ORDER NO. 01-777

ENTERED AUG 31 2001

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149.	))))	ORDER

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SUMMARY

In this order, the Commission approves new rate schedules for Portland General Electric Company (PGE). The new schedules reflect the unprecedented increases in the prices for electricity on the wholesale power markets. Due to a combination of increased demand, lack of new generating facilities, low water conditions, and the troubled deregulation effort in California, wholesale electricity prices have nearly tripled since PGE's last general rate change in late 1997. At that time, power costs averaged 1.37 cents/kilowatt-hour (kWh). Power costs have since increased some 173 percent, and now average 3.74 cents/kWh. The power markets have also become extremely volatile, with peak power prices exceeding $1.20/kWh at various times last winter.

The new schedules also restructure and reprice PGE's services, beginning March 1, 2002, to meet the requirements of Senate Bill 1149, an electric industry restructuring bill.[1] SB 1149 requires electric utilities to functionally separate their power generation from distribution services and provide consumers with access to power supply options.

The exact impact on customer rates will not be known until September 12, 2001, the date that energy rates will be calculated based on PGE's forward price curves and the value of the company's resources. Based on PGE's latest power cost calculations and the terms of this order, however, the Commission projects an overall rate increase in customer rates of approximately 35 percent. Applying this estimate to the rate spread adopted for the new schedules, residential rates will increase about 26 percent, and industrial rates will increase about 46 percent. In its September 12, 2001 filing, PGE will submit a rate design table identifying, for each rate schedule, the specific percentage increase resulting from the updated power cost estimates and consistent with the terms of this order.

In an effort to help offset rising power costs, the Commission imposes reductions to PGE's non-power Operation and Management (O&M) budget. Given the largely unavoidable power cost increases and the resulting impact on customer rates, the Commission concludes that it is prudent for PGE to reduce other discretionary internal operating costs. With the decisions in

[1] In House Bill 3633, the 2001 Legislative Assembly delayed the implementation of SB 1149 from October 1, 2001 to March 1, 2002.

this order adopting stipulations among the parties and resolving contested issues, the authorized increase, aside from the effect of power costs, is almost $50 million less than the company requested.

In addition, the Commission adopts a Power Cost Adjustment (PCA) mechanism that will lower rates if the company's power costs decline. The PCA establishes how PGE will account for variations between expected power costs included in base rates and actual power costs, and describes the method by which the company and its customers will share in the benefits and burdens of such variations. This mechanism will track the fluctuations in power costs and require a refund to customers of overcollections exceeding a preset amount. The PCA balances the interests of customers and PGE and helps ensure the company's continued ability to secure a reliable source of energy to meet demand.

The Commission also adopts a tiered rate structure for residential customers that will benefit consumers who use lower amounts of energy. The first 225 kWh of electricity used is priced lower than electricity used above and beyond that amount. The rate design also ensures that residential and small farm customers receive the full benefit of low-cost subscription power managed by the Bonneville Power Administration (BPA).

INTRODUCTION

On October 2, 2000, Portland General Electric (PGE) filed Advice No. 00-14, an application for revised tariff schedules. The tariffs were designed to implement a general rate revision and put into operation the provisions of Senate Bill 1149.[2] Among other things, PGE's filing unbundled the company's services into generation, transmission, distribution, ancillary, and customer services, established charges to electricity service suppliers, formulated market-priced standard offers, and calculated competitive transition amounts.

At its October 20, 2000 Public Meeting, the Commission found good cause to investigate the filing and suspended Advice No. 00-14 pursuant to ORS 757.215. Because the Commission determined that the rate investigation could not be completed within an initial six-month suspension period, it ordered that the filing be suspended for a total period of nine months from November 1, 2000.[3] PGE later waived the statutory suspension period and agreed to an extension of the suspension through August 31, 2001, with rates to become effective October 1, 2001.[4]

Prehearing Conference

On October 24, 2000, Michael Grant, an Administrative Law Judge (ALJ), held a prehearing conference to identify parties and to establish a procedural schedule. The following participated as parties to this proceeding: PGE, Industrial Customers of Northwest Utilities

[2] PGE's filing originally included the company's proposal to reclassify its transmission assets. That proposal, however, was later bifurcated to allow timely review by the Federal Energy Regulatory Commission (FERC). On March 14, 2001, PGE, Oregon Office of Energy, and Staff filed a stipulation intended to resolve all issues related to reclassification of transmission assets. No party opposed the stipulation, which was also signed by Fred Meyer Stores. We reviewed the stipulation and adopted it in Order No. 01-325.
[3] Order No. 00-669.
[4] Orders No. 01- 575 and 01-724.

(ICNU), the Citizens' Utility Board (CUB), Fred Meyer Stores (Fred Meyer), City of Portland (Portland), League of Oregon Cities (League), Oregon Office of Energy (OOE), Oregon Steel Mills, Inc. (OSM), City of Glendale (Glendale), PG&E National Energy Group, Inc., Northwest Natural Gas Company, Associated Oregon Industries, PacifiCorp, Northwest Energy Coalition, Renewable Northwest Project, ATOFINA Chemicals, Portland BOMA, Warren Parrish, and the Commission Staff (Staff).

Public Hearings and Presentations

In November and December 2000, the Commission held public comment hearings in Portland and Salem to give the general public an opportunity to comment on PGE's tariff filings. In addition, the Commission held special public meetings for opening and closing presentations by the parties. In March 2001, the Commission heard opening presentations from PGE, PacifiCorp, ICNU, CUB, City of Portland, Fred Meyer Stores, and Staff. In July 2001, the Commission heard closing oral argument from PGE, ICNU, CUB, Fred Meyer, OSM, OOE, and Staff.

Commission Orders

During the course of this proceeding, the Commission issued three orders relating to procedural matters. On December 4, 2000, the Commission issued Order No. 00-765, granting PGE additional protection for confidential information.

On March 21, 2001, the Commission issued Order No. 01-249, denying ICNU's request to allow a former Staff employee, John Thornton, to participate as an expert witness. The Commission, in explaining OAR 860-012-0010(2), set forth an analysis for determining when a former employee may testify for another party. In this case, the Commission determined that Mr. Thornton could not appear as an expert witness in this docket or in docket UE 116, the PacifiCorp restructuring and rate case.

On July 20, 2001, the Commission issued Order No. 01-592, which involved a question certified to the Commission by the presiding ALJs in dockets UE 115 and UE 116. In that order, PGE and PacifiCorp had challenged the agency's Internal Operating Guidelines that govern post-hearing procedures. They claimed that the policies were unlawful and sought the immediate adoption of more stringent procedures recommended in the Report to the Oregon Legislature from the HB 3615 Interim Task Force (Task Force).

The Commission determined that the Internal Operating Guidelines, which allow limited post-hearing communications between Commissioners and so-called "party Staff," were legal. The Commission, however, acknowledged the utilities' concerns about Staff's role in the decision-making process, and noted that the issue will be carefully examined during review of the Task Force Report. Therefore, the Commission concluded that, while the Task Force recommendations should not be fully implemented at this time, Staff witnesses who sponsored testimony or testified at hearing would not appear at decision meetings, and that only "non-party" Staff members would participate in deliberations on rate of return issues.

Evidentiary Hearings

On June 4 and 5, 2001, ALJ Grant held evidentiary hearings in Salem, Oregon. During those proceedings, the following appearances were entered: J. Jeffery Dudley, and Philip Van Der Weele, attorneys, appeared on behalf of PGE; David Hatton, Assistant Attorney General, appeared on behalf of Staff.

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Applicable Law

In this rate case, the Commission's function involves two primary steps. First, we must determine how much revenue PGE is entitled to receive. A utility's revenue requirement is determined on the basis of the utility's costs.[5] Second, we must allocate the revenue requirement among the utility's customer classes.

In the revenue requirement phase of a rate case, we must determine: (1) the gross utility revenues; (2) the utility's 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 the stockholders of the utility are reasonably entitled.[6] The purpose of answering these questions is to determine the utility's reasonable costs of providing service and expected revenues, so that the Commission can set utility rates at just and reasonable levels.

A question has arisen in this case regarding the application of the burden of proof. The phrase "burden of proof" has two meanings: one to refer to a party's burden of producing evidence; the other to a party's obligation to establish a given proposition in order to succeed.[7] To distinguish these two meanings, we refer to the burden of production and the burden of persuasion.[8] In Commission proceedings, ORS 757.210 provides that a "utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." This burden is borne by the utility throughout the proceeding and does not shift to any other party.

PGE acknowledges that the utility has the initial burden of production and persuasion to show that the proposed rates are just and reasonable. PGE contends, however, that once the utility presents its evidence, both burdens shift to parties opposing the rate increase.[9] It relies on the Commission's decision in docket UT 125, *In re U S WEST Communication, Inc.*, which provides, in pertinent part:

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[5] *See, e.g., American Can Co. v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[6] *See Pacific Northwest Bell Tel. Co. v. Sabin*, 21 Or App 200, 205 n. 4, *rev den* (1975).
[7] *See Hansen v. Oregon-Wash. R. & Nav. Co.*, 97 Or 190 (1920).
[8] *See, e.g.*, Oregon Evidence Code, Rule 305 and Rule 307.
[9] We note that PGE's claim is contrary to the argument traditionally raised by utilities when scheduling the filing of testimony and order of appearance at hearing. In rate cases, the utilities have always insisted on having the last word due to its burden to show that the proposed rates are just and reasonable.

> "[U S WEST] as the proponent of the rate increase must submit evidence showing that its proposed rates are just and reasonable. Once [U S WEST] has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claimed costs, must in turn show that the costs are not reasonable. Each time the burden of going forward shifts, the burden of persuasion shifts as well. That is, each party who has the burden of going forward must, in order to prevail, persuade us by competent evidence that its position with respect to that set of costs should prevail."[10]

PGE's reliance on the above-cited language is misplaced. First, PGE ignores the Commission's concluding paragraph to that section, where it clarified that:

> "The Commission's role is to weigh the evidence presented on each issue in the case and determine where the preponderance lies. We make that decision on the record as a whole. The basic decision we make with respect to each issue in this case is whether the utility has produced persuasive evidence that its revenue requirement is reasonable. A component of that decision is whether Staff has persuasively rebutted [U S WEST's] revenue requirement evidence. *We reject [U S WEST's] arguments that Staff has the 'burden of proof' with respect to disallowances and test year adjustments, because the arguments distort the way evidence is presented and decisions are made in a rate case.*"[11]

When the section is read in its entirety, it is clear that the Commission did not agree with U S WEST's arguments about shifting burdens. More importantly, however, the Commission later rescinded Order No. 97-171, and did not readopt the language relied upon by PGE in Order No. 00-191.[12] Thus, that section has been withdrawn and no longer has precedential value.

In our most recent rate case, docket UG 132, *In re Northwest Natural Gas Company*, we stated:

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[10] Order No. 97-171 at 8.

[11] *Id.* at 8. (Emphasis added.)

[12] We note that Order No. 00-191 contained a general reference to the burden of proof language relied upon by PGE. Specifically, the order states at page 15:

> "As we stated above, in the section called [U S WEST's] Burden of Proof Argument, [U S WEST] must show that its expenses are reasonable for us to allow them as part of the revenue requirement calculation."

Although Order No. 00-191 contains no section entitled "[U S WEST's] Burden of Proof Argument," PGE claims that the inclusion of this reference indicates that the Commission implicitly adopted the burden of proof language. PGE is mistaken. We simply made an error by placing a reference to a section in Order No. 00-191 that does not exist.

> "As the petitioner in this rate case, NW Natural has the burden of proof on all issues. Thus, NW Natural must submit evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claim costs, may in turn show that the costs are not reasonable."[13]

We adhere to that language and affirm that, under ORS 757.210, the burden of showing that the proposed rate is just and reasonable is borne by the utility throughout the proceeding. Thus, if PGE makes a proposed change that is disputed by another party, PGE still has the burden to show, by a preponderance of evidence, that the change is just and reasonable. If it fails to meet that burden, either because the opposing party presented compelling evidence in opposition to the proposal, or because PGE failed to present compelling information in the first place, then PGE does not prevail.

STIPULATED ISSUES

PGE entered into five stipulations designed to resolve many of the contested issues in this proceeding. On April 26, 2001, PGE, Staff and Fred Meyer filed a stipulation regarding changes to PGE's cost of service. The stipulation represents a settlement of all revenue requirement issues identified by Staff except the authorized return on equity portion of the cost of capital and net variable power costs. Several non-revenue requirement issues are also covered by the stipulation. The stipulation, which is attached as Appendix B, is supported by joint testimony of Jim Barnes and Sara Cardwell of PGE, and Ed Krantz of Staff.

On June 7, 2001, PGE, Portland, and League submitted a stipulation intended to resolve specific rate and tariff issues identified by Portland and League in their opening testimony. These issues include interconnection standards, restoration of utility services, utility relocation, allocation of ancillary service costs, and streetlights. The stipulation, which is attached as Appendix C, is supported by joint testimony of Sara Cardwell of PGE, David Tooze, Duane Sanger, and Bill Graham of Portland, and Andrea Fogue of League.

On July 27, 2001, PGE, Staff, ICNU, CUB, and Fred Meyer filed a stipulation designed to resolve all power cost issues. Most notably, the stipulation establishes a mechanism by which PGE will value its long-term and short-term resources for the purposes of establishing rates for energy services. It also establishes a mechanism by which PGE will account for variations between expected power costs included in base rates and actual power costs, and the method by which the company and its customers will share in the benefits and burdens of such variations. The stipulation, which is attached as Appendix D, is supported by joint testimony of Stefan Brown of Staff, Bob Jenks of CUB, Lincoln Wolverton of ICNU, Kevin Higgins of Fred Meyer, and Randy Dahlgren of PGE. To help further explain the stipulation, PGE and Staff submitted a letter from PGE counsel that clarifies the assumptions and inputs that the company will use in its final Monet power cost run. The letter, dated August 20, 2001, is included as an additional attachment to the stipulation set forth in Appendix D.

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[13] Order No. 99-697 at 3. (*Statutory language and citation omitted.*)

On August 6, 2001, PGE, Staff, and Fred Meyer filed a supplemental stipulation regarding franchise fees and steam sales. The stipulation adjusts PGE's revenue requirement to reflect the company's agreement to permit cities the ability to choose between the volumetric or revenue-based method of calculating franchise fees. The stipulation also adjusts steam sales to incorporate a recent contract to sell steam at PGE's Coyote Springs Generating Plant (Coyote Plant). The stipulation, attached as Appendix E, is supported by an explanatory brief.

Finally, on August 10, 2001, PGE and Staff filed a stipulation concerning residential rate design for Schedule 7. The stipulation is intended to resolve how the benefits and burdens of subscription power from the Bonneville Power Administration (BPA), as well as cash benefits, should be flowed through to eligible customers, and how the Resource Value Mechanism in PGE's Schedule 125 should be applied to residential and small farm classes of customers. The stipulation is attached as Appendix F and supported by an explanatory brief.

All five stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-014-0085(1). We address each separately.

I. Revenue Requirement Stipulation

PGE, Fred Meyer, and Staff filed a stipulation that represents a settlement of most of the revenue requirement issues raised by Staff. The parties' settlement results in a $135.6 million reduction in rate base, a $40.6 million reduction in operating expenses, and an increase in other revenue of $1.7 million from PGE's original proposal. The stipulating parties believe that each of the adjustments discussed in the stipulation are reasonable and, overall, will yield fair and reasonable rates if adopted by the Commission.

CUB and ICNU are not parties to the stipulation and believe that PGE's non-power O&M costs are inflated. PGE initially sought $229.3 million in non-power O&M costs. The stipulation reduces PGE's request to $206.9 million. CUB and ICNU contend that this stipulated amount is excessive and should be further reduced. To demonstrate the significant increase in these costs, ICNU claims that PGE's regulatory adjusted average cost per customer averaged $219 during 1997-1999. Even with the adjustments contained in the stipulation, ICNU calculates that this figure increases to $275 per customer for 2002, a 25 percent increase.

Preliminarily, CUB and ICNU question whether PGE may have inflated its non-power O&M costs to account for the six-year rate freeze contained in the PGE/Sierra Pacific merger stipulation. This potential rate freeze, CUB and ICNU maintain, appears to have caused the company to inflate its costs in this docket to account for future increases in program costs occurring over the next six-year period.

CUB and ICNU are particularly troubled by the proposed increase in PGE's non-power O&M costs given the significant and largely unavoidable increases in power costs. The parties believe it is inappropriate for PGE to initiate, at this time, large and expensive increases in any portions of its regulated business. Before passing these additional expenses on to ratepayers, CUB and ICNU contend that the Commission should first consider the rate impact on customers and determine whether some non-power expenditures should be delayed or simply not made at this time. CUB notes that the Commission has previously ordered utilities to reduce discretionary costs to mitigate a significant rate increase.[14]

To offset the rising power costs, CUB and ICNU recommend that PGE's non-power O&M costs be limited to the rate of inflation. They each present similar, but slightly differing inflation-escalator models to forecast a reasonable level of expenditures. Adjusting the company's 1999 actual costs for inflation, CUB contends that PGE's 2002 test-year forecast for non-energy expenditures, as originally filed, should be reduced by $61.9 million. CUB proposes the Commission achieve this inflation-based target by accepting some elements of the stipulation and making additional reductions for customer service, labor, distribution O&M, technology, and other revenues. These adjustments, which are further addressed below, reduce PGE's non-power O&M costs by $55 million.

ICNU proposes an alternative test year forecast by taking PGE's 1999 actual non-power O&M expenses, applying the regulatory adjustments from docket UE 88, and escalating the results by anticipated customer growth and inflation. This methodology results in base 2002 test year non-power O&M costs of $175.6 million, a $31.3 million reduction from the stipulation. If the Commission does not adopt this alternative test year forecast, ICNU proposes the Commission make specific adjustments in addition to those contained in the stipulation. These adjustments are also addressed below.

In response, PGE contends that the non-power O&M costs contained in the stipulation are reasonable. It objects to CUB's and ICNU's speculation that the company inflated the 2002 test year forecast in anticipation of the potential six-year rate freeze resulting from the PGE-Sierra Pacific merger. PGE explains that it developed its forecasted revenue requirement using traditional ratemaking principles. It started with budget information and adjusted the numbers to remove abnormalities and to include recurring expenses and revenues that were reasonably certain to occur during the 2002 test year.

Next, PGE objects to CUB's and ICNU's inflation-escalator proposals to establish non-power O&M costs. PGE contends that the approach violates established ratemaking principles. Citing *American Can Co. v. Lobdell*, and *In re Pacific Northwest Bell Co.*, PGE argues that a utility's forecast for the test year must consider known and measurable changes that are expected to persist.[15] PGE points out that, under CUB's and ICNU's proposal, the Commission would ignore numerous factors that relate to the company's operating costs and expenditures. Moreover, PGE contends that CUB and ICNU are essentially asking for a

[14] *See In re Portland General Electric Company*, Order No. 95-322.

[15] *See* footnotes 5 and 6. In *American Can*, the Supreme Court explained that:

> "When an historic test year is used, adjustment to the test year data are made to remove abnormal events not expected to persist into the future. When a future test year is used, the data is drawn from budget figures and financial models of the utility. *Abnormal events of the past are therefore excluded and all know future changes are included.*" (Emphasis added.)

moratorium on all spending that exceeds inflation—without regard to the company's need to make appropriate up-front capital investments and properly maintain its plant. PGE believes that, in the long run, the adoption of a management-by-crisis approach would increase overall costs. Due to these limitations, PGE contends that the inflation-escalator approach cannot establish reasonable expenditures and should be rejected by the Commission.

Before turning to CUB's and ICNU's specific adjustments to PGE's non-power O&M costs, we first find no evidence that the six-year rate freeze adopted in the PGE-Sierra Pacific merger case influenced either PGE's 2002 test year or the revenue requirement stipulation between PGE, Staff, and Fred Meyer. Neither CUB nor ICNU provide any support for their allegation. Moreover, the record contradicts their claim. PGE had completed the underlying budget process before the parties developed the six-year rate freeze in the merger docket, and actually made its rate filing in this case before the Commission approved the merger agreement. In addition, PGE took specific steps to ensure that consideration of a six-year rate freeze did not affect the budget process. For these reasons, we conclude that PGE, Staff and Fred Meyer used a 2002 test year without considering the impact of the Sierra Pacific acquisition.

We also reject CUB's and ICNU's inflation-escalator proposals as independent methods to establish non-power O&M costs for PGE. Consistent with established Oregon ratemaking principles, PGE's test year should be based on actual or budgeted expenditures and adjusted to remove abnormalities and to include known and measurable changes that are expected to persist.[16] The parties' respective inflation benchmark proposals are not appropriate for evaluating PGE's expenditures, because the methodologies do not examine the reasonableness of historical operations, fail to consider abnormalities in the baseline year's results of operations, and do not take into account known and measurable changes between the baseline and test year, such as the passage of SB 1149.

We further conclude, however, that CUB's and ICNU's inflation-benchmark comparisons, as well as ICNU's cost per customer assessment, highlight the increases that PGE is seeking for its non-power O&M costs. While PGE disputes the accuracy of these comparisons and recommends numerous corrections, the fact remains that PGE's stipulated non-power O&M costs are significantly higher than the company's actual costs in 1999. We acknowledge that the implementation of SB 1149 drives many of these cost increases. Nonetheless, given the unavoidable increases in power costs and resulting impact on customer rates, it is imperative that we carefully review the company's internal operating costs and capital expenditures to ensure that proposed increases are reasonable and prudent. With this in mind, we turn to the specific non-power O&M adjustments proposed by CUB and ICNU. We address each parties' recommendations separately.

CUB Recommendations

CUB recommends that the Commission reduce PGE's non-power O&M costs, as originally filed, by $55 million. CUB proposes the Commission achieve this result by accepting

[16] *See, e.g., In re U S WEST Communications*, Order No. 00-191; *In re PacifiCorp*, Order No. 00-091; *In re Pacific Northwest Bell,* Order No. 87-406.

some elements of the stipulation[17] and making additional reductions for customer service, labor, distribution O&M, technology, and other revenues. The individual adjustments are summarized as follows:

1. Customer Service

CUB contends that PGE's proposed revenue requirement for customer service of $54.8 million is simply too great for customers to absorb, given the forecasted increase in power costs. CUB proposes an overall reduction in Customer Service of $13.86 million, which is broken down as follows:

- Reduce PGE's request for $39.2 million to deliver information and service by $11.05 million. CUB believes that the cost of the Web, responding to media requests and initiating channels of information should be split 50-50 between customers and shareholders. In addition, the cost of providing information to customers through telephone and personal contact should be reduced 25 percent.
- Eliminate the $1.2 million cost for PGE's proposed credit card payment option.
- Reduce by two-thirds the cost for Network Meter Reading/Automatic Meter Reading (NMR/AMR) system, as only one-third of the system is for customers located in test areas where the program is necessary to implement SB 1149.
- Eliminate the $750,000 allocation of distributed generation costs to customer service.
- Reduce the cost of customer surveys by $100,000 by increasing the amount allocated to non-regulated operations.
- Eliminate the $160,000 costs for WeatherWise.

In response, PGE contends that—with one minor exception—the record does not support the proposed reductions to customer costs. PGE first claims that CUB provides little

[17] CUB participated in settlement discussion and agrees with some adjustments set forth in the stipulation. Those adjustments, which reduce non-power O&M costs by $26.53 million, are as follows:

Issue #	Description	Adjustment	Issue #	Description	Adjustment
S-14	SERP	-$4.645 million	S-32	SERP O&M	-$1.250 million
S-15	Remove Trojan	-$16.584 million	S-33	Bonus/Incentive Pay	-$2.477 million
S-16	Remove NEIL	+$3.818 million	S-35	OPUC Wage Formula	-$1.717 million
S-28	Public Purpose Adj.	-$0.699 million	S-38	Y2K Amortization	-$1.977 million
S-31	A&G Accounts	-$1.00 million		Total	-$26.53 million

analysis for its proposed $11.05 million reduction for the delivery of information and services. PGE observes that the company already allocates 62 percent of Internet Web (Web) costs to non-regulated activities—well above the 50 percent CUB claims is reasonable. PGE adds that the company has justified the need for, and the benefit of, a credit card payment option for customers, and that the reduction of the scope of the NMR/AMR system will not save money due to the fixed costs of the system. In addition, PGE explains that a portion of distributed generation is properly allocated to customer service, as certain costs involve program development, testing, and analysis. Similarly, PGE maintains that customer surveys are properly allocated to regulated operations, since less than one percent of the cost, effort, and questions related to customer surveys concern non-regulated services. PGE does agree with CUB's proposed adjustment for WeatherWise, and acknowledges that approximately $160,000 should be removed from above-the-line expenditures for this program.

After our review, we share CUB's concerns about the significant increases to PGE's Customer Service costs. While some of these costs are related to PGE's efforts to meet the requirements of SB 1149, others are in response to PGE's belief that its customers want new services, more options, and better communication channels. To address these perceived needs, PGE is adding payment options, expanding communication choices, adding new customer services, and increasing the frequency of customer surveys. PGE admits that these changes cost more, but explains that they provide more value to PGE's customers.

PGE is correct that we should judge these services and the costs associated with them on the basis of the value they provide and the demand they meet. We must do so, however, in the context of PGE's overall request, which includes significant increases to its power costs. While we commend PGE for it efforts to enhance its services based on customer requests, we question whether its customers would enthusiastically support the addition of costly new programs when also faced with unprecedented power cost increases. Indeed, as CUB's counsel explained during oral argument:

> "[A]dvocates of PGE's customers are here to say that we're not nearly as concerned about more payment options right now as we are about how we're going to pay for the electricity we use. More than anything, customers want to be able to afford to use electricity to heat and light their homes, run appliances and, in short, live their lives. Business customers want to stay in business."[18]

We find that some of PGE's Customer Service expenses, such as the distributed generation, NMR/AMR system costs, and others related to SB 1149, should not be reduced or delayed at this time. PGE has showed that postponing these programs will not lead to decreased costs, and may actually increase costs over time. PGE has failed, however, to establish that it has made every reasonable effort to reduce other, discretionary Customer Service costs to help offset its spiraling power costs. We acknowledge that such reductions require difficult choices. Nonetheless, given the increasing wholesale power costs and PGE's reliance on that market to meet customer load, we believe that PGE must consider the rate impact on customers and critically examine whether some of these proposed expenditures should be delayed or simply not made at this time.

[18] Oral Argument, July 13, 2001, Transcript at 32, lines 13-19.

For these reasons, we agree that the stipulated Customer Service costs should be further reduced. As ICNU notes, customers want an economical power supply more than a new Internet Website or the ability to pay their bill with a credit card. However, we decline to adopt CUB's overall proposal to reduce Customer Service costs by $13.86 million. As noted above, some challenged costs should not be reduced or delayed at this time. Moreover, CUB has double-counted some costs, such as the credit card payment option, by targeting the same expense in two separate adjustments, and targeted other expenses that are already reduced by the revenue requirement stipulation. Adjusting CUB's proposal, we conclude that PGE's Customer Service costs forecast for the 2002 test year should be reduced by an additional $3.5 million above and beyond the adjustments contained in the stipulation. We decline to identify particular program areas that may be susceptible to reassessment or to impose specific cost reductions. These discretionary costs are best managed by the company.

2. Labor

CUB notes that, as with any large organization, PGE has staffing vacancies at any point in time. Due to these vacancies, CUB claims that PGE's actual employment costs were 5.3 percent below the budgeted employment level. In order to account for these unfilled positions for the 2002 test period, CUB proposes a reduction of 143.2 full-time equivalent (FTE) positions. This results in a reduction of operating expense of $6.4 million.

PGE questions CUB's methodology, but argues that a proper application of the analysis shows that the stipulated reduction of FTEs is reasonable. Using a longer time period (1995 through 2000), PGE calculates the percentage of unfilled positions to be 2.9 percent below budget. Applying this calculation to the 2002 forecast results in a proposed reduction of 78 FTEs, which is two less than the 80 FTEs eliminated by the stipulation.

We agree with PGE and adopt, as reasonable, the stipulated adjustment to the company's labor costs. PGE has demonstrated that CUB's analysis, when applied over the last six years, supports the stipulated reduction of 80 FTEs. Moreover, the 2002 test period, as stipulated, has a slightly lower FTE count than PGE's FTE total as of December 31, 2000. The stipulation, therefore, effectively caps the level of FTEs included in customer rates to the number of FTEs employed at the end of last year.

3. Distribution O&M

CUB contends that PGE's distribution O&M costs should be limited to 1999 actuals, adjusted for inflation. To accomplish this, CUB argues that these costs should be reduced by $3.9 million. PGE counters that CUB's suggestion to delay these expenditures, which are required to ensure safety, reliability, and regulatory compliance, is irresponsible.

We find no basis to adopt CUB's proposed adjustment to PGE's distribution O&M costs. As PGE notes, CUB has failed to question a single program as unnecessary or unreasonable, and does not allege that PGE's forecast of the cost of any program is inaccurate. We have previously rejected an inflation-escalator approach as an independent means for establishing PGE's revenue requirement. Accordingly, in the absence of any specific information challenging PGE's proposed expenditures for these critical services, we are unwilling to cap such costs with a simple inflation factor, as CUB recommends.

4. Technology

CUB believes that PGE's technology costs support non-regulated activities and should be adjusted accordingly. For example, CUB claims that the company's website provides information on a variety of non-regulated activities, such as wholesale power products and Earth Smart Homes. CUB also contends that its customer database has uses that go beyond the regulated system. For these reasons, CUB proposes a 30 percent, or $4.3 million, reduction in PGE's Information Technology (IT) budget.

PGE responds that CUB's proposed 30 percent reduction is unsupported. PGE explains that the challenged website program is just one of 16 different IT systems presented in PGE's case, and adds that it already allocates almost two-thirds of its web budget to non-regulated activities. Moreover, PGE clarifies that its Customer Information System (CIS) is not part of its IT budget, but rather is part of Customer Services and is specifically subject to the stipulation adjustment S-29.

We reject CUB's proposed reduction to PGE's technology costs. Adjustment S-31 of the stipulation, which CUB supports, already reduces the company's IT costs by $1 million. The stipulation also requires an audit of PGE's IT capital expenditures that will result in a refund to customers of capital costs that are not expended or found to be imprudent.[19] Moreover, PGE agrees that its website has non-regulated uses and has allocated almost two-thirds of its costs to non-regulated activities. For these reasons, we accept, as reasonable, the stipulated adjustments relating to PGE's IT costs.

5. Other Revenue

CUB believes that the company's filing underestimates the Other Revenue that it will receive in 2002. CUB claims that PGE's revenues should continue to increase, because of the company's on-going success in increasing revenues from pole attachments. After accepting some adjustments contained in PGE's rebuttal testimony, CUB proposes that Other Revenues be increased to $15.87 million, some $40,000 more than set forth in the stipulation.

PGE responds that CUB's forecast of Other Revenue is overly optimistic. The company believes that CUB's reliance on the growth in pole attachment revenues is misplaced, because the limited number of poles places a limit on any growth in this area. Additionally, PGE notes that many telecommunications companies have recently suspended build-outs of broadband access systems, and that much of the current growth in telecommunications occurs underground.

We reject CUB's proposal to increase PGE's Other Revenue by $40,000. Staff, PGE, and Fred Meyer have stipulated to pole-rental revenues of $5.8 million for 2002, a $100,000 increase from the company's actual revenues in 1999. Given the company's finite number of poles, the suspension of broadband access systems, and expanding use of

[19] We further address this issue in our analysis of ICNU's proposed adjustments to non-power O&M costs.

underground conduit, we conclude that the projection for Other Revenue contained in the stipulation is reasonable and adopt it.

ICNU Recommendations

Like CUB, ICNU also recommends that the Commission make specific adjustments in addition to those contained in the stipulation. Specifically, ICNU recommends that the Commission: (1) reduce PGE's non-power O&M costs by an additional $13.4 million; (2) adopt certain adjustments proposed by CUB; (3) exclude a portion of PGE's proposed IT costs; and (4) exclude SB 1149 implementation costs. We address each separately.

1. Non-Power O&M Adjustments

ICNU claims that PGE's costs for lobbying, governmental affairs, and strategic planning costs should be excluded from the company's revenue requirement. Citing *Re Cascade Natural Gas Co*, ICNU contends that lobbying and other "expenses for legislative activities should not be borne by ratepayers."[20] These costs include $650,923 for lobbying costs, $510,798 for state, local, and federal governmental affairs, and $1,030,267 for competitive strategic planning, for a total of $2.19 million.

ICNU also contends that PGE has failed to establish that the following new programs and costs increases are warranted and benefit ratepayers: (1) general business support costs ($368,421); (2) administration of compensation programs ($659,717); (3) employee training and development costs ($1,585,831); (4) management of Commission relationship costs ($354,000); and (5) customer service and IT costs ($6,588,577). ICNU states that the removal of these programs results in a total disallowance of approximately $9.5 million.

Finally, ICNU maintains that PGE has included in its test year cost increases related to rates and regulatory affairs that are not reasonably certain to occur in the future. ICNU explains that these costs are related to PGE's filings before state and federal agencies. ICNU does not believe that the year 2000 should be used to gauge a typical level of such activity, and proposes: (1) two adjustments to reduce rates and regulatory affairs costs by a total of $972,697; and (2) two adjustments to reduce legal costs by a total of $691,734. Together, these exclusions result in a $1.66 million reduction.

In response, PGE claims that ICNU has failed to support its specific recommended reductions. First, the company claims that, contrary to ICNU's assertion, the general support and governmental affair cost categories contain no expenses for lobbying. PGE explains that the company always charges lobbying costs below the line. PGE further argues that it has fully justified its costs for general business support, administration of compensation programs, and employee training and development. Moreover, according to the company, historic cost levels and increased regulatory requirements justify the increased expenses for legal services and regulatory affairs.

We agree with a portion of ICNU's proposed adjustments to PGE's non-power O&M costs. PGE adequately rebuts ICNU's allegations relating to governmental affairs and

[20] Order No. 74-898 at 10.

strategic planning, but fails to sufficiently describe or provide evidence detailing the costs in Ledger N42255, General Support-Manage External Relations. PGE's general assertion that the company "always charges lobbying costs below the line" is not, by itself, a sufficient justification for the expense. Accordingly, we adopt ICNU's proposed $650,923 reduction.

Second, we conclude that PGE has justified its programs and proposed cost increases related to general business support and administration of compensation programs. We agree with ICNU, however, that the company has failed to adequately explain why its proposed employee training and development costs increase from $1.6 million in 1999 to roughly $3.2 million in 2002. PGE explains the various training areas within its Human Resource Department, but offers no explanation as to why its test year training costs are twice those incurred in 1999. Similarly, while PGE identified that $1.3 million of its proposed $1.654 million increase for Commission relationship costs was related to SB 1149 project management, it provided no evidence to justify the remaining $354,000 increase in other, non-SB 1149 costs. Therefore, we adopt ICNU's $1,585,831 reduction in employee and development costs, and exclude $354,000 of PGE's costs associated with management of Commission relationships. We have already reduced PGE's Customer Service costs, pursuant to CUB's recommendations, and decline ICNU's additional request.

With regard to test year cost increases related to rates and regulatory affairs, we agree with ICNU that PGE's 2000 costs should not be considered reflective of typical department activity. As the parties are well aware, the year 2000 started a period of extensive regulatory activity at PGE, primarily due to the passage of SB 1149. Before this Commission alone, PGE initiated this rate case, filed a resource plan in docket UE 118, and actively participated in numerous rulemaking proceedings, such as dockets AR 380 and AR 390. The PGE/Sierra Pacific merger proceeding in docket UM 967 occurred that year. Moreover, the company sought an interim rate increase in docket UE 117, and a power cost adjustment mechanism in dockets UM 1008/1009. We do not believe that it is reasonable to assume that this abnormally high level of regulatory activity will continue to occur in all the future years in which PGE's rates will be in effect. We further agree with PGE, however, that 1999 was a relatively quiet year for the company's regulatory activities. The lack of major contested dockets that year, and the future efforts required for the implementation of SB 1149, confirm that the 2002 test year expenditures should be increased above the level of actual regulatory expenditures for 1999. Accordingly, we adopt half of ICNU's proposed $660,945 adjustment, and reduce PGE's 2002 test year expenditures for rates and regulatory affairs by $330,472. This adjustment allows for a considerable increase in PGE's rates and regulatory affairs budget, yet reflects a reasonable level of future regulatory activity.[21]

We make a similar adjustment to PGE's proposed legal costs in its 2002 test year. PGE has forecasted a $1.0 million increase from 1999 costs based on "the restructuring of PGE's business environment from regulated to competitive."[22] As ICNU notes, however, PGE fails to account for any cost decreases that may be associated with unbundling and the transfer of operational control of transmission assets to a Regional Transmission Organization. Moreover, like the company's regulatory activities, we do not believe that all costs associated with the

[21] ICNU also recommended an additional $311,752 reduction in rates and regulatory affairs costs, for a total reduction of $972,679. We do not adopt ICNU's additional adjustment, which would reduce expenditures for PGE's Environmental Affairs.

[22] *See* PGE/700, Stevens/7.

competitive transition will continue to occur in all future years. Accordingly, we adopt ICNU's recommendation and disallow half ($505,829) the proposed increase in legal fees. We do not adopt ICNU's additional $185,805 reduction relating to Ledger Account N44013, which includes the cost of Portland General Holdings (PGH) employees performing legal services for PGE.

2. Adopted CUB Adjustments

While the majority of the proposed adjustments by CUB do not impact industrial customers, ICNU accepts, as reasonable, $32.04 million of those adjustments and recommends the Commission adopt them.

We have previously addressed the relevant CUB adjustments above and need not repeat our analysis here.

3. IT Costs

In addition to the adjustments cited above, ICNU recommends the Commission exclude $49 million of PGE's proposed IT costs from the 2002 rate base. ICNU contends that PGE has failed to provide sufficient justification for the need and reasonableness of these costs. PGE responds that ICNU's proposed disallowance for IT costs is unsupported. We agree with PGE.

As clarified above, PGE has the burden of showing that any proposed expense is just and reasonable. Nonetheless, any intervenor opposing a claimed cost must provide competent evidence that such costs are not reasonable. ICNU's proposal, based solely on three lines of testimony, is not sufficient. In fact, ICNU presents no explanation as to whether it objects to the programs or the program's costs.

After a Staff review of the company's new IT systems and their associated capital costs, Staff determined that PGE's capital costs for the new IT systems were prudent and stipulated to full recovery, subject to audit. In this audit, Staff will examine PGE's actual capital expenditures for IT costs, and only those expenditures that are deemed reasonable and prudent will be authorized in rates. Expenditures that are not made or found to be imprudent will be refunded to customers. We conclude that this stipulated agreement on IT costs is reasonable, will ensure that customers will only pay for prudently incurred expenditures, and should be adopted.

4. SB 1149 Costs

ICNU agrees that PGE should be compensated for prudently incurred SB 1149 costs, but contends that PGE has failed to establish that these costs are reasonably certain to occur during the time period when UE 115 rates will be in effect. ICNU notes that PGE's assumption that the restructuring bill will take effect in October 2001 appears to be erroneous, given the recent passage of HB 3633. Moreover, regardless of the implementation date, ICNU believes that the SB 1149 costs are both extraordinary and nonrecurring and should not be included in revenue requirement. ICNU argues that implementation costs not already incurred to date should be recovered through deferred accounting.

In response, PGE first clarifies that HB 3633 delayed implementation of SB 1149 only until March 2002, so SB 1149 will be in effect during 2002. Second, PGE contends that these expenditures reflect new components of PGE's ongoing operations that are required by SB 1149. Thus, PGE argues they are not extraordinary, uncertain, and nonrecurring.

We agree with PGE. The five-month delay of SB 1149 will not materially affect PGE's activities to implement the restructuring. As PGE notes, SB 1149 will take effect in March 2002, and the company will be making expenditures in the first quarter of next year to prepare for the implementation. Contrary to ICNU's assertions, we conclude that the challenged expenditures reflect ordinary, certain, and recurring costs that should be included in PGE's revenue requirement.

Commission Resolution

We appreciate the efforts of PGE, Staff, and Fred Meyer in negotiating and stipulating to 54 separate revenue requirement issues. With the exception of the additional non-power O&M adjustments sought by CUB and ICNU, the stipulation was unopposed by any party. We have reviewed the unopposed portions of the stipulation, find the proposed adjustments contained therein to be reasonable, and conclude that the results should be adopted.

For the reasons cited above, we also find that the results contained in the disputed portions of the stipulation should be adopted, but conclude that additional reductions to PGE's non-power O&M costs are necessary to yield fair and reasonable rates. These adjustments include an additional $3.5 million reduction in Customer Service expenditures and a $3,427,055 reduction in management of Commission and external relationships, employee training and development, rates and regulatory affairs, and legal costs. Moreover, PGE has agreed to CUB's proposed $160,000 reduction for WeatherWise. Together, these additional adjustments total $7,087,055.

II. Portland and League Stipulation

This stipulation covers several issues raised by Portland and League regarding PGE's proposed tariffs, rules, and rates. Under the stipulation, PGE agrees that its interconnection standards will continue to reference applicable Institute of Electrical and Electronics Engineers (IEEE) criteria and that its interconnection standards will follow those IEEE criteria. If Portland or a member of the League opts to pursue interconnection with PGE's distribution or transmission system, PGE will work cooperatively with that municipality in applying these standards. Moreover, PGE agrees to revise Rule C relating to restoration of utility services to confirm that it will reconnect critical retail load consumers as soon as possible. PGE also agrees to continue to work cooperatively with municipalities and other public bodies to identify critical load customers. In addition, PGE agrees to further revise Rule C to clarify what constitutes a "public works project."

The stipulation also addresses disputed issues related to street lighting. The stipulation addresses four rate-related components: (1) circuit charges (marginal costs of service drops); (2) group relamping; (3) power door luminaries; and (4) emergency pole replacements. PGE, Portland, and League request that the Commission approve the various tariff adjustment described in the stipulation. No other party has filed any objection to the stipulation.

Commission Resolution

We have reviewed the Portland and League stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix C, is adopted.

III. Power Cost Stipulation

In this stipulation, PGE, ICNU, CUB, Fred Meyer, and Staff agree on matters related to power costs issues raised in this docket. The stipulation establishes methodologies or mechanisms by which PGE will: (1) establish its power costs; (2) value its long-term and short-term resources and credit that value to all consumers, including consumers selecting direct access; (3) pass all of the benefits of BPA subscription power to all residential and small farm customers; (4) reflect, in rates, the current adverse hydro conditions facing the company; and (5) share, with its customers, the benefits and burdens of variations between expected power costs included in base rates and actual power costs. The stipulation also includes a shopping credit for commercial customers and addresses charges to Boise Cascade.

Under the stipulation, charges for PGE's energy services are based on a combination of market prices and the value of PGE's resources. PGE will first determine the market price of power using its most recent forward price curves. The company will make that determination on September 12, 2001 for this upcoming year, and on November 15 for each calendar year thereafter.[23] In addition to this market price, PGE will credit or charge each customer with the positive or negative value of PGE's resources. This credit or charge will be calculated from the Resource Valuation Mechanism (RVM) set forth in Schedule 125.

The RVM compares, by customer class, the total cost of power from PGE's long-term and short-term resources to the market price of an equivalent amount of power. If total cost of power from either long-term or short-term resources is less (greater) than the market price of an equivalent amount of power, the difference will be provided as a credit (charge) to customers and spread among customers in the class on an equal cents per kWh basis. PGE will make a similar calculation for BPA subscription power to ensure that 100 percent of the benefits of subscription power will flow to eligible customers.[24]

For purposes of allocating total fixed and variable power costs among customer classes and calculating the RVM, PGE will allocate its long-term and short-term resources as follows:

[23] The stipulation originally listed September 11, 2001 at the valuation date for the upcoming year. In post-stipulation settlement discussions, however, the parties agreed that September 12, 2001 will be the date for final pricing in this docket.

[24] To reflect the projected difference in net variable power costs between expected and normal hydro conditions, PGE will calculate a separate charge under Part C of Schedule 125. This charge is described in Paragraphs 1 and 2 of the Stipulation and is designed to account for the current adverse hydro conditions. The charge applies only until December 31, 2002. The charge is based on reduced hydro generation of 300,000 MWh over the period October 1, 2001 through December 31, 2002, spread to months based on Exhibit E to the stipulation.

(a) First, PGE will allocate its long-term resources among customer classes in proportion to their respective percentages of retail load for the 12 month period ended September 30, 2001;

(b) Second, BPA subscription power will be allocated to the residential and small-farm customers of PGE eligible to participate in BPA's residential exchange program;

(c) Third, PGE will allocate its short-term resources among all customer classes until each customer class has been allocated a sufficient amount of resources to cover the expected load of that class. If resources are insufficient to serve all expected customer load, PGE shall allocate the shortfall among the customer classes in proportion to their respective percentages of expected shortfall. Any shortfall of resources for any customer class shall be filled by market purchases;

(d) Any excess of short-term resources over expected load shall be allocated among all customer classes in proportion to their respective percentages of expected load; and

(e) If, after applying (a) and (b) above, the residential class has sufficient resources to meet expected load, short-term resources shall be allocated to the other classes on a pro rata basis until they reach the same relative position as the residential class. Any remaining short-term resources shall then be allocated in accordance with (d) above.

PGE will next allocate the net variable power costs produced by Monet, its power cost model, for the rate period for long-term resources, short-term resources and BPA subscription power among the customer classes in accordance with their relative percentages of each type of resource. PGE will then allocate and add the fixed costs of long-term resources among the customer classes in accordance with their relative percentages of long-term resources.

The stipulation also adopts a Power Cost Adjustment (PCA) to address the uncertainty in forecasting power costs. The PCA, set forth in Schedule 127, starts with net variable power costs as described above, adjusted for specific items.[25] The credits or charges produced by portions of the RVM are combined with net variable power costs to produce a base net variable power cost (NVPC). The power cost variance (PCV) is then calculated. The PCV is the difference between actual and base NVPC less the difference between actual and base energy revenues. Base energy revenues are the energy revenues forecast from existing tariffs and the load forecast used to develop the base NVPC.

The PCV is then compared to a table in Schedule 127 to determine an adjustment amount that will be charged or credited to customers in rates. The table includes a dead band of negative $28 million to positive $28 million in PCV before there is any adjustment amount. The

[25] Schedule 127 does not apply to BPA Subscription Power.

table also includes percentage sharing of the PCV between PGE and its customers in percentages ranging from 50 percent to 95 percent. This sharing is designed to motivate PGE to manage its power costs prudently, while recognizing the current volatile power markets.

The stipulation also includes a shopping incentive of 0.5 cents per kWh for large nonresidential customers with load less than 1 MWa. This incentive is limited to the first 10 percent of eligible customers that choose direct access, and its cost is recouped from the eligible class. Finally, the stipulation addresses charges to the Boise Cascade St. Helens Plant.

Commission Resolution

As noted above, this stipulation represents a settlement in compromise of the positions of most of the active parties to this docket concerning power costs. The executing parties recognize that PGE's power cost situation is unique, given PGE's exposure to the wholesale energy market and the current uncertainty and volatility of that market. The parties believe that the stipulation produces several benefits for customers that are consistent with the provisions of SB 1149. No party opposed the stipulation.

After our review, we conclude that the stipulation is reasonable. As the executing parties note, the stipulation establishes rates for PGE's energy services based on the market price of energy. This allows customers to know the actual price of energy by sending the appropriate pricing information to the retail market. In addition, the RVM passes the value of PGE's long-term and short-term resources to all of PGE's customers, including those electing direct access and portfolio service. This promotes competition and choice consistent with SB 1149.

The stipulation also provides the methodology to allocate PGE's resources among customer classes. This will more appropriately allocate, to each customer class, the actual cost to provide energy service and resource value to that class and reduce potential cross-subsidies among customer classes. Finally, the stipulation provides a means for PGE to mitigate the adverse impact of current hydro conditions, and implements a PCA that fairly distributes among the customers and PGE the potential benefits and costs resulting from changes in load, resources and the wholesale power market. Accordingly, the stipulation, set forth in Appendix D, the attached Schedules 125 and 127, and the August 20, 2001 letter explaining the assumptions and inputs that PGE will use in the final Monet run, are adopted.

IV. Supplemental Revenue Requirement Stipulation

PGE, Staff, and Fred Meyer filed this stipulation to resolve the treatment of franchise fees and steam sales. In its original filing, PGE believed that ORS 221.450, as modified by SB 1149, required franchise fees to be paid on a volumetric basis, rather than a revenue sensitive basis described in the previous version of the statute. After discussions with the League, however, PGE now agrees that cities will be able to choose the basis that is most advantageous to them pursuant to a specific set of procedures. Because the parties believe that cities will utilize the revenue basis for fees based on revenues collected in 2001, the stipulation permits PGE to revise its revenue requirements to: (1) reflect a $794,000 increase in franchise fees based on 2002 revenues at current rates, and (2) adjust revenue sensitive costs in the test year 2002 to reflect a 2.26 percent rate.

The steam sale adjustment is due to a recent contract to sell steam produced at PGE's Coyote Plant. Under this stipulation, PGE will decrease Other Revenue by $306,000 to remove imputed steam sales as originally filed. Other Revenue is increased by $1,143,000 to reflect PGE's total estimated steam sales revenue for 2002. Further, PGE will make certain adjustments to its Monet power cost model to reflect expected steam sales for each month. PGE, Staff, and Fred Meyer request the Commission to approve the stipulation. No party opposes it.

Commission Resolution

We have reviewed the supplemental revenue requirement stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix E, is adopted.

V. Rate Design Stipulation

Under the Northwest Regional Power Act, residential and small farm customers of PGE are entitled to share in the benefits of the low cost power sold by the BPA. Traditionally, the BPA provided those benefits in cash to PGE, which in turn has credited its customers under Schedule 102. Beginning in October 2001, however, the BPA will begin providing the benefits in the form of both power and cash. This stipulation is intended to resolve how PGE should pass the BPA power and financial benefits to PGE's residential and small farm customers.

Under the stipulation, PGE will value the BPA subscription power by comparing the cost and market value of that power. This value will flow through to customers under Schedule 102 as a credit or charge per kWh, which will be valued consistently with the way PGE prices energy and establishes the RVM under Schedule 125. This gives customers a credit or charge equal to the rate BPA charges PGE for subscription power, and ensures that all of the benefits and burdens of subscription power will flow through to eligible customers. PGE will also pass through the cash benefits in the form of a credit to all residential customers for all kWhs of use in excess of 225 kWh per month.

PGE and Staff designed the application of the BPA credit, BPA cash and the RVM credit or charge to produce an initial rate differential of between 10 and 25 mills per kWh for residential customers between the first 225 kWh of use per month and any kWh of use in excess of 225 kWh per month. Because changes in the forward price curves applied to PGE's final Monet run may produce a rate differential outside these parameters, the stipulation allows an adjustment to the rate differential so that there is an initial price differential that is neither too large nor too small.

In the stipulation, PGE and Staff also agree that the basic or customer charge shall be $10 per customer per month. Although PGE had originally requested a $7 per month charge, the company provided evidence that customer-related costs are in excess of $15 per month. According to the explanatory brief, Staff and PGE believe that the stipulated rate of $10 per month more accurately reflects the per-customer costs incurred by PGE. PGE and Staff request the Commission to approve the stipulation.

CUB and OOE are not parties to the stipulation, and object to certain portions of it. CUB does not oppose the content of the stipulation, but believes that the explanatory brief supporting the stipulation mischaracterizes the reason why the parties negotiated an increase in the basic or customer charge. While it does not support the proposed increase to $10 per month, it recognizes that the increase avoids the perverse result of having some low use customer rates go down, while overall rates go up. CUB claims that this is the basis for the stipulated increase, not the one contained in the explanatory brief. CUB believes that adoption of the stipulation based on the need to "more accurately reflect the per customer costs incurred by PGE" represents a significant change to Commission policy that is not supported by the record.

OOE also does not oppose PGE's and Staff's settlement on residential rate design. OOE contends, however, that the proposed stipulation does not provide adequate inversion to residential rates to move the rate for use over 1,000 kWh per month significantly closer to the long-run incremental costs for space heat use. Therefore, it recommends the Commission further modify the stipulation by adopting its rate design proposal. Like the stipulated rate design, OOE recommends an initial residential block set at the per-customer amount of BPA power and priced equal to what BPA charges PGE. OOE proposes a second block for use above the BPA block and below 1,000 kWh per month, and a third block, or tail block, for all use above 1,000 kWh.

To move energy charges for space heating closer to the high costs to serve these loads, OOE recommends that the calculation of the average rate for the first 1,000 kWh should equal the sum of the commodity charges, plus the $3.00 increase in the basic rate, divided by 1,000 kWh. It then recommends PGE decrease the net rates for the first 1,000 kWh and increase the net rate for the tail block to obtain a rate differential of 1.1 cents per kWh. OOE explains that this 1.1 cent differential would exist only until further adjustments are applied after October 1, 2001, and that the rate differential could be greater or less than 1.1 cents after that date. OOE claims that the higher tail block rate will begin to provide better price signals for residential customers when making home-heating decisions.

Commission Resolution

We have reviewed the rate design stipulation and find the proposals contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix F, is adopted. In making this decision, we clarify that we adopt the proposed increase in the basic or customer charge based on reasons cited by CUB. The increase will avoid a rate decrease to low use customers while overall rates are increasing.

We decline to adopt OOE's proposed modification. OOE provides little evidence or analysis of how its proposal would affect consumers or whether it will accomplish its apparent goal of reducing space heating. OOE's proposed rates could significantly affect a large number of customers that live in multi-family dwellings and, consequently, have no control over their heat source. Moreover, it is unclear how many customers that live in single-family dwellings would switch to gas heating under OOE's proposal. Only about 16 percent of PGE's residential customers heat with electricity. Many of these homes have no duct systems, which are necessary for the convenient installation of gas systems.

CONTESTED ISSUES

I. RATE OF RETURN

The United States Supreme Court established the standard for determining cost of capital allowance in utility rate-making proceedings:

> "[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]"[26]

To determine a rate of return on rate base that is appropriate for PGE, we must first identify the costs and components of the company's capital structure. The cost of each capital component is estimated and weighted according to its percentage of total capitalization. These weighted costs of capital are combined to calculate PGE's overall cost of capital, which becomes the allowed rate of return on rate base.

During settlement discussions, PGE and Staff reached agreement on all rate of return issues except PGE's required return on equity (ROE or cost of equity). PGE estimates its required ROE to be 11.5 percent and seeks an authorized ROE at or above that level. PGE contends that this return is the appropriate rate, using a 2002 test year and considering the company's pricing and operation risks. The company's ROE recommendations are based on the joint testimony of Mr. Patrick Hager, PGE's Manager of Regulatory Affairs, and Mr. William Valach, PGE's Manager of Finance (collectively Hager-Valach). Hager-Valach present ROE estimates using a single-stage and multi-stage Discounted Cash Flow (DCF), the Risk Positioning Method, and a comparison of actual determinations of required equity returns in other jurisdictions.[27]

Staff contends that PGE's request is excessive and recommends the adoption of an ROE for the company of 9.0 percent.[28] Staff presents ROE estimates from two witnesses. Bryan Conway (Conway), Staff's Program Manager of Economic and Policy Analysis, presents cost of equity estimates using a single-stage DCF model, the Fisher-Kamin version of the Capital Asset Pricing Model (CAPM), and a qualitative analysis of the Commission's most recent contested ROE decision in docket UG 132.[29] James A. Rothschild (Rothschild), President of Rothschild Financial Consulting, quantifies his cost of equity recommendations using the single-stage and multi-stage DCF model and two versions of what he calls the risk premium/CAPM method.

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[26] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944). We note that the 2001 Legislative Assembly recently codified this standard in HB 3502, amending ORS 756.040(1).

[27] In rebuttal testimony, Hager-Valach update their original ROE recommendations based on information available through April 30, 2001, and make certain adjustments to their DCF analysis based on Staff's testimony. In this order, we address Hager-Valach's recommendations contained in their rebuttal testimony.

[28] Staff originally recommended an authorized ROE of 8.9 percent, but adjusted its recommendation in its opening brief to account for the increase in risk free rate. *See* footnote 35, *infra*.

[29] *In re Northwest Natural Gas Company*, Order No. 99-697.

Our discussion is divided by methodology. For each section, we begin with a review of the methodology, followed by a summary of the parties' recommendations. We then address and resolve the contested issues under each specific methodology. After addressing all five methodologies, we conclude our discussion by adopting an authorized ROE for PGE.

1. Discounted Cash Flow (DCF)

The DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation. The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.

In this case, the parties used two DCF models. The basic, or single-stage DCF formula assumes a constant growth rate in future dividends. It is generally expressed as:

$$k_e = \frac{D_1}{P_0} + g$$

Where:

k_e = cost of equity;
D_1 = dividends per share over the next 12 months;
P_0 = current stock price; and
g = annual growth rate in future dividends per share.

The multi-stage, or complex DCF formula assumes that growth rates may change over time. That formula is expressed as:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \ldots + \frac{D_n}{(1+k_e)^n}$$

Where:

$D_1 \ldots D_n$ = the expected stream of annual dividends per share.

DCF Estimates

Hager-Valach could not apply the DCF model directly to PGE, because the company is no longer publicly traded following the merger with Enron Corporation. Therefore, as a proxy for PGE, Hager-Valach use three sample groups of electric utility companies. The first group, which they had originally selected in their direct testimony, is comprised of 17 utilities listed in *Moody's* Electric Utility Index and *Standard & Poor's* Electric Utility Index. The second and third sample groups are ones used by Staff in its testimony. Although PGE does not agree with Staff's sample groups, Hager-Valach include them to demonstrate that the different samples did not significantly impact the DCF calculations. Hager-Valach use both the single-stage and multi-stage DCF models.

For their single-stage DCF analysis, Hager-Valach estimate the dividend yield (D_1 / P_0) as four times the most recent quarterly dividend payment divided by the stock price.[30] To calculate stock price, Hager-Valach use the month-high closing price, month-low closing price, and the month-end price for each month during the February through April 2001 period.

To determine future growth (g), Hager-Valach use the *br* + *vs* method, which allows for growth through stock issuance and through earnings growth. In this formula, *b* represents the percentage of earnings retained by the company, and *r* represents the rate of return investors expect to earn on the company's book value. For these inputs, Hager-Valach rely on *Value Line*[31] forecasts. For the *vs* component, *v* represents the portion of the proceeds from future stock expected to exceed book value, and *s* is the growth rate of the stock outstanding. For these inputs, Hager-Valach use historical data.

For their multi-stage DCF analysis, Hager-Valach separate dividend growth into three stages. For the first stage, they use *Value Line* forecasts for the indicated dividend for the next 12 months. These forecasts reflect implicit one-year growth rates. Hager-Valach estimate the second growth rate as the annual growth rate occurring between 2001 and 2004. The 2004 dividend is estimated as an average of estimated dividends for the years 2003-2005, as estimated by *Value Line*. For the final growth rate, Hager-Valach use the *br* + *vs* calculations they use in their single-stage DCF.

For the three electric utility sample groups, Hager-Valach's single-stage DCF cost of equity estimates range from 11.44 to 12.80 percent, while their complex DCF estimates range from 10.90 to 12.13 percent.

Staff presents a total of three DCF models: Conway's single-stage model and Rothschild's single-stage and multi-stage models. Conway applies his single-stage DCF analysis to a sample of 42 electric utility companies he believes are suitable for use as a proxy cost of equity estimate for PGE. He limits his sample to companies covered by the *Value Line* Investment Survey that are primarily engaged in retail sales of electricity, companies that have not omitted an annual dividend in the past five years and for whom *Value Line* is forecasting continued dividend payments, and those companies for whom he could calculate CAPM betas.

To compute his yield component, Conway uses reported stock prices for January 11, 2001, and *Value Line* forecasts of dividend per share for each company for the next 12 months. To estimate future growth, Conway uses past dividend growth as an indicator of the marginal investor's expectations of future growth. For his sample of electric companies, Conway examines both the arithmetic and geometric means across the sample of historical dividend growth. Conway's single-stage DCF analysis produces a cost of equity estimate between 7.75 and 8.0 percent.

Rothschild applies his single-stage DCF analysis to four sample groups. First, he examines the groups of electric companies selected by PGE in this proceeding and by PacifiCorp in docket UE 116. Next, to confirm the reasonability of his estimates, he performs a DCF

[30] Hager-Valach initially used a different methodology, but adopt this approach in response to Staff's testimony. Although Hager-Valach believe that this approach causes the cost of equity to be understated, Hager-Valach adopt it for purposes of this case.

[31] *Value Line* is a widely-circulated subscription service that provides independent analysis of stocks.

analysis on the group of gas distribution companies used by PacifiCorp in docket UE 116, as well as a group of water companies.

Rothschild considers dividend yield data at a recent point in time and over the last year. First, he calculates dividend yield by dividing the most current annualized dividend rate declared by each company by the spot stock price as of February 28, 2001 for each company. He also divides the most current annualized dividend rate declared by the average high and low stock price of each company over the year ended February 28, 2001. He increases the dividend yield result by adding one-half the future expected growth rate so that the yield is equal to an estimate of dividends over the next year.

To calculate a growth rate, Rothschild uses a $br + vs$ formula similar to that used by Hager-Valach, but with different data. He calculates b, the retention rate, based on a derived dividend yield on book value, and r, return on book equity. To determine r, Rothschild examines both analysts' forecasts and historical data for returns on book equity. Finally, he uses *Value Line* forecasts for his vs inputs.

Rothschild's simplified DCF results produce a cost of equity range of 9.17 to 9.24 percent for the PacifiCorp sample group, and a range of 9.47 to 9.71 percent for the PGE sample group. He places no weight, however, on the results for the PGE sample group, which he considers to be an upwardly biased example.

In his multi-stage DCF model, Rothschild separates dividend growth into two stages. His first stage of the model is based on *Value Line's* forecasts for earnings per share and dividends per share for 2000 through 2004. Because *Value Line* does not forecast a specific earnings and dividend projection for every year in that period, Rothschild projects those omitted years by extrapolating the available data.

Rothschild determines second stage earnings by multiplying the future book value per share by the future expected return on book equity used to calculate future growth, g, in his single-stage DCF model. Rothschild projects growth in his second stage for 40 years into the future. Rothschild's complex DCF results produce a cost of equity range of 9.71 to 9.81 percent for PacifiCorp's sample group of electric utility companies.

Disputed DCF Issues

Of the two DCF versions presented, the parties differ the most with regard to the single-stage DCF model. Specifically, the parties disagree significantly on the proper method to calculate the growth component. PGE criticizes Conway's single-stage DCF estimate, because he uses historical data to estimate the growth rate component. While Rothschild uses the same $br + vs$ formula used by Hager-Valach to calculate growth, PGE claims that Rothschild's estimates for retention ratios, b, and return on book equity, r, are highly subjective, downwardly biased, and flawed. Staff counters that Hager-Valach's use of *Value Line* forecasts for retention ratios, b, combined with an historic dividend rate in their calculations, seriously overstates the cost of equity. Staff contends that the mismatch in the time chosen to estimate these two inputs creates substantial and unnecessary error. These differences are so significant that Staff suggests that the Commission simply reject the use of the single-stage version of the DCF model in favor of the multi-stage formula.

Staff and PGE agree that the single-stage version of the DCF model can only be properly used if dividends, earnings, stock price and book value are expected to grow at the same rate. The difficulty arises, however, in selecting the values to use for these inputs. PGE and Staff disagree on whether the use of a forecasted retention ratio requires an adjustment to the current dividend to avoid double counting. Both parties provide a reasonable basis for their respective positions, but neither has sufficiently established why the opposing methodology should be rejected.

We have previously favored use of the multi-stage DCF analysis over the single-stage DCF formula. In docket UG 132, *In re Northwest Natural Gas Company*, we noted that the multi-stage DCF improves on the implicit assumption in the single-stage version that dividends grow indefinitely at the same rate.[32] This limitation of the single-stage DCF model is even more significant given the ongoing restructuring of the electric industry. For this reason, and in light of the parties' significant disagreements over the proper application of the single-stage DCF model, we adopt Staff's recommendation to reject the single-stage DCF analysis in favor of PGE's and Staff's multi-stage DCF results. We conclude that the parties' single-stage DCF analyses provide no information not already contained in their complex DCF analyses. Parties are free to use the single-stage version of the DCF method in future dockets, but they will be expected to show that the required industry stability is present.

Turning to the multi-stage DCF models presented, PGE identifies four primary errors in Rothschild's multi-stage DCF calculation, three of which relate to his second stage growth projections. First, PGE criticizes Rothschild's estimate for expected return on book equity, *r*. PGE notes that, while Rothschild claims to have relied, in part, on *Value Line* forecasts for the companies in PacifiCorp's sample group, he actually lowers that average by omitting the company with the highest expected return—DPL, Inc. (DPL). Rothschild retained DPL in his sample for the purpose of calculating market-to-book ratio (M/B).

Staff responds that Rothschild's exclusion of DPL is justified, because the *Value Line* forecast of a 23 percent return on equity for that company is not indicative of the return investors expect could be maintained into the future. Staff notes that the 23 percent forecast is more than three standard deviations above the mean for the forecasted returns for the sample group, and that only one company earned more than 20 percent on equity in any given year out of about 150 historic earned returns reported by *Value Line*.

Staff is correct that the *Value Line* forecast for DPL is high by historical standards. The issue presented, however, is not whether to include DPL in the DCF estimate, but rather if data for the company should be used selectively in the analysis. As discussed above, Rothschild excludes DPL to estimate return on book equity, but includes the company to calculate his average M/B for the PacifiCorp sample group. This selective use of data overlooks the interrelationship between the various components of the DCF model. Given the high forecasted return on book equity, it is likely that investors have bid up DPL's stock price, which is the numerator of the M/B calculation. Because a higher stock price produces a higher M/B, it is not surprising that DPL, the company with the highest forecasted return on book equity, also has the highest M/B. Thus, we agree with PGE that Rothschild has, in effect, decreased his cost

[32] Order No. 99-697 at 23.

of equity estimate by using DPL's relatively high stock price but excluding the company in his assessment of the expected returns that generated the higher stock price in the first place. Accordingly, we conclude that Rothschild's expected return on book equity for his second stage of his DCF calculation should be adjusted to 13.37 percent—the value Rothschild used for the last year (2004) of his first stage calculation.

Second, PGE claims that Rothschild erred in calculating the retention rate, *b*. PGE explains that, rather than relying on *Value Line* forecast, Rothschild reverts to a 2001 retention rate for his second stage growth projection. PGE observes that Rothschild's reversion to the 2001 retention rate creates a sharp discontinuity between the first and second stages in his model. PGE also contends that Rothschild provides no basis to disregard *Value Line* forecasts in his second stage. PGE notes, while he claims the current retention rate is "more consistent with investor expectations," Rothschild fails to provide any basis for that statement. PGE adds that he also failed to sufficiently explain why he used the current forecast in this docket, when he had used long-term forecasts in a prior Commission docket, UE 102.

In examining Rothschild's calculation of the retention rate, we are not persuaded that current data should be used instead of forecasted rates. To explain his switch in methodologies since docket UE 102, Rothschild refers to a large forecasted difference that existed in an intervening case, but fails to explain whether a similar difference existed in this case. He similarly fails to support his assertion that the current retention rate seems to better represent investor expectations. Indeed, Rothschild's adjustment causes a steep decline in retention ratios after 2004, reversing an upward trend forecasted by *Value Line*. We concur with PGE that the use of a forecasted retention rate should be used in this docket. We are not precluding the use of historical retention rate information in future dockets, but parties advocating such usage must justify the use of such data.

Third, PGE criticizes Rothschild's use of *Value Line* forecasts to estimate the sale of newly issued stock, the *s* term in *vs*. Although PGE admits that DCF inputs should, in general, be based on forecasts rather than historical rates, PGE contends that an exception is appropriate here, because *Value Line* does not forecast large but relatively infrequent public offerings.

Staff disagrees and believes it inappropriate for PGE to favor the use of historical data to estimate *s*, while strenuously arguing that forward-looking projections should be used for both *b* and *r*. We agree. Moreover, while we acknowledge the difficulty in predicting large offerings, PGE failed to establish that *Value Line* expressly excludes the possibility of such offerings in forecasting future sales of newly issued stock. Moreover, Staff demonstrated that the historic data is misleading, since new stock sales as a percentage of the amount of stock outstanding has been in a steep decline. Based on this record, we conclude that projections should be used to estimate the sale of newly issued stock in this docket.

PGE contends that the fourth flaw in Rothschild's multi-stage DCF model is his calculation of stock price using a mismatched M/B. PGE explains that, for each stock in the sample group, Rothschild calculated a M/B using a February 28, 2001 stock price but an estimated book value as of year-end 2000. He then used the sample average M/B rate of 1.78 to calculate a sample average 2000 stock price for his first value for market price—\$38.47.[33] PGE claims that Rothschild should have used, for his first value for market price, the actual average stock price of \$36.99.[34] By using the higher stock price, PGE contends that Rothschild drove down the cost of equity, because the higher the stock price, the lower the discount rate—which is the cost of equity in the multi-stage calculation—needed to equate future cash flows to the stock purchase price. PGE adds that the use of the correct, lower stock price, also requires reducing the M/B, since the stock price serves as the numerator in that calculation. Otherwise, PGE explains, the cost of equity will be overstated.

Further, PGE claims that Rothschild used the wrong denominator for his M/B. PGE observes that, for this figure, Rothschild used *Value Line's* estimated book value for the sample for year-end 2000, which ignores the growth in book value expected to occur by February 28, 2001. Thus, PGE contends that, in his analysis, Rothschild should have added to the year-end book value one-sixth of the expected growth in 2001. This, according to PGE, results in a book value of \$21.70, and a M/B of 1.70. PGE adds that this lower M/B results in lower proceeds from the sale of stock and, all things being equal, reduces the cost of equity.

We agree with PGE's observations and conclude that Rothschild's multi-stage DCF estimates should be adjusted so that the average stock price on February 28, 2001 of \$36.99 is used for the hypothetical stock purchase. There is no explanation why an investor would irrationally pay \$38.47 for a stock that he or she can buy on the market for \$36.99. Moreover, because of this adjustment, both the numerator and denominator of Rothschild's M/B calculation should also be modified. For the numerator, Rothschild should have used the average stock price of \$36.99; for the denominator, Rothschild should have increased year-end 2000 book values by one-sixth of the increase in the estimated year-end 2001 book values.

2. Capital Asset Pricing Model (CAPM)

Another method of estimating cost of equity is the CAPM. The CAPM is a risk premium analysis that calculates the expected equity return by adding a risk premium to a "risk free" rate of return. Risk is represented by the term "beta," which measures the stock's volatility relative to the market as a whole. The beta for the market is equal to one. Therefore, a stock with a beta greater than one is more risky than the average stock, while a stock with a beta of less than one is less risky than the average stock. The risk premium is generally calculated by multiplying the company's beta by the difference between the expected market return and the risk free rate. The formula is generally stated as follows:

$$K_e = \text{Risk-free rate} + \text{beta (market risk premium)}$$

CAPM Estimates

Only Staff presents ROE estimates based on the CAPM. Conway's CAPM analysis relies on the traditional formula set forth above. Assuming that investors have intermediate-term investment horizons, Conway calculates a risk-free rate based on an average of intermediate-term U.S. Treasury notes. Averaging the yields-to-maturity of the 5-, 7-, and

[33] *See* Staff/702, Rothschild Schedule JAR 5, page 1, column 9.
[34] *See* Staff/701, Rothschild Schedule JAR 3, page 1, column 5.

10-year U.S. Treasury securities quoted in the March 21, 2001 edition of *The Wall Street Journal*, Conway calculates a risk free rate of 4.7 percent.[35]

Using Staff's traditional Fisher-Kamin method and a new GARCH approach,[36] Conway then calculates a beta for his sample group of electric utility companies of between 0.26 and 0.29. He estimates the sample companies beta by "regressing" their stock returns—minus a risk-free proxy rate—on the combined portfolio of NYSE/AMEX/NASDAQ stock returns—minus a risk-free rate proxy. Conway notes that his beta calculations may require some subjective adjustment, because they are significantly lower than historical beta estimates. Noting that 5-, 7-, and 10-year moving averages for beta estimates are 0.40, 0.42, and 0.44, respectively, Conway believes it is reasonable for the Commission to rely on the longer-term historical beta in this docket.

To estimate the expected market risk premium, Conway assumes that the average market risk premium over a large number of historical intermediate-term holding periods is a reasonable estimate of the expected intermediate-term market risk premium. He estimates the average historical intermediate term market risk premium by calculating the difference between expected compounded returns on the market portfolio and the compounded returns on the risk free asset over an intermediate period. The difference is then annualized.

To make his estimate, Conway uses monthly returns from 1926 to 1999 for all NYSE/AMEX/ NASDAQ stocks as a proxy for the theoretical market portfolio returns. He then estimates the risk-free rate over that period by using 1926 to 1999 data on intermediate-term U.S. Treasury securities. Next, he separates the 1926 to 1999 data into holding periods of five to ten years each, such that all the data were used just once. Finally, he calculates the average rate of return difference between holding the market portfolio and holding the risk-free rate over the intermediate-term.

Conway estimates a range of historical market-risk premia of 6.6 to 6.8 percent.[37] Inserting these figures into the CAPM formula with his beta range of 0.29 to 0.44 and a risk free rate of 4.7 percent, Conway estimates a range of cost of capital for his electric utility company sample of 6.6 to 7.7 percent.

Rothschild uses two different versions of what he calls the "CAPM/risk premium method."[38] His first version estimates the cost of equity by adding the historic inflation premium to investors' current expectation for inflation. In this calculation, Rothschild first estimates the expected rate of inflation to be 2.0 percent by comparing the yields on Treasury bonds with inflation-indexed Treasury bonds. He then adds this 2.0 percent factor to a 6.6 to 7.2 percent

[35] In its opening brief, Staff updates the risk-free rate to 4.8 percent, based on the arithmetic average of the three U.S. Treasury rates listed in the June 20, 2001 edition of *The Wall Street Journal*.
[36] Staff explains that the GARCH approach was developed by Dr. Curt Wells, Professor of Economics at the Lund University in Sweden.
[37] Conway also derives market risk premium calculations based on the recommendations of Dr. Pettit, who reviewed Staff's risk premium estimation procedures in 1999. Utilizing Dr. Pettit's recommended approach, Conway estimates the market risk premium to be 4.5 to 4.8 percent. Conway does not rely on these estimates in his CAPM recommendation, however.
[38] Although these can fairly be called risk premium methods, we do not consider them versions of CAPM.

historic return on common stocks net of inflation to get an inflation risk premium indicated cost of equity for an investment average risk of 8.6 to 9.2 percent.

Rothschild adjusts this return to account for the lower than average market-risk for the electric utility sample group. To accomplish this, he subtracts the 4.83 percent yield on 90-day U. S. Treasury bills from the historic return on common stocks. He then multiplies this figure by the average *Value Line* beta for the PacifiCorp sample group of 0.53 to derive a 0.94 to 1.26 risk adjusted equity premium. Finally, Rothschild adds this risk adjusted equity premium back to the 6.6 to 7.2 percent range of historic returns on common stocks to derive a 7.77 to 8.09 percent risk premium for the sample group.

In his second risk premium analysis, Rothschild estimates PGE's cost of equity based on an increment to the historic annual earned returns. He makes four separate calculations using various interest rates—ranging from 4.83 to 6.71 percent—as his risk-free rate, and various market risk premia—ranging from 3.51 to 5.33 percent. Rothschild takes the average of these four calculations using both an average risk beta of 1.0 and the *Value Line* beta of 0.53 for electric utilities. Under this methodology, he produces a cost of equity range of 7.60 to 9.55 percent.

To arrive at his final recommendation, Rothschild averages the high-end and low-end of his two methodologies to obtain a range of 7.69 to 8.82 percent, with a midpoint of 8.25 percent.

Disputed CAPM Issues

PGE begins its criticism of Staff's CAPM analysis by attacking the reliability of the model itself. PGE contends that there are several problems with the CAPM model in general, and with Staff's Fisher-Kamin version of CAPM, in particular. PGE contends that these problems are so significant that the Commission cannot rely on CAPM estimates to establish an ROE for the company.

PGE argues that the most persuasive evidence against the use of CAPM in this case is the unrealistically low results it is producing. PGE observes that both Rothschild and Conway made numerous *ad hoc* adjustments to artificially inflate their CAPM results. PGE claims that Rothschild and Conway's true CAPM results are uniformly below the company's cost of new, long-term debt, which is 8.17 percent.[39] PGE contends that such low results are not consistent with financial theory—that the return on a riskier asset, like common stock, should be higher that the return on a less risky asset, like long-term debt.

[39] PGE contends that Rothschild's true CAPM/Inflation Risk Premium results yield a range of cost of equity of 6.83 to 8.58 percent, not 7.60 to 9.55 percent as reported in his testimony. PGE asserts that Rothschild inflated his results by using, without explanation, a beta of 1.0 to calculate one of his four findings. PGE also claims that, in his inflation-based analysis, Rothschild uses an unconventional method to calculate the company-specific risk premium that increased his estimate by 94 basis points.

Similarly, PGE contends that Conway's CAPM results would have been significantly lower had he followed Staff's traditional CAPM approach or adopted the recommendations made by Drs. Wells and Pettit for calculating betas and market risk premium. For example, PGE notes that, while Conway calculated the Fisher-Kamin beta to be 0.29, he actually used a beta of 0.44 derived from a 10-year historical average. PGE believes that this adjustment is contrary to Staff's traditional endorsement of the Fisher-Kamin methodology, namely that it allows betas to change over time.

Staff defends the CAPM model and disputes PGE's specific criticisms. Staff notes that the CAPM model is a commonly accepted method of determining cost of equity and contends that the CAPM estimates here provide important insights into PGE's cost of equity. Staff acknowledges that the CAPM may be currently understating the cost of equity due to present market conditions. Nonetheless, Staff adds that Conway and Rothschild took this fact into consideration and liberally rounded up the results in their analyses.

This Commission has relied on the CAPM as an appropriate method for estimating a utility's cost of common equity for over 20 years. Recently, however, many utilities have argued against its use for reasons similar to those presented by PGE in this proceeding. To date, this Commission has rejected those arguments, concluding that the CAPM remains a viable method for determining cost of equity.[40]

We acknowledge that Staff's CAPM methodology faces its biggest challenge yet. Staff cannot escape the fact that its CAPM analyses appear to be producing results below PGE's current cost of new, long-term debt. While Staff recognizes that the CAPM may be currently understating cost of equity, it is unable to fully explain the significant drop in the Fisher-Kamin betas used in its calculations.[41] It has also failed to convince us that its upward adjustments and rounding of results have accurately and fully compensated for the current CAPM deficiencies.

While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity. After our review of the results in this case, however, we further conclude that the CAPM does not provide supportable and reasonable results in this docket. Accordingly, we give no weight to the CAPM results in determining an appropriate cost of equity for PGE.[42]

3. Risk Positioning Method

The Risk Positioning Method is a risk premium model that estimates the cost of equity by adding a premium for risk to a current or expected interest rate. In this analysis, PGE contends that the non-stipulated ROE decisions by regulatory bodies provide, on average, unbiased estimates of the cost of equity for electric utilities. By measuring differences between the authorized returns on equity and the yields on electric utility corporate bonds and yields on U.S. Treasuries, PGE calculates ranges of estimates of the equity risk premium. The company then adds the equity risk premia estimates to the current bond and treasury yields to derive a range for cost of equity.

In their analysis, Hager-Valach rely on approximately 500 reported, non-stipulated ROE decisions dating back to January 1983. Using the Risk Positioning Method with corporate bonds, Hager-Valach estimate a risk premium of 3.44 percent. Adding that figure to the yield from PGE's most recent non-callable bond (8.19 percent) and the yield for A-rated

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[40] *See, e.g.*, Order No. 99-697 at 19.

[41] Conway's 0.29 beta is based on data through the year 1999. Using data through the year 2000, PGE found that the Fisher-Kamin beta for companies in Conway's sample declined to 0.09—a risk figure close to that for U.S. Treasuries that are used as the "risk-free" rate in CAPM calculations.

[42] This conclusion also applies to Rothschild's "CAPM/Risk Premium" analyses.

bonds from the *S & P Bond Guide* (8.21 percent), Hager-Valach produce a range for PGE's cost of equity of 11.28 to 11.48 percent.

Hager-Valach calculate a risk premium range of 5.70 to 5.80 percent using the Risk Positioning Method with U. S. Treasury Bonds. Adding that range to the 7-year U. S. Treasury rate for 2002 using the WEFA forecast (5.39 percent), Hager-Valach calculated a range for PGE's cost of equity of 11.09 to 11.19 percent.

Staff contends that the Commission should place little weight on PGE's Risk Positioning Method for three primary reasons. At the outset, Staff notes that the proposed methodology is not a commonly accepted method for determining cost of equity. Second, Staff believes that PGE's proposed analysis is flawed, because it measures cost of equity without a review of whether the allowed return, relative to the interest rate, is more or less than the cost of equity actually demanded by investors.

Next, Staff contends that PGE's Risk Positioning Method suffers from omitted variable bias. Staff explains that, in conducting a regression analysis, it is critical to include all relevant variables to eliminate bias. While PGE admits that many factors influence commissions in setting the return on equity, such as business risk, interest rate risk, financial risk, and liquidity risk, Staff points out that the company's Risk Position Method fails to consider them, instead relying solely on lagged treasury rates. Because PGE fails to include all the relevant variables relied upon by the various commissions, Staff contends that PGE's regression equation suffers from omitted variable bias and should be rejected.

This Commission rejected a similar risk-positioning method proposed by another utility in a recent rate case.[43] We reach the same conclusion here. As Staff notes, PGE's proposed methodology using authorized ROEs and yields on treasuries and corporate bonds is unconventional and has not been accepted by other regulatory agencies as a reliable means for determining cost of equity. Because the methodology is not based on accepted regulatory principles, we decline to adopt it for use in this proceeding.

4. ROEs Authorized by other Regulatory Commissions

In addition to their DCF and Risk Positioning Method estimates, Hager-Valach rely on recent authorized ROE decisions by other regulatory commissions. Hager-Valach note that, during the last twelve months, electric utilities received an average authorized ROE of 11.6 percent, with a range of 11.0 to 12.9 percent. Because an investor will consider this type of information when making an investment, Hager-Valach believe that PGE should be awarded a common equity return within this range.

Staff objects and contends that PGE's proposal is circular in reasoning, because decisions would simply be based by looking at what other commissions allow. Staff adds that PGE's proposal would have the effect of improperly transferring to other jurisdictions the Commission's obligation of setting cost of equity for Oregon utilities. Finally, Staff notes that the Commission rejected a similar request made by NW Natural in docket UG 132:

[43] *See, e.g.,* Order No. 99-697 at 19.

> "NW Natural contends that the Commission should rely on recent common equity return decisions made in other jurisdictions. We disagree. As Staff and NWIGU point out, there is frequently a substantial lag between the time evidence is prepared in a rate case and when a decision is finally rendered. Because interest rates have been steadily declining during the past several years, the failure to account for the regulatory lag could result in an overstatement of cost of capital. Moreover, as noted above, the authorized ROE is just one component of setting rates and is often tied to other, unknown elements in a rate case. Therefore, while other ROE determinations may provide evidence to confirm a decision, we are reluctant to base an award for NW Natural on unknowable parameters from other cases, set in other jurisdictions and different capital market conditions."[44]

PGE believes that a review of other authorized ROEs is relevant to determine investor's expectations. Because an investor views a commission decision as the utility's best estimate of the cost of equity at the time of the decision, PGE maintains that the investor will go elsewhere if the authorized ROE is set too low for the risk of the investment. PGE adds that, contrary to its argument here, Staff has previously asked the Commission to consider ROE decisions from other jurisdictions. As an example, PGE notes that Staff referred the Commission to a decision by Nevada Commission to justify its ROE recommendation in docket UG 132.[45]

We adhere to our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award. Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket.

Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions to base an ROE award for a utility.

5. Qualitative Analysis

Staff's final cost of equity estimate is based on a qualitative analysis that updates the Commission's most recent contested ROE decision. Conway notes that, in docket UG 132, Order No. 99-697, the Commission set rates for NW Natural based on a return on equity of 10.25 percent. There, the Commission adopted a market risk premium of 8.5 percent, a risk-free rate of 6.3 percent, and a beta estimate of 0.46, to obtain a rounded CAPM estimate of

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[44] Order No. 99-697 at 23.
[45] Order No. 99-697 at 24.

10.2 percent. The Commission averaged that estimate with a DCF estimate of 10.3 percent to obtain a 10.25 percent cost of equity.

Updating those figures with new information, Conway presents a range of estimates for PGE's cost of equity from 8.3 to 10.1 percent. Conway provides this range as an upper bound for ROE estimates.

While recognizing that Conway's qualitative analysis favors the company, PGE contends that it is misleading and unprincipled. PGE notes that Conway developed its upper cost of equity estimate of 10.1 percent using: (1) the Fisher-Kamin beta for NW Natural; (2) an updated 1999 estimate for the market risk premium plus 150 basis points; and (3) the 6.3 percent risk-free rate used in that prior docket. PGE questions how the 1999 beta for Northwest Natural is applicable to PGE in this case, and why Conway relies on an outdated risk-free rate even though he acknowledges that it is contrary to Commission policy. PGE believes that Conway's analysis is unprecedented and another example of the contortions through which that Staff is willing to go rather than admitting that the Fisher-Kamin CAPM is not producing realistic results.

Staff responds that PGE misrepresents its qualitative analysis. Staff explains that it provided the qualitative analysis to give an upper bound to the range of reasonable cost of equity, consistent with the Commission's internal operating guidelines.[46] Furthermore, Staff notes that its testimony made clear that the analysis illustrated various permutations and combinations of factors to update the Commission's decision in docket UG 132.

We acknowledge and commend Staff's efforts to provide additional analyses for our review of this issue. Nonetheless, we agree with PGE that the adjustments included in the qualitative analysis are not sufficiently linked to the company to provide a valid cost of equity estimate in this docket. Accordingly, we give it no weight.

Commission Resolution

We begin with the range of rates of return on common equity offered by each of the parties. For the reasons stated above, we reject the parties' single-stage DCF estimates, Staff's CAPM and risk premium calculations, PGE's Risk Positioning and Comparison to Authorized methods, and Staff's Qualitative Analysis. Focusing on PGE multi-stage DCF calculations, we adjust Hager-Valach's estimates by using *Value Line* forecasted information to calculate s, the growth rate of new stock. This produces a cost of equity range of 10.4 to 11.5 percent, with a mid-point of 10.95 percent.

Turning to Rothschild's multi-stage DCF analysis and using the PacifiCorp sample group and actual stock closing prices as of February 28, 2001, we first adjust his estimate by using the average forecasted retention rate, b, for 2004 (43.74 percent) throughout his second stage. This increases his overall cost of equity estimate to 9.89 percent. Next, we adjust Rothschild's second stage input for the expected return on book equity, r, by using the year 2004

[46] Those guidelines provide that Staff is "responsible for ensuring that the record includes a range of legally supportable positions so that the Commission has options when making a final decision." Order No. 01-253, App C at 1.

value of 13.37 percent. This adjustment further increased Rothschild's DCF estimate to 10.13 percent. Finally, we correct Rothschild's inputs for the stock purchase date and price set at February 28, 2001, and adjust his M/B accordingly. This produces a final adjusted DCF estimate of 10.53 percent.

Together, these two adjusted estimates produce a cost of equity range of 10.53 to 10.95 percent, with a mid-point of 10.74 percent. We round this number to 10.75 percent. We find that this average of 10.75 percent is an appropriate cost of equity for the comparable group of electric utilities. We conclude, however, that this figure should be adjusted for PGE, whose capital structure contains a substantially higher percentage of common equity than the average for the comparative group of electric utilities.

It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly.

The question therefore becomes how much of an adjustment should be made. This record contains varying estimates that the cost of equity for regulated electric utilities decrease anywhere from 4 to 13.8 basis points for each one percent increase in the level of common equity in the capital structure. We find Rothschild's proposed 25 basis point reduction to be a reasonable adjustment to account for the above average percentage of common equity in PGE's capital structure. Contrary to PGE's arguments, this reduction does not constitute a "penalty." Rather, it is simply an adjustment to acknowledge PGE's reduced financial risk due to its increased level of common equity in its capital structure. Reliance on the stipulation in docket UM 814 is reasonable for the purpose of establishing a capital structure for PGE. The stipulation, however, cannot reasonably be used to argue for an ROE that does not correspond to the adopted capital structure.

Accordingly, we will adopt this adjusted average of 10.50 percent as an appropriate and reasonable cost of equity for PGE.[47] Evidence shows that this award will allow PGE to maintain a reasonable financial structure and attract capital at a reasonable cost. Using this figure in connection with other stipulated capital costs and the company's capital structure, which we find reasonable and adopt, yields a rate of return for PGE of 9.09 percent.

Capital Component	Ratio	Cost	Weighted Cost
Long-term Debt	46.32 %	7.508 %	3.48 %
Preferred Stock	1.53 %	8.432 %	0.13 %
Common Equity	52.16 %	10.50 %	5.48 %
Total	100.00 %		9.09 %

Finally, we close this subject with a short discussion on efforts expended in this docket to fix a reasonable ROE for PGE. ROE determinations have always been a fundamental

[47] Given this conclusion, we need not address PGE's argument that Staff's ROE recommendation, if adopted, would impair the company's bond ratings.

part of utility regulation and, despite a decline in the frequency of traditional utility rate cases, continue to play an important role in ratemaking. The task of determining a reasonable ROE, however, is often one of the most difficult and contentious aspects of a rate case proceeding. This docket was no different. PGE and Staff presented ROE testimony from seven witnesses and submitted over 600 pages of prefiled testimony and supporting documents. They required two full days of hearing on the ROE issue, at which they introduced approximately 30 new exhibits. After hearing, PGE and Staff produced over 100 pages of legal argument on the issue, and spent a majority of their time at oral argument addressing the issue to the Commission.

We recognize the inherent complexity of the issue, and that it may be impossible to devise a method to make the process of determining a reasonable ROE an agreeable one. Others with more time and expertise have tried to establish a consensus on the overall efficacy of ROE techniques and methodologies, but failed. It appears that contention over ROE is unavoidable. Nonetheless, while we recognize our inability to make the ROE process easy, we believe that the adoption of certain principles on this matter will make the process of setting a reasonable ROE easier. Based on our experience in this and in other dockets, we offer guidelines, set forth in Appendix A, for witnesses providing cost of equity recommendations.

II. PRICING

The parties to this docket largely agree with PGE's proposed pricing structure, tariff building blocks, rules and regulations, rate design and rate spread. ICNU, OSM, and OOE disagree with specific proposals, which we address below.

1. Customer Impact Offset

To help mitigate the rate impact on customers, PGE proposes to limit rate increases to not more than 150 percent of the overall average increase in base rates. Consequently, PGE proposes prices for Schedules 38, 48, 49, 93, and 97, that are less than the cost of service. To offset the revenue lost by this limitation and the effect of certain special contracts, PGE proposes to increase the energy charges of the remaining schedules.

While it acknowledges the need to mitigate large rate increases, ICNU contends that it is equally important to have an orderly transition to cost-based rates. Therefore, rather than embed a subsidy in base rates, ICNU recommends that PGE establish an adjustment schedule to phase out the customer impact offset over a two- to five-year period. ICNU explains that the adjustment schedule should be implemented such that, once a year, prices are increased for schedules whose prices are significantly below the long run incremental cost (LRIC) of service and reduced by a corresponding amount for the remaining schedules.

Commission Resolution

If adopted, ICNU's proposal would move all customers to LRIC in as little as two years, essentially eliminating the customer impact offset. Even under a full five-year period, the Commission would be required to determine how much certain rates should be increased, resulting in administrative difficulty and confusing price changes. In the past, this Commission has phased out the customer impact offset and similar offsets in conjunction with other general rate changes. We affirm that practice, which allows us the opportunity to consider the impact of rate changes on all customer classes at the time that general rates are being changed.

2. Non-Conforming Load Charge

PGE's proposed Schedule 83 and 583 includes a Nonconforming Load Charge of $5.60 per kW/month.[48] PGE explains that this charge is needed to offset the costs required to maintain generating capacity for these highly variable loads.

OSM contends that PGE failed to establish that the charge is either necessary or that the amount is appropriate. Therefore, OSM asks the Commission to reject the proposed charge. In the alternative, OSM requests that, if the Commission determines a special charge is necessary to cover the cost of load following and load regulation for highly variable loads, the charge should be based on the actual costs associated with providing the service.

Commission Resolution

We conclude that PGE's proposed non-conforming load charge is premature. PGE admits that no customers will be subject to the charge until 2004. While PGE claims that the charge is proposed to recover the costs of regulating capacity, it is not known what those costs will be at that future date to serve these variable loads. Accordingly, we reject PGE's proposed non-conforming load charge. During the next three years, PGE will have the opportunity to observe industry developments and propose, at a more timely date, an appropriate charge for load following and load regulation for non-conforming loads.

III. OTHER ISSUES

1. Emergency Default Service

PGE's Schedule 82 is designed to provide back-up service for any direct-access customer that loses its Electricity Service Supplier (ESS) and has not provided PGE with the notice required to receive service under the applicable standard offer service rate. PGE proposes to provide Emergency Default Service under Schedule 82 on a restricted "as available" basis. Schedule 82, as proposed, provides in part:

> "In all territory served by the Company, Emergency Default Service shall be provided by the Company as available. The Company may restrict customer loads returning to this schedule if it experiences constraints in the availability of electricity."

PGE explains that the purpose of the "as available" language is to prevent a returning direct access customer from causing PGE to curtail service to other customers who did not go to direct access or who are already on Schedule 82. Without limiting the availability of emergency default service, PGE explains that these direct access customers—who do not pay to have backup resources in case their ESS fails—would have the ability to get firm service under

[48] PGE defines "nonconforming loads" as consumer loads grater than 10 MW that routinely cycle up and down during the course of the day at a rate of at least 10 MW per minute.

Schedule 82 for free. PGE contends that other customers should not be required to suffer rolling outages to provide emergency default service or to pay for standby resources for direct access customers.

Staff and ICNU contend that PGE's proposal is discriminatory and could act as a barrier to competition. Because PGE remains the provider of last resort within its service territory, Staff notes that the company is obligated to provide safe and adequate service to all customers within its service area regardless of whether the customer is returning to utility service or has remained as a PGE customer. Thus, Staff contends that PGE should not be permitted to treat customers who choose direct access and subsequently return to PGE's Schedule 82 differently than other customers within its territory.

ICNU adds that ORS 757.622 requires the Commission establish terms and conditions for emergency default service for direct access customers that "provide for viable competition among electricity service suppliers." It adds that any customer with critical reliability concerns or large costs associated with a disruption of service could be dissuaded from going to direct access under PGE's proposed Schedule 82.

Commission Resolution

We share ICNU and Staff's concerns. For the successful implementation of SB 1149, it is important that direct access customers be treated equally to those customers who remain with the utility. For that reason, we agree that customers who choose direct access should not be limited to default service on an "as available" basis. We are not persuaded by PGE's claims that the restriction is necessary to protect existing customers. As ICNU notes, PGE's argument focuses on extreme conditions when power is not available at any price and rolling blackouts are imminent. Under such conditions, PGE's ability to offer Schedule 82 on an "as available" basis would not guarantee service reliability for existing customers. Furthermore, contrary to PGE's claim, returning customers would not be receiving firm service under Schedule 82 for free. In its filing, PGE proposes to charge a 25 percent premium on the Dow Jones Mid-Columbia Daily on-peak and off-peak Firm Electricity Price Index for emergency default service under Schedule 82. While PGE claims in its brief that this premium covers only the administrative costs, its testimony explains that the premium is necessary to mitigate the risk associated with the supply of emergency default service and "to cover the unpredictable nature of service under this rate."[49]

PGE's Rule K Curtailment Plan specifies that the utility may initiate certain actions "when necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is connected." We agree with ICNU that PGE should follow the Rule K procedures for Schedule 82 customers under short-term emergencies. Accordingly, we adopt ICNU's recommendation that PGE's Schedule 82 conditions be modified so that the "Available" section reads:

> "In all territory served by the Company. The Company may restrict Consumer load returning to this schedule in accordance

[49] *See* PGE/100, Fowler-Lesh at 12.

with Rule K, Curtailment Plan and Stage 5 Utility Actions under short-term emergency conditions."

2. Refusal of DASR

A Direct Access Service Request (DASR) is an electronic notification provided by an ESS to PGE that a customer has selected the notifying ESS as the customer's supplier of electricity service. As applicable here, PGE proposes that the company should have the authority to refuse a DASR when:

> (1) The Company has not received full payment from the Consumer for past due amounts or other obligations related to regulated charges from a Consumer's prior Electricity Service account(s) unless such charges are part of a pending Consumer dispute; or
>
> (2) The Company has not received full payment or the Consumer or ESS has not made an arrangement to pay the balance on an existing Budget Payment Option or other agreements.[50]

Staff objects to PGE's proposal and believes that, if the ESS has not paid PGE, the customer should not be held hostage and not be allowed to switch electricity suppliers. It contends that the consumer should be allowed to switch and that PGE should address non-payment issues through its disconnection policies. PGE responds that Staff's proposal simply creates a potential conflict between PGE, the customer and ESS. It contends that it would be simpler to allow the company to refuse the request until past due amounts are paid, rather than requiring it to make the switch and then subsequently disconnect the customer from its new service supplier for non-payment of past bills.

Commission Resolution

Both parties raise valid concerns. A customer should not be held hostage due to the misconduct of its ESS. At the same time, however, it would be confusing and administratively burdensome for the company to switch a customer to a new ESS, then disconnect the customer for unpaid charges from a prior account. We believe it is appropriate to focus on the party at fault. PGE's Rule H should be amended to allow the company the limited ability to refuse a request for direct access for a customer if that customer has not fully paid PGE for prior regulated services rendered. PGE should not be allowed to refuse a DASR where the ESS, not the end-user customer, has failed to make full payment.

3. Offsetting Termination Payments

PGE has proposed that its ESS service agreement allow any termination payment owed to the defaulting party to be offset against any amounts due or owed by the defaulting party

[50] *See* Advice No. 00-14, PUC Oregon No. E-17, Original Sheet No. H-15, as marked in copy attached to PGE's Opening Brief.

or any of its affiliates to the non-defaulting party. ICNU does not dispute the ability to offset, but contends that it is not industry practice for the offset to include the non-defaulting party's affiliate under any other agreements.

Commission Resolution

We disagree with ICNU's contention. As PGE explains, the language contained in the ESS service agreement was modeled after the Edison Electric Institute Master Purchase and Sale Agreement, which is becoming the model for power purchase and sales agreements throughout the country.

4. Portfolio Fees

PGE's proposed Rule J addresses eligibility requirements and enrollment terms and procedures for residential and small non-residential customers participating in the portfolio options and standard offer service. After an initial free enrollment period, PGE proposes to charge residential customers a $5.00 fee each time a portfolio selection is made or changed. PGE proposes a $20 switching fee for small non-residential customers moving between portfolio options or switching to or from direct access or the standard energy offer.

CUB and Portland believe that PGE's proposed switching fees will create economic disincentives for customers to exercise choice. Portland contends that PGE should recover any administrative costs by recovery through rates, not by separate fees to individual customers. Portland recommends that PGE recover the modest costs associated with option enrollment and switching through the basic charge. Portland maintains that a separate charge would be confusing and unnecessary, and impede access to new electricity options.

Commission Resolution

We first note that PGE's proposed fees are authorized by OAR 860-038-0220(9)(e), which provides that "an electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options." CUB and Portland offer no evidence that the proposed fees are so high as to prevent a customer from switching services or providers. In fact, as PGE notes, many service providers might offer to pay any switching fees, as is common in the telecommunications industry. We find no reason why PGE should not be allowed to charge these fees to customers on a cost-causation basis under the SB 1149 rules.

5. Purchase of Transmission Services

In its Schedule 600, PGE proposes the requirement that an ESS must purchase firm transmission service on a monthly basis under PGE's Open Access Transmission Tariff. Portland contends that the minimum duration of purchase of transmission services by ESSs should be reduced from one month to one day. Portland notes that PGE's merchant function can purchase transmission services for as little as one day.

Commission Resolution

We are not persuaded by Portland's argument. As PGE notes, Portland attempts to compare transmission for merchant trading with transmission to serve retail load. PGE must secure transmission service for its retail service customers on a firm basis to ensure reliable service. ESSs should not be allowed to provide any less reliable transmission services. Indeed, OAR 860-038-0590(2) requires electric companies to coordinate the filings of tariffs "to ensure that all retail and direct access customers are offered comparable services at comparable prices." Moreover, if ESSs were to purchase non-firm transmission on a daily basis, they would run the risk that no transmission would be available on certain days because firm purchasers take priority over the short-term and non-firm purchasers. We believe that, like PGE, ESSs should be required to secure firm transmission on a long-term basis.

6. Merchant Trading Fee

Staff seeks to impose a one-half percent fee on the absolute value of all PGE's Merchant Trading Activity. Staff proposes the fee to compensate ratepayers for the use of expertise gained in PGE's regulated trading operations. It believes that PGE's unregulated Merchant Trading activity benefits from the knowledge and expertise its traders gain from conducting trades for the company's retail customers.

PGE objects to the proposed fee. It contends that the fee is prohibited by the stipulation approved by the Commission in the Enron-PGE merger, docket UM 814, in which PGE agreed to pay ratepayers $105 million for the expertise used or to be used in PGE's unregulated wholesale trading activities. It relies on Paragraph 20A of that stipulation, which provides, in relevant part:

> "Enron and PGE are obligated to provide PGE's customers $105 million upon merger completion, which represents full payment for any entitlement PGE's customers may have to value that relates to:
>
> > (1) use of PGE's name, reputation, business relationships, expertise, goodwill or other intangibles;
> >
> > (2) wholesale and non-franchise retail activities that PGE has undertaken that will not take place within PGE after the merger (this includes but is not limited to PGE's discontinued term wholesale trading and risk management activities), and wholesale and non-franchise retail activities that PGE might have undertaken had the merger with Enron not occurred; and,
> >
> > (3) added value of the merged entity that is achievable because of the combination or because of the association with PGE.

> This payment obligation also shall constitute full payment to PGE's customers for any entitlement to the revenues, value or other benefits arising from the business activities of the merged entity, other than the regulated business activities conducted by PGE. The term 'regulated business activities' shall mean the assets and services of PGE which are subject to economic regulation under Oregon or federal law."[51]

PGE contends that Staff's proposed fee violates: (1) the release relating to all future customer claims to PGE's expertise set forth in Condition 20(A)(1); (2) the release relating to wholesale and non-franchise retail sales the PGE might have undertaken had the merger not occurred, as stated in Condition 20(A)(2); and (3) the release as it relates to unregulated activities of the merged entity set forth in the final paragraph. Staff responds that the stipulation anticipated that PGE would discontinue wholesale trading after the merger with Enron. Thus, Staff contends, the stipulated $105 million payment applies only to wholesale trading activities that PGE had engaged in prior to, but not after the merger.

Commission Resolution

The wording of the stipulation is ambiguous, and our ability to determine the parties' intent in drafting the language is frustrated by the fact that, at the time of entering the stipulation, both PGE and Staff believed that PGE would permanently discontinue its Merchant Trading activities. We need not, however, resolve the issue of whether Staff's proposed fee is barred by the merger stipulation. Even assuming that the PGE-Enron merger does not control, we agree with PGE's alternative argument that Staff's Merchant Trading fee proposal lacks sufficient evidentiary support.[52]

Both Staff and PGE agree that benefits of trading expertise and information flow both ways between the company's Retail and Merchant Trading activities. The combination of functions give the Merchant Trading operations access to information about regulated utility operations that is generally not available to independent trading operations. At the same time, the company's Retail Trading operations gain greater access to price information as a result of the contacts made through Merchant Trading. The combination of functions also enables PGE to leverage better terms for purchases to meet retail load requirements.

There is nothing in this record, however, that sufficiently quantifies the value of this expertise and information. Consequently, we are unable to determine whether the flow of this information is, as Staff believes, so unbalanced as to require the imposition of a fee on PGE's Merchant Trading activity. Indeed, there is no empirical evidence to establish that the value of information and expertise that PGE's Merchant Trading operation receives is greater than the value of the information and expertise that it provides to the company's Retail Trading activities. Moreover, there has been no analysis on what effect Staff's proposal may have on retail rates, as the imposition of a trading fee would provide the company incentive to transfer the Merchant Trading activity to an unregulated affiliate.

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[51] Order No. 97-196 at Appendix A, page 6.

[52] In light of this conclusion, we also need not address PGE's motion to strike Staff's testimony relating to the proposed Merchant Trading Fee.

In short, we find that the synergies of joint trading operations flow both ways between PGE's retail and Merchant Trading operations. In the absence of any evidence that establishes that the flow of this expertise and information is unbalanced in favor of PGE's unregulated operations, we reject Staff's proposal to adopt a one-half percent fee on the absolute value of all PGE's Merchant Trading Activity.

CONCLUSIONS

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

2. The stipulations, attached as Appendix C, D, E, and F, should be adopted. The results contained in the revenue requirement stipulation, attached as Appendix B, should be adopted with the additional adjustments to non-power O&M costs described above.

3. Based on the record in this case, PGE's rates that result from the stipulations and the Commission's conclusions in the body of this order are just and reasonable. A results of operations spreadsheet is attached as Appendix G.

ORDER

IT IS ORDERED that:

1. Advice No. 00-14, filed by Portland General Electric Company on October 2, 2000, is permanently suspended.

2. The stipulations attached as Appendices C, D, E, and F are adopted in their entirety.

3. The results contained in the stipulation attached as Appendix B are adopted, with the additional adjustments to non-power O&M costs described above.

4. In its September 12, 2001 power cost filing, PGE shall submit a rate design table identifying, for each rate schedule, the specific percentage increase resulting from the updated power cost estimates and consistent with the terms of this order.

5. PGE may file revised tariffs consistent with findings of fact and conclusions of law contained in this order, to be effective no earlier than October 1, 2001.

Made, entered, and effective AUG 3 1 2001

Roy Hemmingway
Chairman

Roger Hamilton
Commissioner

Joan H. Smith
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.

UE115F04

TO : GAIL

ORDER NO. **01-777**

GUIDELINES FOR COST OF EQUITY WITNESSES

When providing cost of equity recommendation in Commission proceedings, witnesses should bear in mind the following guidelines:

- Clarity: All witnesses should clearly and fully explain the methodologies used and the theoretical support for using the methodologies. When advocating a new approach, or one previously rejected by the Commission, a witness should explain why the Commission should adopt the proposed methodology in the present docket.

- Candor: All witnesses should clearly explain the use of every subjective adjustment and explain the reasons for making them, whether they are based on academic literature, personal judgment, or other reasons. The witnesses should include any such explanations in the text of their testimony, rather than bury them in footnotes, work papers, or appendices.

- Reproducible Results: All witnesses should clearly explain every formula, calculation, and adjustment used in sufficient detail to allow other parties and the Commission the ability to easily reproduce and adjust their results. If necessary, the witnesses should include electronic spreadsheets and step-by-step instructions for use.

- Professionalism: When challenging the opinions offered by others, witnesses should exercise a high degree of professionalism. While the Commission must consider the credibility of witnesses, the emphasis in testimony and briefs should be on the evidence presented, not the integrity of opposing witnesses. Criticism of opposing testimonies should be clearly articulated and objectively supported. Before criticizing other positions, witnesses should ensure that their own opinions are properly supported and clear.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Public Utility Commission of Oregon
Administrative Hearings Division

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	)))	STIPULATION REGARDING CHANGES TO PGE'S REQUESTED COST OF SERVICE

This Stipulation is entered into for the purpose of resolving specified adjustments to Portland General Electric Company's (PGE) requested revenue requirements in this docket. This Stipulation presents a partial settlement of revenue requirement issues and does not resolve all issues in this docket.

I. INTRODUCTION

On October 2, 2000, PGE filed Advice No. 00-14 to produce a $324 million increase in its base prices to its customers. The filing was based on a projected test year of 2002. Advice No. 00-14 was suspended by the Commission at its October 20, 2000 Public Meeting, Order No. 00-669.

The Administrative Law Judge held a Prehearing Conference on October 24, 2000 to establish a procedural schedule in the case. Pursuant to that schedule, Staff and Intervenors published settlement proposals on January 12, 2001. Settlement Conferences commenced January 16 through 19 and were continued to January 23, January 26, January 30, and February 1. The Settlement Conferences were open to all parties.

As a result of the settlement conferences, the parties signing this Stipulation (Parties) have agreed to a reduction in PGE's requested revenue requirement with respect to specified adjustments. The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. TERMS OF STIPULATION

1. The Parties to this Stipulation agree that PGE will reduce its revenue requirement request to reflect the adjustments listed in Attachment A to this Stipulation. The parties agree to calculate the revenue requirement impact of the adjustments listed in Attachment A consistent with the final Commission approved Cost of Capital in this case.

2. The Parties recommend that the Commission approve the various tariff, rule, rate base, expense and other revenue adjustments described in Attachment A.

3. The Parties request the Commission allow PGE to place certain items in supplemental tariffs. Specifically, the Parties request that adjustments S-22 (Y2K Deferral), S-38 (1999 Y2K Amortization), S-39 (Neil Settlement), S-42 (Property Sale Gains), and S-46 (Non-recurring property sales) be placed in supplemental tariffs.

4. The parties agree to work in good faith to agree on the unbundling of the stipulated adjustments in Attachment A in accordance with OAR 860-038-0200. Absent agreement on unbundling the adjustments in Attachment A, such adjustments will be unbundled pursuant to the unbundling approved in the final order of the Commission.

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

6. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

7. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

8. 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.

9. By entering into the Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principals, 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.

10. 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.

Dated this 7th day of March, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: J. Jeffrey Dudley

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By:

PACIFICORP

By:

FRED MEYER STORES

By:

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

David B. Hatton

By: David B. Hatton

CITIZENS' UTILITY BOARD

By:

OTHER

By:

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This Stipulation is entered into by each Party on the date entered below.

Dated this 7th day of March, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ______________________

PACIFICORP

By: ______________________

FRED MEYER STORES

Michael L. Kurtz

By: Michael L. Kurtz

CITIZENS' UTILITY BOARD

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

OTHER

By: ______________________

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Attachment "A"

The Stipulated Adjustments are described below and summarized in Attachments A1 (Cost of Capital), A2 (Other Revenue, Operating Costs and Rate Base), A3 (Tariff Language Revisions), A4 (Schedule 48 & 105, Rules B-G, I, K and L) and A5 (Tariff Schedule Review). The adjustments below do not include the impact of revenue sensitive costs (e.g., taxes and bad debt expense). The revenue requirement impact of each of the adjustments (including revenue sensitive costs) will be determined once the Cost of Capital issue (S-0) is settled.

S-0 Cost of Capital: The parties agree on the capital structure, cost of preferred stock, and cost of long-term debt as provided in Attachment A-1. No stipulation on the cost of equity at this time.

S-1 FERC Wholesale Fee: Reduce A&G expenses by $372,000.

S-2 Montana Production Tax: Increase Taxes Other Than Income by $450,000.

S-3: Colstrip O&M: Increase Production O&M by $1,043,000 and increase Transmission O&M by $25,000.

S-4: Transmission O&M: All Transmission O&M issues are addressed under Staff issue S-30.

S-5: FERC Hydro Fee: Reduce Production O&M by $14,000 and increase A&G expense by $714,000.

S-6: Income Tax Apportionment: This adjustment is incorporated into Staff issue S-41.

S-7: Trojan Severance Program: Increase Amortization by $66,000 to reflect a three-year recovery of the unamortized balance at October 1, 2001.

S-8: Oregon Analytical Lab Sale: Reduce Production O&M by $83,000, Transmission O&M by $28,000, Distribution O&M by $223,000, and rate base by $439,000. Increase A&G expense by $108,000 and Amortization by $100,000.

S-9: PGH Billings: Reduce A&G expense by $436,000.

S-10: Retail Unbundling: Increase Customer Service expense by $435,000 and A&G expense by $303,000.

S-11: Beaver Turbine: Increase Depreciation by $182,000, Property Taxes by $14,000, and rate base by $2,789,000.

S-12: Other Revenue: This item is considered under Staff issue S-24.

S-13: State Tax Credit: This adjustment is incorporated into Staff issue S-41.

S-14: SERP Rate Base & MDCP expense: Decrease A&G Expense by $4,645,000 and rate base by $2,122,000.

S-15: Remove Trojan: Reduce Amortization expense by $16,584,000 and rate base by $102,904,000 to comply with the Commission Order No. 00-601 in Docket UM-989.

S-16: Remove NEIL: Increase Production O&M by $2,400,000 and A&G by $1,418,000 to comply with the Commission Order No. 00-601 in Docket UM-989.

S-17: Remove Other Debits & Credits: Decrease Other Revenue by $589,000 and Amortization by $959,000. Increase rate base by $181,000. This complies with the Commission Order in Order No. 00-601 in Docket UM-989.

S-18: Solar for Schools: Reduce Customer Service costs by $55,000 to reflect removal of the cost of this program as a regulated activity.

S-19: Salmon Spring Reclassification: Increase Other Revenue by $183,000.

S-20: Green Power Purchase: Reduce Purchased Power by $420,000.

S-21: Property Tax Unbundling Correction: Transfer $902,000 of property taxes from Transmission to Production.

S-22: Y2K Deferral: Incremental Y2K costs incurred in 2000 will not be recovered through base rates in UE-115. Accordingly, there will be no adjustment in item S-22. The parties further agree that PGE will collect the unamortized balance of these 2000 Y2K costs at 10-1-01 through a balancing account (approximately $363,000) and supplemental tariff. The balancing account will accrue interest at PGE's last approved cost of capital.

Recovery of the 2000 Y2k costs is subject to a prudence review by Staff. Staff will attempt to complete the review before June 1, 2001.

S-23: Two-Cities: Increase Wheeling expense by $129,000 and rate base by $96,000.

S-24: Misc. Electric Revenue: Increase Other Revenue by $998,000.

S-25: Variable Power Cost: No stipulation at this time.

S-26: Customer Acct. Non-Labor: Reduce Customer Service costs by $1,600,000.

S-27: Category A Advertising: The parties agree to include in base rates Category A advertising costs equal to 1/8 of one percent (.125 percent) of revenues in accordance with OAR 860-026-0022(3)(a). Based on PGE's filed revenue requirement, this results in a reduction of $2,405,000 in Customer Service costs. The parties agree that this calculation will be updated to reflect the final Commission approved revenue requirement in this case.

The Parties further agree that PGE may defer (for future amortization in rates) amounts spent in excess of the final approved amount for the twelve month period starting when UE-115 rates go into effect subject to Staff audit of all Category A advertising and related expenses. This is an annual deferral that continues until new base rates are established. Interest will accrue on deferred amounts at PGE's most recently approved cost of capital. The Parties agree that the mechanism described above is an automatic adjustment mechanism and no earnings test is required.

S-28: Public Purpose Adjustment: Reduce A&G expense by $149,000 to reflect removal of Lighting Lab costs. Remove $550,000 from Customer Service expense for DSM Evaluation and Verification (E&V) costs. The parties agree that the DSM E&V costs may be deferred and recovered through Schedule 101 subject to a review of prudence by the Staff. Deferral will continue until all energy efficiency programs receiving lost revenue recovery are closed out. The Parties agree that the mechanism described above is an automatic adjustment mechanism and no earnings test is required.

S-29: Marketing and Sales Expense: Reduce Customer Service expense by $800,000.

S-30: Transmission & Distribution O&M: Reduce Transmission O&M by $1,505,000 and Distribution O&M by $990,000. The Open Access Transmission Tariff (OATT) and intertie revenue will be revised based on the final transmission revenue requirement. This update cannot occur until the cost of capital (Issue S-0) is finalized.

S-31: A&G Accounts: Reduce A&G expense by $1,000,000.

S-32: SERP O&M: Reduce A&G by $1,250,000.

S-33: Bonus/Incentive Pay: Reduce A&G expense by $2,237,000, payroll taxes by $240,000, and rate base by $602,000.

S-34: Workforce Level: Reduce A&G expense by $4,821,000, payroll taxes by $518,000 and rate base by $1,046,000.

S-35: OPUC Wage Formula: Reduce A&G expense by $1,550,000, payroll taxes by $167,000, and rate base by $336,000.

S-36: Distribution Plant: Reduce net average plant by $2,000,000, Depreciation expense by $60,000, and Property Taxes by $30,000. Sales to Consumers is increased by $1,075,452.

S-37: Materials and Supplies: Reduce rate base by $3,681,000.

S-38: Y2K Amortization: The parties agree that PGE should recover the unamortized balance of 1999 incremental Y2K costs deferred through a supplemental tariff versus base rates as initially proposed by PGE. Accordingly, reduce Amortization expense by $1,977,000 and rate base by $4,942,000. The unamortized balance at 10-1-01 will be placed in a balancing account, accruing interest at PGE's last approved cost of capital, for future amortization in rates through a supplemental tariff.

S-39: NEIL Amortization: The parties agree that PGE should refund amounts due to customers resulting from the settlement of NEIL through a balancing account, accruing interest at PGE's last approved cost of capital, and supplemental tariff. Accordingly, there is no adjustment for issue S-39.

S-40: Acc. Deferred Taxes: Reduce rate base by $22,832,000.

S-41: Income Tax Adjustments: The parties agree that the composite state income tax rate for the UE-115 filing is 6.6547%, that PGE will incorporate $917,000 in expected state income tax credits into the final calculation of test year state income tax expense, and that the interest deduction for tax purposes will be calculated consistent with the weighted cost of debt, as provided in Attachment A1 to this Stipulation, and the final approved rate base total in this case. The S-41 adjustment will be calculated after all the component factors are finalized.

S-42: Property Sale Gains: Starting the later of 10-01-01 or the date UE-115 rates go into effect, PGE will assign actual gains and losses from the sale of utility property into a balancing account for later refund or collection from customers in a supplemental tariff. The balancing account will accrue interest at PGE's last approved cost of capital. Accordingly, increase Amortization expense by $477,000 to reflect the removal of forecast property sale gains/losses from the calculation of PGE's base rates.

S-43: Depreciation Study: Reduce Depreciation expense by $3,567,000 and increase rate base by $1,784,000 to reflect the stipulation in Docket UM-982, Order No. 01-123.

S-44: SB 1149 Implementation Costs: Increase A&G expense by $416,000, Customer Service expense by $376,000, and Rate Base by $459,000. Certain prudently incurred expenses only occur in 2002. Those one-time expenses are included in rates at 1/6'th of the 2002 amount and are also included in rate base, based on a six-year average. The adjustments listed previously incorporate the six year recovery of the one-time costs.

S-45: CIS/IT Capital Costs: PGE will place into base rates, 100% of the 2002 revenue requirement related to the 2000, 2001 and 2002 capital additions for the CIS/IT capital items listed below. The 2002 revenue requirement included in base rates will be trued-up to the actual revenue requirement for the CIS/IT capital costs. OPUC Staff will audit PGE's actual capital expenditures for the CIS/IT capital items below. Only those CIS/IT costs that are deemed reasonable and prudent will be authorized for inclusion in the "actual" revenue requirement calculation. Accordingly, relative to the CIS/IT costs included in UE-115 base rates, customers will receive a refund for any CIS/IT costs PGE does not expend or CIS/IT costs the OPUC rules imprudent. This ensures customers will only pay for prudently incurred CIS/IT costs.

UE-115 2000-2002 CIS/IT Capital Items

A) Customer Information System (CIS).
B) Enterprise Resource Planning (ERP) system.
C) Network Meter Reading (NMR) backbone and data store (excluding the meters).
D) Miscellaneous capitalized information technology costs.

The amount of the 2000-2002 gross capital additions included in the UE-115 filing for the CIS/IT capital items is $96.85 million.

Audit / Deferral Process
Prior to April 1, 2003, PGE will report to the Commission Staff its 2000-2002 capital expenditures for the CIS/IT capital items. Staff will audit PGE's information technology programs and expenditures at any time, but will complete their audit by June 1, 2003. If PGE disagrees with the results of Staff's audit, PGE may present their concerns to the Commission who will decide which CIS/IT costs are recoverable. Based on the "actual" CIS/IT costs approved by the Commission/Staff, PGE will calculate its "actual" revenue requirement. If the actual 2002 revenue requirement is less than the base rate 2002 revenue requirement, the difference will be deferred in a balancing account for future refund to customers. The balancing account will accrue interest at PGE's last approved cost of capital. The balancing account will presume the deferral was known and measurable as of January 1, 2003, and will accrue interest from that date forward. PGE agrees to waive an earnings review if one is required to implement the potential refund.

It is possible that some of the forecasted CIS/IT capital items will be delayed and not expended until 2003. If there are expenditures in 2003, the above audit process will be repeated in 2004 for the incremental 2003 expenditures. The actual revenue requirement for the 2003 expenditures will be added to the actual revenue requirement for 2002, this combined actual revenue requirement will be compared to the base rate 2002 revenue requirement. If the combined actual revenue requirement is less than the 2002 base revenue requirement, the difference will be deferred in the balancing account with an effective date of January 1, 2004, Each January 1st thereafter, an amount equal to the 2003 true-up will be deferred in the balancing account. The annual deferrals will terminate when new base rates are established.

To facilitate the audit process, Staff will receive and be an active participant in existing PGE processes for monthly or quarterly monitoring and/or progress reports for PGE's information technology projects. Staff's audit will focus on determining whether the information technology systems are providing reasonable performance and are used and useful.

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S-46 Supplemental Amortization Tariff – Nonrecurring Property Sales: PGE will refund the items listed below (including any applicable interest) to customers through a supplemental tariff. The start date of the amortization will be established separate from this Stipulation.

- The $2,179,000 of property transactions listed in PGE Exhibit/209, Barnes 1.
- The $2,500,000 per the Trojan Offset Settlement, Order No. 00-601.
- The $10,468,236 gain from the sale of the Coyote II Common Facilities, Order No. 00-214. Subject to Staff verifying the gain calculation.

S-47 Rate Spread/Rate Design: No stipulation at this time.

S-48 Residential Customers CTM/PAA/PCA, etc: No stipulation at this time.

S-49 Proposed Tariff Language Revisions, Schedules 100, 101, 108 and 115: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A3.

S-50 Decoupling Adjustment, Schedule 123: No stipulation at this time.

S-51 Proposed Revisions to Schedule 48, 105, Rules B-G, I, K, and L: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A4.

S-52 Tariff Schedule Review: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A5.

S-53 ESS Service Agreement: No stipulation at this time. The Parties are working together to develop an ESS Service Agreement.

S-54 Reclassification of Transmission Plant: The Parties agree to the re-classification of Transmission, Distribution and Generation plant (and related operating costs) proposed in PGE's UE-115 filing, Exhibit 1500, subject to certain conditions. A separate stipulation will be developed for this issue.

Attachment A1

Cost of Capital

Portland General Electric Composite Cost of Capital: Settlement (Excluding ROE) Test Year Based on 12 Months Ending 12/31/02 ($000)				
	Average Outstanding	Percent	Percent Cost	Weighted Average Cost
Long Term Debt	$887,900	46.32%	7.508%	3.48%
Preferred Stock	$29,250	1.53%	8.432%	0.13%
Common Equity	$999,781	52.16%		
Composite Cost of Capital	$1,916,931	100.00%		

Attachment A2

Other Revenue, Operating Costs, Rate Base

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Financial Summary Reflecting Stipulated Positions — **Attachment A-2**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	FERC Wholesale Fee (S-1)	Montana Production Tax (S-2)	Colstrip O & M (S-3)	Transmission O & M (S-4)	FERC Hydro Fee (S-5)	Income Tax Apportion (S-6)	Severance Program (S-7)	OAL Sale (S-8)	PGH Billings (S-9)	Retail Unbundling Allocation (S-10)
Retail Revenues										
Other Revenue										
Production O&M			1,043		(14)			(83)		
Transmission O&M			25					(28)		
Distribution O&M								(223)		
Purchased Power										
Generation										
Wheeling										
A&G	(372)				714			108	(436)	303
Customer Service										435
Depr. & Amort.							66	100		
Other Taxes		450								
Rate Base (excluding working cash)								(439)		

Revenue Requirement Category	Beaver Turbine (S-11)	Other Revenue (S-12)	State Tax Credit (S-13)	Remove SERP Rate Base & MDCP Expense (S-14)	Remove Trojan (S-15)	Remove Neil (S-16)	Remove Other ebits & Credits (S-17)	Solar For Schools (S-18)	Salmon Springs Reclassification (S-19)	Green Power Purchase (S-20)
Retail Revenues										
Other Revenue							(589)		183	
Production O&M						2,400				
Transmission O&M										
Distribution O&M										
Purchased Power										(420)
Generation										
Wheeling										
A&G				(4,645)		1,418				
Customer Service								(55)		
Depr. & Amort.	182				(16,584)		(959)			
Other Taxes	14									
Rate Base (excluding working cash)	2,789			(2,122)	(102,904)		181			

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Financial Summary Reflecting Stipulated Positions — Attachment A-2

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	CRM (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)	Public Purpose Adjustment (S-28)	Remove Marketing & Sales Expense (S-29)	T&D O&M (S-30)
Retail Revenues										
Other Revenue				998						
Production O&M										
Transmission O&M										(1,505)
Distribution O&M										(990)
Purchased Power										
Generation										
Wheeling			129							
A&G								(149)		
Customer Service						(1,600)	(2,405)	(550)	(800)	
Depr. & Amort.										
Other Taxes										
Rate Base (excluding working cash)			96							

Revenue Requirement Category	Reduce A & G Accounts N44173 & N44174 (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)	Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)
Retail Revenues						1,075				
Other Revenue										
Production O&M										
Transmission O&M										
Distribution O&M										
Purchased Power										
Generation										
Wheeling										
A&G	(1,000)	(1,250)	(2,237)	(2,411)	(1,550)					
Customer Service				(2,411)						
Depr. & Amort.						(60)		(1,977)		
Other Taxes			(240)	(518)	(167)	(30)				
Rate Base (excluding working cash)			(602)	(1,046)	(336)	(2,000)	(3,681)	(4,942)		(22,832)

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Financial Summary Reflecting Stipulated Positions — **Attachment A-2**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Income Tax Adjustments (S-41)	Remove Property Sales Gains (S-42)	Depreciation Study Adj. (S-43)	SB 1149 Implementation Costs (S-44)	CIS/IT Disallowance Adjustments (S-45)
Retail Revenues					
Other Revenue					
Production O&M					
Transmission O&M					
Distribution O&M					
Purchased Power					
Generation					
Wheeling					
A&G				416	
Customer Service				376	
Depr. & Amort.		477	(3,567)		
Other Taxes					
Rate Base (excluding working cash)			1,784	459	

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Attachment A3

ISSUE S-49: Tariff Language Changes

Schedule 100 – The Attorney General's office will review Section 43 of SB1149 and provide a written summary on how to treat special contracts that may have a provision within the contract limiting the applicability of adjustment schedules. PGE will abide by the Attorney General's summary.

Schedule 101 – All of Staff's proposed changes listed in the January 12, 2001 Staff Settlement Proposal, with the exception of adding back in the Demand Side Management Refund, will be incorporated into Schedule 101.

Schedule 108 – All of Staff's proposed changes listed in the January 12, 2001 Staff Settlement Proposal will be incorporated into Schedule 108.

Schedule 115 - The Attorney General's office will review Section 43 of SB1149 and provide a written summary on how to treat special contracts that may have a provision within the contract limiting the applicability of adjustment schedules. PGE will abide by the Attorney General's summary.

Attachment A4

S-51: Revisions to Schedule 48 and 105, Rules B-G, I, K and L.

PGE TARIFF REVIEW
PGE Exhibit 1602
Oregon E-17
Issue S-51

OVERALL STAFF COMMENT
Throughout the tariff PGE has replaced "customer" with the term "consumer". The company has defined consumer as "a person who has applied for, been accepted, and is currently receiving service." This is the definition of a "customer" per OAR 21-0008(3).

In a few places, they also replaced "applicant" with consumer which does not mean exactly the same thing. Customers have specific rights which applicants do not have.

The tariffs need to be aligned with the meanings of customer and applicant in OAR Division 21.

Status Resolved.
Discussion PGE will review for consistency and submit edits if necessary towards the end of the ratecase process for Staff review.

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Schedule 48 – Standard Offer Service
Irrigation and Drainage Pumping Small Nonresidential
Added a notice under minimum charge that "...the Company may require the Consumer to execute **a written agreement specifying a higher Minimum Charge** if necessary, to justify the Company's investment in service facilities". The tariff should specify the circumstances under which the charge is incurred.

Status Resolved.
Discussion No change required to language as filed.

Schedule 105 – Property Transactions Adjustment - Property is spelled "propery" in the title

Status Resolved.
Discussion Will be corrected.
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Rule B – Definitions
Applicant – "A person or business applying to the Company for Electricity Service or reapplying for service at a new or existing location after service has been discontinued ***for greater than 20 days***." This tariff is not in compliance with OAR 21-0008(1). It mixes up a customer's right to retain customer status for twenty days after a voluntary disconnect with the definition of an applicant. A customer becomes an applicant automatically if service is involuntarily disconnected.

Status	Resolved.
Discussion	'for greater than 20 days' - phrase will be stricken.

Rule B – Definitions
Customer Service Charge – deleted, should be included.

Status	Resolved.	
Discussion	Customer Service Charge-	This term is eliminated.
	Basic Charge -	Definition will be added.
	Energy Charge -	Definition will be added.
	Demand Charge -	Definition will be added.
	Reactive Demand Charge-	Definition will be added.

Rule B – Definitions
Premises – deleted the section regarding the circumstances under which various types of business properties are considered one premises. If there has been no change in intent, the deleted portion should be restored.

Status	Resolved.
Discussion	Definition of SITE added (as written in AR-390 Order 01-073 entered Jan 3, 2001). PGE will review use of the term "premise" versus "site" towards end of the ratecase process for Staff review.

Rule B – Definitions
- Kilovar – deleted, should be included.
- Kilowatt – deleted, should be included
- Kilowatt Hour – deleted, should be included

Status	Resolved.
Discussion	All three definitions will be added back.

Rule B – Definitions
Irrigation Service – deleted, should be included

Status	Resolved.
Discussion	This will be left out as this statement is included in the individual schedules in E-17, and which irrigation customers qualify for the RPA credit is defined under Schedule 102 in E-17.

Rule B – Definitions
Residential Consumer – deleted the reference to 30-days for transient occupancy, deleted the description of a dwelling, and the caveat that a recreational vehicle is not a dwelling. Deleted the section regarding multi-family dwellings. Verbiage in the current tariff regarding the definition of a dwelling, recreational vehicles, and multi-family dwellings was the result of several different complaints handled by Consumer Services. It should be retained in order to maintain the clarity of the tariff.

Status Resolved.
Discussion * Definition for "Residential Consumer" will be modified to include descriptions of the terms transient occupancy, dwelling, and multi-family.
* Definition of "Transient Occupancy" will be added to Rule B. (30 day limitation is included).
* Recreational Vehicles qualify for residential service as per SB1149.

Rule B – Definitions
Transient Occupancy – deleted. Transient occupancy is referred to in the definition of residential service, the definition should be included.

Status Resolved.
Discussion Definition returned.

Rule C – Conditions Governing Consumer Attachment to Facilities
C-8 Hazardous Substances – deleted term "applicant" throughout. Because "consumer" does not have the same meaning, applicant should be restored where applicable.

Status Resolved.
Discussion Restored where applicable.

Rule C – Conditions Governing Consumer Attachment to Facilities
C-14 Service Restoration is an entirely new section putting into the tariff the restoration priorities. It states "The Company will not give priority to any Consumer or ESS but will employ the above process over the Company's entire territory served." Is this a change from the policy that allowed identification of medically needy accounts for restoration purposes?

Status Resolved.
Discussion No editing required.

Rule D – Consumer Service Requirements
D-1 allows applications to be accepted from **third-parties** such as landlords. This is not within current accepted procedures. Only the person intending to be the customer of record can obligate themselves to paying for service.

Status Resolved.
Discussion PGE will revise wording so this option is available but the implication that this is a common situation for landlords will be removed.

Rule D – Consumer Service Requirements
D-4 leaves out the term "same type of utility service" (OAR 21-0200) under deposit requirements and letter of credit option. It should be restored to be in line with Division 21.

Status Resolved.
Discussion Wording added.

Rule D – Consumer Service Requirements
D-5 states a notice shall be mailed six business days before disconnection. "No less than" should be added to avoid a problem with disconnects occurring past six days.

Status Resolved.
Discussion Wording added.

Rule D – Consumer Service Requirements
D-5 deleted the part about customers on a Time Payment Agreement who default on deposit arrangements (OAR 21-0205(7). Needs to be added.

Status Resolved.
Discussion Added sentence and OAR reference.

Rule D – Consumer Service Requirements
D-6 adds a new section "Like Occupancy" – "When a Residential Applicant requests Electricity Service and the previous occupant(s) of the dwelling continues to reside at the dwelling, the Applicant will be considered a co-Consumer and may be required to pay a deposit." This does not comply with OAR 21-335 (Refusal of Service Rule) or 21-200 (Establishment of Service).

Status Resolved.
Discussion Deleted.

Rule D – Consumer Service Requirements
D-7 nonresidential deposit requirements added a consumer who "has had their Electricity Service discontinued by an ESS for nonpayment of charges." Consumer Services is concerned about basing deposits for regulated services on credit history with an unregulated company.

Status Resolved.
Discussion PGE will insert the following language instead: The Company reserves the right to check an applicant's credit and, based on the credit report, a deposit may be requested.

Rule D – Consumer Service Requirements
D-9 added that credit is established one year after a deposit or final deposit installment is paid. OAR 21-215 only uses the term "one year after a deposit is made. It doesn't mention installments. So this means that a customer who makes installment arrangements does not establish credit for fourteen months.

Status Resolved.
Discussion Language removed.

Rule E – Billings
E-1 Continuing Nature of Charges – "Disconnect and reconnect transactions do not relieve a Consumer from the obligation to pay charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Consumer." The charges in question need to be clearly identified.

Status Resolved.
Discussion PGE added the word 'Basic' so it now reads: "... do not relieve a Consumer from the obligation to pay Basic or Minimum Charges that accumulate....

Rule E – Billings
E-2 Responsibility for Payment deleted the option for closure of an account by a landlord. This could impact the ability of a new tenant to put service in their name if the outgoing tenant has not closed their account.

Status Resolved.
Discussion New language added: "The Company may accept a change of occupancy notification from a third party. The Company may refuse to process a change of occupancy until it receives satisfactory evidence of the third party's authority to request such a change."

Rule E – Billings
E-3 Assessed Demand deleted two sentences from the current tariff: "Demand will be billed to the nearest whole kilowatt, and Reactive Demand will be billed to the nearest whole kilovar. At the Company's option, Demand may be determined by test or assessment." The material deleted clarifies the tariff.

Status Resolved.
Discussion Word "whole" included in Rule B definitions.

Rule E – Billings
E-4 Special Meter Reading deleted the allowance for one special read in twelve months at no charge. The charge is now $24 for each special read that does not result in a billing correction.

Status Resolved.
Discussion Clarifying language added: "The first special read is free if the purpose is to verify a previous read but that if the special read is associated with movement to open access, the one free read does not apply."

Rule E – Billings
E-4 Unmetered Loads deleted the description of how estimated monthly usage is calculated (1/12 of the annual use determined by the Company by test or estimated from equipment ratings).

Status Resolved.
Discussion No change required. This change is okay based on the need to not use 1/12 for some consumers that may go direct access.

Rule E – Billings
E-5 Payment of bills changes the calculation for prorated bills from multiplying the number of days in the period and dividing by 30.4167 to 30 (except for Consumers billed by the legacy system).

Status Resolved.
Discussion No change required.

Rule F – Disconnection and Reconnection
F-1 Deletes all references to the OAR which were in the previous tariff.

Status Resolved.
Discussion OAR cites returned.

Rule F – Disconnection and Reconnection
F-1 Grounds for Disconnection leaves out "Oregon" in "For failure to pay Company Tariff charges…" **(OAR 21-0305(5))**

Status Resolved.
Discussion The word "Oregon" is returned.

Rule F – Disconnection and Reconnection
F-2 Adds section "A Consumer who has avoided disconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Consumer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a documented good faith attempt to notify the Consumer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day. When remitting for dishonored funds the Consumer shall make the payment in either cash, money order, cashier's check or verified credit card payment.

- Consumer Services suggests changing to "A Consumer who has avoided disconnection, *established credit, or gained reconnection* of Electricity Service..."
- Also, add a section under credit establishment to clarify that an Applicant who establishes credit or pays an outstanding bill from a prior account by making a non-cash payment which is returned does not obtain customer status. They would still come under the one-day notice but it would make it clear they are NOT customers with the right to a TPA or medical certificate option.

Status	Resolved.
Discussion	Language change will be reviewed with Staff.

Rule G – Line Extensions
G-1 Purpose does not include Applicant in the list of folks who may request a line extension.

Status	Resolved.
Discussion	Researching editing possibilities as Applicant has a different meaning in Rule G. Language changes will be reviewed with Staff.

Rule G – Line Extensions
G-1 Does not include Applicant as being represented by an agent.

Status	Resolved.
Discussion	Researching editing possibilities as Applicant has a different meaning in Rule G. Language changes will be reviewed with Staff.

Rule G – Line Extensions
G-2 Line extension cost omitted "labor" from the list of costs.

Status	Resolved.
Discussion	The word "labor" is returned.

Rule G – Line Extensions
G-9 Deleted the section on Unity installations

Status Resolved.
Discussion Unity is now described on Sheet G-4. No action required.

Rule G – Line Extensions
G-9 • Adds a section on "Service Locates" which states that there is a charge to locate underground utility services on private property along the Applicant's proposed trench route"

- Add the clarification this applies only to subdivision (per Schedule 300)
- How does this relate to One-Call?

Status Resolved.
Discussion PGE is researching clarifying language which will be reviewed with Staff.

Rule I – Metering
I-3 Nonstandard Metering deletes the option for customers to choose nonstandard metering, now limits the request to ESS.

Status Resolved.
Discussion No change required. Customers still have the right to other meters. It is discussed under Interval Metering on the same sheet.

Rule I – Metering
I-4 Inaccessible Meters states that the company may *in its sole discretion* permit the Consumer to read the meter. The tariff does not comply with OAR 21-120(3)(a) which states ..."the energy utility shall seek the customer's cooperation in obtaining monthly readings (for example, having the customer complete and return a meter reading form).

Status Resolved.
Discussion The words 'in its sole discretion' are removed.

Rule K – Curtailment Plan

K-2 Curtailment Target deleted the calculations.
K-5 Stage 3 Notification deleted "Who will be audited... and who request" from "Provide Curtailment Targets to ESSs and Consumer. It also deleted a paragraph about providing Information regarding exemption and processing requests for exemption.
K-6 Identification of the Base Year deleted "weather-normalized".
K-6 Estimating Base Billing...Changed audited customers with an option to exclude residential and small use to "all Consumers".
K-7 Communicating Curtailment Target Information deleted reference to retroactive Information for audited customers.
K-8 Threshold Consumption Level deleted reference to changes required by the state.
K-8 Excess Electricity Calculation deleted how the excess load is calculated.
K-9 Non-Financial Penalties deletes references to sampling and substantially changed the penalty options.
K-10 Application for Exemption deletes reference to audited customers.
K-10 Granting Requests for Exemption deletes a paragraph with options to provide credit against further curtailment and the statement advising customers exemptions may not protect them against stage 5 curtailment.

<u>Status</u> Resolved.
<u>Discussion</u> E-17 Rule K language changes have been replaced with existing E-16 Rule M Curtailment Plan language.

Rule K – Curtailment Plan

K-2 General Use Consumer shows 43,800 MWh. Previous tariff had 48,300. Major Use Consumer had 43,800 in old (and new). Verify which was in error.

<u>Status</u> Resolved.
<u>Discussion</u> Corrected. Proposed E-17 now reads 43,800.

Rule L – Special Types of Electricity Service

L-1 Availability changed Applicant to Consumer (they do not have the same meaning).

<u>Status</u> Resolved.
<u>Discussion</u> It now reads, "Where Facilities other than those specified above are needed to provide service, the provisions of Rule G, Line Extensions, will apply."

Attachment A5

S-52: Tariff Schedule Review

Tariff Language Changes to PGE Exhibit 1602 Oregon E-17 Issue S-52

The following review is broken into two parts, "A" and "B." Staff contacts for part A are Jack Breen. Deborah Garcia, and Rebecca Hathhorn. The staff contact for Part B is Stefan Brown.

Part A

RATE SCHEDULES

Schedule 7 – Residential Service
Portfolio Option Enrollment

- The language for portfolio option enrollment is subject to the decisions of the Advisory Committee as approved by the Commission.

STATUS RESOLVED.
DISCUSSION The language will be revised based upon Advisory Committee recommendation.

Schedule 82 – Emergency Default Service Nonresidential

- Availability

STATUS Not stipulated.

Direct Access Schedules – 500 series
ESS Charges

- The last sentence states, "...the Company's charge for Direct Access Service may not be separately stated on the bill." In Data response No. 171, PGE intends to use alternative wording "The Company charges for Direct Access Service are not required to be separately stated on an ESS consolidated bill."

STATUS RESOLVED.
DISCUSSION The alternative wording in Data Response #171 will be used.

Schedule 300 – Miscellaneous Charges

Interest accrued on Consumer Deposits

- The rate is now 6%. The tariff will need to be modified accordingly. Additionally, the title should delete "Consumer" to clarify that deposit interest applies to an ESS deposit, as well as a consumer deposit.

STATUS RESOLVED.
DISCUSSION Staff changes adopted..

Schedule 600 – Energy Service Supplier Charges

ESS Support Services

- Maintenance Fee

STATUS Not stipulated.

Schedules 7, 15, 32, 38, 48, 49, and 86

Term

- Staff questions the justification of the requirement of a one-year term for service under these schedules. In Data response No. 174, PGE states it will further consider the issue and may provide revised term provisions at a later date.

STATUS RESOLVED.
DISCUSSION Term requirements were removed from Schedule 7 (unless required by a Portfolio Option) and set at 1 year for 15, 32, 38, 48, 49, and 86.

Schedules 83, 91, 92, 93, and 97

Term

- Staff questions the justification of the requirement of a five-year term for service under these schedules. In Data response No. 175, PGE states it will further consider the issue and may provide revised term provisions at a later date.

STATUS RESOLVED.
DISCUSSION Term requirements were removed from Schedule 83 (unless required by a pricing option) and set at 1 year for 91, 92, 93, and 97.

RULES

Rule C – Conditions Governing Consumer Attachment to Facilities
<u>Sheet C-3 C. Limitation on Damages</u>

STATUS Not stipulated

<u>Sheet C-14 Service Restoration</u>

- A. PGE should add language similar to: "Restoration priority is independent of whether a consumer purchases supply services from the Company or its affiliates, or from an ESS."

STATUS RESOLVED.
DISCUSSION PGE agrees. The following language is located on last page of Rule C:
"The Company will not give priority restoration to any Consumer or ESS, but will employ the above process over the Company's entire territory served."

Rule D – Consumer Service Requirements
<u>Sheet D-6 Deposit Requirement</u>

- Staff believes the credit-screening criteria language of B.(2) should be modified to correspond to the establishment of credit language in Sheet D-9 Treatment of Deposits A.(2)

STATUS RESOLVED.
DISCUSSION The revision will be made on Sheet D-6 at 4B(2)

Sheet D-7 Nonresidential Credit Standards

- (6) Staff believes the nonresidential deposit requirement in (6) should be deleted. A consumer who has had their Electricity Service discontinued by an ESS for nonpayment of charges may have a legitimate dispute, and the consumer's nonpayment to the ESS should not be the sole basis for a deposit request. PGE may consider nonpayment to an ESS as it would any other nonpayment to a creditor within the context of a credit report. In Data Response 202, PGE reaffirmed that it intends to require a deposit from a consumer who had electricity disconnected by an ESS for nonpayment.

STATUS RESOLVED.
DISCUSSION The disputed language was deleted. The following was added to the credit screening requirements:

> "The Company reserves the right to check an Applicant's credit and, based on the credit report, a deposit may be requested."

Rule E – Billings
Sheet E-11 ESS Billing Responsibilities

- 24-hour turnaround for ESS

STATUS Not stipulated.

Rule F – Disconnection and Reconnection
Sheet F-3 – Disconnection and Reconnection Charges

- A. In the last sentence, "reconnection" should be changed to "disconnection". "Should this require a second trip to the premises to perform the ~~reconnection~~ disconnection the charge for reconnects at Other Than the Meter Base...." In Data response No. 207, PGE agreed to correct the error.

STATUS RESOLVED.
DISCUSSION Error corrected.

Rule G – Line Extensions
Sheet G-5 (d)

- Delete "All costs incurred by the Company shall be included as Line Extension Costs."

STATUS RESOLVED.
DISCUSSION This sentence will be moved and modified such that it is clear that customers building their own lines will be charged based on estimated actuals. Wording may fit better on Sheet G-2.

Sheet G-6 Applicants for New Permanent Service

- The language in existing tariffs should be retained.

STATUS RESOLVED.
DISCUSSION Add wording under the "Other Than Individual Applicants" section that clarifies residential subdivision refunds are not based on expected load.

Sheet G-14 Nonpermanent Line Extension

- The section deletes the payment of interest on money paid for a nonpermanent extension that becomes permanent. Why?

STATUS RESOLVED.
DISCUSSION PGE will pay interest.

Rule H – Requirements Relating to ESSs
Sheet H-1 & H-2 Service Agreement

- See settlement package work papers for line S-53. Staff suggests a workshop be held to discuss the content of a service agreement.

STATUS Being considered under S-53.

Sheet H-2 Credit Requirements and Security

- Delete "or more" from the last sentence of the first paragraph.
- (2) Staff is concerned about PGE exercising discretion in the credit evaluation process. The criteria should be explicitly identified in the tariff or standard service agreement, rather than being applied on a case-by-case basis.
- 3 (b) PGE should add "equal to 90 days of business volume" to the first sentence after "A letter of credit ...."

STATUS Being considered under S-53.

Sheet H-3 Default of ESS Service Agreement

- Staff believes the customer must be notified as soon as possible of the switch to emergency default service. A provision for notification should be added.

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-3 Information and Credit Updates

- See Staff's discussion under H-2 Credit Requirements and Security.

STATUS Being considered under S-53.

Sheet H-5 Electronic Data Transfer

- Staff believes the first paragraph should be changed so that the ESS is required to notify the Company only if it plans to modify its electronic data interchange systems if it will affect the form or content of the information. In the last sentence, "may" should be changed to "will."

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-6 Criteria for Recommending Decertification

- **(12) "...or should have known..." should be stricken from the tariff.**

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-8 Refusal of DASR

- 1. Staff believes this should be deleted. Acceptance of a DASR does not necessarily mean that a consumer will receive service. For example, if the consumer does not pay regulated charges, service can be disconnected.

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 2. Staff believes this should be deleted. The Company cannot hold a customer responsible for ESS obligations.

STATUS Being considered under S-53

Sheet H-8 Refusal of DASR (continued)

- 4. Staff recommends this be deleted.

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 5. Standard offer term obligations are in question.

STATUS RESOLVED.
DISCUSSION Staff's changes adopted.

Sheet H-8 Refusal of DASR (continued)

- 6. Staff recommends this replacement: "The ESS is not certified by the Commission."

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 7. This should be deleted. The issue of full payment from the ESS for charges assessed to the ESS should be addressed in disconnection of an ESS within the tariff or service agreement.

STATUS Being considered under S-53.

Sheet H-9 Return of Consumer Deposits

- Staff suggests that the last sentence be modified so that it is clear that the Company is holding a deposit for regulated services only.

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Sheet H-10 Company Billings to the ESS

- Remove requirement for electronic payment, unless there is a reciprocal agreement between the Company and the ESS. Change due and payable period from five to fifteen days in accordance with OAR 860-021-0125.

STATUS RESOLVED.
DISCUSSION Changed to 15 days.

Sheet H-12 Company Scheduling Responsibilities

B. Major Outage Procedures

- Should add statement that Company intends to negotiate reductions in energy scheduling in a nondiscriminatory fashion.

STATUS RESOLVED.
DISCUSSION Staff's alternate wording is adopted:

> "The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources."

Sheet H-16 Dispute Resolution

- The dispute resolution process should be consistent for all ESSs, not a function of the individually negotiated terms and conditions of a service agreement.

STATUS Being considered under S-53.

Rule I – Metering

Sheet I-2 Meter Verification Fee

The last sentence should be changed to reflect the current tariff. "...the Company will waive the Meter Verification fees..." rather than "may."

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Sheet I-3 Interval Metering

- 45 days is too long for a meter installation. In addition, the customer is prohibited from purchasing electricity from the ESS for that period.

STATUS RESOLVED.
DISCUSSION 45 days changed to 30 days.

^^^

Part B

Rule K – Curtailment Plan

The Company withdraws its proposed changes to Rule K (Rule M in current E-16 tariff) with the exception of the correction to the MWh number.

STATUS RESOLVED.
DISCUSSION PGE withdraws its proposed changes to Rule K (Rule M in current E-16 tariff) with the exception of the correction to the MWh number.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	))))	STIPULATION WITH CITY OF PORTLAND AND LEAGUE OF OREGON CITIES

This Stipulation is entered into for the purpose of resolving specific issues identified by the City of Portland (City) and the League of Oregon Cities (League) in their Opening Testimony filed March 12, 2001. This Stipulation presents a full settlement of the detailed issues.

I. INTRODUCTION

On October 2, 2000, Portland General Electric Company (PGE) filed Advice No. 00-14 proposing certain increases in its base prices to its customers. The filing was based on a projected test year of 2002 and included tariffs changing rates paid by the City and members of the League. Advice No. 00-14 was suspended by the Commission at its October 20, 2000 Public Meeting, Order No. 00-669.

The Administrative Law Judge issued a Ruling on March 12, 2001, requiring, among other things, that the City and the League enter into settlement talks with PGE. A Settlement Conference, which was open to all parties, was held on April 23, 2001.

As a result of that settlement conference, the parties signing this Stipulation (Parties) have agreed to specific adjustments in PGE's requested tariff and rate proposals. The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. GENERAL TERMS OF STIPULATION

1. The Parties to this Stipulation agree that PGE will adjust its proposed tariffs and rate proposals to reflect the agreements detailed in this Stipulation.

2. The Parties recommend that the Commission approve the various tariff, rule, and other adjustments described in this Stipulation.

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

4. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained in it.

5. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks changes in PGE's tariffs that depart from the terms of this Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and introduce evidence to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

6. 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.

7. By entering into the Stipulation, no Party shall be considered 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 considered to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

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

III. SPECIFICALLY STIPULATED ADJUSTMENTS

For issues raised by the City and the League regarding PGE's proposed tariffs, rules, and rates, the Parties agree as follows:

9. With regard to Interconnection Standards, PGE publishes interconnection standards as part of its avoided cost filing based on the most current version of IEEE published standards. These standards apply whether or not a generating unit qualifies as a QF under State and Federal law, and whether or not a particular generating technology is identified in such laws. An interconnection at transmission level or one that affects the transmission system is also subject to the interconnection provisions of PGE's Open Access Transmission Tariff. PGE agrees that its interconnection standards will continue to reference applicable IEEE criteria, and that implementation of such standards will follow such IEEE criteria. If the City or another member of the League opts to pursue this course, PGE will work cooperatively with that municipality as necessary if the municipality chooses to apply for Exempt Wholesale Generator (EWG) or similar status at the Federal Energy Regulatory Commission.

10. With regard to Restoration of Utility Services, PGE will propose to rewrite part of Rule

C. In addition to other clarifying changes, the language in the currently proposed Part (7)(B)(2) will be rewritten to read: "The Company will first make the necessary repairs to transmission lines, substations, and distribution facilities that connect substations to critical load Consumers. Then the Company will continue to repair remaining transmission lines and substations after critical load Consumers have been restored to service." In addition, PGE agrees that it will continue to work cooperatively with municipalities and other public bodies to identify such critical load Consumers or accounts.

11. With regard to the Definition of a Large Non-Residential Consumer, the City and the League understand that PGE's definition will result in automatic reclassifications if the Consumer's usage varies, as determined by the classification standards approved by the Commission and reflected in PGE's Tariff.

12. With regard to Utility Relocation, PGE will propose to rewrite Part 6(b)(1) of Rule C to read: "The rearrangement can be identified to be a public works project. Examples of public works projects include but are not limited to public transit and a road widening financed by public funds."

13. With regard to the Allocation of Ancillary Service Costs, the City and the League accept the proposal in PGE Exhibit 2402.

14. With regard to Streetlights, the City, the League, and PGE agree as follows:

a. With regard to Luminaire/Circuit charges, PGE will withdraw the proposed revisions identified in its October, 2000 filing. Specifically, PGE will eliminate that component of the distribution charge for Schedule 91 service that recovers the marginal cost of service drops (identified as $1.139 million in PGE's October 2000 filing, Exhibit 1603 at 12). The existing Luminaire/Circuit charges contained in the Streetlight Agreement between PGE and the City dated May 1, 1997, will remain in place without modification and will apply to all Schedule 91 accounts. These charges are as follows:

Option A lights will be charged $0.64/month/light.

Option B lights will be charged $0.64/month/light.

Option C lights will be exempt from the circuit charge.

Option C circuits will be charged $0.64/month/circuit consistent with the Streetlight Agreement between PGE and the City dated May 1, 1997, and current Schedule 91.

b. With regard to Group Relamping, PGE will charge for group relamping services at an effective rate of 19% per year, (or 95% over five years), while continuing to provide services at a level of relamping 20% of all streetlights per year (or 100% over a five year period).

c. With regard to Power Doors Luminaires, PGE will use a maintenance level of 175 per year for power door usage, which translates into a frequency of 0.47%.

d. With regard to Pole Replacement, PGE will use a replacement frequency of 0.25% for calculation of all rates and charges.

15. The City and the League agree that, except for the issues specifically noted below, all other issues addressed in their direct testimony will not be pursued in this docket but may be addressed in other proceedings:

a. Allocation of the CTM credit among customer classes;

b. Minimum duration of ESS purchase of transmission service;

c. Portfolio Enrollment and Switching Fees (Schedule 300); and,

d. Aggregation of accounts through metering (Rule E).

This Stipulation is entered into by each Party on the date entered below.

Dated this 6 day of June, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

CITY OF PORTLAND

By: Benjamin Walters

LEAGUE OF OREGON CITIES

By: ______________________

STAFF OF THE OREGON PUBLIC UTILITY COMMISSION

By: ______________________

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Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	STIPULATION CONCERNING POWER COSTS

This Stipulation is among Portland General Electric Company (PGE), Staff of the Public Utility Commission of Oregon (Staff), Fred Meyer Stores, the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board (CUB) and any other parties signing this Stipulation (collectively, the Parties).

The Parties have been active participants in this docket. As part of that participation, PGE has filed proposed tariffs, and PGE and other Parties have filed testimony and exhibits addressing PGE's proposals to establish power costs in this docket, PGE's proposal to value its Long-Term Resources, PGE's proposal to value its Short-Term Resources, PGE's proposal to adjust rates to account for changes in power costs and Energy Revenues from those used to establish base rates in this docket, and proposals made by other Parties. Capitalized terms used in this Stipulation have the meanings ascribed to them in this Stipulation or the attached tariff schedules.

The Parties held settlement conferences on these matters on May 24, May 25, June 1, June 12, June 28, July 11, and July 16, 2001. As a result of those settlement discussions, the Parties have negotiated this Stipulation to accomplish the following:

(a) To establish the mechanism by which PGE will value its Long-Term and Short-Term Resources for the purpose of establishing rates for energy services in this docket;

(b) To account for the current hydro and market conditions affecting PGE. The Parties intend to reflect in Part C of Schedule 125 the difference in PGE's projected NVPC between such costs under expected hydro and market conditions (Expected NVPC), and such

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costs under the normal hydro conditions ordinarily used to established rates (Base NVPC). In general, this adjustment accounts for the current low reservoir levels and their effect on future power costs, but assumes normal weather on a going-forward basis;

(c) To establish the mechanism by which PGE will account for variations in its actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish PGE's energy prices in this docket, and the method by which PGE and its customers will share in the benefits and burdens of such variations;

(d) To establish the method and date upon which PGE's Expected NVPC, Base NVPC and Base Energy Revenues will be calculated; and

(e) To establish a Shopping Incentive for large non-residential customers who use less than 1000 kWa.

The Parties agree to and request that the Commission adopt orders in this docket as follows:

1. PGE's Long-Term Resources and Short-Term Resources shall be valued under the mechanism described in Schedule 125. The Commission shall adopt Schedule 125 (attached to this Stipulation as Exhibit A) in its entirety for purposes of this docket.

2. The effect of adverse hydro conditions on PGE's projected NVPC shall be taken into account under Part C of Schedule 125. The Part C costs and revenues shall be a part of actual NVPC and actual Energy Revenues under Schedule 127. The Parties recognize that Part C expires December 31, 2002. The Part C adjustment shall be based on reduced hydro generation from that available in the water year used to develop normalized power costs of 300,000 MWh over the period October 2001 through December 2002 which shall be allocated to months based on Exhibit E attached to this Stipulation.

3. Schedule 127 shall be used to calculate the variances in PGE's actual NVPC from Base NVPC and actual Energy Revenues from Base Energy Revenues used to establish rates in this docket for the period ending December 31, 2002, and for the purpose of sharing the benefits

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and burdens of such variances between PGE and its customers. Schedule 127 shall not apply to Schedule 83 customers unless they elect the Annual Fixed Price Option. The Commission shall adopt Schedule 127 (attached to this Stipulation as Exhibit B) in its entirety for purposes of this docket. The Parties recognize that PGE will collect or refund through the Power Cost Adjustment Rate only the Adjustment Amount for the period October 2001 through December 2002.

4. The Parties agree that the mechanisms provided in Schedules 125 and 127 fairly balance the interests of customers and PGE with respect to variations in PGE's actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish rates in this proceeding and the effect that such variations will have upon the earnings of PGE for the period ending December 31, 2002. Accordingly, the Parties agree and request that:

(a) To the extent that a deferral of revenues or costs is necessary to implement the mechanism provided in Schedule 127, the Commission, at the request of PGE or any other Party, shall defer the variation in actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish rates in this docket. The Parties will not oppose any such deferral application and will support any such deferral consistent with this stipulation;

(b) The Parties shall request that the Commission allow PGE to amortize into rates, both before and after December 31, 2002, that portion of the variation in actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues that is the Adjustment Amount produced by the application of Schedule 127, notwithstanding the results of any earnings review that the Commission may be required to conduct under ORS 757.259. In any such earnings review, the Parties shall support full recovery or refund of the Adjustment Amount without any adjustment, except those adjustments specifically allowed in this Stipulation.

(c) The Parties agree to support recovery or refund of the Adjustment Amount in any proceeding to amortize such Adjustment Amount into rates or to implement Schedule 127.

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(d) Any balance in the Power Cost Adjustment Account under Schedule 127 will begin to accrue interest on and after January 1, 2003. In addition, there shall be added to the balance at January 1, 2003, an amount equal to the product obtained by multiplying one-half of the balance at December 31, 2002, by an interest rate equal to 15 months of PGE's last approved Cost of Capital.

5. (a) PGE will estimate the difference between what the Boise Cascade St. Helens Plant (Boise) is projected to pay under actual rates for the three-month period October 2001 through December 2001 and what Boise is projected to pay on standard rates. This difference will be credited to all customers with interest at PGE's cost of capital as a separate kWh credit over the 15-month period October 1, 2001, through December 31, 2002, under the Special Contract Adjustment Schedule 131 (attached to this Stipulation as Exhibit C). The Commission shall adopt Schedule 131 in its entirety for purposes of this docket. This credit will be included as an offset to actual Energy Revenues under Schedule 127.

(b) For purposes of determining Base Energy Revenues for Schedule 127, PGE will assume that Boise is on standard rates for the entire period of October 2001 through December 2002.

(c) For purposes of determining actual Energy Revenues for Schedule 127 for Boise for the October 2001 through December 2001 period, the following shall be summed:

- Energy Revenues as if Boise was billed under standard rates, and
- The difference between actual bills to Boise and bills calculated as if Boise was under standard rates.

6. PGE shall establish its Expected NVPC and Base NVPC for purposes of this docket by running its Monet Power Cost Model on or about September 11, 2001, or such later date as may be determined by the Commission.

7. PGE shall remove $100,000 in administrative and general costs from its revenue requirement used to set rates to reflect costs included in its revenue requirement related to its

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demand exchange program. This adjustment reflects the uncertainty that demand exchanges will occur under Schedule 86, PGE's demand exchange tariff. For any month beginning October 2001 and ending December 2002 in which PGE and a customer participate in a demand exchange under Schedule 86, PGE shall add $8,333 to its actual NVPC for purposes of Schedule 127. This will allow PGE to recognize costs of the demand exchange when and if demand exchanges occur.

8. The Parties recognize that PGE's power cost situation is unique, given its exposure to the wholesale energy market in order to serve its retail customers and the current uncertainty and volatility in the wholesale energy market. Accordingly, this Stipulation represents a settlement in compromise of the positions of the Parties with respect to the matters contemplated by this Stipulation in light of the unique circumstances of PGE and the wholesale market energy market. This Stipulation may not be cited or used as precedent by any party or person in any proceeding except for those proceedings implementing the terms of this Stipulation.

9. For the purpose of allocating total fixed and variable power costs among PGE's customer classes and calculating Parts A and B of Schedule 125, the Parties agree that PGE shall allocate its Long-Term and Short-Term Resources and market purchases as follows:

(a) First, PGE shall allocate its Long-Term Resources (including a credit for any PGE provided ancillary services) among customer classes in proportion to their respective percentages of PGE's expected retail load (adjusted to remove the effects of any demand exchanges) for the 12 months ended September 30, 2001;

(b) Second, Subscription Power from the Bonneville Power Administration shall be allocated to the residential and small-farm customers of PGE eligible to participate in BPA's Residential Exchange Program;

(c) Third, PGE shall allocate its Short-Term Resources among all customer classes until each customer class has been allocated a sufficient amount of Long-Term

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Resources, BPA Subscription Power and Short-Term Resources to cover the expected load of that class; except that, to the extent that the resources available under paragraphs (a), (b) and this paragraph (c) are insufficient to serve all expected customer load, PGE shall allocate such shortfall among the customer classes in proportion to their respective percentages of expected shortfall. Any shortfall of resources for any customer class shall be filled by market purchases; and

(d) Any excess of Short-Term Resources over expected load shall be allocated among all customer classes in proportion to their respective percentages of expected load.

(e) If, after applying (a) and (b) above, the residential class has sufficient resources to meet expected load, Short-Term Resources shall be allocated to the other classes on a pro rata basis until they reach the same relative position as the residential class. Any remaining Short-Term Resources shall then be allocated in accordance with (d) above.

10. The Parties agree to support Schedule 130, Shopping Incentive for large non-residential customers below 1MWa described in Exhibit D attached to this Stipulation. The Commission shall adopt Schedule 130 in its entirety for purposes of this docket.

11. ICNU and Fred Meyer Stores will not argue in this docket that the residential and small farm customer classes should be assigned additional costs of load shaping and load following related to BPA Subscription Power allocated to the residential and small farm customer classes.

12. The Parties agree that, so long as PGE does not file a general rate case for rates to become effective prior to December 31, 2002, they will not advocate or support, for rates effective prior to January 1, 2003, an adjustment to PGE's estimated or projected NVPC similar to the adjustment which the Staff sought to introduce into evidence in the proposed surrebuttal testimony of Staff Witness Bill Wordley in this docket, which testimony was disallowed by the Administrative Law Judge. The Parties also agree that, except as otherwise provided in this Stipulation, they are not bound by the terms of this Stipulation in any future general rate

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proceeding initiated by or against PGE.

13. The Parties agree and support the conclusion that Paragraphs 9 and 11 of this Stipulation and Schedule 125 are designed to ensure that 100% of any federal system benefits provided by BPA to PGE, on behalf of its residential and small farm consumers, will flow through to such consumers.

14. The Parties agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order rejecting this Stipulation or adding such material condition.

15. Upon written request, PGE shall make available to any Party to this Stipulation, within 10 business days, all data and workpapers that support the calculations required under the Schedules attached hereto.

16. The Parties shall file this Stipulation with the Commission.

17. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute only one agreement.

18. The parties to any dispute concerning this Stipulation agree to confer and make a good faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

19. The parties agree that the combination of PGE's Standard Offer tariff schedules and the Schedule 125 Resource Valuation Mechanism provides cost-of-service options to customers eligible to receive service under such schedules.

20. The parties acknowledge that legislation has delayed the date for direct access under SB 1149 and that Administrative Law Judge Grant has issued a Post-Hearing Conference

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this 27th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: ______________________	By: ______________________
CITIZENS' UTILITY BOARD	
By: ______________________	

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _____ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________________

FRED MEYER STORES

By: Michael L. Kurtz

Michael L. Kurtz, Esq.

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: ______________________________

ORDER NO. 01-777

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _______ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

FRED MEYER STORES

By: ______________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: ______________________

CITIZENS' UTILITY BOARD

By: Robert T. Jenks

Robert T. Jenks

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this 27th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: David B. Hatton
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: ______________________	By: ______________________

Tonkon Torp LLP
888 SW Fifth Avenue, Suite 1600
Portland, Oregon 97204
503-221-1440

ORDER NO. 01-777

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _____ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

FRED MEYER STORES

By: ______________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: S. Bradley Van Cleve

Tonkon Torp LLP
888 SW Fifth Avenue, Suite 1600
Portland, Oregon 97204

SCHEDULE 125
RESOURCE VALUATION MECHANISM

PURPOSE

To recognize the difference between the market price and costs of power on an annual basis.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service calculated under all rate schedules specified herein, including contracts, except where explicitly exempted.

PART A – LONG-TERM RESOURCES

Part A shall reflect the difference between the projected total cost of power (including a credit for any Company provided Ancillary Services) from long-term resources owned or controlled by the Company including associated transmission by others and the market price of an equivalent amount of power. The market price shall be based on the forward price curve that the Company uses to set the Annual Fixed Price Option. Long-term resources are all generating plants and power purchases with an initial term longer than five years, except BPA Subscription Power.

PART B – SHORT-TERM RESOURCES

Part B shall reflect the difference between the projected cost of power from short-term resources including associated transmission by others and the market price of an equivalent amount of power. The market price shall be based on the forward price curve that the Company uses to set the Annual Fixed Price Option. Short-term resources are all resources that do not meet the definition of long-term resources except BPA Subscription Power.

EXHIBIT A
PAGE 1 OF 5

SCHEDULE 125 (Continued)

PART B – SHORT-TERM RESOURCES (Continued)

A Large Nonresidential Consumer may provide Preliminary Direct Access Notice 12 months in advance of the next Part B adjustment informing the Company that it does not want the Company to plan to serve its load. In such case, the Consumer will be exempt from the Part B adjustment beginning with the next Part B adjustment and continuing until it gives 12-month notice to return to Part B eligible status. The first such notice shall be for the 12-month period beginning January 1, 2003.

PART C – ADVERSE HYDRO CONDITIONS

Part C shall reflect the projected difference in Net Variable Power Costs (as defined in Schedule 127) between expected and normal hydro conditions, on or about August 1, 2001, for the period of October 2001 through December 2002 of $xxxx.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after the effective date of this schedule, shall be:

		Adjustment Rate	
Schedule	Part A	Part B	Part C
7	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
15	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
32	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
38	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
48	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
49	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
82 Small Nonresidential	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Large Nonresidential			
Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh

EXHIBIT A
PAGE 2 OF 5

SCHEDULE 125 (Continued)

Adjustment Rate (continued)

Schedule		Adjustment Rate Part A	Part B	Part C
83	Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
91		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
92		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
93		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
97		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
99	(where applicable)	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
515		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
532		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
549		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
583	Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
591		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
592		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh

ANNUAL ADJUSTMENT REVISIONS

The adjustment rates for Part A and Part B shall be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. For the first year of implementation, the service year will last 15 months, beginning on October 1, 2001 and ending on December 31, 2002, causing the filing to be made on or by August 15, 2001. Part C will be set to zero effective January 1, 2003.

EXHIBIT A
PAGE 3 OF 5

SCHEDULE 125 (Continued)

Part A shall be based on the Company's most recent rate order, adjusted for the service year. Part B shall be based on the Company's purchase obligations for the next calendar year entered into on or before September 15 of the filing year (August 1, 2001 for the October 2001 through December 2002 period). The Part A and Part B revisions shall reflect updates to the following:

- Applicable resources
- Company market power purchases
- Costs of fuel and transportation
- Hydro operating constraints imposed by governmental agencies
- Market power prices (including transmission to the Company)
- Transmission and ancillary services
- Retail load forecast

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

If the net difference of load between:

1. Consumers who provided Preliminary Direct Access Notice and subsequently selected the Annual Fixed Price Option of Schedule 83 (Category 1 Consumers) and

2. Consumers who did not provide Preliminary Direct Access Notice and did not select the Annual Fixed Price Option of Schedule 83 (Category 2 Consumers)

is greater than 25 aMW, the Company may adjust the Part A or Part B adjustment for large nonresidential consumers to account for such difference in load.

If the load of Category 1 Consumers exceeds that of Category 2 Consumers, the Company will adjust the Part A adjustment for large nonresidential consumers to reflect the deviation between the market prices used to set the Part A adjustment and actual market prices experienced in acquiring power to meet the difference in load.

If the load of Category 2 Consumers exceeds that of Category 1 Consumers, the Company will adjust the Part B adjustment for large nonresidential consumers to reflect the deviation between the market prices used to set the Part B adjustment and actual market prices experienced in disposing of power to meet the difference in load.

EXHIBIT A
PAGE 4 OF 5

SCHEDULE 125 (Concluded)

RESOURCE CHANGES

The Part A Adjustment Rates shall be modified at any time to reflect changes in the Company's resources resulting from the implementation of all or a portion of a Commission-approved Resource Plan, any other Commission-approved resource change, or the catastrophic failure of a resource. In the case of a catastrophic failure, Part A shall be adjusted by replacing the variable costs of the resource with the cost of replacement power.

EXHIBIT A
PAGE 5 OF 5

SCHEDULE 127
POWER COST ADJUSTMENT

PURPOSE

To recognize in rates differences in actual net power costs from those assumed in base energy rates.

APPLICABLE

To all bills for electric service calculated under Schedules 7, 15, 32, 38, 48, 49, 83 (Annual Fixed Price Option only), 91, 92, 93, 97, and contracts, except for BPA power delivered for service to residential consumers and also where explicitly exempted.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are defined as the total power cost for energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission / wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude the Regional Power Act Exchange Credit, the cost of BPA Subscription Power, and payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude the results of any transaction arising from the Company's merchant trading business; that is, transactions relating to the acquisition and disposition of wholesale power, hedges, options and other financial instruments solely for the Company's own account and at its own risk.
- Include as a cost (or exclude from revenue) all losses (except those related to merchant trading) that the Company incurs, or is reasonably expected to incur, as a result of any non-retail customer failing to pay the Company for the sale of power during the period in which this schedule is in effect.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.

BASE NVPC

The Base NVPC are defined as the NVPC used to develop existing rate schedules including Parts A and B of Schedule 125. The current Base NVPC are:

$x,xxx October 2001 through December 2002

ENERGY REVENUES

Energy Revenues are defined as the total revenues from Energy Charges of tariff Schedules 7 through 99, plus all charges or credits under Schedule 125, Resource Valuation Mechanism and Schedule 131, Special Contract Adjustment. To the extent that the Energy Charges of a particular rate schedule contain elements not directly related to the cost of power (e.g. system usage charges), such elements shall be excluded from Energy Revenues.

BASE ENERGY REVENUES

The Base Energy Revenues are defined as the Energy Revenues, excluding Part C of Schedule 125 and Schedule 131, forecast from existing tariffs and the load forecast used to develop the Base NVPC. The current Base Energy Revenues are:$x,xxx October 2001 through December 2002

POWER COST VARIANCE

The Power Cost Variance (PCV) is the difference between actual and Base NVPC less the difference between actual and Base Energy Revenues for the period October 2001 through December 2002. The Adjustment Amount shall be determined according to the following based on the level of the PCV:

Power Cost Variance	Adjustment Amount
-$28.0 million to $28.0 million	zero
$28.0 million to $38.0 million	50% of PCV between $28.0 million and $38.0 million
$38.0 million to $100 million	$5.0 million plus 85% of PCV between $38.0 million and $100 million
$100 million to $200 million	$57.7 million plus 90% of PCV between $100 million and $200 million
over $200 million	$147.7 million plus 95% of PCV in excess of $200 million
-$28.0 million to -$38.0 million	50% of PCV between -$28.0 million and -$38.0 million
-$38.0 million to -$100 million	-$5.0 million plus 85% of PCV between -$38.0 million and -$100 million
-$100 million to -$200 million	-$57.7 million plus 90% of PCV between -$100 million and -$200 million
less than -$200 million	-$147.7 million plus 95% of PCV less than -$200 million

POWER COST ADJUSTMENT ACCOUNT

The Company will maintain a Power Cost Adjustment Account to record overcollections and undercollections. The Account will contain the difference between the actual Adjustment Amount and revenues collected/credited under this schedule. Interest will accrue on the account at the Company's authorized rate of return beginning January 1, 2003. In addition, there shall be an amount added to the balance on January 1, 2003 equal to the product obtained by multiplying ½ the balance on December 31, 2002 by an interest rate equal to 15 months of the Company's authorized rate of return.

POWER COST ADJUSTMENT RATE

The Power Cost Adjustment Rate shall be revised on a quarterly basis. It shall be determined as an amount per kilowatt-hour, carried to the nearest 0.001 cents per kilowatt-hour, necessary to bring the projected balance of the Power Cost Adjustment Account (including the projected Adjustment Amount for the period October 2001 through December 2002) to zero at the end of 2002. Each quarter the Company will forecast the PCV and resulting Adjustment Amount for the October 2001 through December 2002 period based on actual results to date and a forecast of the remaining months. This amount less collections to date under this schedule will be the projected balance of the Power Cost Adjustment Account. The new Power Cost Adjustment Rate will be equal to this projected balance divided by the load forecast minus the amount of power delivered by BPA to PGE residential consumers for the remaining period.

If this tariff is terminated for any reason prior to December 31, 2002, the Commission shall determine the Adjustment Amount on a prorated basis consistent with principles of this schedule. In such case, or when this tariff otherwise terminates, any balance in the Power Cost Adjustment Account shall be amortized to rates over a period to be determined by the Commission.

Each Consumer's billing shall state the dollar amount of this adjustment.

TIME AND MANNER OF FILING

Forty-five days prior to the effective date of the revised Power Cost Adjustment Rate, the Company shall submit to the Commission the following information:

(1) A letter of transmittal that summarizes the proposed changes under the schedule.
(2) A revised rate schedule page that reflects the new quarterly Power Cost Adjustment Rate.
(3) Working papers supporting the calculation of the revised Power Cost Adjustment Rate.

ADJUSTMENT RATE

The Power Cost Adjustment Rate, applicable for service on and after the effective date of this rate schedule shall be:

Schedule		Adjustment Rate
7		0.000 ¢ per kWh
15		0.000 ¢ per kWh
32		0.000 ¢ per kWh
38		0.000 ¢ per kWh
48		0.000 ¢ per kWh
49		0.000 ¢ per kWh
83*	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
	Subtransmission	0.000 ¢ per kWh
91		0.000 ¢ per kWh
92		0.000 ¢ per kWh
93		0.000 ¢ per kWh
97		0.000 ¢ per kWh
99	(where applicable)	0.000 ¢ per kWh

* **Annual Fixed Price Option only**

SCHEDULE 131
SPECIAL CONTRACT ADJUSTMENT

PURPOSE

To refund to Consumers $___ million of special contract collections.

APPLICABLE

To all bills for electric service.

ADJUSTMENT RATE

- ____ cents per kwh

TERM

This adjustment shall terminate on December 31, 2002.

EXHIBIT C
PAGE 1 OF 1

SCHEDULE 130
SHOPPING INCENTIVE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Consumers using less than 1 MWa at a site in the prior calendar year (after adjusting to remove the effects of any demand exchanges).

SHOPPING INCENTIVE (PART A)

Consumers for whom this rider is applicable and who elect to receive service under Schedule 583 will receive a Shopping Incentive credit of 0.500¢ per kWh. The Shopping Incentive will be limited to the first ten percent (10%) of Qualifying Consumer Load, measured on a kWa basis that is served under Schedule 583, where Qualifying Consumer Load is equal to the estimated total load of Large Nonresidential Consumers using less than 1 MWa at a site in the prior calendar year (after adjusting to remove the effects of any demand exchanges). No Consumer, business, or group of affiliated businesses with common or similar ownership shall receive Shopping Incentives for single or multiple locations that represent more than 2.5% of Qualifying Consumer Load.

SHOPPING INCENTIVE RECOVERY ADJUSTMENT (PART B)

The Shopping Incentive Recovery Adjustment shall be applied to all applicable Large Nonresidential Consumers.

At least 30 days prior to January 1 of each year (October 1, 2001 for the period October 2001 through December 2002) the Company will file an adjustment rate to recover credits provided under this Schedule. The rate shall be set to recover the estimated credits to be given during the year plus any over- or under-collections during prior periods.

Effective October 1, 2001 the Shopping Incentive Recovery Adjustment shall be

_______ cents per kWh

EXHIBIT D
PAGE 1 OF 2

SCHEDULE 130
SHOPPING INCENTIVE RIDER (Concluded)

TERM

Shopping Incentive credits under this rider will expire three years after direct access is first available under the provisions of section 2, chapter 865, Oregon Laws 1999.

The Shopping Incentive Recovery Adjustment shall expire four years after direct access is first available under the provisions of section 2, chapter 865, Oregon Laws 1999.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the Tariff of which this schedule is a part.

EXHIBIT D
PAGE 2 OF 2

Exhibit E

Allocation of Hydro Adjustment to Months

		Mwh Adjustment
Oct	2001	-65,780
Nov	2001	-42,465
Dec	2001	-44,999
Jan	2002	-97,437
Feb	2002	-102,967
Mar	2002	-83,851
Apr	2002	24,525
May	2002	33,976
Jun	2002	-11,485
Jul	2002	9,707
Aug	2002	-46,502
Sept	2002	24,819
Oct	2002	8,090
Nov	2002	32,132
Dec	2002	62,236
Total		-300,000

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TonkonTorp LLP
ATTORNEYS

AUG 2001 RECEIVED OPUC SALEM

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August 20, 2001

Janice Fulker, Administrator
Regulatory and Technical Division
Oregon Public Utility Commission
550 Capitol St. NE, Suite 215
Salem, OR 97301-2551

Re: UE 115 Monet Run

Dear Ms. Fulker:

Pursuant to Judge Grant's Post-Hearing Conference Memorandum dated July 17, 2001, enclosed is PGE's "final draft" Monet Run. This was delayed due to settlement discussions among the Parties. Staff, ICNU, CUB and PGE held settlement discussions on August 13, 15, 16 and 17, 2001, concerning the June 1 and July 27, 2001, Monet Runs and the corrections and updates to the June 1 Monet Run that would be included in the "final draft" Monet Run and the final Monet Run used to establish final pricing in this docket in September 2001.

Attached to this letter is a list of 16 corrections and updates that were included in PGE's July 27, 2001, Monet Run that were not included in the June 1, 2001, Monet Run distributed to the parties. This list was attachment 3 to PGE's comments filed August 9, 2001, on the July 27, 2001, Monet Run. Staff and PGE have agreed that the "final draft" Monet Run and the September 2001 Monet Run will be based on the inputs to the June 1 Monet Run with the adjustments contained in items 2, 10-14 and 16 on the attached list of corrections and updates, and will not include the other items on the attached list. In addition, PGE will remove from these runs a merchant trading transaction that was inadvertently included in the June 1, 2001, Monet Run. CUB and ICNU will not oppose the use of the June 1, 2001, Monet Run with the inclusion of these corrections and updates. Staff and PGE have agreed that the September Monet Run will be based on the "final draft" Monet Run updating only the most recent gas and electric forward curves. CUB and ICNU will not oppose this agreement.

At the request of ICNU, the date for final pricing in this docket will be September 12, not September 11.

Janice Fulker
August 20, 2001
Page 2

PGE withdraws its motion to reopen the record filed August 9, 2001.

Very truly yours,

Michael M. Morgan

MMM/pcs
Enclosure
cc: UE 115 Service List
Mr. Maury Galbraith

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Attachment 3 to
PGE's August 9 Comments

On Thursday, August 2nd, PGE met with Staff and discussed the following corrections and updates to the June 1st Monet model run that were incorporated into the July 27th Monet model run:

1. Updating the cost of coal for Boardman, including transportation, based on the most recent information available. This update was incorporated in the June 1, 2001 Monet run.
2. Updating Coyote fuel costs for the cost of gas to operate the auxiliary boiler to produce steam, consistent with the 2nd Stipulation with Staff on revenue requirement issues and Commission Order 01-489.
3. Updating the Wells Settlement contract output based on hydro output.
4. Update contract cost for the Portland Hydro Project based on most recent available information.
5. Utilize 48-month average for Thermal Availability and Thermal Maintenance based on historical data through 12/31/00 (the most recent data available).
6. Update firm Gas Transportation for most recent tariff information available.
7. Update variable Gas Transportation costs to include losses due to compressor usage.
8. Update cost of Ogden/Mt. Tabor contract based on most recent available information.
9. Update cost of Lake Oswego Street Lighting contract based on most recent available information.
10. Incorporate BPA subscription power at expected contract cost (28.3 mills) rather than forecast market.
11. Correct the load forecast for two months to match forecast provided in PGE's Rebuttal Testimony (STF01AE).
12. Utilize most recent forward curves for market gas/electricity.
13. Utilize most recent contracts for gas/electricity.
14. Incorporate Staff/PGE Stipulation on expected Hydro output.
15. Expected output of Vancycle Ridge contract updated to 10 aMW using most recent available information.
16. Correct capacity of Chelan Exchange In contract from 50 MW to 25 MW in October 2002.