939 P.2d 608 (1997), *clarifying Fifth Avenue Corp. v. Washington Co.*, 282 Or. 591, 597-98, 581 P.2d 50 (1978). Another change to ORS 757.210(1)(a) was the addition of a sentence to the end of the section: "The commission may not authorize a rate or schedule of rates that is not fair, just and reasonable." Again, as we have always been required to establish fair and reasonable rates[13], we still were not convinced that the addition of this sentence by the legislature had added to or changed our ratemaking authority.

However, a review of the general policy statement found in the preamble of SB 408 causes us to believe that the legislature intended immediate action. This preamble language states: "Utility rates that include amounts for taxes should reflect the taxes that are paid to units of government to be considered fair, just and reasonable." SB 408, Section 2 (1)(f). While general policy statements can serve as contextual guides, "they are instructive only insofar as they have genuine bearing on meaning of provision that is being construed." *DLCD v. Jackson County*, 151 Or.App. 210, 218, 948 P2d 731 (1997), *rev. den.* 327 Or 620, 971 P2d 412. In this instance, the legislature adopted a statute requiring that consideration be given to taxes paid by certain public utilities.[14] The policy statement language of Section 2(1)(f) uses the same words as are found in revised ORS 757.210(1)(a). In interpreting this language, we believe we are required to consider taxes paid to governmental units when setting rates for PacifiCorp in this docket.

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[11] For example, review of the utility filed tax reports and implementation of an automatic adjustment clause.

[12] For instance, revisions to ORS 757.210(1)(a) found in Section 5.

[13] "The commission shall balance the interests of the utility investor and consumer in establishing fair and reasonable rates." ORS 756.040(1).

[14] SB 408, Section 3(12) applies to certain specific public utilities described by the following language:

A) A regulated investor-owned utility that provided electric or natural gas service to an average of 50,000 or more customers in Oregon in 2003; or

B) A successor in interest to an entity described in subparagraph (A) of this paragraph that continues to be a regulated investor-owned utility.

PacifiCorp is one of four utilities that meets these requirements.

The legislative intent behind SB 408 is clear – we are to depart from historic practice and consider taxes paid by a utility or its parent when setting rates.[15] When we authorize rates for the utilities covered by the bill, those rates must reflect the taxes paid to units of government in order to be fair, just and reasonable.

Determining a tax adjustment - Having decided that we must apply SB 408 to this docket, we turn to the positions of the parties. We must reject PacifiCorp's recommendation to maintain our stand-alone approach as we are required to attempt to match the taxes collected from ratepayers to the taxes paid by the utility and its parent to governmental units.

We also reject PacifiCorp's argument that our administrative rule requires a stand-alone approach. *See* fn. 9. While we agree with PacifiCorp that we must follow our own rules, we view this rule differently than PacifiCorp. This rule is an accounting rule, which requires an energy utility to keep its books of account on a stand-alone basis. Frankly, that is reflective of our historic practice, which the legislature has told us to change. In the past, we have always done the tax calculation on a stand-alone basis, so we ask utilities to keep books of account that reflect our practice. We are not, however, bound to maintain our practice of stand-alone calculations, particularly when a new statute comes into play. The rules promulgated under SB 408 may require adoption of different accounting rules. If so, we will amend OAR 860-027-0048 rule so that utilities can provide the information we need for ratemaking purposes and regulatory reporting.

We also reject Staff's proposed adjustment. We acknowledge that customers may be bearing the burden of PHI debt if such debt caused PacifiCorp's debt costs to be higher than they would have otherwise been. However, Staff acknowledges that its estimates as to the amount of that burden are "imprecise" because rating agencies use their discretion in making ratings and do not simply rely on credit metric formulas. More importantly, however, Staff does not allocate any of the interest expense deduction or tax benefit among the various PHI affiliates, and specifically PacifiCorp. As this is the process envisioned in SB 408, we reject the adjustment recommended by Staff.

Accordingly, we are left with the adjustments proposed by CUB and ICNU. As described above, the parties' adjustments are similar, but differ in methodology. The primary difference between the two is the method of allocating the interest expense deduction among PHI affiliates. CUB bases its allocation on gross profits, while ICNU uses PacifiCorp's share of net assets. Of the two, we find CUB's methodology more persuasive, even though it based its methodology on gross profits, rather that net taxable income, which is the basis for taxes. While gross profits are obviously distinguishable from net taxable income, CUB's adjustment is based on profits, which represents a better allocation factor than using net assets, as proposed by ICNU.

[15] Assuming, *arguendo*, that we are incorrect in holding that the legislature intended SB 408 to apply to this rate case, we choose to use our discretion and apply SB 408 principles to this rate case.

CUB chose to make its adjustment based solely on federal taxes, and declined to make any recommendations concerning Oregon taxes. We believe it is more appropriate to use a composite rate in an attempt to have taxes collected from ratepayers more closely match taxes paid to the state and federal governments. Therefore, CUB's $14.8 million should be adjusted to use the composite tax factor of 37.95 percent rather than solely using the federal rate of 35 percent. This results in an adjustment to taxes of $16.07 million. Interestingly, CUB's revised adjustment of $16.07 million and ICNU's recommended adjustment of $16.64 million turn out to be fairly close, differing by just $0.57 million.

In reaching this decision, we acknowledge that this adjustment is not precise. But it is reasonable, and it is the best we can do under present circumstances.

Our first goal – one which we believe SB 408 requires – is to do our best to align the estimated taxes included in PacifiCorp's rates with the amount that PacifiCorp (or its affiliated group) will eventually pay. It is not possible to know what PacifiCorp (or its affiliated group) will pay each year, but we know that the PHI tax benefit is a constant that SB 408 requires to be passed on to customers. That means that, over time, we will do a better job of meeting the goals of SB 408 if we reflect that tax benefit in the rates we are now setting for PacifiCorp.

Doing a better job of aligning estimated taxes included in rates with the amount that a utility or its affiliate group eventually pays is consistent with our second goal. That goal is to reduce, to the extent possible, the amount that flows through the automatic adjustment clause. Because we know that the PHI tax benefit will flow to customers, we will likely reduce, over time, the amount flowing through the clause if we now lower what we allow PacifiCorp for taxes in this case. As we say above, because there is no way to predict the actual tax payment of PacifiCorp (or its affiliate group) for each year, we cannot say that reflecting this benefit will precisely match taxes in rates with taxes PacifiCorp will pay each year, but we can say that, over time, our decision should reduce what flows through the account.

2. Transition Adjustment Mechanism (TAM)[16]

In Order No. 04-516 (Docket No. UM 1081), this Commission adopted an interim transition adjustment mechanism for PacifiCorp to use for direct access during the Fall 2004 open enrollment window. In our order, we mused about some items that should be included a long-range transition adjustment. For example, we stated that, "Ideally, a transition adjustment will value utility resources impacted by direct access based on actual, appropriate operational responses." *Id.* at 10. We also said our desire was to develop a TAM that values resources on PacifiCorp's actual operational responses based on appropriate planning. *Id.* at 12. We directed PacifiCorp, Staff and other parties

[16] Parties have used the terms "Transition Adjustment Mechanism (TAM) and Resource Valuation Mechanism (RVM) interchangeably throughout the proceedings. We use the term "Transition Adjustment Mechanism (TAM) in this order as it applies to PacifiCorp. We maintain usage of RVM when referring to PGE.

to meet and work towards developing a TAM that values resources affected by direct access using actual, appropriate operational responses, and addresses how GRID model projections would change if PacifiCorp's operational assumptions change, or if the characteristics of direct access programs change. *Id.* at 11, 12-13. Finally, we directed PacifiCorp, Staff and other parties to continue investigating the utilization of transmission rights and the proper value of avoided transmission. PacifiCorp was ordered to file a TAM by November 15, 2004. PacifiCorp complied with this order by filing its TAM as part of the general rate case filing.

Parties' Positions

PacifiCorp's proposed TAM relies on its power cost model, GRID. PacifiCorp proposes to make two GRID runs for each rate schedule, one with full Oregon load and one with a 25 MW load reduction shaped according to the rate schedule. These runs will be used to calculate the weighted market value of the energy used to serve direct access customers. The TAM then calculates the adjustment by comparing the weighted market value to the cost of service rate under the customers' specific, energy-only tariff. Included in the process is an annual power cost update to ensure that both the weighted market value and the cost of service are calculated for the same period using the same data. PacifiCorp chose to procedurally base its TAM on the RVM utilized by PGE, with the hope that it would be easier to use a model that has already been tested by the Commission.

Staff agrees that a TAM should be in place, and should be updated annually. In the Third Partial Stipulation, Staff reached agreement with PacifiCorp as to the costs to be included in the 2006 TAM. [17] No agreement has been reached as to costs to be included in any future TAMs. Staff believes that the agreed-to TAM will provide an accurate accounting of the likely impacts of direct access on PacifiCorp's system operations. According to Staff, this process should result in transition adjustment rates that prevent unwarranted cost shifts between utility investors and direct access customers.

CUB does not take a position on the specific calculation of adjustment rates, but rather argues that whatever process is adopted should not apply to residential customers. CUB states that the purpose of the TAM is to identify the transition benefit or charge for direct access customers. Since residential customers are neither eligible for nor benefit from direct access, residential customers should be exempt from its application and not subject to the annual Net Variable Power Cost update.

ICNU advocates for a "market-plus" approach, similar to the approach it argued in Docket No. UM 1081. This approach assumes that PacifiCorp will avoid energy purchases and related transmission expenses due to customers going direct access. ICNU also objects to an annual process, stating that it is unnecessary, harmful to

[17] In the Third Partial Stipulation, Staff and PacifiCorp agreed that if the Commission approved PacifiCorp's TAM, the final GRID run will exclude deferred maintenance, thermal ramping, station service and planned outages adjustments for 2006.

ratepayers, unduly burdensome, and addresses a non-existent problem. According to ICNU, the PacifiCorp TAM does not capture the value of the freed-up resources because it does not simulate the planning and operational changes that would occur if customers elect direct access, does not reflect changes in transmission costs, and may include other "biases" that undervalue resources used to serve direct access customers. ICNU Opening Brief at 39.

Staff opposes ICNU's market-plus approach as it would not accurately account for the likely impacts of direct access on PacifiCorp's operations. Staff Prehearing Brief at 17. Staff also opposes CUB's recommendation as it would create two cost-of-service rates for customers, one for direct access eligible customers and one for non-eligible customers, adding unwieldy complexity to the ratemaking process.

PacifiCorp also opposes both ICNU's and CUB's recommended approaches. PacifiCorp states that ICNU's approach has already been rejected by the Commission in Order No. 04-516. Further, PacifiCorp asserts, any argument about graveyard hour market liquidity caps has been mooted by the stipulation submitted May 4, 2005. As to ICNU's issue about planning for direct access load loss, PacifiCorp points out that this is an issue in its current integrated resource plan, Docket No. LC 39. Finally, PacifiCorp argues that annual updates are not unduly burdensome, and that the updates ensure that the TAM applied to departing customers is accurate.

PacifiCorp urges us to reject CUB's proposal, as updating power costs for a subset of customers would be extremely difficult. PacifiCorp also agrees with the Staff that it is desirable to maintain a single set of cost-of-service rates.

Commission Resolution

We adopt the TAM proposed by PacifiCorp with annual updates, and we adopt the specific 2006 adjustments agreed to by Staff and PacifiCorp as shown in PPL/604-606 and PPL/607-608 except for the Deferred Maintenance, Thermal Ramping, Station Service and Planned Outages adjustments. These exhibits are attached as Appendices F and G and incorporated herein. We find that the TAM proposed by PacifiCorp, with annual updates, most closely meets the requirements established in Order No. 04-516. The purpose of the TAM is not to promote direct access, as ICNU would have us do. Rather, the TAM is to capture costs associated with direct access, and prevent unwarranted cost shifting. We also agree that adopting an approach similar to PGE's RVM will hopefully mitigate some of the complexity involved in this process.

Having adopted the TAM, however, we believe that further investigation is necessary into some of the concerns raised by the parties. We are somewhat concerned about establishing the TAM with its annual update because there is a certain amount of one-sidedness to PacifiCorp's annual updates without concomitant adjustments by intervenors and Staff. We will continue to look at the TAM and investigate to whatever extent we believe is necessary.

3. Prudence Issues

West Valley Lease

PacifiCorp entered into the West Valley lease on March 5, 2002. On May 31, 2002, the Commission approved the lease pursuant to ORS 757.495, determining that the lease met the requirements of our administrative rules by complying with the "lower of cost or market" standard. *See,* Order No. 02-361, Appendix A at 6. Since June 1, 2002, the West Valley lease has been included as part of net power costs in PacifiCorp's rates.

In 2004, PacifiCorp issued RFP 2004-X, which solicited proposals for a lower-cost alternative to the West Valley lease. As PacifiCorp did not find a lower-cost alternative, it decided not to exercise its option of terminating the lease. PPL/901, Tallman/7.

Due to ICNU's assertion that PacifiCorp could have met its need through RFP 2003-A, PacifiCorp analyzed the RFP 2003-A market offerings and compared them to the West Valley lease. The results of the analysis showed the market alternatives to be $181 million less economical than the West Valley lease, if costs of direct debt are included. PPL/903, Tallman/2.

Staff analyzed the acquisition of the West Valley lease in 2002 in Docket UE 134, and concluded that PacifiCorp was acting prudently in entering into the lease. (UE 134; Staff 200). Staff asserts that the initial acquisition of this resource in 2002 was prudent. In 2004, PacifiCorp also made a prudent decision when it passed on an option to terminate the lease, says Staff. In this docket, Staff reviewed the RFP 2004-X process, which solicited market proposals as alternatives to West Valley. Upon review, Staff concluded that PacifiCorp acted prudently in retaining the lease. Staff recommends that the Commission reject ICNU's proposed adjustment related to West Valley.

Gadsby CT

In late 2001, PacifiCorp entered into a contract with General Electric (GE) to lease some mobile CT peaking units to be installed at PacifiCorp's Gadsby site. During the life of the agreement, GE offered PacifiCorp larger and more efficient equipment to install at the Gadsby site. As part of the offer, GE agreed to waive the remaining $7.5 million lease obligation due under the initial contract. PacifiCorp accepted the offer.

ICNU proposes a $7.5 million adjustment, as PacifiCorp received a one-time savings that should flow through to customers rather than shareholders. The cost reduction was never reflected in rates. Further, PacifiCorp had a conflict of interest when it negotiated for the new equipment. In its review, the Utah Division of Public Utilities' Staff supported such a disallowance in Utah.

Staff recommends that we reject ICNU's proposed adjustment, stating that it did not see any conflict of interest. Further, according to Staff, GE's offer was better than the competing offers PacifiCorp was pursuing for replacement, even excluding the waiver of the remaining lease obligation.

Currant Creek, Phase One

After evaluating the alternatives presented through RFP 2003-A, PacifiCorp determined to construct the Current Creek project. PacifiCorp's assessment was supported by the external consultant hired by PacifiCorp to evaluate the bids. This consultant, Navigant Consulting, Inc., determined Current Creek to "be the lowest cost resource option within the contest of the RFP process." PPL/900, Tallman/5, citing Navigant report at 5.

ICNU contends that the costs of Current Creek are above market and should be excluded as imprudent expenses.

Staff analyzed the economic evaluation done by PacifiCorp supporting the acquisition of Currant Creek, and concluded that the resource was the least cost option, and would provide benefits to customers.

Commission Resolution

When reviewing PacifiCorp's decisions about West Valley, Gadsby and Currant Creek, we look to whether the actions were reasonable at the time that PacifiCorp made those decisions. As we have previously stated: "Prudence is determined by the reasonableness of the actions 'based on the information that was available (or could reasonably have been available) at the time.'" *In re PacifiCorp,* Docket Nos. UM 996/UE 121/UC 578, Order No. 02-469 at 4, citing *In re PGE,* UE 102, Order No. 99-033 at 36-37 (footnote omitted). In a prudence review, "we cannot let the luxury of hindsight allow us to second guess a utility's conduct." *In re PGE,* Docket No. UE 139, Order No. 02-792 at 11. It is possible that a prudently-made decision in the past might turn out to be "wrong" in the future. We cannot use hindsight, however, to judge the utility's decision.

We hold that PacifiCorp's decisions regarding the West Valley Lease, Gadsby CTs and Currant Creek Phase I were prudent decisions and the costs of these resources should be included in rates. Staff review of all three resources establishes that PacifiCorp acted prudently in its actions for all three resources, as all three were analyzed against results of a competitive bidding process.

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

On June 6, 2005, PacifiCorp filed an application for waiver of OAR 860-038-0080(1)(b)[18] as to its acquisition of three generating resources: West Valley lease, Gadsby, and Phase One of Currant Creek. PacifiCorp wished to include the following in revenue requirement: 1) the capital costs of Gadsby and Currant Creek in rate base for ratemaking purposes; 2) the operations and maintenance costs of Gadsby and Currant Creek; and 3) the costs associated with the West Valley lease. PacifiCorp's Application for Waiver at 1.

Parties' Positions

In its application, PacifiCorp cited OAR 860-038-0001(4)[19] which allows the Commission to waive a Division 38 rule upon "good cause shown." PacifiCorp noted that costs of two of the resources (Gadsby and West Valley) are already included in revenue requirement, and that Gadsby is currently included in rate base.

The waiver is in the best interests of customers, asserts PacifiCorp, because it has already shown in its Integrated Resource Plan, through testimony in Dockets UE 134 and UE 147, and testimony in this case that its generating resource portfolio, which includes all three resources, provides its customers with price and rate stability. Currant Creek and West Valley were procured through a competitive process, and Gadsby compares favorably with both, PacifiCorp argues. These resource decisions are sound, and, PacifiCorp asserts, are in the best interests of customers. PacifiCorp asks that the Commission waive application of the rule.[20]

On June 23, 2005, ICNU filed a response to PacifiCorp's application. ICNU itemized numerous reasons in its response and in its briefs why the application should be denied:

1. Filed too late in the proceeding.
2. Commission never determined that costs of the three resources were prudent, or that they should be included in rates at cost.
3. Granting application would violate SB 1149 because direct access customers would be subject to the costs of new resource decisions, and it could result in new stranded costs.

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[18] This rule states:

> Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company.

[19] Upon application by an entity subject to these rules and for good cause shown, the Commission may relieve it from any obligations under these rules.

[20] In Order No. 05-133, Docket No. UM 1066, we stated:

> If an electric utility wants to include a new resource in its revenue requirement at cost . . . then the utility must file a request to waive the administrative rule. *Id.* at 2.

4. Granting application would violate ORS 757.646 by increasing PacifiCorp's vertical and horizontal market power.
5. PacifiCorp has not developed an opt-out option as required by Order No. 05-133.
6. PacifiCorp has not proposed any way to mitigate the anticompetitive impacts of cost-based treatment for new resources.
7. Waiving the rule after construction or purchase of resource provides inappropriate incentives to the utility if "market price" means current market price.
8. PacifiCorp failed to meet its burden of proof in establishing that waiver of rule is in the public interest.

Staff asserts that PacifiCorp has shown that including these facilities in rates at cost is beneficial to customers. The acquisition process, cost and impact upon customers of the West Valley CTs were analyzed in UI 196 and UE 134. Staff concluded in UE 134 that PacifiCorp was prudent in entering into the lease agreement. Further, the Commission has already concluded, in Order 02-361 (Docket No. UI 196) that the lease agreement was fair, reasonable and not contrary to the public interest. Staff/800, Wordley/4, citing UE 134, Staff/200 (testimony in Docket No. UE 134). The Gadsby CTs were included in rates at the same time as West Valley. *See*, Order No. 02-343.

As for Currant Creek, it resulted from RFP 2003A, and will be coming on line shortly before the entry of an order in this docket. Staff analyzed the economic evaluation done by PacifiCorp supporting the acquisition of Currant Creek, and concludes that the resource was the least cost option, and will provide benefits to customers. Staff recommends the Commission approve the waiver, and include the three resources at cost.

Commission Resolution

We previously approved a waiver of this rule in Order No. 04-376, Docket No. LC 33. In that instance, PGE asked for a waiver of the rule for the new generating plant it was planning to build (Port Westward). Specifically, PGE asked that the rule be waived so it would not be prohibited from including: 1) Port Westward capital costs in PGE's rate base; 2) operation and maintenance costs of Port Westward in its revenue requirement; and 3) acknowledged contracts with third parties in PGE's revenue requirement. *Id.* at 1.

PGE's request came as part of its Integrated Resource Plan (IRP), and we carefully walked the line about not making a ratemaking decision in an IRP docket. In making our decision, we reviewed the process undertaken by PGE, and the analysis it presented, and determined that including Port Westward's capital costs in rate base and Port Westward's operation and maintenance costs in revenue requirement was appropriate.

In this case, we are making a ratemaking decision. We have already determined that PacifiCorp acted prudently in its actions regarding these three generating resources. Order, *supra* at 23. The question now is whether to waive the rule and allow PacifiCorp to include the resources into its rate base and revenue requirement at cost. We agree with Staff's recommendation, and grant the application to waive OAR 860-038-0080(1)(b).

Although we have considered all of ICNU's objections, we will respond to only a few of them here. We do not agree that we have violated any provisions of SB 1149 or ORS 757.646 in granting this application. On the contrary, we have engaged in a similar review process as to the one undertaken for PGE. Our review supports our determination that least cost options have been used, and that these resources will provide benefits to customers. While we have asked parties to continue working on an opt-out option, we never made an opt-out option a requirement for our case-by-case determination of whether the rule should be waived for specific generating resources. The burden to be met by PacifiCorp is "good cause," which it has established.

5. Regional Transmission Organization (RTO) Costs

PacifiCorp has been involved for at least five years in developing an RTO, currently known as Grid West. PacifiCorp included Grid West expenses as an ongoing regulatory expense. PacifiCorp expects the level of costs for consulting, airfare, lodging, along with secondary salary, legal and other employee expenses to remain the same after Grid West becomes operational. These costs total, on a company-wide basis, \$3.057 million for the 2006 test year, of which approximately \$0.9 million is the Oregon-allocated amount.

ICNU, through witness James Selecky, states that because the RTO is neither operational nor expected to be operational during the test year, the expenses associated with the RTO are neither used nor useful during test year 2006. Further, these RTO related expenses do not provide any current benefit to ratepayers. Therefore, RTO related expenses should be excluded from the revenue requirement until such time as an RTO is operating and providing a benefit to customers. ICNU recommends that a deferred account be established for RTO expenses, which should be subject to a comprehensive prudency review once an RTO provides benefits to Oregon ratepayers.

Staff agrees that these RTO expenses should be included in revenue requirement as on-going costs. Staff points out that the Grid West proposal includes staged implementation, which requires ongoing development work by PacifiCorp and other entities in the region.[21] The costs are reasonable, and should be included in the test year revenue requirement.

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[21] According to Staff, the testimony supporting *Partial Stipulation filed May 4, 2005*, indicates that CUB and Fred Meyer, along with PacifiCorp and Staff, support including Grid West development costs. *See,* Staff/1400; Brown/3. CUB, however, in its prehearing brief says that it takes no position on the issue. CUB Prehearing Brief at 5, dated July 13, 2005.

Commission Resolution

The RTO related costs, which include consulting, airfare, lodging, other employee expenses, legal and secondary salary expenses, are expected to continue after Grid West becomes operational. Although initial operations are not expected to begin until 2007 (*See*, Staff/1402; Brown/2), these expenses have been incurred while meeting FERC requirements to develop regional transmission entities. We find these expenses to be reasonable and hold that they should be included in PacifiCorp's test year revenue requirement.

6. Outages During UM 995 Deferral Period

PacifiCorp uses a rolling 48-month amortization of thermal plant outages. This methodology allows PacifiCorp to include a normal level of thermal plant outages in rates, based on historical information. In this proceeding, the four-year period used includes November 1, 2000 through September 9, 2001, known as the "UM 995 deferral period." As part of *In re PacifiCorp,* Order No. 02-469, the excess net power costs associated with PacifiCorp power plant outages occurring from November 2000 to September 2001 were placed in a deferred account. ICNU alleges that costs incurred during this time have already been paid by Oregon ratepayers, and that PacifiCorp should be required to remove all power plant outages that occurred during this time period. Unless these outages are removed, ICNU contends, PacifiCorp will recover its costs twice.

As part of its calculation, PacifiCorp completely removed the Hunter 1 outage from its calculation by excluding five months of outage information. According to PacifiCorp, if all of the other outages were removed, as requested by ICNU, the net power costs would be much greater. Further, the proposed ICNU adjustment is flawed because all of the outages other than Hunter 1 were consistent with the normal four-year average outage level as shown in power costs in base rates in effect during that specific period.

Staff does not support ICNU's adjustment. Staff explains that all outages for a portion of the historical four-year period were excluded, then the four-year average would be distorted and not reflective of what has occurred. While it makes sense to exclude a one-time aberration such as the Hunter 1 outage, it is nonsensical to exclude other normal, expected outages.

Commission Resolution

We do not agree with ICNU that an adjustment needs to be made. We are looking at the historical trend, absent any unusual circumstances, to forecast what outages may occur in the future. There is no "double recovery" by PacifiCorp by including the normal outages that occurred during the UM 995 deferral period. We agree with the Staff recommendation to include all outages, except for Hunter 1.

7. Revised Protocol (RP) Treatment of Qualifying Facility (QF) Contracts

In Order No. 05-021, this Commission ratified the use of the RP in future rate cases to determine how costs and wholesale revenues associated with PacifiCorp's generation, transmission and distribution systems would be allocated among the six states that comprise PacifiCorp's service territory. One of the elements of the RP is the treatment of new and existing QF contracts.

"Existing QF contracts" are defined as contracts entered into prior to the effective date of the RP, while "new QF contracts" are all QF contracts that are not existing QF contracts. *See,* Order No. 05-021, Attachment A at 50, 52. The costs of new QF contracts are allocated on a system-wide basis, while the costs of existing QF contracts are allocated on a situs basis. *See, Id.*, Attachment A at 38-39. According to the RP, the "Protocol will be effective and apply to all PacifiCorp retail general rate proceedings initiated subsequent to June 1, 2004." *Id.*, Attachment A at 35. While the parties do not dispute that the RP applies to this rate case, they do disagree as to whether four QF contracts (US Magnesium, Desert Power, Kennecott and Tesoro)[22] should be treated as new or existing QF contracts.

ICNU contends that the earliest "effective" date of the RP is January 12, 2005, the date this Commission entered Order No. 05-021. Since the four QF contracts were in place before January 12, 2005, ICNU argues that the contracts should be treated as existing, and not new, contracts. ICNU further argues that June 1, 2004, was merely the "proposed" effective date,[23] and that the RP only became effective upon Commission ratification.[24]

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[22] The initial delivery date for each contract is as follows:

US Magnesium – January 2005
Desert Power – September 2004
Kennecott – October 2004
Tesoro – September 2004

[23] Section II states:

II. Proposed Effective Date
The Protocol will be effective and apply to all PacifiCorp general rate proceedings initiated subsequent to June 1, 2004. *Id.*, Attachment A at 13.

[24] The relevant language is found in Section XIII D, which states:

Interdependency among Commission Approvals
The Protocol has been developed by the parties as an integrated, interdependent, organic whole. Therefore, final ratification of the Protocol by any of the Commissions of Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon similar ratification of the Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions. Upon any rejection of the Protocol, or any material deletion, alteration, or addition to its terms, by any one or more of the four Commissions, the Commissions who have previously conditionally adopted the Protocol shall initiate proceedings to determine whether they should reaffirm their prior ratification of the Protocol, notwithstanding the action of the other Commission or Commissions. ***The Protocol shall only be in effect for a State upon final ratification by its Commission.*** The Company will continue to bear the risk of the inconsistent allocation methods among the States. *Id.*, Attachment A at 44, emphasis added.

Staff and PacifiCorp disagree with ICNU's interpretation. They contend that the contracts should be treated as new as they were entered into after June 1, 2004, the effective date of the RP. PacifiCorp points out that the RP was filed May 20, 2004, and that the June 1, 2004, effective date would obviously precede the final ratification date by Oregon and other states. The expectation of the signing parties[25] is that the effective date would remain June 1, 2004, unless specifically modified by one or more of the state commission approval orders. In essence, according to PacifiCorp, this Commission ratified the June 1, 2004, effective date when it ratified the RP in January 2005.

Commission Resolution

While we understand the basis of ICNU's argument, we do not agree with it. First, when we ratified the RP in January 2005, we also ratified the contractual effective date of June 1, 2004. This intent has been carried out in this rate case, as PacifiCorp made its filing in November 2004 using the RP. Second, we do not read Section XIII D, the Interdependency Clause, in the same manner as ICNU. This clause provided an "out" to any state commission that ratified the RP prior to action by other state commissions, and later learned that either another state commission decided not to ratify the RP, or chose to modify the terms of the RP. Contrary to ICNU's assertion, the Interdependency Clause does not establish an effective date different than that of June 1, 2004. Third, the title of Section II, Proposed Effective Date, does not modify the language contained in the section. Rather, June 1, 2004, was the "proposed" effective date, which in reality became the effective date once the protocol was ratified by this and other state commissions.

We hold that the effective date of the RP is June 1, 2004. Therefore, the four QF contracts at issue must be treated as new contracts. Under the terms of the RP, the costs will be allocated system-wide and not assigned on a situs basis.

CONCLUSIONS

1. PacifiCorp is a public utility subject to the Commission's jurisdiction.

2. The stipulations, attached as Appendices A, B, C, D and E, should be adopted, subject to the changes made by later filed stipulations, and subject to the income tax adjustment described above.

3. Based on the record in this case, the PacifiCorp rates that result from the stipulations adopted and the conclusions reached in the body of this order are fair, just and reasonable. A results of operations spreadsheet is attached as Appendix H.

[25] ICNU did not sign the RP, and contested its ratification by this Commission.

ORDER

IT IS ORDERED that:

1. Advice No. 04-018, filed by PacifiCorp on November 12, 2004, is permanently suspended.

2. The stipulations attached as Appendices A, B, C, D, and E are adopted in their entirety, subject to the changes made by later filed stipulations, and subject to the income tax adjustment described above.

3. PacifiCorp will file revised tariffs consistent with the findings of fact and conclusions of law in this order, to be effective no earlier than October 4, 2005.

Made, entered, and effective SEP 2 8 2005.

Lee Beyer Chairman	**John Savage** Commissioner
	Ray Baum Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 170

In the Matter of PACIFIC POWER & LIGHT (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**PARTIAL STIPULATION**

This Partial Stipulation is entered into for the purpose of resolving specified adjustments to PacifiCorp's requested revenue requirement in this docket. It represents a settlement of the issues listed in Paragraph 5 of the Stipulation. It does not address the following issues: cost of capital; pensions and benefits; the Transition Adjustment Mechanism ("RVM") and all power costs updates filed in this case associated with the RVM; outages during the UM 995 deferral period; revenues associated with the GP Camas contract; modifications to the Company's partial requirements rate design; issues related to PacifiCorp's consolidated tax filing; allocation factors; a billing cycle issue; rate spread and rate design; and issues raised pursuant to Paragraph 6(e) of this Partial Stipulation.

PARTIES

1. The initial parties to this Partial Stipulation are PacifiCorp (or the "Company"), the Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Fred Meyer Food Stores and Quality Food Centers, Divisions of Kroger Co. ("Fred Meyer") (together "the Parties"). This Partial Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of this Partial Stipulation.

BACKGROUND

2. On November 12, 2004, PacifiCorp filed revised tariff schedules to effect a $102 million increase in its base prices to Oregon electric customers. PacifiCorp based its filing on a 2006 calendar year test period.

3. Pursuant to Administrative Law Judge Kirkpatrick's Prehearing Conference Memorandum, settlement conferences on UE 170 issues commenced on April 5, 2005. The settlement conferences were open to all parties.

4. As a result of the settlement conferences, the Parties have reached agreement on the matters set forth below. The net effect of this Partial Stipulation is a reduction in PacifiCorp's proposed revenue requirement to approximately $71 million, not taking into account any adjustment for the tax issues covered in paragraphs 5(h) and 5(i) and the allocation factor update covered in paragraph 5(l). The Parties submit this Partial Stipulation to the Commission and request that the Commission approve the settlement as presented.

AGREEMENT

5. Except for the issues reserved pursuant to Paragraph 6 of this Partial Stipulation, the Parties agree that the following adjustments, and the revenue requirement levels resulting from their application, are fair and reasonable:

a. Net Power Costs: The Parties agree that the Company's annual Net Power Costs will be set at approximately $785 million on a Total Company basis. The Partial Stipulation addresses all of the Parties' proposed adjustments to the Company's Net Power Costs as originally filed, including STF margin, extrinsic value, the costs of the Aquila hydro hedge, P4 production, Morgan Stanley call, regulation modeling, hydro modeling (Vista), other outages, CT outage rate, JB 4 outage, Cholla 4 minimum, HDN-1 catastrophic outage, Colstrip 4 catastrophic outage, other Company error outages, loss modeling and reverse DJ-3 derate. The Partial Stipulation does not include issues raised by the Company's two supplemental filings related to power costs or the issues raised by the Company's proposal to adopt an RVM, specifically: (1) outage update period; (2) maintenance schedule; (3) thermal ramping; (4) deferred maintenance; and (5) station service. It also excludes an issue reserved by ICNU relating to outages during the UM 995 deferral period and non-power cost modeling issues such as GP Camas and new resource issues addressed in the Multi-State Process. This adjustment results in an $8.00 million reduction in the Company's filed revenue requirement, an adjustment which the Company will incorporate into its RVM upon approval of this Partial Stipulation. Nothing in this Partial Stipulation suggests whether any Party will support or oppose the RVM. The Parties further agree that PacifiCorp will commit sufficient resources during the year following the approval of this Partial Stipulation to permit the evaluation of stochastic modeling of Net Power Costs for possible incorporation into rates. The analysis will consider the volatility of hydro generation, electricity prices, natural gas prices, system load and forced outages, as well as the correlations among these variables. PacifiCorp, with input from Staff, will develop a plan to complete the evaluation of stochastic modeling, including a schedule of quarterly public workshops to provide progress reports and receive inputs from interested parties. This Partial Stipulation does not address the appropriateness of introducing stochastic modeling of Net Power Costs into rates.

b. Load Forecast Revision: The Parties agree that the line losses included in the Company's load forecast should be updated. This update and the resulting change in allocation factors reduces the Company's filed revenue requirement by $9.16 million.

c. Operating Revenue: The Parties agree that the Company's annual net operating revenue for the test period should not include an operating deduction related to the OPUC fee. This results in a $0.138 million reduction in the Company's filed revenue requirement.

d. Incentive Programs: The Parties agree that the Company's annual net costs for the test period for incentive programs will be set at $35.6 million on a Total Company basis. This adjustment ties PacifiCorp total compensation to market and excludes a portion of the incentive tied to the Company's financial performance. In addition, this adjustment excludes 100 percent of the Company's Long Term Incentive Compensation ("LTIP"). This adjustment results in a $5.5 million reduction in the Company's filed revenue requirement.

e. Non-Labor Administrative and General Costs: The Parties agree to a $6.123 million reduction in the Company's filed revenue requirement in non-labor administrative and general costs. This does not include ICNU's proposed adjustment related to Regional Transmission Organization (RTO) costs.

f. Other Revenues: The Parties agree to a $2.2 million reduction in the Company's filed revenue requirement to account for growth in other revenue accounts 450, 451, 454 and 456.

g. Bridger Coal: The Parties agree to smooth the impact of the nonrecurring (coal) costs in the test year associated with Bridger by amortizing the difference between the actual 2004 costs and the forecasted 2006 costs over a three-year period. The Company will recover a return on the unamortized balance. This results in a $2.4 million reduction in the Company's filed revenue requirement.

h. FIT and SIT: The Parties agree that the Company's income tax expense for the test period should be adjusted based upon the final weighted average cost of debt.

i. Production Activity Deduction: The Parties agree to the methodology proposed by the Company for purposes of this proceeding. The final amount will be determined based upon the final revenue requirement authorized in this docket. In the event that the Internal Revenue Service approves the production activity deduction methodology proposed by the Edison Electric Institute ("EEI"), the Company reserves its right to file for deferred accounting for the difference between the amount under the methodology proposed herein and the EEI methodology.

j. Hydroelectric Relicensing Costs: The Parties agree to remove this adjustment, which was first proposed by Staff.

k. Miscellaneous Corrections: The Parties agree that the Company's revenue requirement will be increased by $1.3 million for an adjustment to rate base allocated on the Ditbal factor; $0.992 million to correct the allocation factors for Hermiston and Gadsby; and $0.250 million to account for the costs of WSCC Membership and Little Mountain.

l. Allocation Factor Update: The Parties agree that the Company's revenue requirement will be updated based upon the new allocation factors resulting from the change described in paragraph 5 (b).

m. Schedule 200 Tail Block: To effect a smooth transition from Schedules 28 to 30, the Parties agree that the Cost-Based Supply Service Energy Charges in Schedule 200 will have equal tailblock charges applicable for Schedules 28 and 30.

n. Change in G/Y Market Caps for Transition Adjustment Calculation: For purposes of calculating the Transition Adjustment as proposed in the RVM, the Parties agree that if 25 MW of Direct Access load is assumed in the calculation, the wholesale market caps during the graveyard hours will be increased by 10 MW for the COB and Mid C wholesale markets, respectively. If the amount of Direct Access load assumed in the calculation is different than 25 MW, the wholesale market caps during graveyard hours at COB and Mid-C will be changed proportionately. The increase in wholesale market caps is limited to the Transition Adjustment calculation and the increase shall not otherwise be used in the calculation of Net Power Costs or revenue requirement.

6. The Parties agree on the following in terms of settled and non-settled issues:

a. The Parties to this Partial Stipulation agree that it resolves all issues related to the cost/revenue items and categories associated with the adjustments listed in Paragraph 5, except as specifically noted;

b. Staff agrees to raise only the following issues in this case: cost of capital; pensions and benefits; the RVM, RVM input assumptions, and all power costs updates filed in this case associated with the RVM; revenues associated with the GP Camas contract; modifications to the Company's partial requirements rate design; and rate spread and rate design. Staff reserves the right to review and comment on issues raised by other parties to this case;

c. CUB's issues list for testimony in this case consists of the issues reserved by Staff, plus issues related to PacifiCorp's consolidated tax filing, allocation factors, and a billing cycle issue. CUB reserves the right to add additional issues if uncovered in further analysis and review and comment on issues raised by other parties to this case;

d. Fred Meyer reserves the right to address cost-of-service, rate spread, rate design, and RVM issues not included in Paragraph 5. Fred Meyer reserves the right to respond to issues raised by other parties to this case; and

e. ICNU reserves the right to raise any issue in this proceeding except as specifically resolved by Paragraph 5 of this Partial Stipulation.

7. The Parties agree that this Partial Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Partial Stipulation shall not be admissible as evidence in this or any other proceeding.

8. This Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Partial Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

9. The Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. If this Partial Stipulation is challenged by any other party to this proceeding, the Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Partial Stipulation.

10. The Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Partial Stipulation or imposes additional material conditions in approving this Partial Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

11. By entering into this Partial Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Partial Stipulation, other than those specifically identified in the body of this Partial Stipulation. No party shall be deemed to have agreed that any provision of this Partial Stipulation is appropriate for resolving issues in any other proceeding, except as previously identified in Paragraph 5 of the Partial Stipulation.

12. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each party on the date entered below such party's signature.

Signatures follow on next page

PACIFICORP

By: ______________________

Date: May 2, 2005

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

FRED MEYER

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: 5/3/05

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

FRED MEYER

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: [signature]

Date: 5/3/05

FRED MEYER

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: Robert Jenks

Date: May 3, 2005

ICNU

By: ______________________

Date: ______________________

FRED MEYER

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

FRED MEYER

By: ______________________

Date: May 3, 2005

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 170

In the Matter of PACIFIC POWER & LIGHT (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**STIPULATION REGARDING PARTIAL REQUIREMENTS AND ECONOMIC REPLACEMENT POWER TARIFFS**

This Stipulation is entered into for the purpose of resolving modifications to PacifiCorp's tariff schedules for standby electric service for consumers that supply all or some portion of their load by self-generation on a regular basis ("partial requirements consumers"), to propose adoption of a new tariff schedule for partial requirements consumers and to propose adoption of new tariff schedules that would provide partial requirements consumers with the opportunity to purchase energy from the Company or an Electricity Service Supplier ("ESS") to replace some or all of the consumer's on-site generation when the consumer deems it is more economically beneficial than self-generation ("economic replacement power").

This Stipulation describes the settlement and includes proposed partial requirements and economic replacement power tariff schedules for which the Parties are seeking approval by the Commission. This Stipulation represents a settlement of all issues with respect to the proposed tariff schedules except the issues described in Paragraph 7 below.

PARTIES

1. The initial parties to this Stipulation are PacifiCorp (or the "Company"), the Staff of the Public Utility Commission of Oregon ("Staff"), the Industrial Customers of Northwest Utilities ("ICNU"), and the Oregon Department of Energy ("ODOE") (together "the Parties").

This Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of this Stipulation.

BACKGROUND

2. On November 12, 2004, PacifiCorp filed revised tariff schedules applicable to its electric service in Oregon. PacifiCorp's filing included revised Schedules 47 and 747 and new Schedule 247. These schedules provide for standby electric service from the Company (Schedules 47 and 247) or an ESS (Schedule 747) to large nonresidential consumers that supply all or some portion of their load by self-generation on a regular basis, where the Consumer's self-generation has a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater.

3. Since the November 12, 2004 filing, at Staff's request, PacifiCorp also circulated to the parties to this proceeding draft schedules that provide for economic replacement power service from the Company (Schedules 76R and 276R) or an ESS (Schedule 776R) to partial requirements consumers.

4. Workshops on the proposed partial requirements and economic replacement power services commenced on January 20, 2005. Subsequently, workshop participants determined that settlement of all or some of the issues related to partial requirements and economic replacement power services could be achieved. Settlement conferences commenced on March 15, 2005. The settlement conferences were open to all parties to this proceeding.

5. As a result of the settlement conferences, the Parties have reached agreement on the matters set forth below. This Stipulation does not address PacifiCorp's revenue requirement.

The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

AGREEMENT

6. Except as described in Paragraph 7 below, the Parties agree that it is fair, just and reasonable for PacifiCorp to adopt the proposed Schedules 47, 247, 747, 76R, 276R, and 776R (collectively, the "Schedules") attached hereto as Exhibits A through F. The Parties agree that the revisions to the existing partial requirements tariffs (Schedules 47 and 747) and proposed partial requirements tariff (Schedule 247) embodied in Exhibits A through C allow the tariffs to more closely reflect the cost of providing standby electric service to partial requirements consumers, which are consumers that supply all or some portion of their load by self-generation on a regular basis. The Parties also agree that the proposed economic replacement power tariffs (Schedules 76R, 276R, and 776R) will provide partial requirements consumers with the opportunity to purchase energy from the Company or an ESS to replace some or all of the consumer's on-site generation when the consumer deems it is more economically beneficial than self-generation. Existing Schedule 47 partial requirements customers will be required to enter into new partial requirements service agreements to conform with the Schedules as approved by the Commission. Line extension agreements will be unaffected by the new partial requirements service agreements.

7. With the limited exceptions described in this Paragraph, the Company agrees to sponsor, and the Parties agree to support, all revisions and proposals embodied in the Schedules. The Parties agree that this Stipulation resolves all issues related to the Schedules except as follows:

a. The proposed Schedule 247 (Exhibit B) states that PowerDex Hourly is the market index that will be used to determine unscheduled energy charges. All Parties except ICNU agree to support the use of PowerDex Hourly as the market index for this purpose. Although ICNU does not agree to join in or provide testimony supporting the use of PowerDex Hourly as the market index for this purpose, ICNU supports the Commission's approval of this settlement as presented. To facilitate this, ICNU agrees that it will not file testimony or take any other action in this proceeding to oppose the use of PowerDex Hourly as the market index to determine unscheduled energy charges under Schedule 247.

b. The following charges in the Schedules reflect the revenue requirement as originally filed by the Company in this proceeding: (1) Distribution, Reserves, and Transmission and Ancillary Services Charges under Schedule 47 (Exhibit A); (2) Distribution and Reserves Charges under Schedule 747 (Exhibit C); (3) Transmission and Ancillary Services and Daily ERP Demand Charges under Schedule 76R (Exhibit D); and, (4) Daily ERP Demand Charge under Schedule 776R (Exhibit F). Upon adoption of this Stipulation and the determination of a final revenue requirement in this proceeding, the Company will file compliance tariffs updating the Schedules to conform to the outcome of this proceeding. All Parties reserve the right to review and challenge PacifiCorp's compliance filings for conformity with the outcome of this proceeding. The Parties intend that the Schedules will become effective at the same time as new rates are implemented in this proceeding.

c. All Parties reserve the right to review and comment on issues raised by other parties to this case.

8. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

9. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein. However, the Parties reserve the right to raise issues related to the Schedules in future proceedings.

10. The Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation in this proceeding. If this Stipulation is challenged by any other party to this proceeding, the Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

11. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

12. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party

in arriving at the terms of this Stipulation. No party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

13. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such party's signature.

PACIFICORP	STAFF
By:	By: ______________
Date: May 6, 2005	Date: ______________
ICNU	ODOE
By: ______________	By: ______________
Date: ______________	Date: ______________

in arriving at the terms of this Stipulation. No party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

13. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such party's signature.

PACIFICORP	STAFF
By: ______________________	By: ______________________
Date: ______________________	Date: 5/6/05
ICNU	ODOE
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________

in arriving at the terms of this Stipulation. No party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

13. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such party's signature.

PACIFICORP	STAFF
By: ______________	By: ______________
Date: ______________	Date: ______________
ICNU	ODOE Phil Carver
By: ______________	By: Philip H. Carver
Date: ______________	Date: May 6, 2005

in arriving at the terms of this Stipulation. No party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

13. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such party's signature.

PACIFICORP	STAFF
By: ______________	By: ______________
Date: ______________	Date: ______________
ICNU	ODOE
By: Irion Sanger	By: ______________
Date: 5/6/5	Date: ______________

RECEIVED
MAY 0 9 2005
Public Utility Commission of Oregon
Administrative Hearings Division

Exhibit A

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS – 1,000 KW AND OVER
DELIVERY SERVICE

OREGON
SCHEDULE 47

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge and Transmission & Ancillary Services Charge plus applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
Distribution Charge	Secondary	Primary	Transmission
Basic Charge			
Facility Capacity <= 4,000 kW, per month	$290.00	$260.00	$300.00
Facility Capacity > 4,000 kW, per month	$540.00	$480.00	$550.00
Facilities Charge			
<=4,000 kW, per kW Facility Capacity	$1.50	$0.70	$0.40
> 4,000 kW, per kW Facility Capacity	$1.35	$0.60	$0.40
On-Peak Demand Charge, per kW	$1.40	$1.55	$1.09
Reactive Power Charges			
Per kvar	$0.65	$0.60	$0.55
Per kVarh	$0.0008	$0.0008	$0.0008
Reserves Charges			
Spinning Reserves			
per kW of Facility Capacity	$0.27	$0.27	$0.27
Spinning Reserves (with Company-approved Self-Supply Agreement)			
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)
Supplemental Reserves			
per kW of Facility Capacity	$0.27	$0.27	$0.27
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)			
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)
Transmission & Ancillary Services Charge			
per kW of On-Peak Demand	$0.94	$1.04	$1.36

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Pacific Prevailing Time (PPT) Monday through Saturday, excluding North American Electric Reliability Council (NERC) holidays.

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9723.
A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0285.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

Facility Capacity shall be the average of the two greatest non-zero monthly Demands established during the 12 month period which includes and ends with the current Billing Month, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(continued)

Supplemental Reserves
In addition to the Supplemental Reserves provided for the Consumer's Baseline Demand, Supplemental Reserves provide Electricity within the first ten minutes after a Consumer's demand rises above Baseline Demand.

Self-Supply Agreement
Consumers with Nameplate Generation of 15 MW or greater may self-supply needed Spinning Reserves, Supplemental Reserves, or both upon agreement between Consumer and the Company. The agreement shall specify the kW of Spinning Reserves, Supplemental Reserves, or both provided by the Consumer at 3.5 percent for Spinning Reserves and 3.5 percent for Supplemental Reserves of Facility Capacity, the notification processes for delivery of reserve Energy, the requirements for Consumer delivery of requested reserves, the requirements for Consumer notification to Company of any changes in the ability to self-supply Reserves, the settlement process to be used when Reserves are supplied by the Consumer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. For Consumers who self-supply Reserves, Reserves kW credits will be applied to Consumer's bill based on the kW amount of Self-Supplied Spinning Reserves, Supplemental Reserves or both specified in the Self-Supply Reserves Agreement.

Supplemental Reserves Load Reduction Plan
For purposes of calculating Supplemental Reserves charges, a Consumer may submit to the Company a load reduction plan demonstrating the ability to reduce load within the first ten minutes of generator failure and specifying a kW amount of load reduction. The Consumer's load reduction plan must be approved by the Company. If approved by the Company, and adhered to by the Consumer, a load reduction plan kW credit will be applied to Consumer's bill based on the kW amount of load reduction specified in the Company-approved Load Reduction Plan.

If Consumer fails to follow the Company-approved Load Reduction Plan, all kW credits for the subsequent three months (Penalty Period) shall be forfeited. If the Consumer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period the load reduction plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Consumer fails to follow the Company-approved Load Reduction Plan during the Penalty Period, all kW credits for an additional three months period shall be forfeited. If the Consumer satisfactorily follows the Company-approved Load Reduction Plan during the second three month Penalty Period, the load reduction plan kW credit will be reinstated at the end of the second three month Penalty Period.

If the Consumer fails to follow the Company-approved Load Reduction Plan a second time during the combined six month period, the Load Reduction Plan shall be terminated.

The duration of the Penalty Period shall not be limited by the establishment of a new contract.

Following termination or contract expiration, Consumer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Consumer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.
Notwithstanding the above, Consumer may terminate the Company-approved Load Reduction Plan upon giving written notice to Company as provided in the Self-Supply Agreement.

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 247.

Reactive Power Charges

Per kVar. Equal to the maximum 15-minute reactive demand (kVar) for the month in kilovolt-amperes in excess of 40% of the monthly registered demand.
Per kVarh. Equal to all reactive kilovolt-ampere hours (kVarh) registered in excess of 40% of the registered monthly kilowatt-hours (kWh).

Minimum Charge

The Minimum Charge shall be the Monthly Billing as defined in this Schedule. In addition, the Company may require a higher Minimum Charge, if necessary, to recover the Company's investment in service Facilities.

Special Conditions

1. Prior to receiving service under this schedule, the Consumer and the Company must enter into a written agreement specifying the terms and conditions of service, the Consumer's Baseline Demand, Supply Service option, the Company's and Consumer's contact information, and any other information necessary for implementation of service under this schedule. These terms and conditions shall be consistent with this schedule.

2. A Consumer must inform the Company within thirty minutes of taking Unscheduled Energy at a rate of 5 MW or greater; such notice must include the anticipated time that the generator will return to normal operations.

3. Consumers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

4. If the Consumer is served at Primary or Transmission Voltage, the Consumer shall provide, install, and maintain on the Consumer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Consumer also shall provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring shall be of types and characteristics approved by the Company, and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Month, the Consumer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Consumer's generator, the payments for OATT charges for Transmission Service Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but shall not exceed the Monthly Demand for the Schedule 47 monthly Transmission Demand multiplied by the applicable OATT and such credit shall not exceed the Transmission and Related Services Charge incurred under this schedule.

6. Power and energy sold by Company to Consumer shall not be resold.
7. A Consumer's failure to inform the Company of the use of on-site generation shall not relieve the Consumer of responsibility for the charges and requirements under this schedule.
8. The Consumer's Baseline Demand may be modified as requested by the Consumer upon the addition of permanent energy efficiency measures, load shedding, or the addition or removal of equipment or permanent or long-term changes in loads or generator operations. The Consumer's Baseline Demand may be modified by the Company if the Company determines that the Consumer's Baseline Demand does not reflect load adjusted for the actual Consumer generation.
9. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council, NERC and FERC guidelines.
10. Service taken under the terms of Schedule 76R and Schedule 276R shall not affect the monthly readings for the Facilities Capacity, the On-Peak Demand Charge, or the Transmission & Ancillary Services Charge utilized for rendering the Monthly Billing for Schedule 47, nor shall they affect charges under Schedule 247.

Term

The term shall be one year and may be longer as mutually agreed to between Company and Consumer.

Rules and Regulations

Service and rates under this Schedule are subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

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Exhibit B

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Energy Charge

The Energy Charge is comprised of the following:

Baseline Energy

Baseline Energy shall be charged at the applicable Energy Charge under Supply Service Schedule 200 or Schedule 220, as appropriate and in accordance with the Applicable section of Schedule 200 or Schedule 220. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to other replacement power services approved by the Commission and provided by the Company.

Usage on an hourly basis up to and including the Baseline Demand as specified in Schedule 47 will be considered Baseline Energy.

Scheduled Maintenance Energy

Scheduled Maintenance Energy shall be charged at the applicable Supply Service Schedule 200 or Schedule 220, as appropriate and in accordance with the Applicable section of Schedule 200 or Schedule 220.

Scheduled Maintenance Energy is Energy prescheduled for delivery to serve the Consumer's load normally served by the Consumer's own generation (i.e., above Baseline Energy). Scheduled Maintenance must be prescheduled at least 30 days before delivery for a time period mutually agreeable to the Company and the Consumer. If resource, market, or other system conditions deviate significantly from expected conditions at the time the Company accepted the customer's request for Scheduled Maintenance Energy, the Company may cancel Scheduled Maintenance Energy at any time with seven days notice prior to the beginning of a Scheduled Maintenance period. If canceled, Company will make its best effort to reschedule Scheduled Maintenance Energy. For this event, Consumer will be required to submit a revised preschedule, but the 30 day advance notice requirement will be waived.

Scheduled Maintenance Energy may be taken for two events per calendar year. At the discretion of the Company the number of Scheduled Maintenance Energy events may be extended. Scheduled Maintenance Energy offerings shall not exceed a total of 31 days per calendar year.

(continued)

Energy Charge *(continued)*

Unscheduled Energy

Any Electricity provided to the Consumer that does not qualify as Baseline Energy or Scheduled Maintenance Energy shall be Unscheduled Energy and priced at an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex Mid-C Hourly Firm Index) plus 0.14¢ per kWh, plus the adjustment for Losses. Prices reported with no transaction volume or as survey-based shall be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Pacific Prevailing Time (PPT) Monday through Saturday excluding North American Electric Reliability Council (NERC) holidays. Off-peak hours are all remaining hours.

The Company may request that a Consumer taking a significant amount of Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

Losses

Losses shall be included by multiplying the applicable Energy Charge by the following adjustment factors:

Transmission Delivery Voltage	1.0454
Primary Delivery Voltage	1.0691
Secondary Delivery Voltage	1.0995

Special Conditions

Special conditions contained in Delivery Service Schedule 47 apply to this Schedule.

Rules and Regulations

Service and rates under this Schedule are subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

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Exhibit C

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS – 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 747

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Reserves Charges plus applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
Distribution Charge	Secondary	Primary	Transmission
Basic Charge			
Facility Capacity <= 4,000 kW, per month	$290.00	$260.00	$300.00
Facility Capacity > 4,000 kW, per month	$540.00	$480.00	$550.00
Facilities Charge			
<=4,000 kW, per kW Facility Capacity	$1.50	$0.70	$0.40
> 4,000 kW, per kW Facility Capacity	$1.35	$0.60	$0.40
On-Peak Demand Charge, per kW	$1.40	$1.55	$1.09
Reactive Power Charges			
Per kvar	$0.65	$0.60	$0.55
Per kVarh	$0.0008	$0.0008	$0.0008
Reserves Charges			
Spinning Reserves			
per kW of Facility Capacity	$0.27	$0.27	$0.27
Spinning Reserves (with Company-approved Self-Supply Agreement)			
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)
Supplemental Reserves			
per kW of Facility Capacity	$0.27	$0.27	$0.27
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)			
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Pacific Prevailing Time (PPT) Monday through Saturday, excluding North American Electric Reliability Council (NERC) holidays.

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9723.
A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0285.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

Facility Capacity shall be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Month, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

Supplemental Reserves

In addition to the Supplemental Reserves provided for the Consumer's Baseline Demand, Supplemental Reserves provide Electricity within the first ten minutes after a Consumer's demand rises above Baseline Demand.

(continued)

Self-Supply Agreement
Consumers with Nameplate Generation of 15 MW or greater may self-supply needed Spinning Reserves, Supplemental Reserves, or both upon agreement between Consumer and the Company. The agreement shall specify the kW of Spinning Reserves, Supplemental Reserves, or both provided by the Consumer at 3.5 percent for Spinning Reserves and 3.5 percent for Supplemental Reserves of Facility Capacity, the notification processes for delivery of reserve Energy, the requirements for Consumer delivery of requested reserves, the requirements for Consumer notification to Company of any changes in the ability to self-supply Reserves, the settlement process to be used when Reserves are supplied by the Consumer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. For Consumers who self-supply Reserves, Reserves kW credits will be applied to Consumer's bill based on the kW amount of Self-Supplied Spinning Reserves, Supplemental Reserves or both specified in the Self-Supply Reserves Agreement.

Supplemental Reserves Load Reduction Plan
For purposes of calculating Supplemental Reserves charges, a Consumer may submit to the Company a load reduction plan demonstrating the ability to reduce load within the first ten minutes of generator failure and specifying a kW amount of load reduction. The Consumer's load reduction plan must be approved by the Company. If approved by the Company, and adhered to by the Consumer, a load reduction plan kW credit will be applied to Consumer's bill based on the kW amount of load reduction specified in the Company-approved Load Reduction Plan.

If Consumer fails to follow the Company-approved Load Reduction Plan, all kW credits for the subsequent three months (Penalty Period) shall be forfeited. If the Consumer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the load reduction plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Consumer fails to follow the Company-approved Load Reduction Plan during the Penalty Period, all kW credits for an additional three month period shall be forfeited. If the Consumer satisfactorily follows the Company-approved Load Reduction Plan during the second three month Penalty Period the load reduction plan kW credit will be reinstated at the end of the second three month Penalty Period.

If the Consumer fails to follow the Company-approved Load Reduction Plan a second time during the combined six month period, the Load Reduction Plan shall be terminated.

The duration of the Penalty Period shall not be limited by the establishment of a new contract.

Following termination or contract expiration, Consumer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Consumer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.
Notwithstanding the above, Consumer may terminate the Company-approved Load Reduction Plan upon giving written notice to Company as provided in the Self-Supply Agreement.

Transmission & Ancillary Services
Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Reactive Power Charges

Per kVar. Equal to the maximum 15-minute reactive demand (kVar) for the month in kilovolt-amperes in excess of 40% of the monthly registered demand.
Per kVarh. Equal to all reactive kilovolt-ampere hours (kVarh) registered in excess of 40% of the registered monthly kilowatt-hours (kWh).

Minimum Charge

The Minimum Charge shall be the Monthly Billing as defined in this Schedule. In addition, the Company may require a higher Minimum Charge, if necessary, to recover the Company's investment in service Facilities.

Special Conditions

1. Prior to receiving service under this schedule, the Consumer and the Company must enter into a written agreement specifying the terms and conditions of service, the Consumer's Baseline Demand, Supply Service option, the Company's and Consumer's contact information, and any other information necessary for implementation of service under this schedule. These terms and conditions shall be consistent with this schedule.

2. A Consumer must inform the Company within thirty minutes of taking Unscheduled Energy at a rate of 5 MW or greater; such notice must include the anticipated time that the generator will return to normal operations.

3. Consumers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

4. If the Consumer is served at Primary or Transmission Voltage, the Consumer shall provide, install, and maintain on the Consumer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Consumer also shall provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring shall be of types and characteristics approved by the Company, and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. Power and energy sold by Company to Consumer shall not be resold.

6. A Consumer's failure to inform the Company of the use of on-site generation shall not relieve the Consumer of responsibility for the charges and requirements under this schedule.

7. The Consumer's Baseline Demand may be modified as requested by the Consumer upon the addition of permanent energy efficiency measures, load shedding, or the addition or removal of equipment or permanent or long-term changes in loads or generator operations. The Consumer's Baseline Demand may be modified by the Company if the Company determines that the Consumer's Baseline Demand does not reflect load adjusted for the actual Consumer generation.

8. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council, NERC and FERC guidelines.

9. Service taken under the terms of Schedule 776R shall not affect the monthly readings for the Facilities Capacity or the On-Peak Demand Charge utilized for rendering the Monthly Billing for Schedule 747.

Term

The term shall be one year and may be longer as mutually agreed to between Company and Consumer.

Rules and Regulations

Service and rates under this Schedule are subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

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Exhibit D

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE/PARTIAL REQUIREMENTS SERVICE – ECONOMIC REPLACEMENT POWER RIDER DELIVERY SERVICE

OREGON
SCHEDULE 76R

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus applicable adjustments as specified in Schedule 90:

		Delivery Voltage	
	Secondary	Primary	Transmission
Transmission and Ancillary Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.037	$0.041	$0.053
Daily ERP Demand Charge per kW of Daily ERP On- Peak Demand	$0.055	$0.060	$0.042

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

(continued)

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

Special Conditions

1. Prior to receiving service under this schedule, the Consumer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule, the ERPA and the corresponding written agreement. All other Energy supplied will be made under the terms of Schedule 47. All notice provisions of this schedule and agreement must be complied with for delivery of Energy.

3. Service taken under the terms of this Schedule shall not affect the monthly readings for the Facility Capacity, the On-Peak Demand Charge, or the Transmission & Ancillary Services Charge utilized for rendering the Monthly Billing for Schedule 47, nor shall they affect charges under Schedule 247.

4. All charges and requirements of Schedule 47 shall apply except as provided for under this Schedule.

5. ERP supplied shall not be resold.

6. The Company may interrupt ERP due to Transmission constraints.

7. The Company is not responsible for providing market information to Consumer.

8. The Company has no obligation to provide the Consumer with ERP except as explicitly agreed to between Company and Consumer.

9. Each day of delivery begins HE 0100 and ends HE 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

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Exhibit E

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to by Consumer and the Company.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47. In addition, this tariff may only be provided in conjunction with Delivery Service Schedule 76R.

Energy Needs Forecast (ENF) Fee

per ENF submission or revision	$75.00

Economic Replacement Power Agreement (ERPA) Processing Fees

Daily ERPA

Per each Daily ERPA,	$100.00
and not to exceed (per calendar month)	$400.00

A single, Daily ERPA covering multiple days in a calendar month will be treated as one Daily ERPA.

Monthly or Quarterly ERPA

Per Monthly or Quarterly ERPA	$400.00

Energy Charge

per kWh of ERP	See below for ERP Pricing

Energy Needs Forecast

The Energy Needs Forecast (ENF) specifies the total prescheduled amount of electricity in megawatts (MW) per hour that the Company is requested to serve. The ENF requests service for all or a portion of the Consumer's load normally supplied by the Consumer's generation. The Company may choose to provide all or a portion of the ENF and shall inform the Consumer of any such adjustment to the submitted ENF. The agreement between Consumer and Company shall specify how the ENF shall be delivered to Company.

Blocks of Energy – equal MWs per hour for all of the hours:
Heavy Load Hour (HLH) block is equal to 16 hours Monday – Saturday, Hour Ending (HE) 0700 – HE 2200 Pacific Prevailing Time (PPT).
Light Load Hour (LLH) block is equal to 8 hours Monday – Saturday, HE 2300 - HE 0600 PPT and 24 hours on Sunday.
Flat block (Flat) is equal to 24 hours Monday – Sunday.

Non-Standard Blocks of Energy – equal MWs per hour for all of the hours:
Non-Standard Blocks are blocks of energy that are not in multiples of 25MW, i.e. may be less than 25MW or greater than 25 MW for HLH, or LLH or Flat.

Consumer may request both Standard Blocks and Non-Standard Blocks of Energy in an ENF.

(continued)

Daily ENF
Prior to HE 0615 PPT on the Pre-schedule Day, Consumer shall provide to Company Consumer's ENF specifying daily preschedule quantities by hour in equal volume blocks. By HE 0630 PPT on the Pre-schedule Day, Company shall notify Consumer of its acceptance of Consumer's ENF or modifications to Consumer's ENF. If Company has modified Consumer's ENF, by HE 0645 PPT on the Pre-schedule Day, Consumer shall notify Company of its acceptance of the modified ENF. Acceptance by Company of Consumer's ENF or acceptance by Consumer of Company's modification of Consumer's ENF shall constitute an ERPA (described below).

Unless modified pursuant to the Western Electricity Coordinating Council (WECC) Interchange Scheduling and Accounting Subcommittee (ISAS) Pre-scheduling Calendar, "Pre-schedule Day" means the business day immediately preceding the day of delivery unless the day of delivery is Sunday or Monday, in which case the Pre-schedule Day shall be the immediately preceding Friday, or unless the day of delivery is Saturday, the Pre-schedule Day shall be the immediately preceding Thursday. In the event the Pre-schedule Day falls on a NERC-defined holiday, the pre-schedule requirement shall be adjusted to reflect such holiday.

Monthly or Quarterly ENF
Between 0900 and 1159 PPT during the last day of gas bid week (Annually, Company will provide participating Consumers with a twelve month calendar of gas bid week days), Consumer shall contact the Company at a designated telephone number and receive a Mid Columbia market price quoted by a broker for the ENF. During that telephone call, the Consumer may purchase the HLH, LLH or Flat block of monthly or quarterly energy at a volume agreed to by Company and Consumer and at the price quoted. Unless accepted by Consumer during the telephone call, the price quoted shall expire at the end of the telephone call. Acceptance by Consumer of the price quoted shall constitute an ERPA (described below).
Broker quote. A Broker quote is a price quote from a brokering house or trading platform that the Company is utilizing on a given day.

Economic Replacement Power Agreement

The Economic Replacement Power Agreement (ERPA) specifies Electricity supplied by Company and agreed to by Consumer to meet in whole or in part an Energy Needs Forecast (ENF). An ERPA shall be required for transactions covered by an ENF. The Consumer shall use best efforts to conform actual Energy usage to the ERPA. If Consumer cannot take ERP as agreed to in an ERPA, Consumer shall promptly notify Company of the same. Such notice shall include, where applicable, the time when the shutdown occurred or is expected to occur and the anticipated duration of such shutdown and any other arrangements as represented in the written agreement.

ERP options

Option 1. 25 MW Standard block Take-or-Pay pricing. Consumer agrees to receive 25 MW per hour, on a daily, monthly (calendar month), or quarterly (calendar quarter) basis as specified in Consumer's ERPA and designated as either HLH, LLH or Flat. If Consumer takes less than the 25 MW per hour agreed to in the ERPA, Consumer shall remain obligated to pay for the 25 MW per hour agreed to in the ERPA.

(continued)

<u>Option 2.</u> Non-Standard Block (NSB) Take-or-Pay pricing. Consumer agrees to receive non-standard block quantities of MW per hour on a daily, monthly (calendar month) or quarterly (calendar quarter) basis as specified in Consumer's ERPA and designated as either HLH, LLH or Flat. If Consumer takes less than the quantities of MW per hour agreed to in the ERPA, Consumer shall remain obligated to pay for the quantities of MW per hour agreed to in the ERPA.

ERP Pricing

DAILY

<u>25 MW Standard block take-or-pay pricing.</u> Energy shall be priced at the settled Electricity Price Index Dow-Jones Mid-Columbia HLH and LLH prices, plus 0.14 cents per kWh, plus the adjustment for losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' prices within HLH or LLH periods, as applicable shall determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based shall be considered reported.

<u>Non-Standard Block (NSB) take-or-pay pricing.</u> Energy shall be priced at the settled Electricity Price Index Dow-Jones Mid-Columbia HLH and LLH prices, plus a five percent NSB fee, plus 0.14 cents per kWh, plus the adjustment for losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' prices within HLH or LLH periods, as applicable shall determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based shall be considered reported.

MONTHLY

<u>25 MW Standard block take-or-pay pricing.</u> Energy shall be priced at the fixed monthly Mid Columbia market price as a Broker Quote, plus 0.14 cents per kWh, plus the adjustment for losses.

<u>Non-Standard Block (NSB) take-or-pay pricing.</u> Energy shall be priced at the fixed monthly Mid Columbia market price as a Broker Quote, plus a five percent NSB fee, plus 0.14 cents per kWh, plus the adjustment for losses.

QUARTERLY

<u>25 MW Standard block take-or-pay pricing.</u> Energy shall be priced at the fixed quarterly Mid Columbia market price as a Broker Quote, plus 0.14 cents per kWh, plus the adjustment for losses.

<u>Non-Standard Block (NSB) take-or-pay pricing.</u> Energy shall be priced at the fixed quarterly Mid Columbia market price as a Broker Quote, plus a five percent NSB fee, plus 0.14 cents per kWh, plus the adjustment for losses.

Losses

Losses shall be included by multiplying the ERP Charge by the following adjustment factors:

Transmission Delivery Voltage	1.0454
Primary Delivery Voltage	1.0691
Secondary Delivery Voltage	1.0995

(*continued*)

Special Conditions

1. Prior to receiving service under this schedule, the Consumer and the Company must enter into a written agreement governing the terms and conditions of service, including, but not limited to, consequences of failure to perform. In particular, the written agreement shall specify that under a *force majeure* event, Company and Consumer shall make best efforts to mitigate damages.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule, the ERPA and the corresponding written agreement. All other Energy supplied will be made under the terms of Schedule 247. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Consumer is required to maintain Schedule 247 service unless otherwise agreed to by the Company.

3. All charges and requirements of Schedule 247 shall apply except as provided for under this schedule.

4. ERP supplied shall not be resold.

5. The Company may interrupt ERP due to Transmission constraints.

6. The Company is not responsible for providing market information to Consumer other than as specified in this tariff.

7. The Company has no obligation to provide the Consumer with ERP except as explicitly agreed to by both parties.

8. Each day of delivery begins HE 0100 and ends HE 2400 under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

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Exhibit F

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus applicable adjustments as specified in Schedule 90:

		Delivery Voltage	
	Secondary	Primary	Transmission
Daily ERS Demand Charge			
per kW of Daily ERP On- Peak Demand	$0.055	$0.060	$0.042

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

Daily ERS On-Peak Demand

Daily ERS On-Peak Demand shall not be less than the maximum ERS On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERS On-Peak Demand will be billed for each day in the month that the Company supplies ERS to the Consumer.

Special Conditions

1. Prior to receiving service under this schedule, the Consumer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERS supplied by an ESS pursuant to this schedule, and corresponding written agreements. All other Energy supplied will be made under the terms of Schedule 747. All notice provisions of this schedule and agreement must be complied with for delivery of Energy.

3. Service taken under the terms of this Schedule shall not affect the monthly readings for the Facility Capacity and the On-Peak Demand Charge utilized for rendering the Monthly Billing for Schedule 747.

4. All charges and requirements of Schedule 747 shall apply except as provided for under this Schedule.

5. ERS supplied shall not be resold.

6. The Company may interrupt ERS due to Transmission constraints.

7. The Company is not responsible for providing market information to Consumer.

8. The Company has no obligation to provide the Consumer with ERS except as explicitly agreed to between Company and Consumer.

9. Each day of delivery begins HE 0100 and ends HE 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 170

In the Matter of PACIFIC POWER & LIGHT (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**SECOND PARTIAL STIPULATION**

This Second Partial Stipulation is the second stipulation entered into for the purpose of resolving specified adjustments to PacifiCorp's requested revenue requirement in this docket. It represents a settlement of the issue listed in Paragraph 5 of the Stipulation. Issues pertaining to employee benefits were specifically excluded from the first Partial Stipulation in this case; this Second Partial Stipulation now resolves these issues.

PARTIES

1. The initial parties to this Second Partial Stipulation are PacifiCorp (or the "Company"), the Staff of the Public Utility Commission of Oregon ("Staff"), the Industrial Customers of Northwest Utilities ("ICNU"), the Citizens' Utility Board ("CUB") and Fred Meyer Food Stores and Quality Food Centers, Divisions of Kroger Co. ("Fred Meyer") (together "the Parties"). This Second Partial Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of this Partial Stipulation.

BACKGROUND

2. On November 12, 2004, PacifiCorp filed revised tariff schedules to effect a $102 million increase in its base prices to Oregon electric customers. PacifiCorp based its filing on a 2006 calendar year test period. On March 15, 2005, PacifiCorp filed a Net Power Cost update, increasing its requested revenue requirement. On May 4, 2005, PacifiCorp and several

of the parties entered into the first Partial Stipulation. This Stipulation reduced PacifiCorp's requested revenue requirement in the November 12, 2004 filing to approximately $71 million.

3. On June 14, 2005, the parties reconvened the settlement conferences first convened on April 5, 2005. The settlement conferences were open to all parties.

4. As a result of the settlement conferences, the Parties have reached agreement on the matters set forth below. The net effect of this Second Partial Stipulation is a reduction in PacifiCorp's proposed revenue requirement by approximately $2.44 million. The Parties submit this Second Partial Stipulation to the Commission and request that the Commission approve the settlement as presented.

AGREEMENT

5. The Parties agree that the following adjustment, and the revenue requirement levels resulting from its application, is fair and reasonable:

> Benefits: The Parties agree to a $2.44 million reduction in the Company's filed revenue requirement for full-time employee benefits. This reduction reflects a change from budgeted fiscal year 2004 base data to calendar 2004 base data, with lower escalation rates than PacifiCorp originally proposed for medical benefits and the Workers Compensation Levy. It also reflects an agreement to amortize $750,000 of external system development costs associated with Other Salary Overhead over two years.

6. The Parties agree that this Second Partial Stipulation removes employee benefits from the list of non-settled issues reserved for continuing litigation in this case contained in paragraph 6 of the first Partial Stipulation.

7. The Parties agree that this Second Partial Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Second Partial Stipulation shall not be admissible as evidence in this or any other proceeding.

8. This Second Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this Second Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Second Partial Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

9. The Parties agree that they will continue to support the Commission's adoption of the terms of this Second Partial Stipulation. If this Second Partial Stipulation is challenged by any other party to this proceeding, the Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Second Partial Stipulation.

10. The Parties have negotiated this Second Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Second Partial Stipulation or imposes additional material conditions in approving this Second Partial Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

11. By entering into this Second Partial Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Second Partial Stipulation, other than those specifically

identified in the body of this Second Partial Stipulation. No party shall be deemed to have agreed that any provision of this Second Partial Stipulation is appropriate for resolving issues in any other proceeding, except as previously identified in Paragraph 5 of the Second Partial Stipulation.

12. This Second Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Second Partial Stipulation is entered into by each party on the date entered below such party's signature.

Signatures follow on next page

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

ICNU

By: ______________________________

Date: ______________________________

CUB

By: ______________________________

Date: ______________________________

FRED MEYER

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: 6/29/05

ICNU

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

FRED MEYER

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

CUB

By: Bob Jenks

Date: 6/28/05

FRED MEYER

By: ______________________

Date: ______________________

PACIFICORP

By: ____________________

Date: ____________________

STAFF

By: ____________________

Date: ____________________

ICNU

By: ____________________

Date: 6-28-05

CUB

By: ____________________

Date: ____________________

FRED MEYER

By: ____________________

Date: ____________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

FRED MEYER

By: [signature]

Date: 6/22/05

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 170

In the Matter of PACIFIC POWER & LIGHT (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**THIRD PARTIAL STIPULATION**

This Third Partial Stipulation is the third stipulation entered into for the purpose of resolving specified adjustments to PacifiCorp's requested revenue requirement in this docket. It represents a settlement of the issues listed in Paragraph 5 of the Stipulation. Issues pertaining to the RVM power costs and a fuel handling charge were excluded from the first Partial Stipulation in this case; this Third Partial Stipulation now resolves these issues between PacifiCorp and Staff of the Public Utility Commission ("Staff"). It also reflects Staff's agreement to support PacifiCorp's position in this case on the following issues: waiver of the New Resource Rule; the Company's forced outage rate; use of 2006 test year; and application of the Revised Protocol to the Company's QF contracts signed after execution of the Revised Protocol.

PARTIES

1. The initial parties to this Third Partial Stipulation are PacifiCorp (or the "Company") and Staff (together "the Parties"). This Third Partial Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of this Third Partial Stipulation.

BACKGROUND

2. On November 12, 2004, PacifiCorp filed revised tariff schedules to effect a $102 million increase in its base prices to Oregon electric customers. PacifiCorp based its filing on a 2006 calendar year test period. On May 4, 2005, PacifiCorp and several of the parties

entered into the first Partial Stipulation. The first Partial Stipulation reduced PacifiCorp's requested revenue requirement to approximately $71 million.

3. On June 14, 2005, the parties reconvened the settlement conferences first convened on April 5, 2005. The settlement conferences were open to all parties.

4. As a result of the settlement conferences, PacifiCorp, Staff, the Industrial Customers of Northwest Utilities, CUB and Fred Meyer entered into a Second Partial Stipulation, which addressed employee benefits and reduced PacifiCorp's requested revenue requirement by approximately $2.44 million. The Parties have also reached agreement on the matters set forth below. The net effect of this Third Partial Stipulation, is a $2.49 million increase in the Company's filed revenue requirement, and, if RVM is adopted, a decrease from PacifiCorp's original proposed revenue requirement for RVM on January 1, 2006. The Parties submit this Third Partial Stipulation to the Commission and request that the Commission approve the settlement as presented.

AGREEMENT

5. The Parties agree that the following adjustments, and the revenue requirement levels resulting from their application, are fair and reasonable:

a. <u>RVM Power Costs</u>: The Parties agree that if RVM is implemented to set the Company's Transition Adjustment, RVM power costs should be set at $800.5 million, prior to the inclusion of RVM updates for this docket. This would result in an approximately $4.3 million increase in the Company's revenue requirement established for the general rate case portion of this case, effective January 1, 2006. $4.3 million is an estimate; the actual change will be determined by the November 15, 2005 final GRID power cost model run. The final GRID run will include all the adjustments proposed by the Company in PPL/604-606 and PPL/607-608 except the Deferred Maintenance, Thermal Ramping, Station Service, and Planned Outages adjustments. As part of the settlement of this issue, Staff also agrees to the following additional items:

i. Staff will support PacifiCorp's June 6, 2005 application for a waiver of the New Resource Rule as it relates to the West Valley Lease, the Gadsby CTs, and Currant Creek projects.

ii. Staff will accept the level of plant forced outages included in the Company's case.

iii. Staff agrees not to raise any issues regarding an alleged "mismatch" between a September 12, 2005 base rate change effective date and the calendar year 2006 test period.

iv. Staff will support the allocation treatment under the Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (or the "Revised Protocol") of the Company's contracts with Qualifying Facilities ("QFs") added to the Company's power costs in this case.

b. Fuel Handling Charge: The Parties agree that the Company's revenue requirement should be corrected to include a fuel handling charge. This results in a \$2.49 million increase in the Company's filed revenue requirement.

6. The Parties agree on the following in terms of settled and non-settled issues:

a. The Parties to this Partial Stipulation agree that it resolves all issues related to the adjustments, and the revenue requirement levels resulting from their application, listed in Paragraph 5.

b. The Parties agree that this Third Partial Stipulation removes RVM issues from the issues reserved by Staff for continuing litigation in this case contained in paragraph 6 of the first Partial Stipulation. Staff, however, reserves the right to comment on the positions of other parties on this issue.

7. The Parties agree that this Third Partial Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Third Partial Stipulation shall not be admissible as evidence in this or any other proceeding.

8. This Third Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this Third Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Third Partial Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

9. The Parties agree that they will continue to support the Commission's adoption of the terms of this Third Partial Stipulation. If this Third Partial Stipulation is challenged by any other party to this proceeding, the Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Third Partial Stipulation.

10. The Parties have negotiated this Third Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Third Partial Stipulation or imposes additional material conditions in approving this Third Partial Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

11. By entering into this Third Partial Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Third Partial Stipulation, other than those specifically identified in the body of this Third Partial Stipulation. No party shall be deemed to have agreed that any provision of this Third Partial Stipulation is appropriate for resolving issues in any other proceeding, except as previously identified in Paragraph 5 of the Third Partial Stipulation.

12. This Third Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Third Partial Stipulation is entered into by each party on the date entered below such party's signature.

PACIFICORP	STAFF
By: ______________	By: ______________
Date: ______________	Date: ______________

ORDER NO. 05-1050

10. The Parties have negotiated this Third Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Third Partial Stipulation or imposes additional material conditions in approving this Third Partial Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

11. By entering into this Third Partial Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Third Partial Stipulation, other than those specifically identified in the body of this Third Partial Stipulation. No party shall be deemed to have agreed that any provision of this Third Partial Stipulation is appropriate for resolving issues in any other proceeding, except as previously identified in Paragraph 5 of the Third Partial Stipulation.

12. This Third Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Third Partial Stipulation is entered into by each party on the date entered below such party's signature.

PACIFICORP	STAFF
By: ______________________	By: ______________________
Date: ______________________	Date: 6/29/05

APPENDIX D
PAGE 6 OF 6

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 170

In the Matter of PACIFIC POWER & LIGHT (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**FOURTH PARTIAL STIPULATION**

This fourth Partial Stipulation is the fourth stipulation entered into for the purpose of resolving specified adjustments to PacifiCorp's requested revenue requirement in this docket. It represents a settlement of certain issues remaining in the case, as described in Paragraph 7 of this Stipulation. It does not address the following issues: issues related to the tax adjustments proposed by the Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB") and the Industrial Customers of Northwest Utilities ("ICNU"); PacifiCorp's proposed Transition Adjustment Mechanism and Resource Valuation Mechanism (or "RVM") and the power costs updates related to that mechanism; and issues reserved by ICNU pursuant to Paragraph 8 of this fourth Partial Stipulation.

PARTIES

1. The initial parties to this fourth Partial Stipulation are PacifiCorp (or the "Company"), Staff, ICNU, CUB and Fred Meyer Food Stores and Quality Food Centers, Divisions of Kroger Co. ("Fred Meyer") (together "the Parties"). This fourth Partial Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of this fourth Partial Stipulation.

BACKGROUND

2. On November 12, 2004, PacifiCorp filed revised tariff schedules that would result in a $102 million increase in its base prices to Oregon electric customers. PacifiCorp based its

filing on a 2006 calendar year test period. PacifiCorp filed two Net Power Cost updates, increasing its requested revenue requirement by approximately $10.7 million. Pursuant to Administrative Law Judge Kirkpatrick's Prehearing Conference Memorandum, the Parties commenced settlement conferences on April 5, 2005. On May 4, 2005, the Parties entered into the first Partial Stipulation. The first Partial Stipulation reduced PacifiCorp's requested revenue requirement by approximately $31 million.

3. On June 14, 2005, the Parties reconvened the settlement conferences first held on April 5, 2005. The settlement conferences were open to all parties. As a result of the settlement conferences, the Parties entered into the second Partial Stipulation, dated June 29, 2005, which addressed employee benefits and reduced PacifiCorp's requested revenue requirement by approximately $2.44 million.

4. Also as a result of the settlement conferences reconvened on June 14, 2005, PacifiCorp and Staff entered into the third Partial Stipulation, dated June 29, 2005, which resolved issues between PacifiCorp and Staff pertaining to RVM power costs and a fuel handling charge. If approved, the resolution of the RVM issues in the third Partial Stipulation will result in an approximately $4.3 million increase to the Company's revenue requirement effective January 1, 2006. The third Partial Stipulation reflects an agreement to allow the Company to correct its revenue requirement to include a fuel handling charge, an increase of $2.49 million, as part of the Company's revenue requirement increase proposed to be effective September 12, 2005. In addition, the third Partial Stipulation contains Staff's agreement to support PacifiCorp's position on the waiver of the New Resources Rule and the treatment of new Qualifying Facility ("QF") contracts as being consistent with the Revised Protocol. Overall the third Partial

Stipulation would increase PacifiCorp's revenue requirement by approximately $6.79 million. CUB and ICNU do not support the third Partial Stipulation.

5. On July 15, 2005, the Company filed sur-surrebuttal testimony updating its revenue requirement increase to $75.9 million taking effect on September 12, 2005, and an additional $4.3 million taking effect on January 1, 2006, for a total revenue requirement increase of approximately $80.2 million. This update is summarized in the exhibit to the sur-surrebuttal testimony of Mr. Paul Wrigley, PPL/1602, Wrigley/1, and explained in the sur-surrebuttal testimony of Mr. Wrigley at PPL/1601, Wrigley/1-3.

6. Settlement conferences were reconvened on July 18, 2005, resulting in the agreement on the matters set forth below. The net effect of this fourth Partial Stipulation is a reduction in PacifiCorp's proposed September 2005 revenue requirement from $75.9 million to approximately $52.5 million to reflect adjustments to cost of capital and pensions and an agreement to move the effective date to October 4, 2005. Exhibit A to this fourth Partial Stipulation shows the derivation of the $52.5 million change to the Company's revenue requirement. The Parties submit this fourth Partial Stipulation to the Commission and request that the Commission approve the settlement as presented.

AGREEMENT

7. Except for the issues reserved pursuant to Paragraph 8 of this fourth Partial Stipulation, the Parties agree that the following adjustments, and the revenue requirement levels resulting from their application, are fair and reasonable:

a. Cost of Capital: The Parties agree that the overall rate of return should be set at 8.057 percent. The Parties further agree that, for all Oregon regulation purposes, until such time as the Commission issues a general rate order subsequent to UE 170, PacifiCorp will use the weighted cost of capital set at 8.057 percent rate of return ("ROR") and the capital components including the capital structure as set forth in the table below. The Parties accept this Cost of Capital settlement only because they believe that it results in a reasonable overall revenue requirement in this case. The Parties, except as provided above with regard to ongoing regulatory reporting, do not necessarily agree on each of the specified capital components as set forth in the table. This change to the Company's cost of capital results in a $24.4 million reduction from the Company's original revenue requirement request.

COST OF CAPITAL - STAFF Position	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	51.34%	6.288%	3.228%
Preferred Stock	1.10%	6.590%	0.073%
Common Equity	47.56%	10.000%	4.756%
Total	100.00%		**8.057%**

b. Pensions: The Parties agree that the Company should adjust its pension expense to reflect the $52.5 million revenue requirement increase in light of the agreement on cost of capital, which will permit PacifiCorp to recover its full FAS 87 pension expense. This agreement on pension expense shall not bind any party to any position regarding pension expense in the future.

c. Rate Spread: Except for the modifications indicated, the Parties agree that the rate spread methodology as shown in PPL Exhibit 1210, Griffith/1 is the appropriate rate spread methodology to employ in setting rates in UE 170.

(1) The overall average net percentage increase (the "Net Increase") will be computed as shown in column 15, line 22 of PPL Exhibit 1210, Griffith/1 and excludes the effect of Schedule 94.

(2) None of the major rate schedules shall receive more than 1.5 times the Net Increase, except if the final ordered revenue requirement produces an outcome whereby application of 1.5 times the Net Increase is less than two (2) percentage points above the Net Increase, the cap on any major schedule Net Increase shall be equal to the sum of two (2) percentage points and the Net Increase.

(3) Large General Service Schedule 48 shall not receive more than 1.45 times the Net Increase. This cap shall apply for Schedule 48 regardless of the final ordered revenue requirement.

(4) The Parties agree that there shall be no Rate Mitigation Adjustment ("RMA") surcredit or surcharge applied to Residential Schedule 4. Schedule 48 will not receive an RMA surcharge and may receive an RMA surcredit. Other rate schedules may receive RMA surcharges or surcredits in order to implement the rate spread methodology.

d. Rate Design:

(1) The Parties agree that time of day demand and energy pricing shall be implemented on an experimental basis until PacifiCorp's next rate case for Schedule 48/200 as proposed in PPL Exhibit 1200 with the exception that the differential between on-peak and off-peak rates will be 1 mil instead of 3 mils per kWh. PacifiCorp agrees to complete a study within twelve months of the date of the final Commission order that analyzes the wholesale cost differences between on-peak and off-peak rate differentials. In addition, data shall be collected

to analyze the effectiveness of this program and the ability of Schedule 48 customers to change their usage patterns. The Parties agree to further discuss on-peak and off-peak rates subsequent to the completion of the study. This agreement is for settlement purposes only and all Parties are free to raise issues about the validity, effectiveness or any other issue regarding further applicability of the time of day pricing to Schedule 48 only at the expiration of this experimental time of day pricing for Schedule 48.

(2) The Schedule 28/200 tailblock equalization shall be as described in PPL Exhibit 1204, Griffith/6-7 and Staff Exhibit 900, Breen/15.

e. Bill Proration: For residential customer bills, PacifiCorp shall implement the "All Bills Proration" proposal as proposed by CUB and described in PPL Exhibit 1209, Griffith/5, lines 11-19. Any consumer complaints relating to the correct application of the All Bills Proration proposal for residential customers shall not be counted against the Company's consumer complaint metrics.

f. Rate Change Effective Date: The Parties agree that the rate change in UE 170 should go into effect on October 4, 2005. The Company agrees to waive the current tariff suspension date of September 12, 2005 to October 4, 2005.

8. The Parties to this fourth Partial Stipulation agree that it resolves all issues related to the cost/revenue items and categories associated with the adjustments listed in Paragraph 7. The following items are specifically excluded from this fourth Partial Stipulation.

a. Staff, ICNU and CUB exclude their tax adjustments from this fourth Partial Stipulation.

b. ICNU and CUB exclude PacifiCorp's RVM proposal from this fourth Partial Stipulation. ICNU and CUB also exclude from this Stipulation their objections to the third Partial Stipulation and all the RVM power costs adjustments.

c. ICNU specifically excludes the following issues: the Company's fuel handling correction; the allocation treatment of the Company's new QF contracts; the prudence of the Company's new generation resources (the West Valley Lease, the Gadsby CTs, and Currant Creek); the UM 995 deferral period outages; PacifiCorp's request for waiver of the market price rule; treatment of the costs related to development of the RTO; and the third Partial Stipulation issues, including a GRID model outage and heat rate update adjustment.

9. The Parties agree that this fourth Partial Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this fourth Partial Stipulation shall not be admissible as evidence in this or any other proceeding.

10. This fourth Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this fourth Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this fourth Partial Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

11. The Parties agree that they will continue to support the Commission's adoption of the terms of this fourth Partial Stipulation. If this fourth Partial Stipulation is challenged by any other party to this proceeding, the Parties agree to cooperate in cross-examination and put on

such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this fourth Partial Stipulation.

12. The Parties have negotiated this fourth Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this fourth Partial Stipulation or imposes additional material conditions in approving this fourth Partial Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

13. By entering into this fourth Partial Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this fourth Partial Stipulation, other than those specifically identified in the body of this fourth Partial Stipulation. No party shall be deemed to have agreed that any provision of this fourth Partial Stipulation is appropriate for resolving issues in any other proceeding, except as previously identified in Paragraph 7 of the fourth Partial Stipulation.

14. This fourth Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This fourth Partial Stipulation is entered into by each party on the date entered below such party's signature.

RECEIVED
AUG 0 1 2005
Public Utility Commission of Oregon
Administrative Hearings Division

PACIFICORP

By: Doug Larson

Date: July 29 2005

STAFF

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

FRED MEYER

By: ______________________

Date: ______________________

RECEIVED
AUG 0 1 2005
Public Utility Commission of Oregon
Administrative Hearings Division

PACIFICORP

By: ____________________

Date: ____________________

STAFF

By: [signature]

Date: July 29, 2005

ICNU

By: ____________________

Date: ____________________

CUB

By: ____________________

Date: ____________________

FRED MEYER

By: ____________________

Date: ____________________

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Administrative Hearings Division

PACIFICORP

By: ________________________

Date: ________________________

STAFF

By: ________________________

Date: ________________________

ICNU

By: [signature]

Date: 7/28/05

CUB

By: ________________________

Date: ________________________

FRED MEYER

By: ________________________

Date: ________________________

ORDER NO. 05-1050

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Public Utility Commission of Oregon
Administrative Hearings Division

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

CUB

By: Jason Eisdorfer

Date: July 28, 2005

FRED MEYER

By: ______________________

Date: ______________________

RECEIVED
AUG 0 1 2005
Public Utility Commission of Oregon
Administrative Hearings Division

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

FRED MEYER

By: Michael L. Kurtz

Date: 7/28/05

ORDER NO. 05-1050
Exhibit A

RECEIVED
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Public Utility Commission of Oregon
Administrative Hearings Division

PACIFICORP - OREGON
Issue Summary
UE 170 - CY 2006 Test Year
($000)

Item	Adjustments (Base Rates)	Revenue Requirement Increase (Decrease)
	Rev. Req. on the Company's Filed Results:	**$102,024**
S-0	Rate of Return	**($24,409)**
S-00	Operating Revenue Deduction Adjustment	**($209)**
S-1	Load Forecast Revision	**($8,657)**
S-2	Incentive Programs	**($5,434)**
S-3	Pension Adjustment	**$1,320**
S-4	Benefit Adjustment	**($2,410)**
S-5	Non-Labor Administrative and General Cost Adjustments	**($6,057)**
S-6	Revenue Growth Adjustment	**($2,141)**
S-7	Bridger Coal Costs	**($2,025)**
S-8	FIT and SIT Adjustment	**$0**
S-9	Production Activity Deduction	**($855)**
S-10	Hydroelectric Relicensing Cost Adjustment	**$0**
S-11	Extrinsic Value of Resources	**$0**
S-12	Aquila Hydro Hedge	**$0**
S-13	GP Power Cost Adjustment	**($2,049)**
S-14	Margin	**($7,287)**
C-1	Holding Company Interest Deduction	**$0**
P-1	Fuel Handling	**$2,390**
P-2	DITBAL Allocation	**$1,312**
P-3	Hermiston/Gadsby Allocation Correction	**$914**
P-4	WSCC Membership & Little Mountain	**$250**
P-5	Klamath Irrigators. Sch 33 Revenue	**$7,187**
P-6	USRB/UKRB Rate Base Adjustments Klamath Irrigators	**($1,364)**
P-7	Cost of Debt	**$0**
P-8	RVM Power costs	**$0**
	Total Adjustments (Base Rates)	**($49,524)**
	Revenue Requirement Change (Base Rates)	**$52,500**
	Percentage Overall Rate Change	**6.44%**

Case UE 170
PPL Exhibit 604
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Supplemental Direct Testimony of Mark T. Widmer

February 2005

Q. Are you the same Mark T. Widmer that filed direct testimony with the Company's original filing?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to make the Company's original filed net power costs more complete and accurate. The Company decided to make this filing now and outline these adjustments in this formal manner because of the added complexity that the Company's proposal to initiate an RVM-type mechanism adds to the power costs issues in the case. The Company has met with other parties to the case and outlined these adjustments. PacifiCorp understands that the parties have agreed to the filing of this Supplemental Testimony. Individual adjustments go either direction; the adjustments lower Net Power Cost (NPC) by $10.4 million to $803.4 million Total Company. The adjustments are summarized on PPL Exhibit 605.

Q. Please explain the "Marginal Units/Variable O&M" adjustment.

A. The Company's original filing incorrectly assigned reserve credits for Cholla 4 to all five West Valley CT units in the commitment decision. A reserve credit is the value credited to the higher cost gas units in the commitment logic when they carry reserves in lieu of reserves being carried on lower cost coal plants. The previous modeling resulted in uneconomic generation because the sum of the reserve carrying capability on the gas plants exceeded the level of reserves carried on coal units. This adjustment also incorporates the incremental cost per MWh of future overhauls for the Gadsby and West Valley units in the commitment decision. The incremental value recognizes that the units have a set number of service hours that they can be operated before a major overhaul is required. It should be noted that the overhaul cost included in the commitment decision is not included in NPC. This correction increases NPC by $1.5 million.

Q. Please explain the "Deferred Maintenance" adjustment.

A. The Company's original filing incorrectly assumed deferrable thermal maintenance was performed only during weekend hours. This resulted in GRID producing more coal generation on-peak and less off-peak than occurred during the 48-Month historical period ended March 2004, as shown in PPL Exhibit 606. This correction more accurately reflects the operation of the Company's thermal facilities and increases NPC by $4.1 million.

Q. Please explain the "Thermal Ramping" adjustment.

A. The Company's original filing overstated coal generation because thermal availability rates assume that coal units are available at full load when the units are being shut down for maintenance and when restarted after maintenance and forced outages. In reality, the units are not available at full load when ramping down for maintenance and ramping up from outages due to the physical capabilities of the units. As such, generation is lost while a unit ramps to the minimum level required for synchronizing with the grid and when a unit is being shut down for maintenance. This adjustment corrects the Equivalent Forced Outage Rates (EFOR) to account for the lost generation and increases NPC by $2.4 million. It should be noted that this adjustment is conservative because the Company does not have this data for plants that are operated by shared owners.

Q. Please explain the "Quick Start Availability" adjustment.

A. The Company's original filing incorrectly assumed quick start reserves can be carried on all Gadsby CT units. The Gadsby CTs are restricted to one unit on average due to temperature and humidity conditions and because the Questar Pipeline is a low pressure pipeline. This adjustment removes quick start capability from two Gadsby CT units and increases NPC by $2.2 million.

Q. Please explain the "Station Service" adjustment.

A. The Company's original filing overstated coal generation because station service for coal plants that are offline was not captured. Station service is the electricity that the plant uses onsite. Station service is not captured in energy sales or revenue calculations either. This adjustment corrects coal generation and increases net power costs by $2.7 million. It should be noted that the adjustment is conservative because the Company does not have station service data for (1) plants that are operated by shared owners and (2) Jim Bridger, because of the metering configuration.

Q. Please explain the "Colorado Transmission" adjustment.

A. At the time of the filing, negotiations were underway for transmission contracts between our Colorado resources and the Company's Utah transmission area. The Company's original filing estimated the configuration of this transmission based on conversations with UAMPS and WAPA. These contracts provide transmission to move Craig and Hayden generation to the Utah area. The capability was forecasted in the original filing. This correction incorporates the agreed upon configuration and decreases NPC by $1.0 million.

Q. Please explain the "West Side Transfer" adjustment.

A. Scheduling personnel recently indicated that to the extent transmission is available on Path C, up to 100 MW of operating reserves may be held in the western control area (PACW) for the eastern control area (PACE), by rescheduling some of the Bridger generation southbound. The Company's original filing did not model this assumption. This adjustment corrects the Company's modeling and decreases NPC by $6.3 million.

Q. Please explain the "Hydro Generation" adjustment.

A. This adjustment corrects various hydro modeling deficiencies. The Klamath River VISTA generation included in the Company's original filing did not include the US Bureau of Reclamation's operating strategies. Those strategies are impacted by endangered species act requirements, fishery obligations, and tribal trust responsibilities. In addition, other environmental considerations in the upper Klamath Basin and on the Klamath River below Iron Gate dam have increased the pressures on water supply. To help ensure full delivery of water to Klamath Irrigation Project farmers, the US Bureau of Reclamation has routinely directed the amount of flow through the Company's hydro facilities. These actions have reduced the Company's hydro operating flexibility and operating effectiveness. These operating constraints are now included in VISTA simulations to reflect the US Bureau of Reclamation's water management policies and flow directives. The adjustment also includes runner upgrades at JC Boyle on the Klamath River, the expected Swift 2 turbine efficiency improvement, adjusts Swift 1 reserve carrying capability for January 2006, and corrects a data input error for Fall Creek Hydro.

This adjustment increases NPC by $1.5 million.

Q. Please explain the "Gas Related Adjustments" adjustment.

A. Natural gas consumption at gas-fired plants is influenced by interaction of other resources, gas prices and market prices. This adjustment incorporates the sale of excess gas resulting from the revised dispatch of Utah gas generation units, which in part, is predicated upon updates discussed above. Also, this adjustment corrects the calculation of the pipeline reservation fees included in the NPC. This adjustment decreases NPC by $17.5 million.

Q. Does this conclude your supplemental testimony?

A. Yes.

Case UE 170
PPL Exhibit 605
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Mark T. Widmer
Oregon Update Adjustment Summary

February 2005

PPL Exhibit 605

Step	Name	$	Description
	Oregon NPC CY2006 Gold	**813,904,335**	
1	Marginal Units/Variable O&M	1,470,662	Marginal Unit/Maintenance Overhaul
2	Deferred Maintenance	4,090,531	Correct on/off split
3	Thermal Ramping	2,400,500	Capture lost generation
4	Quick Start Availability	2,186,227	Remove quick start on Gadsby 4 and 5
5	Station Service	2,734,752	Capture station service
6	Colorado Transmission	(1,037,955)	Final Contract Terms
7	West Side Transfer	(6,274,391)	C&T Update
8	Hydro Generation	1,501,478	Miscellaneous Hydro
9	Gas Related Adjustments	(17,533,915)	Gas Sales/Gas Pipeline
	Total Updates	**(10,462,110)**	
	Oregon NPC CY2006 Update	**803,442,226**	

Case UE 170
PPL Exhibit 606
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Mark T. Widmer
Coal Generation Anaylsis

February 2005

Coal Generation (MWh)
Hunter 1 Outage Normalized

PPL Exhibit-606-1

Actual Generation - 48 Months Ending March 2004

	Actual		Oregon CY2006 Updated NPC Without Deferrable Maintenance, Thermal Ramping, or Station Service		Delta	
	Generation(1)	Ratio	Generation	Ratio	Generation	Ratio
HLH	25,457,452	56.52%	25,992,409	57.47%	534,958	0.95%
LLH	19,585,901	43.48%	19,236,625	42.53%	(349,275)	-0.95%
Total	45,043,352	100.00%	45,229,035	100.00%	185,682	0.00%

Oregon CY2006 Updated NPC		Delta	
Generation(2)	Ratio	Generation	Ratio
25,682,774	56.97%	225,322	0.46%
19,395,539	43.03%	(190,362)	-0.46%
45,078,312	100.00%	34,960	0.00%

Footnote

1 Hunter Unit 1 2001 outage removed, average generation based on remaining number of days
2 Includes reduction of 67,177 MWh for Station Service

Exhibit PPL-606.xls

On & Off Peak Outage Summary - Deferred Maintenance
48 Months Ending March 2004

PPL Exhibit 606-2

	TOTAL ON - OFF Peak Hours	
UNIT	ON	OFF
CHO-4	4.70	4.07
COL-3	124.42	154.47
COL-4	218.20	192.97
CRB-1	147.30	142.55
CRB-2	507.34	511.91
CRG-1	86.25	71.78
DJ-1	56.83	57.32
DJ-2	105.97	79.53
DJ-3	738.95	552.63
DJ-4	552.48	434.34
HDN-1	296.28	254.73
HDN-2	145.13	152.93
HTG-1	40.08	60.40
HTG-2	48.00	50.73
HTR-1	432.03	430.62
HTR-2	676.55	644.85
HTR-3	267.50	213.22
JB-1	142.03	151.73
JB-2	81.82	78.52
JB-3	68.93	116.25
JB-4	110.38	167.70
NTN-1	128.63	126.27
NTN-2	401.60	525.63
NTN-3	550.30	535.90
WYO-1	451.00	303.35
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Total	6,382.71	6,014.39
Percentage	51.49%	48.51%

Case UE 170
PPL Exhibit 607
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Additional Supplemental Direct Testimony of Mark T. Widmer

March 2005

Q. Are you the same Mark T. Widmer that filed direct testimony with the Company's original filing?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. Pursuant to the schedule in this case, my testimony presents the March 15, 2005 Net Power Cost (NPC) update, including a description of the individual adjustments. This update results in a new system NPC of $851.9 million. The adjustments are summarized on PPL Exhibit 608.

Q. Please describe the nature of the adjustments included in this update.

A. With one exception, the adjustments are designed to incorporate information or developments which were not available or known at the time of the filing, including new contracts, new forward price curve data, new fuel costs and new data relevant to historical averages. The exception is the planed outage adjustment, which reflects the outages actually scheduled during the test period consistent with PGE's RVM process.

Q. Please explain the "December Forward Price Curves" adjustment.

A. The Company's original filing used our September 30, 2004 Official Forward Price Curve. This adjustment incorporates more recent market price projections in the Company's Official Forward Price Curve dated December 30, 2004. This impacts several GRID model inputs including wholesale market prices for gas and electricity, indexed wheeling losses and contract prices tied to market prices. The specific contracts impacted are: Tesorro QF, Kennecott QF, US MagCorp QF, Desert Power QF, Sunnyside QF, Transalta, and Clark Storage & Integration. In total, this update increases NPC by $5.19 million.

Q. Please explain the "Planned Outages" adjustment.

A. The Company's filed NPC was based on a historical average of planned outages from the 48 month period ending March 2004. This adjustment updates planned outages to reflect those actually scheduled for the test period and increases NPC by $13.32 million.

Q. Please explain the "Idaho Irrigators" adjustment.

A. The Company entered a new irrigation load control program to reduce peak load requirements during the summer irrigation season. This adjustment incorporates the projected test year benefits of this demand response program and decreases NPC by $0.09 million.

Q. Please explain the "UAMPS Sale" adjustment.

A. The Company entered a new sales agreement with UAMPS subsequent to our filing to cover line losses on another UAMPS contract. This adjustment incorporates the new contract and decreases NPC by $0.27 million.

Q. Please explain the "UBS Purchase" adjustment.

A. The Company entered a new purchase power agreement to meet load requirements with UBS subsequent to our filing. This adjustment incorporates the new contract and increases NPC by $0.39 million.

Q. Please explain the "US MagCorp" adjustment.

A. At the time of the Company's original filing, the US MagCorp load curtailment and QF purchase contracts were not in place. Since then, the agreements have been finalized. The original filing modeled the load curtailment and QF purchase contracts as expected at the time of the filing. The finalized agreements consist of a load curtailment, operating reserve, and QF purchase power contract. This adjustment revises inputs to reflect final contract terms and decreases NPC by $2.86 million.

Q. Please explain the "Tri-State" adjustment.

A. Subsequent to our filing, Tri-State Generation and Transmission Association, Inc. provided the prices, which are based on their costs, that will be in effect in 2005 for our Tri-State purchase contract. This adjustment incorporates the new prices and increases NPC by $1.41 million.

Q. Please explain the "Sierra Pacific II" adjustment.

A. Subsequent to our filing, the prices for the Sierra Pacific II sales were recalculated for Calendar Years 2005 to 2008 pursuant to contract terms. This adjustment incorporates the new prices and decreases NPC by $0.60 million.

Q. Please explain the "Deseret Purchase" adjustment.

A. Subsequent to our filing, Deseret Power Electric Cooperative provided the maintenance schedule of their Deseret Power Bonanza Unit for Calendar Year 2006. The scheduled maintenance impacts the amount of energy the Company purchases under the Deseret Purchase agreement. This adjustment incorporates the planned maintenance and increases NPC by $1.11 million.

Q. Please explain the "Mid Columbia Fixed Prices" adjustment.

A. Subsequent to our filing, updated budgets were provided by Grant, Chelan, and Douglas County PUDs. This adjustment incorporates the impact of the budget revisions and decreases NPC by $0.23 million.

Q. Please explain the "Wheeling Contracts" adjustment.

A. Subsequent to our filing, the Company entered new wheeling contracts with UAMPS, WAPA, and Deseret. A price increase settlement for BPA Transmission agreements was also finalized with Northwest Utilities. This adjustment incorporates the firm expense of the new contracts as well as the BPA price increases and increases NPC by $3.52 million.

Q. Please explain the "STF" adjustment.

A. Subsequent to our filing, the Company entered new Short Term Firm (STF) wholesale sales and purchase power contracts to balance the system. This adjustment incorporates the new contracts and increases NPC by $3.44 million.

Q. Please explain the "Coal Prices" adjustment.

A. This adjustment includes the Cholla impact of the Surface Transportation Board's Decision, dated December 13, 2004, arising from a lawsuit, in which the Board vacated the rate prescription previously imposed by the Board in 1998. The adjustment also includes the impact of updated mine plans from Bridger Coal Company and updated Deer Creek Mine costs for the Carbon, Hunter, and Huntington Plants. The price of coal delivered to the Craig Plant was updated to reflect a new Trapper Mine plan. Also, the Peabody Mine will be closing in 2005, which will influence coal delivery to the Hayden Plant. This adjustment includes the expected delivery of coal to the Hayden Plant after the close of the Peabody Mine. This delivery is currently being negotiated with Peabody. The adjustment increases NPC by $7.48 million.

Q. Please explain the "BPA Hermiston Losses" adjustment.

A. Subsequent to our filing, BPA notified the Company that it had failed inadvertently to meter Hermiston losses and that it would begin metering Hermiston and billing for losses in the future. This adjustment models the losses on a prospective basis and increases NPC by $3.17 million.

Q. Please explain the "De-Rate/Heat Rate" adjustment.

A. The forced outage, maintenance de-rates, and heat rates included in the Company's original filling were based on the 48 month historical period ending March 2004. The 48 month averages are updated on a semi-annual basis ending March and September of each year. This adjustment updates these inputs to the 48 months ending September 2004. This adjustment increases NPC by $7.19 million.

Q. Please explain the "Gas Sales" adjustment.

A. The level of gas sales included in the Company's NPC is impacted by the volume of gas burned. This adjustment increases the volume of gas sales based on the Company's updated MMBtu position and decreases NPC by $0.28 million.

Q. Please explain the "Kennecott Generation – Incentive Contract" adjustment.

A. Subsequent to our filing, the Company signed a new contract with Kennecott Utah Corporation. The original filing was based on an estimate of the contract terms. This adjustment incorporates final contract terms and increases NPC by

$2.25 million.

Q. Please explain the "Rock River – C&R Discount" adjustment.

A. The Company's original filing assumed the Conservation and Renewable Discount program/contract would be renewed with the same terms when it expires on September 30, 2006. The Company has been informed that the discount will not be renewed once the contract expires. This adjustment incorporates the expiration and increases NPC by $0.52 million.

Q. Please explain the "Grant Reasonable" adjustment.

A. Subsequent to our filing, Grant County delivered a revised forecast of the Company's share of the Grant Reasonable Product associated with the Grant County PUD contract. This adjustment incorporates the revised forecast and increases NPC by $3.83 million.

Q. Does this conclude your supplemental testimony?

A. Yes.

Case UE 170
PPL Exhibit 608
Witness: Mark T. Widmer

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Public Utility Commission of Oregon
Administrative Hearings Unit Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Additional Supplemental Direct Testimony of Mark T. Widmer

Net Power Cost (NPC)

March 15, 2005

March 2005

DOCKETED

Exhibit PPL/608
Widmer/2

Oregon Net Power Cost Update

Step	Name	$			Description
			803,442,226	Oregon NPC CY2006 Update (2.07.05)	
1	December Forward Price Curve	5,192,532			New Forward Price Curve
2	Planned Outages	13,322,978			Planned Maintenance
3	Idaho Irrigators	(90,006)			New Irrigation Program
4	UAMPS Sale	(273,847)			New Sales Contract
5	UBS Purchase	392,556			New Purchase Contract
6	US MagCorp	(2,857,096)			New Contract Structure
7	Tri-State	1,411,330			New Contract Pricing
8	Sierra Pacific II	(599,652)			New Contract Pricing
9	Deseret Purchase	1,115,956			New Contract Structure
10	Mid Columbia Fixed Prices	(230,524)			New Contract Pricing
11	Wheeling Contracts	3,523,079			BPA Price Increase/New Contract
12	STF	3,435,642			New Contracts
13	Coal Prices	7,476,066			New Contract Pricing
14	BPA Hermiston Losses	3,172,629			BPA began metering losses
15	Heat Rate/De-rate Base Period	7,191,950			Update Historical Information
16	Gas Sales	(279,771)			Adjusted based on Volume
17	Kennecott Generation - Incentive Cor	2,252,148			New Contract
18	Rock River C&R Discount	518,637			Terminates Sept. 30, 2006
19	Grant Reasonable	3,830,029			Updated Market Prices & Grant County Specifications
			851,946,860	Oregon NPC CY2006 RVM Initial Update (3.15.05)	

PACIFICORP UE 170
OREGON ISSUE SUMMARY
TEST YEAR ENDING DECEMBER 2006
($000)

Item	Adjustments (Base Rates)	Revenue Requirement Increase (Decrease)
	Rev. Req. on the Company's Filed Results:	**$102,024**
S-0	Rate of Return	**($24,409)**
S-00	Operating Revenue Deduction Adjustment	**($209)**
S-1	Load Forecast Revision	**($8,657)**
S-2	Incentive Programs	**($5,434)**
S-3	Pension Adjustment	**$1,320**
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S-9	Production Activity Deduction	**($855)**
S-10	Hydroelectric Relicensing Cost Adjustment	**$0**
S-11	Extrinsic Value of Resources	**$0**
S-12	Aquila Hydro Hedge	**$0**
S-13	GP Power Cost Adjustment	**($2,049)**
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P-2	DITBAL Allocation	**$1,312**
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P-4	WSCC Membership & Little Mountain	**$250**
P-5	Klamath Irrigators. Sch 33 Revenue	**$7,187**
P-6	USRB/UKRB Rate Base Adjustments Klamath Irrigators	**($1,364)**
P-7	Cost of Debt	**$0**
P-8	RVM Power costs	**$0**
	Total Adjustments (Base Rates)	**($76,149)**
	Revenue Requirement Change (Base Rates)	**$25,875**
	Percentage Overall Rate Change	**3.17%**

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
TEST YEAR ENDING DECEMBER 2006
($000)

	SUMMARY SHEET	2006 Results Per Company Filing (1)	Adjustments (2)	2006 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Retail Sales	$815,356	$0	$815,356	$25,875	$841,231
3	Wholesale Sales	193,049	7,108	200,157	0	200,157
4	Other Revenues	40,217	(3,593)	36,625	0	36,625
5	**Total Operating Revenues**	$1,048,622	$3,516	$1,052,138	$25,875	$1,078,012
6	**Operating Expenses**					
7	Steam Production	$202,413	($1,640)	$200,773	$0	$200,773
8	Hydro Production	10,312	0	10,312	0	10,312
9	Other Power Supply	263,389	(7,536)	255,853	0	255,853
10	Transmission	32,321	0	32,321	0	32,321
11	Distribution	69,005	0	69,005	0	69,005
12	Customer Accounting	31,484	0	31,484	0	31,484
13	Customer Service & Info	3,683	0	3,683	71	3,754
14	Sales	1	0	1	0	1
15	Administrative and General	78,899	(10,463)	68,436	0	68,436
16	**Total Operation & Maintenance**	$691,507	($19,639)	$671,868	$71	$671,939
17	Depreciation	117,476	0	117,476	0	117,476
18	Amortization	17,815	0	17,815	0	17,815
19	Taxes Other than Income	44,872	0	44,872	586	45,458
20	Income Taxes	48,779	(7,771)	41,009	9,578	50,587
21	Miscellaneous Revenue and Expense	(160)	0	(160)	0	(160)
22	**Total Operating Expenses**	$920,289	($27,410)	$892,880	$10,235	$903,115
23	**Net Operating Revenues**	$128,333	$30,925	$159,258	$16,036	$175,294
24	**Average Rate Base**					
25	Electric Plant in Service	$4,330,591	($2,364)	$4,328,227	$0	$4,328,227
26	Accumulated Depreciation & Amortization	(1,901,412)	0	(1,901,412)	0	(1,901,412)
27	Accumulated Deferred Income Taxes	(337,175)	0	(337,175)	0	(337,175)
28	Accumulated Deferred Inv. Tax Credit	(8,523)	0	(8,523)	0	(8,523)
29	**Net Utility Plant**	$2,083,481	($2,364)	$2,081,117	$0	$2,081,117
30	Plant Held for Future Use	0	0	0	0	0
31	Acquisition Adjustments	22,395	0	22,395	0	22,395
32	Working Capital	22,877	(572)	22,305	213	22,518
33	Fuel Stock	14,766	0	14,766	0	14,766
34	Materials & Supplies	27,336	0	27,336	0	27,336
35	Customer Advances for Construction	6	0	6	0	6
36	Weatherization Loans	143	0	143	0	143
37	Prepayments	7,480	0	7,480	0	7,480
38	Misc. Deferred Debits	37,349	0	37,349	0	37,349
39	Misc. Rate Base Additions/(Deductions)	(37,385)	0	(37,385)	0	(37,385)
40	**Total Average Rate Base**	$2,178,448	($2,936)	$2,175,512	$213	$2,175,725
41	**Rate of Return**	5.89%		7.32%		**8.06%**
42	**Implied Return on Equity**	5.42%		8.45%		10.00%

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
INCOME TAX CALCULATION
TEST YEAR ENDING DECEMBER 2006
($000)

		Income Tax Calculations	2006 Per Company Filing (1)	Adjustments (2)	2006 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1		Book Revenues	$1,048,622	$3,516	$1,052,138	$25,875	$1,078,012
2		Book Expenses Other than Depreciation	754,034	($19,639)	734,395	657	735,052
3		State Tax Depreciation	117,476	$0	117,476	0	117,476
4		Interest	68,346	$42,268	110,614	7	110,621
5	Less:	Schedule M Differences	(6,732)	$0	(6,732)	0	(6,732)
6		State Taxable Income	$115,498	($19,113)	$96,385	$25,211	$121,596
7		Add OR Depletion Adjustment	0	0	0	0	0
8		Total State Taxable Income	$115,498	($19,113)	$96,385	$25,211	$121,596
9		State Income Tax @ 4.540%	$5,244	($866)	$4,378	$1,146	$5,524
10		State Tax Credits	826	0	826	0	826
11		Net State Income Tax	$6,070	($866)	$5,204	$1,146	$6,350
12		Additional Tax Depreciation	0	0	0	0	0
13	Plus:	Other Schedule M Differences	0	0	0	0	0
14		Federal Taxable Income	$109,426	(18,247)	$91,179	$24,065	$115,244
15		Federal Tax @ 35%	$37,679	($6,905)	$30,775	$8,432	$39,207
16		Federal Tax Credits	0	0	0	0	0
17		Current Federal Tax	$37,679	($6,905)	$30,775	$8,432	$39,207
18		ITC Adjustment		-			
19		Deferral	0	0	0	0	0
20		Restoration	0	0	0	0	0
21		Total ITC Adjustment	$0	$0	$0	$0	$0
22		Provision for Deferred Taxes	5,030	0	5,030	0	5,030
23		Total Income Tax	$48,779	($7,771)	$41,009	$9,578	$50,587

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
REVENUE SENSITIVE COSTS
TEST YEAR ENDING DECEMBER 2006
($000)

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00278
Taxes Other - Franchise	0.02220
- Other	0.00000
- Resource supplier	0.00046
State Taxable Income	0.97456
State Income Tax @4.540%	0.04425
Federal Taxable Income	0.93031
Federal Income Tax @ 35%	0.32561
ITC	0.00000
Current FIT	0.32561
Other	0.00000
Total Excise Taxes	0.36986
Total Revenue Sensitive Costs	0.39530
Utility Operating Income	0.60470
Net-to-Gross Factor	1.6537

PACIFICORP UE170
OREGON ALLOCATED RESULTS OF OPERATIONS
CAPITAL STRUCTURE
TEST YEAR ENDING DECEMBER 2006
($000)

COST OF CAPITAL - STAFF PROPOSED	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	51.34%	6.288%	3.228%
Preferred Stock	1.10%	6.590%	0.073%
Common Equity	47.56%	10.000%	4.756%
Total	100.00%		8.057%

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
ADJUSTMENTS
TEST YEAR ENDING DECEMBER 2006
($000)

	Adjustments	System Losses Adjustment (S-1)	Incentive Programs (S-2)	Pension Adjustment (S-3)	Benefit Adjustments (S-4)	Non-labor A&G Adjustments (S-5)	Revenue Growth Adjustment (S-6)	Bridger Coal Cost Adjustment (S-7)	FIT & SIT Adjustment (S-8)	Production Activity FIT Deduct. (S-9)	Hydro Relicensing Adjustment (S-10)	Extrinsic Value Adjustment (S-11)	Aquila Hydro Hedge (S-12)
1	**Operating Revenues**												
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	$0	0
4	Other Revenues	0	0	0	0	0	2,088	0	0	0	0	0	0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,088**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**												
7	Steam Production	$0	$0	$0	$0	$0	$0	($1,972)	$0	$0	$0	$0	$0
8	Hydro Production	0	0	0	0	0	0	0	0	0	0	0	0
9	Other Power Supply	(8,425)	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	0	0	0	0	0	0	0	0	0	0
11	Distribution	0	0	0	0	0	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	0
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0	0	0
14	Sales	0	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	(5,111)	1,285	(2,263)	(5,895)	0	0	0	0	0	0	0
16	**Total Operation & Maint.**	**($8,425)**	**($5,111)**	**1,285**	**($2,263)**	**($5,895)**	**$0**	**($1,972)**	**$0**	**$0**	**$0**	**$0**	**$0**
17	Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0	0
20	Income Taxes	3,199	1,960	(488)	868	2,238	792	749	0	(517)	0	0	0
21	Misc. Revenue and Expense	0	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	($5,226)	($3,151)	$797	($1,395)	($3,657)	$792	($1,223)	$0	($517)	$0	$0	$0
23	**Net Operating Revenues**	**$5,226**	**$3,151**	**($797)**	**$1,395**	**$3,657**	**$1,296**	**$1,223**	**$0**	**$517**	**$0**	**$0**	**$0**
24	**Average Rate Base**												
25	Electric Plant in Service	$0	($1,611)	$0	($753)	$0	$0	$0	$0	$0	$0	$0	$0
26	Accum. Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0	0
27	Accum. Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0
28	Accum. Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	($1,611)	$0	($753)	$0	$0	$0	$0	$0	$0	$0	$0
30	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(109)	(66)	17	(29)	(76)	16	(25)	0	(11)	0	0	0
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0	0
35	Customer Adv. for Construction	0	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Add. /(Deduct.)	0	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($109)**	**($1,677)**	**$17**	**($782)**	**($76)**	**$16**	**($25)**	**$0**	**($11)**	**$0**	**$0**	**$0**
41	**Revenue Requirement Effect**	**($8,657)**	**($5,434)**	**$1,320**	**($2,410)**	**($6,057)**	**($2,141)**	**($2,025)**	**$0**	**($855)**	**$0**	**$0**	**$0**

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
ADJUSTMENTS
TEST YEAR ENDING DECEMBER 2006
($000)

	Adjustments	GP Power Cost Adjustment (S-13)	Margin Adjustment (S-14)	Interest Tax Deduction Adjustment C-1	Fuel Handling P-1	DITBAL Allocation P-2	Hermiston Gadsby Allocation P-3	WSCC Little Mtn. P-4	Klamath Irrigators Adjustment P-5	USRB/ UKRB Adjustment (Irrigators) P-6	Cost of Debt P-7	RVM Power Costs P-8	**Total Adjustments (Base Rates)**
1	**Operating Revenues**												
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	7,108	0	0	0	0	0	0	0	0	0	7,108
4	Other Revenues	0	0	0	0	0	0	0	($7,010)	$1,330	0	0	(3,593)
5	**Total Operating Revenues**	**$0**	**$7,108**	**$0**	**$0**	**$0**	**$0**	**$0**	**($7,010)**	**$1,330**	**$0**	**$0**	**$3,516**
6	**Operating Expenses**												
7	Steam Production	($1,994)	$0	$0	$2,326	$0	$0	$0	$0	$0	$0	$0	($1,640)
8	Hydro Production	0	0	0	$0	0	0	0	0	0	0	0	0
9	Other Power Supply	0	0	0	0	0	$889	0	0	0	0	0	(7,536)
10	Transmission	0	0	0	0	0	0	0	0	0	0	0	0
11	Distribution	0	0	0	0	0	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	0
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0	0	0
14	Sales	0	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	0	0	0	$1,277	0	$243	0	0	0	0	(10,463)
16	**Total Operation & Maint.**	**($1,994)**	**$0**	**$0**	**$2,326**	**$1,277**	**$889**	**$243**	**$0**	**$0**	**$0**	**$0**	**($19,639)**
17	Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0	0
20	Income Taxes	757	2,697	(16,073)	(883)	(485)	(337)	(92)	(2,660)	504	0	0	(7,771)
21	Misc. Revenue and Expense	0	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	($1,237)	$2,697	($16,073)	$1,443	$792	$552	$151	($2,660)	$504	$0	$0	($27,410)
23	**Net Operating Revenues**	**$1,237**	**$4,411**	**$16,073**	**($1,443)**	**($792)**	**($552)**	**($151)**	**($4,350)**	**$826**	**$0**	**$0**	**$30,925**
24	**Average Rate Base**												
25	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,364)
26	Accum. Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0		0
27	Accum. Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0		0
28	Accum. Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,364)
30	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	($26)	56	(334)	30	16	11	3	(55)	10	0	0	(572)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0	0
35	Customer Adv. for Construction	0	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Add. /(Deduct.)	0	0		0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($26)**	**$56**	**($334)**	**$30**	**$16**	**$11**	**$3**	**($55)**	**$10**	**$0**	**$0**	**($2,936)**
41	**Revenue Requirement Effect**	**($2,049)**	**($7,287)**	**($26,625)**	**$2,390**	**$1,312**	**$914**	**$250**	**$7,187**	**($1,364)**	**$0**	**$0**	**($51,531)**

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
INCOME TAX ADJUSTMENTS
TEST YEAR ENDING 2006
($000)

	Income Tax Calculation Adjustments	System Losses Adjustment (S-1)	Incentive Programs (S-2)	Pension Adjustment (S-3)	Benefit Adjustments (S-4)	Non-labor A&G Adjustment (S-5)	Revenue Growth Adjustment (S-6)	Bridger Coal Cost Adjustment (S-7)	FIT & SIT Adjustment (S-8)	Production Activity FIT Deduction (S-9)	Hydro Relicensing Adjustment (S-10)	Extrinsic Value Adjustment (S-11)	Aquila Hydro Hedge (S-12)
1	Book Revenues	$0	$0	$0	$0	$0	$2,088	$0	$0	$0	$0	$0	$0
2	Book Exp. Other than Depreciation	(8,425)	(5,111)	1,285	(2,263)	(5,895)	0	(1,972)	0	0	0	0	0
3	State Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
4	Interest	(4)	(54)	1	(25)	(2)	1	(1)	0	(0)	0	0	0
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	0
6	State Taxable Income	$8,429	$5,165	($1,286)	$2,288	$5,897	$2,087	$1,973	$0	$0	$0	($0)	$0
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$8,429	$5,165	($1,286)	$2,288	$5,897	$2,087	$1,973	$0	$0	$0	($0)	$0
9	State Income Tax	$383	$234	($58)	$104	$268	$95	$90	$0	$0	$0	$0	$0
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0
11	Net State Income Tax	$383	$234	($58)	$104	$268	$95	$90	$0	$0	$0	$0	$0
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	0
14	Federal Taxable Income	$8,046	$4,931	($1,228)	$2,184	$5,629	$1,992	$1,883	$0	$0	$0	($0)	$0
15	Federal Tax @ 35%	2,816	1,726	(430)	764	1,970	697	659	0	(517)	0	0	0
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0
17	Current Federal Tax	$2,816	$1,726	($430)	$764	$1,970	$697	$659	$0	($517)	$0	$0	$0
18	**ITC Adjustment**												
19	Deferral	0	0	0	0	0	0	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
23	**Total Income Tax**	$3,199	$1,960	($488)	$868	$2,238	$792	$749	$0	($517)	$0	$0	$0

PACIFICORP UE 170
OREGON ALLOCATED RESULTS OF OPERATIONS
INCOME TAX ADJUSTMENTS
TEST YEAR ENDING 2006
($000)

	Income Tax Calculation Adjustments	GP Power Cost Adjustment (S-13)	Margin Adjustment 0 (S-14)	Interest Tax Deduction Adjustment C-1	Fuel Handling 0 0 P-1	DITBAL Allocation 0 P-2	Hermiston Gadsby Allocation P-3	WSCC Little Mtn. 0 P-4	Klamath Irrigators Adjustment P-5	USRB/ UKRB Adjustment (Irrigators) P-6	Cost of Debt P-7	RVM Power Costs P-8	Total Adjustments (Base Rates) 0
1	Book Revenues	$0	$7,108	$0	$0	$0	$0	$0	($7,010)	$1,330	$0	$0	$3,516
2	Book Exp. Other than Depreciation	(1,994)	0	0	2,326	1,277	889	243	0	0	0	0	($19,639)
3	State Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	$0
4	Interest	(1)	2	42,352	1	1	0	0	(2)	0	0	0	$42,268
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0		$0
6	State Taxable Income	$1,995	$7,106	($42,352)	($2,327)	($1,278)	($889)	($243)	($7,008)	$1,329	$0	$0	($19,113)
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0		$0
8	Total State Taxable Income	$1,995	$7,106	($42,352)	($2,327)	($1,278)	($889)	($243)	($7,008)	$1,329	$0	$0	($19,113)
9	State Income Tax	$91	$323	($1,923)	($106)	($58)	($40)	($11)	($318)	$60	$0	$0	($866)
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0	0	$0
11	Net State Income Tax	$91	$323	($1,923)	($106)	($58)	($40)	($11)	($318)	$60	$0	$0	($866)
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	$0
14	Federal Taxable Income	$1,904	$6,783	($40,429)	($2,221)	($1,220)	($849)	($232)	($6,690)	$1,269	$0	$0	($18,247)
15	Federal Tax @ 35%	666	2,374	(14,150)	(777)	(427)	(297)	(81)	(2,342)	444	0	0	($6,905)
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	0	$0
17	Current Federal Tax	$666	$2,374	($14,150)	($777)	($427)	($297)	($81)	($2,342)	$444	$0	$0	($6,905)
18	**ITC Adjustment**												
19	Deferral	0	0	0	0	0	0	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	0	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0	0	$0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0		$0
23	**Total Income Tax**	$757	$2,697	($16,073)	($883)	($485)	($337)	($92)	($2,660)	$504	$0	$0	($7,771)