BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 180

General Rate Case Filing

PORTLAND GENERAL ELECTRIC COMPANY

Testimony and Exhibits

March 15, 2006

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

James J. Piro
Pamela G. Lesh

March 15, 2006

Policy

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I. Introduction

Q. What are your names and position with Portland General Electric?

A. My name is James J. Piro. I am Executive Vice President and Chief Financial Officer for PGE. My qualifications appear at the end of this testimony.

My name is Pamela G. Lesh. I am PGE's Vice President, Rates and Regulatory Affairs and Strategic Planning. My qualifications also appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Describe PGE's strategic direction and goals, which serve as the context for this filing (Section II);
- Present the key proposals made in this filing (Section III);
- Explain the objectives that guided the development of those proposals (Section IV); and
- Introduce the rest of PGE's testimony (Section V).

II. PGE's Strategic Direction and Goals

Q. What is PGE's business purpose?

A. PGE's business purpose is to provide excellent electric utility service within our Oregon service territory, achieving the results our customers, workforce, and owners' needs through thoughtful decision making and strong execution. In 2003, we adopted the Mission that appears in our rolling three-year Statement of Direction. That mission is:

PGE is a company customers depend on to provide electric service in a safe and reliable manner, with excellent customer service at a reasonable price.

Q. What is PGE's Statement of Direction?

A. This is a document we update annually, to guide our annual budget development and Scorecard performance process. With our Company values as the foundation, we reassess the key results and initiatives that will further our business purpose. We group these into seven long-term goals. These are:

High Customer Value – We will increase customers' experience of value received from PGE.

Reliable, Reasonably Priced Supply – We will design and maintain an energy resource portfolio with cost-effective resources that provide a reliable supply of electricity to customers at prices that are no higher than necessary and as stable and predictable as possible.

Active Corporate Responsibility – We will act in a manner true to our company's values, which reflects the values of our customers and the communities we serve.

Economic Strength – We will exert a positive influence on the long-term economic strength of our service territory.

Engaged, Valued Workforce – We will be an employer that fosters its employees' best efforts and talents. We will focus on improving employee unity, work-life satisfaction, performance and accountability.

Sustained Operational Excellence – We will maintain high performance levels in safety, power quality, reliability, plant availability, customer service, regulatory and environmental stewardship, and improve performance where it is cost effective to do so.

Strong Financial Performance – We will achieve a return on equity that is at or above that achieved by a group of vertically integrated utilities with similar operating characteristics, service territory environment and business risks.

Q. What is the Scorecard performance process?

A. Scorecards at PGE start at the top, with a Scorecard for our Chief Executive Officer that expresses company-wide results and initiatives. With this as a guide, each officer develops a Scorecard for his or her functional area(s), adding depth to the company-wide results and initiatives and adding those specific to the function. The officers share these during development to ensure that we identify the linkages and dependencies among all of the functions. Following that, each officer's managers develop Scorecards for their areas, followed by Scorecard development underneath them. In many areas of PGE, individual employees all have Scorecards.

The Scorecards, at all levels, align the organization around common goals, focus our limited resources on areas that provide the greatest value to customers, and provide a way to measure our performance in the work we do. In addition, they serve as the basis for earning incentive pay (or pay-at-risk) and as an input to performance appraisals.

Q. How does PGE's budget development relate to the Statement of Direction and Scorecard process?

A. Officers align their budgets and Scorecards. The 2006 budget from which PGE developed the 2007 test year revenue requirement forecast expresses the 2006 – 2008 Statement of Direction and 2006 Scorecard. The cost forecasts we present are those we believe necessary to fulfill our mission and achieve the goals set forth above.

III. Requests in this Filing

Q. What are PGE's key proposals in this general rate case (GRC)?

A. This rate case seeks Oregon Public Utility Commission (OPUC or Commission) approval of the following:

- Retail prices that, based on expected 2007 loads, allow PGE an opportunity to recover an increase of approximately $25 million (above the adjustment that would otherwise occur through Schedule 125, the Resource Valuation Mechanism or RVM) in our costs of serving customers over the costs reflected in the prices set in UE 115.
- An authorized rate of return on common equity of 10.75%, which we believe is, per ORS 756.040, "(a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."
- A capital structure that allows PGE to maintain our current secured credit ratings at a "BBB+" level, which will provide the financial strength necessary to make ongoing investment in our system and provide access to today's volatile wholesale fuel and power markets.
- Based on a finding of prudence, the inclusion in rate base of PGE's investment in the Port Westward combined-cycle combustion turbine generating plant, acquired pursuant to PGE's 2004 Integrated Resource Planning (IRP) Action Plan, and the Beaver 8 peaking resource. For Beaver 8, we also request that the Commission

waive its rule that precludes new resources from entering a utility's rate base and requires that they enter cost of service at market prices.

- Based on a finding of prudence, the inclusion in rate base and expenses of certain costs related to the relicensing of PGE's hydroelectric generating projects on the Deschutes, Clackamas and Willamette Rivers.
- Automatic adjustment clause tariffs under which PGE annually will change retail prices to reflect accurately the net variable power costs (NVPC) we forecast to incur to serve customers in the following year (replacing current Schedule 125) and under which we will share with customers the variances between those forecasted NVPC and the NVPC PGE actually incurs. These tariffs will help ensure that our cost-of-service rates accurately reflect our actual costs.
- A proposed capital expenditure program to replace our existing monthly-read meters with Advanced Metering Infrastructure (AMI) that will both control costs and support the development of many customer benefits, including demand-side management opportunities and billing options.
- A lower annual customer contribution to the Nuclear Decommissioning Trust (NDT) and return of $20 million from this fund, based on PGE's completion – under budget – of all radiological decommissioning and termination of our operating license and the need to store nuclear waste at Trojan until we can ship it to the federal long-term waste storage facility.
- The results of PGE's most recent depreciation study, which generally lowers PGE's depreciation expense.

- Changes to PGE's direct access program, based on our experience to date, including termination of the Part B Short Term Resource Notice under Schedule 125, and addition of monthly opportunities for customers to choose direct access or market-based pricing for the balance of a given year.
- A new pricing option under which our larger load customers can place 50% of their load on an Energy Service Supplier (ESS) and the remainder on a PGE cost-of-service rate.
- A new Schedule 89 (and 589 for direct access) for business customers whose loads exceed 1,000 kW to better reflect cost differences for these larger customers and a re-opening of Schedule 38, time-of-day service, for mid-size seasonal customers who may benefit from its pricing structure.
- New options under Schedule 483 by which PGE can offer customers choosing this long-term opt-out from PGE's cost of service resources market-based prices for the three or five years.
- A two-year notice requirement for self-generating customers to place load presently met with their own generation back on cost of service, comparable to the notice required of customers choosing a five-year opt-out from PGE's cost of service resources.

Q. What level of price increase is PGE requesting that the Commission approve in this filing?

A. These revised or new schedules reflect an overall increase in electric prices of 1.7% over the prices that would otherwise take effect January 1, 2007 under PGE's RVM and use a forecast of our revenues and expenses for 2007. We presently estimate the 2007 RVM price increase to be 4.1%.[1] As in past years, this estimate is subject to change as we continue to purchase power and fuel for 2007 throughout this year.

This filing also includes PGE's revenue needs related to the addition of the Port Westward generating plant (Port Westward) to our resources. Net of the power cost benefits this plant will provide our customers, we estimate that the effect of including this generating plant in PGE's rate base is 2.9%. The Port Westward price increase will not occur until the plant begins providing service to customers, which we presently estimate to be March 1, 2007. We explain below our recommended procedure for adjusting prices to reflect this new resource and update certain important forecasts of our cost of service during this proceeding. The total of these components is an overall increase of 8.9%.

The chart below shows, by class, our present estimate of the 2007 RVM and the increments associated with this GRC and Port Westward.

	% Change 2007 RVM	% Change 2007 GRC	% Change Port Westward
Residential	2.4	3.2	2.7
Sm Nonresidential	5.0	2.7	2.5
Lg Nonresidential	5.6	-0.3	3.2
Other	3.8	7.1	1.9
Total	4.1	1.7	2.9

Q. What is the primary reason for the RVM price increase?

A. The prices of natural gas and electric power we purchase in international wholesale markets are the biggest causes of our 2007 RVM price increase. Demand for natural gas remains high, driven in large part by high international demand for oil, for which natural gas often serves as a substitute. Between March 1, 2005 and March 1, 2006, the price for the month of January 2007 natural gas at the Sumas hub, from which PGE purchases much of our gas,

[1] This estimate excludes Part B opt-out load and spreads the UE 115 supply function fixed revenue requirement ($213 million) across our current 2007 RMV load forecast

rose 33%. Because much of the generation in the Western Electric Coordinating Council (WECC) – where PGE purchases electric power – uses natural gas, pressure on the price of natural gas puts pressure on the price of power as well. The change in forward power prices for the month of January 2007 rose for the same period a year ago by 22% (flat pricing).

The prices we see today are the result of supply and demand. There are no low-cost resources one can buy that are not already allocated to some set of retail customers; what is available for purchase is on the margin. Moreover, credit requirements are now standard practice, making long-term contracts difficult without a very strong balance sheet to support the mark-to-market changes and credit calls one will inevitably face over the life of a power or fuel contract. For example, as of February 2006, we estimated that a 50% drop in the market price of power and natural gas would require an increase in deposits of $164 million. The highest we have seen this measure was $200 million in December of 2004 and January of 2005. And these measures generally relate to contracts whereby the margining rights are limited to three years' duration. The requirements of long-term contracts could be much greater if we are unable to limit the margining rights to three years or less.

We forecast our 2007 NVPC to be $225 million or 36% higher than in 2006. NVPC are now more than 50% of PGE's total revenue requirement. This reflects not only the drivers discussed above, but also growth in PGE's load. PGE Exhibit 400 discusses the changes in NVPC from 2006 to 2007 in greater detail. It is likely that natural gas and power prices will fall or rise in 2008; the unlikely outcome is that they remain exactly the same. The year-over-year volatility of these commodities is the primary reason we are proposing Schedule 125, which continues the annual updating of PGE's NVPC even though we use another mechanism to calculate transition adjustments for customers choosing direct access.

Without an annual update, both PGE and customers bear too much risk that the prices we charge will be significantly out of alignment with our actual costs.

Q. Will the addition of Port Westward to PGE's resource portfolio mitigate the 2007 RVM price increase?

A. Yes. We currently estimate that Port Westward will save customers $12 million from what PGE would have incurred had we had to purchase the equivalent amount of power from the wholesale market. This estimate will change as the forward curves for 2007 power change throughout this year.

Q. Does that mean that adding Port Westward results in a lower rate increase than PGE would otherwise have requested in this case?

A. No, these NVPC savings are just one aspect of Port Westward's effect on PGE's costs. PGE is incurring approximately $285 million in capital construction costs, which we propose to recover over 28 years. We will also incur operating and maintenance (O&M) costs for the plant. The net effect of including Port Westward in PGE's resource portfolio is an increase of approximately $45 million, or 2.9% as we mentioned above. The primary reason this occurs is the shape of capital cost recovery, which is highest during the early years of a resource's life and declines over time as the utility depreciates the resource.

Q. If Port Westward increases PGE's 2007 costs, why did you decide to proceed with the project?

A. Port Westward is a long-term resource that, over its service life, we expect to reduce PGE's costs compared to what they would have been without it. During our IRP, we estimated that Port Westward would provide a net present value benefit to PGE's resource portfolio of greater than $169 million (2004$) over the next 30 years. PGE Exhibit 300 discusses Port

Westward in greater detail. Some of PGE's most cost-effective resources are generating plants in which we invested one or two decades ago, including the Boardman and Colstrip coal-fired plants.

And we note here a "back to the future" aspect of adding new generation and the wholesale market prices: just as in the 1970s and 1980s, the gap between embedded cost and marginal cost is large and it is marginal cost that is the higher of the two. While this also was true in the late 1980s and early 1990s, it was academic because few utilities needed new resources – enough was built in the prior decade to cover for many years. But many years ultimately run out and we now face needing to replace old resources and to add new ones for increasing customers and loads.

Q. What is the effect on PGE's costs of relicensing your hydroelectric generating projects?

A. For 2007, these new licenses increase costs by $9.3 million, part of which ($2.9 million) relates to increased O&M for the projects and part of which is recovery of the capital PGE applied to obtain the licenses. In future years, we expect the capital costs to increase significantly as we construct the modifications necessary to lessen the environmental impacts of these projects. We currently estimate that the projects will require $371 million in capital expenditures (through 2020) to comply with the requirements of the new licenses.

Q. Why did PGE proceed to obtain new hydro licenses if their environmental and other conditions will increase costs?

A. Notwithstanding the capital costs that our new licenses will require, PGE's hydroelectric generating resources remain our most cost-effective resources. We have estimated the net present value benefits of our granted and pending licenses at $697 million total, across all of the projects. PGE Exhibit 400 discusses this in greater detail.

Q. What is causing the cost increases included in your general rate case?

A. Aside from the wholesale market and resource cost changes we discussed above, the upward pressure on our costs comes from:

- More customers – by 2007, we will have added approximately 60,000 customers since our last GRC – and improved service for our customers, including enhanced and expanded contact options;
- Labor costs, including a steady rise in the wages and salaries we must offer to retain and attract a high quality workforce and the much higher costs of health and pension benefits, with which the whole economy is struggling. We hold our total compensation to the market median to ensure we pay no more than necessary for our workforce; and
- Compliance costs for regulatory initiatives such as the Sarbanes-Oxley Act of 2002 (SOX) and the Federal Energy Regulatory Commission's Order 2004 Standards of Conduct, which are both direct – such as increased outside auditing costs – and indirect in some of the procedures required by these initiatives.

Q. Are all of PGE's costs rising?

A. No. This case includes some major cost decreases. We highlighted two of these above: the decrease in our overall depreciation expense and the lower customer contribution to the Nuclear Decommissioning Trust.

In addition, in contrast to UE 115, our revenue requirement no longer includes Enron direct charges and allocations. Partially offsetting this cost decrease are the costs of becoming an independent, publicly-traded company, which include a full Board of Directors, an investor relations function, and trade association memberships.

Our overall cost of long-term debt has fallen from 7.80% since our 2002 test year to 6.69% in the 2007 test year as we took advantage of the extremely low interest rates available as the United States pulled out of the poor economic conditions of 2001 and 2002.

Q. Does PGE work to control costs?

A. Yes. PGE Exhibit 500 describes a number of PGE's cost control initiatives over the past five years. We have a long-standing practice of seeking to maximize the performance and value of our assets, reflected in such efforts as the automation of our hydroelectric plants, the upgrade of the turbines at our Boardman plant and targeted improvements to our transmission and distribution system. We also have a long-standing practice of focusing annual workforce performance on the work most beneficial to customers, including cost control, through our Scorecard system, which we described in Section II. Over the last few years, we have added a strong program to improve management effectiveness, because that is the key to sustained workforce performance and satisfaction.

Q. Why are PGE's prices as high as they are?

A. Two factors are the primary cause for PGE's position in price comparisons with other utilities: the age and mix of our generating resources. Generally speaking, the more that a utility's generation mix is of a "high fixed cost/low variable cost" nature (e.g., coal) and the older it is, the lower the utility's rates. The average age of the resources, in turn, will relate to the kind of load growth the utility has experienced over the last several decades.

How we do ratemaking means that, all else being equal, fixed costs decline over time. Environmental requirements that drive retrofits or operational changes to existing generation can change this (nuclear in the 1980s, hydro in the 1990s and 2000s, coal soon), but even so, these investments rarely increase the cost of an old resource to at or above the cost of a new one.

Regulation has long wrestled with the problem of marginal costs that exceed embedded costs. How should one give customers price signals to cause the right consumption and investment decisions? In the late 1990s, however, the opposite problem occurred: embedded costs briefly exceeded marginal costs, driven largely by the very low price for natural gas and the relatively low fixed cost of generating plants that use natural gas.

PGE came into the mid-1990s with relatively few older, high fixed cost/low variable cost resources and, driven by exceptional load growth, dove deep into the marginal resource stack relying on low-cost market purchases. This resulted in several years of PGE having lower prices than many utilities in the Northwest. When natural gas price changes drove marginal prices far higher than embedded costs, however, PGE's situation changed. OPUC Staff recently estimated that, if 1996 natural gas prices of approximately $1.29/MMBtu still prevailed, PGE's prices would be 23% lower than today.

Going forward, our prices will remain higher than those utilities with a larger amount of older, embedded cost resources with relatively high fixed costs and low variable costs. How soon other utilities exceed their older resource bases depends on the economic growth in their service areas.

Q. Would approval of the relief PGE is requesting serve the interests of your customers?

A. Yes. The new prices and some of our other proposals will restore PGE's financial condition and allow us to attract the capital we need to maintain quality service to customers. We presently estimate that our system will require approximately $1.7 billion in capital investment over the next five years. This is without any new resources that our next IRP and Request for Proposal (RFP) cycle might identify as being most cost-effectively provided by PGE.

This case includes the first generating plant that PGE has added in over ten years. The reasons for this hiatus include expectations of reasonably-priced energy from third-party suppliers and of radical changes in the service obligations to large industrial customers. Our experience has differed from these expectations and we expect in the future to need capital not only for ongoing replacement and extension of our distribution and transmission systems, but for new generating plants as well. This means that our access to reasonably-priced capital is important to customers.

PGE has not achieved the return on common equity approved by the Commission since our last general rate case. As our stock becomes publicly traded, our ability to access capital will depend even more on investor perceptions of our ability to produce a return on capital comparable to investments with similar risks. If PGE cannot attract debt and equity capital on favorable terms, we cannot minimize costs in the long run or assure our customers of the quality of electric service they need for modern businesses and lives.

Q. What do potential investors in PGE deem important?

A. Debt investors care most about the security of the funds they loan a company and the cash that company will have available to pay the interest and principal on such loans. The ratings done by Standard & Poor's, Moody's and Fitch all inform potential investors in PGE's debt about the level of security they can expect. Although all three use somewhat different approaches, they are looking at a variety of indicators of financial strength. As explained in PGE Exhibit 1100, equity investors care most about a company's earnings expectations: will this investment provide a return commensurate with the risk being taken? Both types of investors consider regulatory environment very important when considering a utility investment.

From an investor perspective, the utility should have a good track record of collecting revenues sufficient to cover its prudently incurred costs of service, whether those costs were part of a test year forecast or not. This is one of the reasons we are requesting the automatic adjustment clauses for forecasting and reconciling NVPC. PGE must incur these costs to provide customers service. Unlike some of our O&M or A&G costs, we cannot make decisions to delay these expenditures. Virtually all of the utilities to which our potential investors will compare us have regulatory assurance of recovering prudently-incurred NVPC. All else being equal, the lack of such assurance will increase our cost of obtaining capital.

Q. Will this filing improve PGE's profitability?

A. The prices approved as a result of this filing would allow PGE the opportunity to earn net income of $105 million ($122 million after Port Westward), or 6.4% (7.2% after Port Westward) of our overall revenue requirement, if expenses and revenues meet the test year forecast. This is just $8.0 million (after-tax) higher than five years ago, in UE 115, and is based on an overall cost of capital of 8.97%, compared to 9.08% in UE 115. The filing includes a proposed return on common equity of 10.75% and a capital structure with 56% common equity, 43.75% long-term debt and 0.29% preferred stock. If the Commission approves our proposed NVPC automatic adjustment clauses, we can expect a fair opportunity to earn this return if we manage our business well and make prudent expenditures.

Q. Is PGE proposing a decoupling mechanism in this filing?

A. No. PGE last sought a decoupling mechanism in 2001, through Docket UE 126. The Commission denied this request. We remain open to the concept and would be happy to discuss a suitable mechanism if any party to this proceeding proposes one. We continue to believe that de-linking a utility's near-term profit, at least in part, from its kWh sales is a good public policy choice.

Q. Do you recommend that the Commission set a schedule that can result in decisions on the direct access changes prior to the Commission's decisions on the remainder of this filing?

A. Yes. We recommend that the Commission set a schedule so that it can decide on our proposed direct access changes by September 1, so that customers can make choices regarding long-term direct access under Schedules 483 and 489 with full understanding of changes to short-term direct access. An early decision on these matters also will enable us to offer the November short-term access window with minimal confusion. For purposes of informing potential direct access customers of transition adjustments, we will estimate the January 1, 2007 cost of service rate change and Port Westward rate change for the November window. Schedule 128 will calculate the change to the transition adjustment from these general rate actions automatically.

Q. Do you recommend that the schedule adopted for this proceeding include times at which PGE will update certain information necessary for establishing revenue requirement and setting prices?

A. Yes. While we developed this filing with the best information available at the time, we expect that we and other parties to the case will want to include more up-to-date information for certain critical elements.

Q. Which elements do you believe may need to be updated?

A. While the parties may agree that other items may require updating, it appears that, at a minimum, we should update the load forecast, certain inputs to our power cost model (MONET), the fixed costs of Port Westward, and the cost of equity capital.

Q. What is your proposed schedule?

A. We propose to update the following elements coincident with our rebuttal testimony:

- Load Forecast.
- MONET inputs of forced outage rates, planned maintenance of plants, loads, power and fuel contracts, and forward curves.
- Fixed costs of Port Westward.
- Cost of equity.

We propose to again update MONET on September 1 for contracts and forward curves. We will make a final update on November 1 that will include:

- Changes in expected loads resulting from choices of eligible customers during the September 2006 open window for Schedules 483 and 489.
- New physical and financial power and fuel related contracts with a duration of no more than 12 months and entered into with third-party brokers.
- Forward curves.

Q. What procedure are you proposing to include Port Westward in PGE's electric prices?

A. We propose that, in processing this filing, the Commission approve both the fixed and variable revenue requirements associated with Port Westward, based on information updated as proposed below. PGE would file compliance tariffs including this approved revenue requirement in our prices, along with an attestation that Port Westward has achieved commercial operation. We propose that the tariffs take effect one day after filing. This procedure is consistent with how the Commission has handled other utility investments that enter service during or shortly after the end of a test period. It would make little sense and be a poor use of regulatory resources to develop another test period lagged just two months from this one to coincide with the commercial operation of Port Westward.

IV. PGE's Objectives

Q. What were PGE's objectives in developing your proposals in this filing?

A. Our objectives borrow from the past and also look to the future.

First, we designed our proposals, made decisions, and prepared this filing to achieve the lowest expected cost for customers over time. This is the same standard that we use in the IRP. The regulatory framework reflected by and embodied in the tariffs the Commission adopts in this case has implications into the future that, in some cases, persist as long as a resource decision.

Second, PGE strives to increase the value of electric service for our customers over time. This interrelates with the first objective, of course. It permits a cost-benefit review of increased expenditures to improve service.

Q. How do the Commission's decisions on the tariffs in this case affect future costs?

A. The primary future cost that the Commission's decisions affect is PGE's cost of capital. The Commission's decisions in this case affect PGE's cost of capital both directly and indirectly.

Directly, the Commission's decision on the nature and level of costs it allows in PGE's revenue requirement is a primary driver of whether PGE can deliver to customers the services they require and also have an opportunity to recover the cost of capital, particularly equity capital. We maintain the opportunity to recover our cost of capital if the Commission's disallowances or adjustments are of costs that PGE can avoid or stop incurring.

The Commission's decisions on how to handle uncertainty indirectly affect PGE's opportunity to earn a reasonable return on equity and continue to attract capital. By uncertainty we mean the nature or level of costs that PGE will incur but that are impossible to forecast accurately. Examples are customer load, hydroelectric generation, future interest rates, customer direct access choices, and storms. The cost-of-service tariffs in this case reflect a particular allocation of the risk of some of these uncertainties. With respect to load, the tariffs (with few exceptions) allow a customer to use as much power as wanted, whenever wanted and to provide no notice to stop or start service. PGE stands ready to provide the service taken at an average price regardless of the individual or collective costs of such decisions. With respect to direct access, Schedule 128 holds PGE and other customers financially neutral to the effects of customers making direct access choices. With respect to hydroelectric generation, Schedule 126 requires that PGE absorb 10% of the difference between the "average" water hydro generation used in the Schedule 125 forecast and the actual hydro generation that occurs as a part of and along with all other NVPC variances.

The greater the uncertainty risk that PGE bears, in addition to the other risks present in the environment including regulatory risk, the higher the cost of the debt and equity capital we need. PGE plans to issue $375 million in long-term debt by the end of 2007. The outcome of this case is likely directly to affect the cost of this debt.

Q. Are you suggesting that there is a trade-off between a utility's cost of capital and the amount of uncertainty the Commission can allocate to it?

A. Yes, and often commissions decide to minimize the cost of capital by adopting a regulatory framework that passes uncertainty through to prices. The clearest example of this is the manner in which most states handle variances in power and fuel costs. These costs are uncertain, albeit much more so for some utilities than for others. Many commissions have concluded that the capital costs avoided by not allocating some or all of this uncertainty to the utility exceed the additional costs that the pass-through will, at times, impose on customers. Of course, these mechanisms typically work both ways and can as easily pass savings through to customers. Pass-through also ensures that the utility does not over-earn because of temporary deviations in power markets or resource operations.

Q. How should the Commission decide between minimizing the cost of capital and allocating uncertainty to the utility?

A. To do this analytically, one would need to know, over the long term:

- How much the utility needed to invest in its distribution, transmission and generation system to serve its customers;
- What the cumulative variances will be for the costs for which one is allocating the risk of uncertainty; and
- The compensation (in basis points) the utility's debt and equity investors will require for bearing the risk of this uncertainty.

Unfortunately, this is not possible. Even if one attempted to estimate each of the inputs, the degree of error involved by the time one did so for all three inputs would probably render the result meaningless.

Q. If it is not possible to analytically develop a regulatory framework to result in the lowest possible cost for customers, why do you think so many commissions have chosen to pass through in retail prices the actual power and fuel cost a utility incurs?

A. We believe these decisions reflect a judgment that the cost of capital associated with requiring investors to bear costs prudently incurred for customers exceeds what customers would save by not paying such costs. Investors play an important role in bearing the costs deemed by a regulatory body after process to have been imprudently incurred in the course of serving customers, and the cost of capital reflects this risk. These commissions have decided to stop there and not compound the risk.

Q. How is PGE's second objective – of increasing value for customers over time – reflected in this filing?

A. A good example of this objective is our proposal to implement AMI. As PGE Exhibit 800 explains, AMI will:

- Reduce operational costs in the long term.
- Provide customers with better services such as customer-selected due date, outage detection, and reduced intrusions on their property.
- Enable sophisticated demand response programs.
- Provide more accurate and timely billings.

Other examples exist in our review of customer service (PGE Exhibit 700) and distribution (PGE Exhibit 600) costs. The testimony shows that we have continued to work on the customer expectations that we noted in 2000 when we filed UE 115. We said customers wanted:

- More electricity service choices: choices that differ in terms of price, terms, and content. We have now not only created these options but come to understand what is necessary to support them, including having the tools and people available to help customers assess options and programming our systems to maintain a customers' choice even if they change addresses.
- More payment options: PGE offers several options for customers to pay their bills, such as automatic debits, on-line payments over the Internet, and credit and debit card payments, among others. *By 2004, approximately 30% of our*

customers paid their bills electronically. In October 2005, we added the ability to pay by check over the phone and have already taken approximately 21,000 such payments, which is a clear indication that customers appreciated this convenient, simple and no-cost option to pay their bills.

- More communication channels: a web site that allows customer service transactions and e-mail, as well as providing information; and an Interactive Voice Response (IVR) system for reporting outages, receiving outage information, and checking account information. Portlandgeneral.com is fully enabled for customer service needs and in 2005 served about 150,000 residential and business customers. It now includes presentations to help customers understand our costs and tools to help customers choose among competing providers and pricing options. PGE's IVR ranked first in a 2005 benchmarking study by Market Strategies, Inc.
- More information on PGE: regarding our resources, their options, the industry, and the environment; and in multiple languages. PGE provides communications on essential information regarding safety, wise and efficient use of energy, how to reach PGE in the event of an outage, power options, billing and payment options, and general customer service. PGE accomplishes this through channels such as newsletters and bill inserts, television, radio and newspaper advertising, and point-of-sale materials in our community offices.
- Higher reliability: fewer outages and faster restoration during outages. Over the last four years, we have never exceeded the thresholds set by the Commission for our average frequency or duration of outages.

- Better power quality: to run both highly sensitive industrial processes as well as the home electronics we all have without "bumps" that in past years would have gone unnoticed. We now measure momentary interruptions and have instituted the Quality and Reliability Program for our distribution and transmission system to ensure that voltage sags on our system never exceed the tolerances (the SEMI F47 criteria) built into their extremely sensitive manufacturing equipment.
- Better safety: more frequent tree trimming to ensure that no power line affects a tree. A recent report from Environmental Consultants, Inc. states that "PGE is among the best-in-class utilities in terms of tree trimming."

Q. Are these the only customer expectations you noted in UE 115?

A. No. We expected SB 1149 to act as a catalyst to even more significant changes and that did not occur. Below we compare what we said in 2000 and what we now understand:

- 2000: Our customers do not want us to make future long term, resource decisions for them because they do not want the one-size-fits-all service choice dictated by such centralized and unavoidable decisions. 2006: Customers (by and large) do want us to make future, long-term resource decisions for them because they want the security and predictability that can come from a stable resource portfolio. As we noted above, this case includes many of these long-term resource decisions.
- 2000: Our business customers want not only to make their own future choices but also to have a one-time valuation of the costs and benefits related to their share of the prior resource decisions PGE made on their behalf. 2006: Business customers did not want a one-time valuation of costs and benefits of prior resource decisions. This proposal withered for lack of interest. Instead, we

developed an ongoing valuation mechanism – the RVM – and followed that with Schedule 483 that allowed individual customers to seek a valuation of their share of existing resources but did not bar them permanently from returning to cost of service pricing.

- 2000: Our residential customers want to have the Commission guide our future resource decisions in a market setting, using the costs and benefits related to their share of our prior resource decisions as a buffer while the suppliers and systems develop to make individualized resource decisions easy and reliable. 2006: Residential customers did not want all new resources to be from the market. Indeed, PGE's request for a waiver of OAR 860-038-0080(1)(b), which requires that all new resources enter rates at "market", to allow Port Westward to enter rates on a traditional cost of service basis had strong customer support. In this instance, a PGE-financed generating plant was the resource with the lowest expected cost to customers. That may not always be the case, but customers were clear they wanted utility-financed resources among the options.
- 2000: Our customers want building blocks from us, so that they can choose among the blocks and work with each block to add value to it and achieve a service that suits their needs – the result they want – not the generic needs of a "residential" or "commercial" customer. 2006: Customers are not particularly interested in building blocks from us. We have received numerous complaints over the last few years that our price structure is complicated and confusing. Of even greater concern, some of the complexity and options have resulted in unexpected and negative results both to customers choosing the option and

customers not choosing the option. The Part B opt-out provision in Schedule 125 is one of these options and we are simplifying our pricing by removing it.

Of course, for each reference to "customers" we just made, there are probably some for whom the exact opposite of our belief is true. To the extent that "one size fits all" ever was possible – and that is debatable – it is no longer. The balance required is to make decisions that move in the direction of most customers' expectations while accommodating the interests of those whose expectations lie in another direction. Direct access, as we currently propose to offer it, as well as some of the pricing options our tariffs now include, attempt to do just that.

V. Overview of PGE's Testimony in this Filing

Q. What testimony is PGE presenting in this case other than this?

A. PGE is presenting the direct testimony of the following PGE witnesses:

Exhibit 200 summarizes the overall 2007 test year revenue requirement, comparing the request with the 2002 test year used in UE 115, and 2004 actual expenses. This testimony also presents, and uses for test year purposes, PGE's request for new depreciation rates, based on the depreciation study before the Commission in Docket 1233. It discusses PGE's rate base, the costs associated with Port Westward and how PGE proposes to include them in rates, accounting changes, and certain deferred accounts.

Exhibit 300 presents the forecasted plant-related O&M and power operations costs. Overall, these costs have risen by less than inflation since 2002, except for PGE's hydroelectric plants and the addition of Port Westward. This Exhibit explains the re-licensing process for PGE's hydro plants, the requirements of the new licenses, and why the investments are cost-effective. It also discusses the decision to build Port Westward, including its selection and the choice of a contractor.

Exhibit 400 presents the regulatory framework PGE proposes for PGE's net variable power costs (NVPC) and the estimate for 2007 test year NVPC of $857. The testimony includes an estimate of the 2007 RVM, which PGE will file before April 1 under the existing tariff. The framework uses three common regulatory tools – a general rate case, a forward-looking automatic adjustment clause, and a retrospective automatic adjustment clause – to achieve the goal of reasonably reflecting in rates the actual costs of providing service, given that some of these costs are uncertain on a forecast basis.

Exhibit 500 supports PGE's 2007 test year administrative and general costs. Inflation is a primary driver, particularly the higher inflation in benefit costs and pension costs during the last few years. Additional regulatory requirements in the accounting and finance areas, and some new functions, such as investor relations, also increase A&G costs.

Exhibit 600 explains PGE's transmission and distribution system, covering our maintenance practices, test year O&M, and capital amounts.

Exhibit 700 presents PGE's Customer Service functions and costs. This area is responsible for most interactions with retail customers, including response to customer requests and inquiries, meter services, billing, collections, and communication with customers.

Exhibit 800 explains PGE's proposed Advanced Metering Infrastructure system. As discussed above, PGE expects that an AMI system will generate cost savings, allow PGE to provide additional services to customers, and enable additional demand response programs.

Exhibit 900 presents PGE's human resource costs, which reflect our practice of setting each component of a total compensation package at the market median.

Exhibit 1000 presents PGE's proposals to decrease customers' annual contribution to the Nuclear Decommissioning Trust and return $20 million from the Trust, reflecting PGE's success in completing almost all of the work and the delays in a federal waste repository.

Exhibit 1100 supports PGE's forecasted cost of capital for 2007. It discusses PGE's cost of long term debt and the financial markets between 2001 and 2005 during which some of this debt was issued. It also addresses PGE's equity costs, applying the Discounted Cash Flow and Risk Positioning models to support a 10.75% return on equity.

Exhibit 1200 presents PGE's load forecast. PGE forecasts that total retail loads will increase 2.3% from the 2005 weather-adjusted level.

Exhibit 1300 explains PGE's proposed tariff, including the building blocks used to develop rates, the revenue requirement process, and marginal costs.

VI. Qualifications

Q. Mr. Piro, please describe your educational background and experience.

A. My name is James P. Piro. I received a Bachelor of Science degree from Oregon State University in Civil Engineering in 1974 with an emphasis in Structural Engineering. In addition, I have taken graduate courses in engineering, accounting, economics, and rate making. I am a registered Professional Engineer in Civil Engineering in the State of California (Registration No. 28174). I joined Portland General Electric in 1980 and have held various positions in Generation Engineering, Economic Regulation, Financial Analysis and Forecasting, Power Contracts, Economic Analysis, Planning Support, Analysis and Forecasting, and Business Development. I was elected Vice President of Business Development in 1998 and then became Chief Financial Officer and Treasurer on November 1, 2000. I was then named Senior Vice President, Finance, Chief Financial Officer and Treasurer on May 1, 2001, and entered my current position as Executive Vice President, Finance, Chief Financial Officer and Treasurer effective July 25, 2002.

Q. Ms. Lesh, please describe your qualifications.

A. I received a BA degree from Washington State University in 1978. I received my J.D. from the University of Washington School of Law in 1981. I was employed by Portland General Electric from 1986 to 1997, becoming Vice President, Rates & Regulatory Affairs in October of 1996. In June 1997, I became a Vice President of Strategy at Connext, Inc., where I supervised product management staff and strategic alliances as well as negotiating client contracts. In January 1999, I returned to PGE as Vice President, Rates & Regulatory Affairs.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

L. Alex Tooman
Jay Tinker

March 15, 2006

Revenue Requirement

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions with PGE.

A. My name is L. Alex Tooman. I am a project manager for PGE. I am responsible, along with Mr. Tinker, for the development of PGE's revenue requirement forecast. In addition, my areas of responsibility include affiliated interest filings, results of operations reporting, and other regulatory analyses.

My name is Jay Tinker. I am also a project manager for PGE. My areas of responsibility include revenue requirement analyses and other regulatory analyses.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present PGE's $1,645 million revenue requirement for the 2007 test period, before consideration of the incremental effects of Port Westward. On an average 2007 rate base of $1,748 million, this revenue requirement will allow PGE an opportunity to earn an 8.97% overall rate of return and a 10.75% return on an average common equity of 56% in 2007. PGE Exhibit 201, columns 1 through 3, summarizes the development of our revenue requirement.

In addition to presenting this integrated or bundled revenue requirement, we will also present and discuss our unbundled revenue requirement in Section IX.

Q. What increase in rates is PGE requesting?

A. PGE's revenue requirement is $25 million higher in 2007 than the revenues we would expect based on forecasted rates for the 2007 Resource Valuation Mechanism (RVM), and before consideration of the incremental effect of Port Westward. PGE requests that rates be adjusted on January 1, 2007 to yield $25 million of additional revenue (less than 2% overall) on an annualized basis. PGE Exhibit 1300 describes the prices that PGE proposes to allow us an opportunity to recover our revenue requirement.

Q. Is Port Westward included in your request for $25 million of additional revenues?

A. No. As shown in PGE Exhibit 201, columns 4 through 7, we calculate that the incremental annualized impact of Port Westward is an additional increase in revenue requirement of approximately $45 million. PGE requests that the Oregon Public Utility Commission (Commission or OPUC) authorize tariffs to collect this amount on an annualized basis beginning with the on-line date of Port Westward, which we currently expect to be March 1, 2007. To the extent that the on-line date of Port Westward changes, we would anticipate that the effective date of tariffs to recover the incremental impact of Port Westward would shift accordingly. In Section VIII, we discuss the derivation of the incremental revenue requirement of Port Westward.

Q. How did you develop the 2007 revenue requirement?

A. We developed the 2007 revenue requirement based on PGE's 2006 budget, escalated for inflation and known and measurable changes.

Q. What inflation rates did you use to escalate the 2006 budget to 2007?

A. We applied the following escalation rates to the 2006 budget:

- Union Labor = 3.00% effective March 1, 2007
- Non-Union Labor = 4.50% effective April 16, 2007
- Executive Labor = 6.00% effective January 1, 2007
- Outside Services (CE 21, 26, 41, 49) = 3.80% effective 1/1/2007
- Direct Materials (CE 31, 36) = 0.90% effective 1/1/2007
- Employee Business Expenses (CE 61, 68) = 1.60% effective 1/1/2007

Q. Please summarize PGE's 2007 revenue requirement.

A. Table 1 below summarizes PGE's 2007 revenue requirement, before the impact of Port Westward, by major category, and provides a comparison to PGE's 2004 actual costs and the UE 115 2002, test year amounts. We also list the PGE witnesses that address the specific cost categories and provide a graphical representation of the 2007 and 2002 test year revenue requirement components in Figures 1 and 2.

Table 1
Revenue Requirement Summary ($000s)

Revenue Requirement Category	UE 115 2002 Test Year	2004 Actual[1]	2007 Test Period Before PW	Witness and Exhibit Number
Sales to Consumers	$1,503,222	$1,318,041	$1,644,624	Tooman - Tinker, 200
Other Revenue	$15,969	$28,897	$17,728	Tooman - Tinker, 200
NVPC	$757,921	$560,233	$856,968	Lesh - Niman, 400
Production O&M	$70,458	$68,924	$72,188	Quennoz - Schue, 300
Transmission O&M	$6,273	$7,637	$10,279	Hawke, 600
Distribution O&M	$56,968	$50,630	$60,336	Hawke, 600
Customer Service	$44,465	$59,924	$68,732	Hawke, 700
A&G	$93,980	$87,154	$109,785	Piro - Tooman, 500
Depr. &Amort.	$178,593	$233,320	$173,232	Tooman - Tinker, 200
Other Taxes	$75,093	$71,957	$85,981	Tooman - Tinker, 200
Income Taxes	$74,981	$56,587	$68,111	Tooman - Tinker, 200
Operating Income	$160,458	$150,572	$156,740	
ROE	10.50%	9.80%	10.75%	Hager -Valach, 1100

1: 2004 Actuals per Results of Operations Report. Sales for Resale are netted against power costs.

Figure 1
2007 Test Year Revenue Requirement (Before PW)

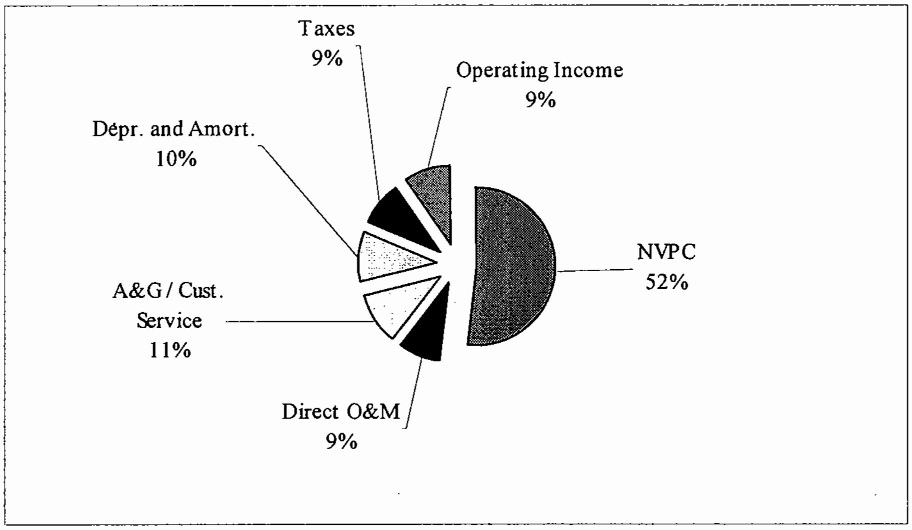
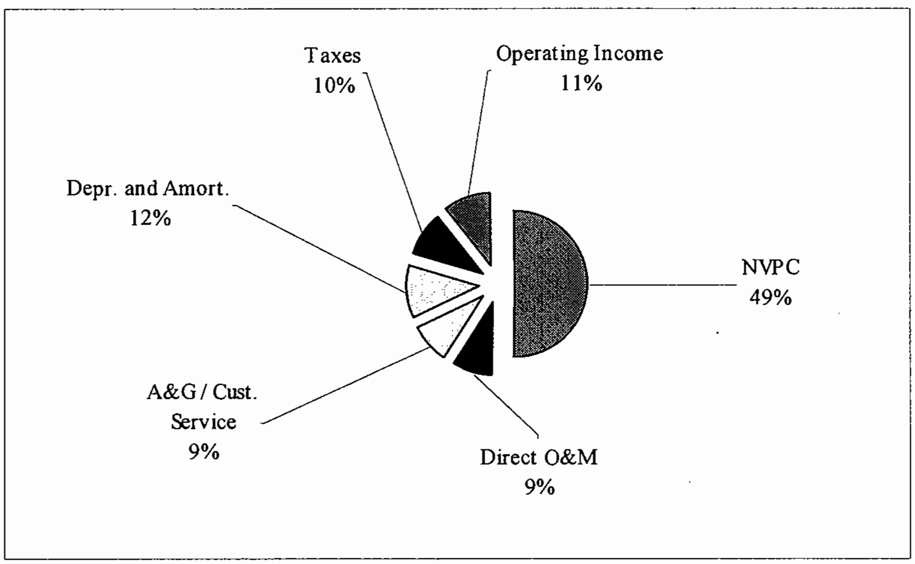


Figure 2
UE 115 2002 Test Year Revenue Requirement



Q. Why did you include 2004 data in Table 1 above?

A. 2004 was the most recent actual calendar-year data available in preparation of the 2006 budget and 2007 test year.

Q. What is Operating Income in Table 1 and Figures 1 and 2?

A. Operating Income consists of a return to those who provide capital to PGE, both equity and debt. The costs of obtaining capital are discussed in PGE Exhibit 1100.

Q. Did you adjust PGE's 2007 revenue requirement to reflect previous rate-making decisions and other regulatory policies?

A. Yes. We made the following regulatory adjustments, summarized in Table 2 below.

Table 2
Regulatory Adjustments ($Millions)

Regulatory Adjustment Item	O&M	Rate Base
Retail Services	$(0.1)	$(0.3)
Charitable Contributions	$(1.0)	
Memberships and Dues	$(0.1)	
MDCP	$(5.1)	
SERP	$(1.5)	
Corp Image Advertising	$(1.1)	
Total Adjustments	$(8.9)	$(0.3)

Q. Please explain these regulatory adjustments.

A. Each adjustment is discussed below.

- Retail Services: removed $0.1 million of O&M and $0.3 million of rate base per the SB 1149 unbundling rules.
- Charitable Contributions: removed $1.0 million from cost of service.
- Memberships and Dues: removed $0.1 million, which is all of the memberships and dues except those approved in UE 115. The adjustment includes the removal of 25% of Edison Electric Institute (EEI) membership dues, consistent with

UE 88 (the last case in which PGE was a member of EEI) and EEI's recent estimate of lobbying expenses.

- Managers Deferred Compensation Plan (MDCP): removed $5.1 million to reflect the Commission's historical policy regarding MDCP.
- Supplemental Executive Retirement Plan (SERP): removed $1.5 million to reflect the Commission's historical policy regarding SERP.
- Corporate Image Advertising: removed $1.1 million to reflect the Commission's historical policy regarding image advertising.

II. Other Revenue

Q. What is PGE's 2007 forecast of other revenues, and how does it compare to prior years?

A. PGE forecasts 2007 other revenues of $17.7 million. This compares to UE 115 test year other revenue of $16.0 million and actual 2004 other revenue of $16.6 million[1].

Q. What are the sources of other revenue?

A. The primary sources of other revenue are rent of electric property, transmission revenues, joint-pole revenues, steam revenues, ancillary service revenues, and revenue from affiliates. PGE Exhibit 202 provides the sources and amounts of other revenues, summarized in Table 3 below.

Table 3
Other Revenue ($000s)

Other Revenue Item	2002 Test Year	2004 Actuals	2007 Test Year
Utility Prop. Rental	$7,097	$6,333	$6,083
Intertie/Other Trans	$4,852	$5,522	$5,635
Late Payment Charges	$950	$1,092	$1,250
Steam Sales	$1,143	$1,111	$1,419
Other Misc. Revenues	$1,930	$2,534	$3,341
Total Other Revenue	$15,971	$16,592	$17,728

[1] Total Other Revenue for 2004 was $28.9 million as reported in PGE's 10K. However, $12.3 million of this total represents power trading accounts and adjustments such as FAS 133 that are not incorporated into the test year. On a comparable basis, PGE's actual Other Revenue for 2004 totals $16.6 million.

III. Depreciation

Q. What is PGE's estimate for 2007 depreciation expense?

A. We estimate $154.4 million in depreciation expense for the 2007 test year. PGE Exhibit 203 summarizes the test year depreciation expense by plant type and provides a comparison to UE 115. PGE currently uses the straight-line method, unit summation procedure, remaining life technique for all plant investment, as approved by the Commission in Docket UM 982 and implemented in October 2001.

Q. Is PGE proposing to change its depreciation method for this filing?

A. Yes. PGE is proposing a life span methodology for all steam and combustion plant assets. The life span methodology recognizes that assets have a finite terminal date, and replaces the probabilistic approach previously used with Iowa curves. In addition, we are proposing to update expected useful service lives and net salvage rates as a result of a comprehensive depreciation study we prepared in the summer of 2005. The study was based on year-end 2004 data and filed with the Commission on November 9, 2005. The changes, in aggregate, decrease 2005 depreciation expense by $13.2 million as shown on PGE Exhibit 204. The Commission is reviewing our depreciation study in UM 1233.

Q. When do you propose to put the proposed depreciation changes into effect?

A. PGE proposes that the changes take effect for accounting purposes as of the date our proposed tariffs in this docket become effective, which we expect to be January 1, 2007.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life, but it relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of assets generally appears in rate base and earns a return at the allowed rate.

Q. Please summarize PGE's 2007 amortization expense.

A. PGE Exhibit 205 details the total 2007 amortization expense of $18.8 million, which we summarize in Table 4. The exhibit also shows comparable figures from the UE 115 2002 test year and actuals over the period 2002 through 2004. PGE has six sources of amortization expense for the 2007 test period:

- Intangible Plant
- Trojan Decommissioning
- Colstrip Common Facilities
- Coyote Major Maintenance Accrual and Amortization
- SB 1149 One-Time Expenses
- Coyote Permit Amortization

We did not include the amortization of deferred property sale gains, ISFSI credits or deferred SB 1149 costs since we propose to refund/collect these items through supplemental tariffs as explained in Section X below.

Table 4
Amortization ($000s)

Amortization Item	2002 Test Year	2004 Actuals	2007 Test Year
Intangible Depreciation	$12,274	$14,541	$13,251
Trojan Decommissioning	$14,041	$14,041	$4,646
Other Reg. Debit Amortization	$508	$54,970	$3,943
Other Reg. Credit Amortization	$0	$(4,444)	$(2,992)
Total Amortization	$26,823	$79,108	$18,848

Q. Please explain the amortization of Intangible Plant included in PGE's 2007 amortization expense.

A. Total Intangible Plant amortization is $13.3 million, which primarily represents the amortization of capitalized software expense.

Q. Please explain the Trojan Decommissioning cost estimate.

A. As detailed in PGE Exhibit 1000, PGE proposes to extend the collection period for Trojan decommissioning costs through the current forecast of ISFSI decommissioning in 2024, rather than collecting through 2011. Based on this change, an update to overall costs to reflect the significant savings that have been achieved, and an update to the other relevant parameters, the decommissioning accrual falls from $14.0 million to $4.6 million.

Q. Has the Colstrip Common Facilities amortization changed?

A. No. We are continuing to amortize this asset as required under prior Commission order.

Q. What is the Coyote Major Maintenance Accrual and Amortization?

A. In UE 93 (OPUC Order No. 95-1216), the Commission approved an accrual and balancing account treatment for Coyote's major maintenance costs. PGE has a long-term service agreement with General Electric to cover major maintenance activities. The major maintenance accrual is based on a multiple-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multiple-year period. PGE's estimate for the 2007 test year is an accrual of $2.0 million, down from the UE 115 accrual of $4.1 million. An estimate of the 2007 average balance in the balancing account of $6.1 million is also included as a credit against rate base.

Q. What are the SB 1149 one-time costs?

A. In UE 115, PGE stipulated to recover certain one-time expenses related to the implementation of SB 1149. The stipulation called for a six-year amortization of these one-time costs[2]. For the 2007 test year, one year's worth of amortization of these costs remains at $1.5 million.

Q. Has PGE included a forecast of property sale gains for the test year?

A. No. In UE 115, PGE stipulated to a deferral mechanism for all utility property sale gains and losses. PGE refunds/collects the balance through a supplemental tariff. We propose to continue the deferral mechanism with this rate case. Since actual gains/losses will be deferred, we do not include any cost of service reduction in the revenue requirement to establish base rates.

[2] See OPUC Order No. 01-777, Appendix B (S-44)

V. Income Taxes, Taxes Other Than Income, and Fees

A. Income Taxes

Q. What is PGE's 2007 estimate of Income Taxes?

A. PGE's 2007 test period Income Tax expense is $68 million, before the impact of Port Westward. PGE Exhibit 206 details the test period calculation of Income Tax expense. This compares to 2004 actual Income Tax expense of $57 million and UE 115, 2002 Test Year Income Tax expense of $75 million. The decrease in 2007 Income Tax expense compared to UE 115 relates primarily to a small decrease in taxable income and a reduction in PGE's effective tax rate.

Q. What methodology did you use to establish an estimate of Income Tax expense for the 2007 test year?

A. We used the "stand-alone" method to determine the test year Income Tax expense. This method uses as inputs only those costs and revenues included in our requested test year revenue requirement to determine the Income Tax expense for the test year. The Commission has traditionally used this approach to determine the Income Tax expense in test year ratemaking.

Q. Does Senate Bill 408, or the associated OPUC rule-making docket (AR 499), impact your estimate of income taxes for this case?

A. No. The Commission has yet to establish permanent rules for implementing SB 408, including the required Automatic Adjustment Clause to capture differences between "Taxes Authorized to be Collected in Rates" and "Taxes Paid." Given the nascent stage of AR 499, it is not appropriate to include any adjustment to PGE's revenue requirement as a result of SB 408/AR 499.

Q. Does PGE currently pay income taxes to government entities?

A. No. As of March 2006, PGE is still part of Enron's consolidated income tax filing. As a result, PGE makes payments to Enron to cover our stand-alone tax liability. Enron's payments to government entities are based on its consolidated tax return, reflecting the impact of operating results from all the entities (including PGE) which form the basis of Enron's consolidated tax return.

Q. Do you expect this to continue?

A. No. We expect that the issuance of PGE stock to or for the benefit of Enron's creditors will occur in April 2006. After that issuance, we will be deconsolidated from Enron for tax filing purposes and will pay income taxes directly to the appropriate government entities based on our actual tax liabilities.

Q. What income taxes will PGE pay?

A. PGE will pay income taxes to the Federal government and the States of Oregon and Montana. PGE will also pay income taxes to local government entities such as Multnomah County.

Q. What are the marginal tax rates for PGE?

A. The Federal marginal tax rate is 35.00%, the State of Oregon marginal tax rate is 6.60%, and the State of Montana marginal tax rate is 6.75%. These are the same marginal tax rates as in UE 115.

Q. What is PGE's composite state tax rate for this filing?

A. PGE's composite state tax rate is 6.617%. The rate is calculated by multiplying the Oregon and Montana marginal tax rates by their respective allocation factors of 96.16% and 4.00% and then summing the weighted rates.

Q. What is PGE's total composite tax rate for this filing?

A. PGE's total composite tax rate for this filing is 39.30%. It is the sum of the Federal marginal tax rate and the state composite tax rate, less the effects of their interaction, or:

$$35.00\% + 6.617\% - (35.00\% * 6.617\%) = 39.30\%$$

Q. Why did you exclude tax rates for local jurisdictions (Multnomah County and City of Portland) from the calculation of the composite tax rate?

A. PGE will charge Multnomah County Business Income Taxes to customers in Multnomah County as a tariff rider to comply with OAR 860-022-0045. As such, we do not include an estimate of the costs as part of our revenue requirement, which is generally allocated to all customers. The City of Portland Business License Fee, which is an income based tax, would also be subject to OAR 860-022-0045. However, the current application of the City of Portland Business License Fee is predominantly non-utility in nature. Therefore, we exclude the tax in our revenue requirement and from any tariff rider.

Q. Did you include an estimate of state tax credits in your estimate of Income Tax expense for 2007?

A. Yes. We have included an estimate of $166,000 in state tax credit amortization for 2007. The state tax credits are pollution control tax credits (except ISFSI tax credits) that have been awarded to PGE for qualifying pollution reducing projects.

Q. Why did you exclude ISFSI tax credits as a reduction in State Income Tax expense?

A. ISFSI tax credit amortization is excluded because, as required by OPUC Order No. 05-136, PGE is deferring ISFSI tax credits as they are used to offset our current Oregon tax liability. Since customers will receive the benefit of the ISFSI tax credits through the deferral mechanism, we exclude their effects on cost of service in the test year.

Q. Did you exclude Business Energy Tax Credits (BETC) from the calculation of Income Tax expense?

A. Yes. We agreed with the OPUC Staff in 2003 that shareholders should bear the costs and benefits of most BETCs. A copy of the letter recording this understanding is included in our work papers. PGE assigns the cost and benefit of BETCs associated with the Clean Wind Development Fund back to the Fund.

Q. Are there any changes to the calculation of income taxes relative to UE 115?

A. Yes. We also included a $4 million deduction for the 2007 test year to reflect the 2005 Tax Act related to domestic manufacturing. The Tax Act provides for a permanent deduction against taxable income that is related to domestic manufacturing; producing electricity is considered domestic manufacturing[3]. The Tax Act provides for a staggered increase in the deduction over time, with an initial deduction of 3% of taxable income that relates to domestic manufacturing, increasing to 6% in 2007 and to 9% in 2009. The estimate for 2007 is based on a 6% deduction.

B. Taxes Other Than Income & Fees

Q. What is PGE's test period total of Fees and Taxes Other Than Income?

A. As shown in PGE Exhibit 207, total fees and taxes other than income are $86.0 million. This compares to the UE 115, 2002 test year total of $75.1 million. The primary sources of the increase from the UE 115, 2002 test period are:

- Franchise Fees: from $34.0 million to $38.5 million in 2007.
- Payroll Taxes: from $8.7 million to $11.6 million in 2007.
- Property Taxes: from $31.5 million to $34.7 million in 2007.

[3] IRS Section 199 codifies the 2005 Tax Act. Per Section 199(c)(4)(A)(i)(III) of the Tax Code, taxable income from the production of electricity is eligible for the deduction.

- Other Miscellaneous Fees: from $0.9 million to $1.2 million in 2007.

Q. What is PGE's estimate of Franchise Fees for 2007?

A. The total test period Franchise Fees are $38.5 million, representing expected costs from the 52 cities that charge PGE Franchise Fees.

Q. How did PGE estimate Franchise Fees?

A. The estimate of Franchise Fees is based on PGE's historical experience of incurred cost relative to retail tariff revenue. While cities have the option of selecting a volumetric method for charging these fees based on OAR 860-022-0040, our experience has been that cities continue to charge using the revenue-based computation. Based on this rule, cities can charge up to 3.5% of gross revenues that will be included in PGE's revenue requirement.

Q. Can cities charge Franchise Fees in excess of 3.5% of gross revenue?

A. Yes. We charge the incremental Franchise Fees above 3.5% directly to customers of the franchise area, consistent with OAR 860-022-0040. Therefore, we do not include these costs in PGE's revenue requirement.

Q. Are Franchise Fees included in PGE's estimate of the net to gross factor for calculating revenue requirements?

A. Yes. Consistent with the unbundling requirements of OAR 860-38-0200, we separately itemize the impact of our incremental revenue needs on Franchise Fees in order to directly assign the incremental costs to the Distribution function. The Franchise Fee rate used to determine this revenue-sensitive cost is 2.34%.

Q. Why have Franchise Fees increased between the 2002 test period used in UE 115 and the 2007 test period?

A. Franchise Fees have increased from $34.0 million in the 2002 test period to $38.5 million in 2007 because of increased revenues in those jurisdictions for which a Franchise Fee is applicable.

Q. What is PGE's estimate of Payroll Taxes for 2007?

A. PGE has included $11.6 million in Payroll Taxes for the 2007 test period.

Q. Why have PGE's Payroll Taxes increased from the UE 115 2002 test year to 2007?

A. Payroll Taxes have increased from $8.7 million in UE 115 to $13.5 million in 2007 primarily as a result of a larger payroll, including additional employees and wage increases at PGE. The 10.5% Payroll Tax rate for 2007 is the same as UE 115, but we applied the rate to a larger wage and salary base in 2007.

Q. What is PGE's estimate of Property Taxes for 2007?

A. PGE has included $34.7 million in Property Taxes for the 2007 test period.

Q. Why have PGE's Property Taxes increased from the UE 115, 2002 test year to 2007?

A. The primary reason for the increase in Property Taxes from $31.5 million in the UE 115, 2002 test period to $34.7 million in 2007 is an increase in tax assessed values and Property Tax rates from the 2002 test year to the 2007 test year.

VI. Capital Expenditures

Q. What are PGE's total 2007 capital expenditures?

A. As shown in PGE Exhibit 208 and summarized in the table below, PGE forecasts $231.7 million in total utility capital expenditures for 2007.

Table 5
Capital Expenditures ($ millions)

Capital Expenditures	2002 TY	2004 Act	2007 TY	Witness / Exhibit Number
Steam Production	$2.2	$17.0	$9.4	Quennoz – Schue, 300
Hydro Production	$10.1	$5.2	$3.0	Quennoz – Schue, 300
Other Production	$4.5	$5.0	$4.0	Quennoz – Schue, 300
Port Westward	$0.0	$12.5	$14.0	Quennoz – Schue, 300
Relicensing Construction	$7.3	$6.9	$37.5	Quennoz – Schue, 300
Transmission	$10.1	$6.1	$7.0	Hawke, 600
Distribution	$106.3	$111.8	$121.4	Hawke, 600
General Plant	$32.8	$15.3	$22.8	Various
Intangible Plant	$6.5	$15.4	$12.6	Various
Total Capital Additions	$179.8	$195.3	$231.7	

The capital expenditures forecasted for 2005 through 2007 relate to a number of projects detailed in other exhibits and work papers. Some of the major projects include relicensing work on the Clackamas and Pelton and Round Butte hydro projects as well as the Port Westward project.

Q. How does PGE account for capital expenditures?

A. As PGE spends capital for utility projects, we record it as Construction Work In Progress (CWIP), a non-rate base account. Once the project is completed, PGE moves the capital expenditures (and associated Allowance for Funds used during Construction) from CWIP to Plant In Service accounts. Once moved to Plant In Service accounts, the project becomes part of PGE's rate base with associated depreciation expense and property tax expense recorded in the appropriate income statement accounts.

Q. When do you expect Port Westward will close to Plant In Service?

A. Port Westward will close to Plant In Service when it becomes operational, currently expected on March 1, 2007.

Q. Are there any significant capital expenditures that PGE does not believe will close to Plant In Service in 2007 and thus not included in rate base?

A. Yes. We project $80.0 million in relicensing project costs over the 2005-2007 period associated with the Clackamas river projects. These projects will close to Plant In Service with the issuance of the new FERC licenses for the Clackamas projects, which we currently expect after the test year.

VII. Rate Base

Q. What is PGE's 2007 average rate base and what does it include?

A. The total 2007 average rate base is $1,748 million, before the inclusion of Port Westward. PGE Exhibit 209 provides the details of the 2007 average rate base, which includes PGE's investment in Plant In Service, net of Accumulated Depreciation, Accumulated Deferred Taxes, and Accumulated Investment Tax Credits (ITC). In addition, the average rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2007 rate base compare to rate base in UE 115 for the 2002 test year?

A. PGE Exhibit 210 shows that for the UE 115, 2002 test year, average rate base was $1,767 million. Since UE 115, PGE's average rate base has fallen by $19 million, before Port Westward, as the net result of several factors. The major changes include:

- The effects of customer growth on our distribution system, increasing rate base by $163 million.
- Higher fuel stock requirements, reflecting both higher prices for fuel and the need for greater inventories, increasing rate base by $11 million.
- Greater working cash needs as a result of higher operating expenses and a higher working cash rate, increasing rate base by $17 million.
- Miscellaneous other changes, including depreciation of prior vintage Plant In Service, additions, deferred tax changes, and other changes that decrease rate base by $210 million.

Q. How did you treat Beaver 8 for this filing?

A. PGE entered into a stipulation in 2004 with CUB and Commission Staff. We agreed that $14.2 million of Beaver 8 capital costs should be assigned to customers. We also agreed to divide this amount into two parts.

Q. What was the first part of the overall $14.2 million customer payment?

A. The Parties agreed to $4 million as the value (market value of turbine, plus site improvements) of Beaver 8 and to add that plant to PGE's rate base on August 1, 2004. The Parties also agreed to support inclusion of Beaver 8 in PGE's rate base in its next general rate case. In addition, they agreed to support inclusion of related depreciation and prudently incurred operations and maintenance expenses in the test year revenue requirement in PGE's next general rate case, which is this filing.

Q. Have customers benefited from regulatory lag on the Beaver 8 plant placed in rate base on August 1, 2004?

A. Yes. Customers have paid neither a return *on* nor return *of* for the $4 million generating asset. This customer benefit began on August 1, 2004, and will continue until the effective date of tariffs established in this proceeding.

Q. Have you included this $4 million (net of depreciation since August 1, 2004), associated depreciation expense, and O&M expenses in the test year revenue requirement calculation?

A. Yes.

Q. What was the second part of the overall $14.2 million customer payment?

A. The Parties to the 2004 Stipulation agreed that, beginning August 1, 2004, PGE would account for the remaining $10.2 million as a regulatory asset, with interest accrual consistent with Commission policy, currently at PGE's authorized cost of capital. Specifically, the Parties agreed to support collection of the regulatory asset and associated interest through PGE's Tariff Schedule 105 during the five-year period beginning January 1, 2005, subject to two provisions:

- Excluding the effect of interest, PGE will collect no more than 60 percent of the $10.2 million initial balance prior to January 1, 2007.
- If prior to the effective date of a Commission order setting rates in PGE's next general rate case, the Commission issues an order allowing addition of new rate base assets on a cost basis, then beginning on the effective date of rates set in PGE's next general rate case, PGE will amortize the outstanding balance of the regulatory asset over the remaining projected useful life of Beaver 8. The test year rate base will include the average unamortized balance, and the test year revenue requirement will include associated amortization and prudently incurred operations and maintenance expenses.

In addition, the Parties agreed that PGE would transfer existing accumulated deferred taxes related to Beaver 8 from non-regulated to regulated books.

Q. Has PGE begun amortizing the regulatory asset?

A. Yes. PGE began amortization on January 1, 2005, at which time the balance was $10.6 million ($10.2 million plus interest at 9.083%). Annual collections through Schedule 105 are approximately $2.7 million.

Q. Has the Commission determined that utilities can add new rate base assets on a cost basis?

A. No. In OPUC Order No. 05-133 the Commission specified that its decision is pending "resolution of Dockets UM 1056 and UM 1182, completion of an investigation into performance-based ratemaking, and a determination of whether a large customer opt-out of new generating resources for PGE and PacifiCorp is possible." However, the Commission may rule on allowing inclusion of new generation assets in rate base at cost prior to a decision on rates in this proceeding.

Q. Does the test year rate base include what is currently the regulatory asset?

A. Yes. We have added the forecast unamortized regulatory asset balance ($7.0 million at the end of 2006) to 2007 test year Plant In Service, with a depreciable life based on the expected life of Beaver 8.

If the Commission does not rule in UM 1066 that utilities may add new generation assets to rate base at cost, or if the Commission rules to the contrary, then PGE will remove this amount from the test year rate base and continue collection of the regulatory asset through Schedule 105.

Q. Does the 2004 Stipulation contain other provisions?

A. Yes. The 2004 Stipulation contains three other provisions. One relates to Beaver 8's net variable margins from August 1, 2004, to the later of December 31, 2006, or the effective date of rates set in PGE's next general rate case (effectively, this proceeding). Another governs a stipulated reduction in PGE's power costs from August 1, 2004, to the effective date of rates set in PGE's next general rate case. A third provision requires PGE to include in the next general rate case filing a cost-benefit analysis of selling Beaver 8 rather than retaining it as a capacity resource.

Q. What does the Stipulation provide regarding Beaver 8's net variable margins?

A. For the period from August 1, 2004, to the effective date of rates set in this proceeding, PGE will track, on a daily on- and off-peak basis, the net variable margins associated with Beaver 8's operations, including testing. PGE will use the daily Dow Jones Mid-Columbia Firm on- and off-peak electric indices and the daily Sumas gas index for the calculations, which will also include gas transportation, line losses, and variable O&M. PGE will then include 50% of these variable margins as an offset to the $10.2 million regulatory asset and associated interest described above.

Q. What have Beaver 8's net variable margins been since August 1, 2004?

A. Margins have been slightly negative using the technique described above – approximately negative $7,000. We ran Beaver 8 on three occasions during the summer of 2005 and three occasions during the fall of 2005. While a literal reading of the 2004 Stipulation would allow us to add $3,500 to the balance of the regulatory asset, we have not done so.

Q. How did the 2004 Stipulation affect power costs?

A. A provision directs that PGE reduce power costs by $50,000 per year, beginning August 1, 2004. PGE implemented this in Section B of Schedule 125 in PGE's 2005 and 2006 RVM filings. PGE's 2005 RVM filing included a $70,902 reduction related to the period from August 1, 2004 through December 31, 2005. PGE's 2006 RVM filing included a $50,000 reduction. Our 2007 RVM filing will also include a $50,000 reduction.

Q. Did PGE perform the cost-benefit analysis required by the Stipulation?

A. Yes. PGE has performed the analysis and determined that it is not cost-effective for customers to sell Beaver 8 and replace it with an alternative capacity resource. Acquiring an equivalent capacity resource (i.e., an approximately 25 MW resource with a heat rate of approximately 11,600 MMBtu per MWh) would cost customers $21 per kW-year, based on recent PGE purchases. The benefit to customers of 95% of the net gain from selling Beaver 8, i.e., 95% of the base sale price net of any associated packing, removal, and restoration costs, would be no more than $3.8 million. Research and discussion with equipment brokers indicate that the market value of Beaver 8 is in the $2 million to $4 million range. The net benefit might well be at the lower end of this range, for these reasons:

- Buyers would have to pay to have it disassembled, packaged, and shipped.
- Most buyers in the U.S. market are familiar with and more likely to purchase GE LM2500 or Frame 5 combustion turbines (CT).
- European buyers (who are familiar with the Alstom unit) want 50 Hz CTs that can run on dual fuels (diesel and natural gas). Beaver 8 is 60 Hz and can run only on natural gas.

Assuming an expected remaining useful life of 19 years, consistent with the 2007 test year and the unit's depreciation schedule, retaining Beaver 8 will cost customers less than $14 per kW-year on a real levelized basis (2007$). It does not make sense for customers to sell Beaver 8 and receive (at most) approximately $3.8 million, and then turn around and effectively spend more than that amount to purchase an alternative capacity resource. The work papers provide an analysis that translates the $3.8 million maximum expected benefit into a figure of $1.11 per kW-month, or less than $14 per kW-year. The work papers also include a copy of PGE's response to OPUC Staff Data Request No. 039 in Docket LC-33, which documents the $21 per kW-year cost of alternative capacity resources.

Q. What is working cash?

A. Working cash is the necessary funds provided by investors on a permanent basis to finance the timing difference between the cash received from billings and the cash paid for operating expenses. To determine the necessary working cash allowance, we use a lead lag study to measure the average number of days between the following activities:

- Providing services and receiving payment, known as revenue lag
- Incurring expenses and making payment, known as expense lag

We determine the number of days between the activity and the payment (a lag) for each source of revenue and expense and multiply it by the amount of the associated revenue or expense to determine the "dollar days." The dollar days represent a weighted lag for each expense and revenue item. The revenue lag minus the expense lag yields the net "excess lag," which is used to determine the working cash allowance factor. In UE 115, the working cash allowance factor was 4.46%.

Q. What working cash allowance factor do you propose for this filing?

A. PGE proposes a 5.20% working cash allowance factor. This is based on the updated lead lag study included in the work papers and summarized in PGE Exhibit 211. The factor has increased from UE 115 as a result of the dominant influence that power costs have on our expense lag relative to the prior study.

Q. How do you use the working cash factor allowance in this filing?

A. We applied the working cash factor allowance to PGE's total 2007 operating expenses of $1,506 million, resulting in the working cash rate base amount of $78 million. The return on the working cash rate base amount compensates PGE for the financing cost of its excess lag.

VIII. Port Westward

Q. What is the annual revenue PGE requires as a result of the addition of Port Westward?

A. As shown in PGE Exhibit 201, PGE requires an additional $45 million annually for Port Westward's expected operating costs, net of dispatch benefits, as well as to provide a reasonable return on investment, including a 10.75% ROE, as supported by PGE Exhibit 1100.

Q. How did you estimate the operating costs of Port Westward?

A. We estimated the operating costs on an annualized basis, reflecting the first full year of operations. Port Westward's O&M costs of $8.4 million and depreciation expense of $10.7 million reflect a full year's costs.

We derived the dispatch benefits of Port Westward by taking the dispatch benefits for the first 10 months of operations (i.e., March 1, 2007 through December 31, 2007) and multiplying them by the ratio of 12 month loads / 10 month loads.

Finally, the rate base balance for Port Westward reflects an average balance over the first full year of operation.

Q. Do you propose a major maintenance accrual for Port Westward?

A. No. Port Westward's major maintenance contract provides for a more levelized annual cost, unlike the contract for Coyote Springs. As a result, we do not expect the significant year-to-year volatility that an accrual would help dampen. Port Westward's major maintenance contract is described further in PGE Exhibit 300.

Q. Does annualizing the dispatch benefits of Port Westward as you describe above result in a fair recovery of PGE's net variable power costs for 2007?

A. Yes. Setting rates to collect a forecast of annual net variable power costs without Port Westward for two months, coupled with rates set to reflect the annualized dispatch benefits of Port Westward beginning March 1, 2007, as described above, results in a collection over calendar 2007 that equals PGE's expected net variable power costs for 2007.

Q. Is PGE requesting rates to recover Port Westward costs effective January 1, 2007?

A. No. As explained in PGE Exhibit 1300, we are requesting rates effective with the on-line date of Port Westward, which we expect to be March 1, 2007. If the on-line date of Port Westward changes, we would suggest updating the estimate of dispatch benefits to reflect the annualized dispatch benefit beginning with the assumed on-line date. The annualized fixed costs of Port Westward should only be minimally affected by the on-line date (e.g., monthly inflation on O&M) and are likely immaterial for small changes in the on-line date.

IX. Unbundling

Q. Have you unbundled the revenue requirement presented in this testimony pursuant to OAR 860-38-0200?

A. Yes. PGE Exhibit 212 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-38-0200, into the required functional areas or revenue requirement categories. In addition, the unbundled revenue requirement is provided with and without Port Westward. Table 6 below summarizes the unbundled revenue requirement for 2007.

Table 6
Unbundled Revenue Requirement ($millions)

Functional Category	2007 Revenue Requirement without Port Westward	2007 Revenue Requirement with Port Westward
Production	1,086.0	1,127.4
Transmission	28.6	31.0
Distribution	423.8	424.9
Metering	18.1	18.1
Billing	33.1	33.1
Other Consumer Services	49.5	49.5
Ancillary Services	5.4	5.4
Retail Services	----------	----------
Public Purposes	Collected by separate tariff	Collected by separate tariff
Total	1,644.6	1,689.5

The sum of the unbundled revenue requirements for these services equals the integrated revenue requirement presented in PGE Exhibit 201.

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on investment – to calculate the revenue requirement for each unbundled service in accordance with 860-038-0200(9)(d).

Q. How did you unbundle PGE's expenses and other revenue?

A. We unbundled expenses and other revenue by analyzing each ledger within those categories. First, we determined which ledgers could be directly assigned to one of the functional categories listed in Table 8 above. Second, we evaluated those ledgers that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and other revenue ledgers assigned or allocated?

A. The majority of ledgers have a direct relationship with a single functional area and we assigned these ledgers based on OAR 860-038-0200(9)(b)(A) through (E). The largest category of allocated costs is A&G. We assigned these costs to a "Support" category and then we allocated the costs to the functional areas based on labor dollars for those areas. Other costs, such as Property Taxes, payroll taxes, income taxes, and the write-off of uncollectible accounts, relate to factors such as net plant, labor, net income, or total revenue. We allocated these costs based on the respective share of those factors per functional area in accordance with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation and amortization, we "functionalized in the same manner as the respective Plant accounts." – see OAR 860-038-0200(9)(c)(A).

Q. Did you allocate any expense or other revenue ledgers to retail or non-utility?

A. No, for two reasons. First, we forecast no labor costs in the ledgers we assigned to retail. As a result, the labor allocation factors will include zero percent to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these ledgers already receive allocations for corporate governance (i.e., A&G / Support costs) and service providers (i.e., facilities, IT, and print and mail services). Therefore, unbundling Support costs to non-utility ledgers would apply these costs twice.

Q. How did you unbundle rate base?

A. There are two broad categories of rate base that we evaluated for unbundling: 1) Plant In Service with associated depreciation reserve accumulated deferred taxes, and accumulated investment tax credits; and 2) other rate base. For Plant In Service, we assigned most assets and their associated contra accounts in accordance with OAR 860-038-0200(9)(a)(A) through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro generating plants, transmission towers and conductors, and distribution poles, conductor, substations, transformers, and service drops). Some general and intangible plant was directly assigned but the majority of these two categories consist of many smaller assets so we allocated them based on labor.

Q. How did you unbundle Other Rate Base?

A. We assigned or allocated Other Rate Base based on the criteria established in OAR 860-038-0200(9)(a)(G). Specifically, we evaluated Other Rate Base on a ledger-by-ledger basis and directly assigned where applicable (e.g., fuel inventories were assigned to generation). For other categories, we allocated the costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on labor).

Q. Why does the Distribution revenue requirement change with Port Westward?

A. With the additional revenues necessary to cover Port Westward's operating and financing costs, PGE incurs additional Franchise Fees as well. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), Franchise Fees are part of the Distribution revenue requirement.

X. Accounting Changes Since UE 115 / Miscellaneous

A. Accounting Changes

Q. What is the major change in accounting since UE 115?

A. The implementation of FAS 143, regarding accounting for implementation of asset retirement obligations (ARO), is the biggest change in accounting since UE 115. FAS 143 required the recognition of legal obligations for dismantlement and restoration costs related to the retirement of long-lived assets. Amounts were recognized as a long-term liability for these ARO obligations and additional carrying amounts were added to the capitalized costs of long-lived assets. The capitalized ARO costs added to the long-lived assets are depreciated over the life of the asset, with annual accretion of the ARO liability.

Q. Does FAS 143 cause a change in PGE's revenue requirement for the 2007 test year?

A. No. The derivation of depreciation expense and the depreciation reserve remain unchanged.

B. Deferred Accounts

Q. What are deferred accounts?

A. As used in this filing, deferred accounts are regulatory assets or liabilities that the Commission has established by order or action. We propose a specific accounting/rate treatment for each item.

Q. Please describe your proposed treatment for specific deferred accounts.

A. For existing deferred accounts that are being recovered/refunded through supplemental tariffs, we generally propose to continue the existing treatment. These items include:

- Deferred SB 1149 Costs: Amounts are currently being collected by Schedule 105 through 2008.

- Deferred Utility Property Sale Gains/Losses: Amounts are currently being refunded through Schedule 105.
- Deferred Category A Advertising Expenses: Amounts are currently being collected through Schedule 105.
- DSM Refinancing: Amounts are currently being collected through Schedule 107.
- Beaver 8 Regulatory Asset: As explained in Section VII above, we propose to transfer the asset from a regulatory asset to Plant In Service and add it to our rate base beginning 1/1/2007.
- UE 115 IT Deferral: Amounts are currently being refunded through Schedule 105. Calendar year 2007 will be the final year of amortization with the reset of base revenue requirement in this case.

In addition, there are other deferred accounts for which amortization is yet to begin. We propose to collect (or refund) these items through supplemental tariffs. As a result, we have excluded amounts from the development of the 2007 test year revenue requirement. All of PGE's proposed supplemental tariffs are included in PGE Exhibit 1300.

XI. Qualifications

Q. Mr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from The Ohio State University in 1976. I received a Master of Arts degree in Economics from the University of Tennessee in 1993 and a Ph.D. in Economics from the University of Tennessee in 1995. I have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. I have worked for PGE in the Rates and Regulatory Affairs Department since 1996.

Q. Mr. Tinker, please state your educational background and experience.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since joining PGE in 1996.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
201	Results of Operations (ROO) Summary
202	Summary of Other Revenue Sources
203	Summary of Depreciation Expense by Plant Type
204	Summary of Depreciation Study Impacts
205	Summary of Amortization Expense
206	Summary of Income Taxes
207	Summary of Taxes Other Than Income
208	Summary of Capital Expenditures
209	Summary of Rate Base
210	Reasons for Changes in Rate Base from UE 115
211	Summary of Working Cash Study
212	Unbundled Results of Operations Summary

PGE Exhibit 201
2007 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2007 Results At Current Base Rates	Change for Reasonable Return	2007 Results without PW at Adjusted Base Rates	Annualized PW Impact	2007 Results with PW	Change for Reasonable Return	2007 Results with PW at Reasonable Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers (Rev. Req.)*	1,619,560	25,064	1,644,624		1,644,624	44,911	1,689,536
Sales for Resale	-		-		-		-
Other Operating Revenues	17,728		17,728		17,728		17,728
Total Operating Revenues	1,637,288	25,064	1,662,352	-	1,662,352	44,911	1,707,263
Operation & Maintenance							
Net Variable Power Cost	856,968		856,968	(11,746)	845,222		845,222
Total Fixed O&M	142,803		142,803	8,440	151,243		151,243
Other O&M	178,384	133	178,517	315	178,832	238	179,070
Total Operation & Maintenance	1,178,155	133	1,178,288	(2,991)	1,175,298	238	1,175,536
Depreciation & Amortization	173,232		173,232	10,667	183,899		183,899
Other Taxes / Franchise Fee	85,395	587	85,981		85,981	1,051	87,032
Income Taxes	58,549	9,562	68,111	(6,216)	61,894	17,133	79,027
Total Oper. Expenses & Taxes	1,495,331	10,281	1,505,612	1,460	1,507,072	18,422	1,525,494
Utility Operating Income	141,956	14,783	156,740	(1,460)	155,280	26,489	181,769
Rate of Return	8.12%		8.97%		7.66%		8.97%
Return on Equity	9.24%		10.75%		8.42%		10.75%

* Revenues at Current Rates in Column 1 include estimated 2007 RVM Revenues.

PGE Exhibit 201
2007 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2007 Results At Current Base Rates	Change for Reasonable Return	2007 Results without PW at Adjusted Base Rates	Annualized PW Impact	2007 Results with PW	Change for Reasonable Return	2007 Results with PW at Reasonable Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Average Rate Base							
Utility Plant in Service	4,316,780		4,316,780	285,205	4,601,985		4,601,985
Accumulated Depreciation	(2,463,112)		(2,463,112)	(5,333)	(2,468,445)		(2,468,445)
Accumulated Def. Income Taxes	(205,677)		(205,677)	(1,758)	(207,435)		(207,435)
Accumulated Def. Inv. Tax Credit	(5,005)		(5,005)		(5,005)		(5,005)
Net Utility Plant	1,642,987	-	1,642,987	278,114	1,921,100	-	1,921,100
Misc Deferred Debits	4,689		4,689		4,689		4,689
Operating Materials & Fuel	50,176		50,176		50,176		50,176
Misc. Deferred Credits	(28,082)		(28,082)		(28,082)		(28,082)
Working Cash	77,757	535	78,292	76	78,368	958	79,326
Total Average Rate Base	1,747,526	535	1,748,061	278,189	2,026,251	958	2,027,208
Income Tax Calculations							
Book Revenues	1,637,288	25,064	1,662,352	-	1,662,352	44,911	1,707,263
Book Expenses	1,436,782	719	1,437,502	7,676	1,445,178	1,289	1,446,467
Interest Rate Base @ Weighted Cost of Debt	51,142	16	51,158	8,141	59,299	28	59,328
Production Deduction	4,017	-	4,017	-	4,017		4,017
Temporary Sch M Differences	(30,787)	-	(30,787)	8,947	(21,840)		(21,840)
Permanent M Differences	(7,623)	-	(7,623)	-	(7,623)		(7,623)
State Taxable Income	183,756	24,329	208,085	(24,764)	183,321	43,594	226,915
State Income Tax	11,992	1,610	13,602	(1,639)	11,964	2,884	14,848
Federal Taxable Income	171,763	22,720	194,483	(23,126)	171,357	40,710	212,067
Fed Income Tax	60,117	7,952	68,069	(8,094)	59,975	14,248	74,224
Deferred Taxes	(12,099)	-	(12,099)	3,516	(8,583)	-	(8,583)
ITC Amort	(1,461)	-	(1,461)	-	(1,461)	-	(1,461)
Total Income Tax	58,549	9,562	68,111	(6,216)	61,894	17,133	79,027

PGE Exhibit 201
General Rate Case - UE-2007 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	Amount	Share	Cost	Weighted
Common Equity	1,275,487	55.96%	10.75%	6.015%
Preferred	6,633	0.29%	8.43%	0.025%
Long-Term Debt	997,280	43.75%	6.69%	2.927%
Total	$2,279,401	100.00%		**8.966%**

Revenue Sensitive Costs:		w/o Fran Fees
Revenues	1.00000	1.00000
Franchise Fees	0.02340	-
O&M Uncollectibles	0.00530	0.00530
State Taxable Income	0.97130	0.99470
State Tax @ 6.62%	0.06427	0.06581
Federal Taxable Inc.	0.90703	0.92889
Federal Tax @ 35%	0.31746	0.32511
Total Income Taxes	**0.38173**	**0.39092**
Total Rev. Sensitive Costs	**0.41043**	**0.39622**
Utility Operating Income	0.58957	0.60378
Net To Gross Factor	**1.6961**	**1.6562**

PGE Exhibit 202
Other Revenue Detail
2002 - 2007 Test Year

Item	PGE Ledger(s)	UE-115 2002 TY	Actual 2002	Actual 2003	Actual 2004	Projected 2005	Budget 2006	Forecast 2007
Salmon Springs Rev	M34322	183,000	252,019	207,612	198,352	174,209	265,800	239,800
Sales of Water & Water Power	M32111	34,775	(122,902)	(21,525)	1,234	(4,545)	-	-
Rental of Utility Operating Property	Note 1	7,096,544	6,977,853	6,453,763	6,332,681	6,232,960	6,082,294	6,082,812
Exchange Wheeling	M34682	1,487,090	1,462,387	1,414,695	1,312,245	1,307,667	1,305,000	1,305,000
Exchange Wheeling PGE Expense	N33008	-	(1,462,387)	(1,414,695)	(1,312,245)	(1,307,667)	(1,305,000)	(1,305,000)
Other Misc. Electric Rev.	Note 2	1,551,581	1,875,211	2,162,365	1,917,314	2,372,541	2,585,915	2,600,733
Late Payment Interest	M38111	950,000	1,047,634	1,158,148	1,092,494	1,109,919	1,200,000	1,250,000
Steam Sale Revenues	M34189	1,143,000	786,936	1,000,952	1,111,427	1,511,733	1,419,110	1,419,110
Utility Non-Kwh Program	M34411	93,574	8,459	61,878	244,113	332,795	362,000	354,500
Transmission for Others	M34581	517,865	772,048	927,549	1,804,155	1,868,397	1,847,152	1,847,152
PNW Intertie Revenues	M34681	2,847,133	4,270,735	4,015,498	3,717,809	3,934,327	3,788,000	3,788,000
Misc. Physical Revenues	M34819	66,700	170,557	178,404	172,813	95,649	145,490	145,490
Misc. Revenue from Affiliates	M34321	-	27,772	-	-	-	-	-
Total Other Revenues		15,971,262	16,066,320	16,144,643	16,592,391	17,627,985	17,695,761	17,727,597

PGE Exhibit 203
Summary of Depreciation
($000)

Property Group	UE-115 2002 TY As Approved	2004 Actual	2007 Forecast
Boardman	11,270	10,875	6,725
Colstrip	13,704	10,772	6,884
Beaver	6,791	6,994	7,487
Bethel	117	-	-
Coyote Springs	7,402	6,946	6,650
Port Westward	-	-	5,784
Hydro	12,530	12,073	6,015
Transmission	3,118	8,002	8,928
Distribution	83,138	90,336	95,240
General Plant	13,698	17,335	22,028
TOTAL	151,768	163,333	165,741

PGE Exhibit 204
UM-1233 Depreciation Study
Annual Effect on Depreciation
($000's)

Property Group	New lives and Curves	New net Salvage Rates	Total Impact on 2005
Boardman	(4,477)	(307)	(4,784)
Colstrip	(2,112)	(898)	(3,010)
Beaver	1,199	368	1,567
Coyote Springs	525	(95)	430
Hydro	(1,225)	(42)	(1,267)
Transmission	439	(17)	422
Distribution	(7,811)	(1,609)	(9,420)
General	1,478	1,377	2,855
TOTAL	(11,984)	(1,223)	(13,207)

PGE Exhibit 205
Amortiation
2002 - 2007 Test Year

Item	PGE Ledger(s)	UE-115 2002 TY	Actual 2002	Actual 2003	Actual 2004	Projected 2005	Budget 2006	Forecast 2007	Adjustments	Test Year 2007
Software Amort	N62111	12,274,000	8,366,246	12,769,796	14,540,675	12,024,176	14,854,284	13,251,500	-	13,251,500
Coyote Permits	N62121	-	39,502	39,502	39,502	39,502	39,502	39,502	-	39,502
Hydro Relicensing	N62131	-	-	-	-	464,303	1,038,528	1,038,528	(1,038,528)	-
Trojan Decomm	N62452	14,041,000	14,041,000	14,041,000	14,041,000	14,041,000	14,041,000	4,500,000	146,000	4,646,000
Coyote Maj Maint (1)	N62599	-	4,107,996	4,108,006	4,108,000	4,108,001	4,108,000	2,044,272	-	2,044,272
Colstrip Common FERC	N62321	322,000	322,140	322,140	322,140	322,140	322,140	322,140	-	322,140
Cat A Amort	N62325	-	-	-	1,056,894	71,611	1,043,646	-	-	-
Pelton-RB Amort	N62328	-	-	-	2,774,506	2,731,364	-	-	-	-
Regulatory Amort	N62329	-	10,435,495	12,243,572	11,872,474	12,031,911	12,340,904	-	-	-
Regulatory Debits	N62506	186,000	11,915,319	12,561,738	12,105,551	12,286,471	-	-	-	-
Regulatory Credits	N62507	-	(274,729)	-	-	-	-	-	-	-
FAS 109 Amort	N62508	-	8,705,401	9,148,344	8,836,537	8,957,813	-	-	-	-
Deferral of Prop Gains	N62513	-	91,155	1,010,545	334,562	2,103,280	500,000	1,100,000	(1,100,000)	-
Debit - ARO	N62515	-	-	2,200,285	3,848,071	3,418,748	3,628,991	1,665,594	(1,665,594)	-
SB1149 Amort	N62516	-	-	1,522,880	7,871,975	7,992,557	8,127,690	8,242,566	(6,707,638)	1,534,928
Deferral of ISFSI Credits	N62518	-	-	-	2,273,779	1,868,761	2,273,778	2,273,778	(2,273,778)	-
Coyote Maj Main Amort (1)	N62614	-	(1,825,972)	(2,917,572)	(159,141)	(2,445,456)	(1,670,777)	(868,611)	-	(868,611)
SB 1149 Deferral	N62605	-	(5,901,687)	(3,450,293)	(2,691,823)	(2,524,869)	(2,348,780)	(2,123,528)	-	(2,123,528)
CS Comm Facilities Sale	N62607	-	(4,264,403)	-	(130,762)	-	-	-	-	-
Prop Sale Gain Amort	N62612	-	-	-	(1,183,315)	(80,177)	-	(1,981,313)	1,981,313	-
Cat A Costs	N62613	-	150,339	(1,748,670)	681,040	(373,848)	-	-	-	-
Amort of Merger Savings	N62616	-	(8,077,540)	-	-	-	-	-	-	-
Amort of Non-Recur Prop Sales	N62617	-	(8,484,173)	-	-	-	-	-	-	-
Amort of Tariff 126 Credit	N62618	-	(23,314,093)	-	-	-	-	-	-	-
BETC Deferral	N62621	-	-	(2,992,107)	21,050.85	-	-	-	-	-
BETC & SAVE Reserve	N62622	-	-	3,150,643	-	-	-	-	-	-
Amort of ISFSI Credits	N62624	-	-	-	-	-	-	(7,678,001)	7,678,001	-
Beaver 8 Reg Credit	N62625	-	-	-	(10,200,000)	-	-	-	-	-
Accretion Expense	N62701	-	-	792,672	813,880	872,961	895,957	848,958	(848,958)	-
Gain from Prop Sales	N91101	-	(92,655)	(1,076,760)	(268,348)	(2,103,280)	(500,000)	(1,100,000)	1,100,000	-
Loss from Prop Sales	N92101	-	60,426	-	8,200,000	-	-	-	-	-
	N91331	-	-	-	-	-	-	2,011	-	2,011
Totals		26,823,000	5,999,767	61,725,720	79,108,249	75,806,968	58,694,863	21,577,396	(2,729,182)	18,848,214
Check		26,823,000	5,999,767	61,725,720	79,108,249	75,806,968	58,694,863	21,577,396		18,848,214

Notes:
(1) The Coyote Major Maintenance Accrual/Amort was recorded in Production O&M in UE 115.

PGE Exhibit 206
Income Tax Summary
Reasons For Change (UE-115, 2002 Test Year vs. 2007 Filing)
(000s)

Income Tax Summary	UE-115 2002 Test Year	No PW UE-&&& 2007 Test Year	W / PW UE-&&& 2007 Test Year
Book Revenues	1,519,191	1,662,352	1,707,263
Book Expenses (including Depreciation)	1,283,751	1,437,502	1,446,467
Interest Deduction	61,442	51,158	59,328
Book Taxable Income	173,997	173,692	201,469
Production Deduction	-	4,017	4,017
Temporary Sch. M	(38,734)	(30,787)	(21,840)
Permanent Sch. M's	(21,802)	(7,623)	(7,623)
Tax Taxable Income	234,534	208,085	226,915
State Tax @ 6.655% for UE115, 6.617% for 2007	15,608	13,768	15,014
State Tax Credits	(917)	(166)	(166)
Net State Income Tax	14,691	13,602	14,848
Federal Taxable Income	220,130	194,483	212,067
Federal Tax @ 35%	77,045	68,069	74,224
ITC Amortization	(1,523)	(1,461)	(1,461)
Deferred Taxes	(15,233)	(12,099)	(8,583)
Total Income Tax	74,981	68,111	79,027
Effective Tax Rate	43.09%	39.21%	39.23%
Change in Taxes		(6,870)	10,916
Analysis of Tax Change:			
Effective Tax Rate Change		-3.88%	N/A
UE 115 Book Taxable Income		173,997	N/A
Decrease in Taxes Due to Lower Effective Rate on UE 115 Book Taxable Income		(6,750)	
Change in Book Taxable Income (2007 vs UE115, 2007 W/PW vs No PW)		(305)	27,777
2007 Composite Tax Rate		39.30%	39.30%
Increase in Taxes Due to Higher Book Taxable Income		(120)	10,916
Total Tax Changes		(6,870)	10,916

PGE Exhibit 207
Taxes Other Than Income
2002 - 2007 Test Year

Item	PGE Ledger(s)	UE-115 2002 TY	Actual 2002	Actual 2003	Actual 2004	Projected 2005	Budget 2006	Forecast 2007
Payroll Taxes	Note 1	8,703,204	9,851,420	10,070,836	10,110,873	11,438,784	12,809,440	11,592,349
Property Taxes - Oregon	N81111	27,294,382	25,057,587	25,014,427	26,368,610	27,960,544	28,142,340	29,794,800
Property Taxes - Washington	N81211	124,800	105,503	103,326	71,731	81,064	69,600	69,600
Property Taxes - Montana	N81311	4,062,200	3,312,530	3,253,080	3,224,455	4,121,180	5,213,880	4,813,880
Franchise Fees	N83111, N83112	33,972,519	29,218,915	32,019,117	31,056,004	31,141,876	32,610,587	38,484,212
Foreign Insurance Excise Tax	N83211	-	-	46,175	31,000	-	32,560	34,200
Montana Production Tax	N83611	450,000	410,965	404,896	420,037	489,449	454,800	477,000
Oregon DOE fee	N83411	480,000	628,047	670,993	673,896	618,805	654,998	720,000
Total Taxes Other Than Income		75,087,105	68,584,967	71,582,850	71,956,606	75,851,702	79,988,205	85,986,041

Note 1: Payroll Tax ledgers include N82111, N82211, N82311, N82411, N82511, N82591, and N82599

PGE Exhibit 208
Capital Expenditures
2007 Test Period, Dollars in Millions

Category	UE-115 2002 Test Year	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
Steam Production	2.2	4.2	7.0	17.0	4.6	8.8	9.4
Hydro Production	10.1	9.6	4.5	5.2	3.6	4.4	3.0
Other Production	4.5	3.5	17.7	5.0	4.8	5.4	4.0
Port Westward	-	-	-	12.5	108.1	113.6	14.0
Relicensing Construction	7.3	-	1.8	6.9	21.1	21.9	37.5
Transmission	10.1	9.4	7.2	6.1	9.5	7.8	7.0
Distribution	106.3	102.8	99.5	111.8	105.9	120.9	121.4
General Plant	32.8	8.5	12.5	15.3	12.7	21.1	22.8
Intangible & Relicensing Process	6.5	40.0	17.3	15.4	16.9	7.5	12.6
Total	179.8	178.0	167.5	195.3	287.2	311.4	231.7

Steam Production Boardman, Colstrip
Other Production Coyote Springs, Beaver

PGE Exhibit 209
Average Rate Base
Test Year based on 12 Months Ending 12/31/07
(000s)

		No PW 2007 Test Year	PW Impact	W / PW 2007 Test Year
Plant In Service		4,316,780	285,205	4,601,985
Less:	Accumulated Depreciation/Amortization	(2,463,112)	(5,333)	(2,468,445)
	Accumulated Deferred Taxes	(205,677)	(1,758)	(207,435)
	Accumulated Deferred ITC	(5,005)	-	(5,005)
Net Utility Plant		1,642,987	278,114	1,921,100
Operating Materials and Fuel Stocks		50,176		50,176
Deferred Debits				
	Colstrip Common FERC Adj	3,168		3,168
	Def Wheeling Cost 2 Cities	1,521		1,521
Deferred Credits				
	Coyote Maint. Accrual	(6,142)		(6,142)
	Injuries & Damages	(6,279)		(6,279)
	Customer Deposits	(4,135)		(4,135)
	Customer Advances	(171)		(171)
	Misc. Other	(11,355)		(11,355)
Working Capital		78,292	1,034	79,326
Average Rate Base		1,748,061	279,147	2,027,208

PGE Exhibit 210
Rate Base Comparison
UE 115, 2002 Test Year vs 2007 Test Year
(000s)

		UE 115 2002 Test Year	Cust Growth	Greater Working Cash Requirements	Higher Fuel Stock Requirements	Misc Other	No PW 2007 Test Year	PW Impact	W / PW 2007 Test Year
Plant In Service		3,636,125	197,285			483,371	4,316,780	285,205	4,601,985
Less:	Accumulated Depr/Amort	(1,756,138)	(34,525)			(672,449)	(2,463,112)	(5,333)	(2,468,445)
	Accumulated Deferred Taxes	(158,426)				(47,251)	(205,677)	(1,758)	(207,435)
	Accumulated Deferred ITC	(21,178)				16,173	(5,005)	-	(5,005)
Net Utility Plant		1,700,383	162,760	-	-	(220,157)	1,642,987	278,114	1,921,100
Operating Materials and Fuel Stocks		33,979			11,058	5,139	50,176		50,176
Misc. Debits		10,171				(5,482)	4,689		4,689
Misc Credits		(38,552)				10,470	(28,082)		(28,082)
Working Capital		60,599		17,692		-	78,292	1,034	79,326
Average Rate Base		1,766,581	162,760	17,692	11,058	(210,030)	1,748,061	279,147	2,027,208

PGE Exhibit 211
Working Cash Study
(Revenue and Expenses based on 01/01/2004 through 12/31/2004 Actuals)
Based on 2004 actuals

Revenues			Annual Revenue	Lag Days	Dollar Days
	Sales to Consumers		1,267,575	35.3	44,791,317
	Meter cycle	15.2 days			
	Billing cycle	2.5 days			
	Collection cycle	17.6 days			
	Other revenues		28,897	23.0	664,631
		Total Revenue	1,296,472	35.1	45,455,948

Expenses			Annual Expense	Lag Days	Dollar Days
Fuel					
	Oil		459	16.3	7,503
	Coal		47,940	21.9	1,047,505
	Natural Gas		14,776	13.8	203,910
		Total Fuel	63,176	19.9	1,258,918
Purchase Power					
	Firm		415,166	15.5	6,445,408
	Non-Firm		312,014	15.2	4,758,055
		Total Purchase Power	727,180	15.4	11,203,463
Labor					
	Hourly		74,665	17.0	1,269,297
	Salary		96,063	17.6	1,690,713
		Total Labor	170,728	17.3	2,960,010
Misc O&M					
	License Fees		39,801	54.5	2,167,186
	Prepaid Insurance		5,804	(135.8)	(788,150)
	Pension		-	-	-
	Rent		5,212	(14.8)	(76,874)
	Other Benefits		128	-	-
		Total Misc O&M	50,945	25.6	1,302,162
Taxes	Federal Income		68,640	47.6	3,265,344
	State & Local Income (Ore.)		11,080	47.6	527,085
	State Income (Mont.)		135	47.6	6,411
	Property Tax (Ore.)		2,639	(44.5)	(117,540)
	Property Tax (Mont.)		3,218	243.0	781,909
	Property Tax (Wash.)		86	395.0	33,916
	Unemployment (Ore.)		0	6.0	3,537
	Unemployment (Fed.)		4	8.8	40
	Tri-Met		0	7.7	1
	FICA		37	1.9	70
		Total Taxes	85,838	52.4	4,500,773
Other	Depreciation & Amortization		235,320	-	0
	Deferred Taxes		(12,346)	-	0
		Total Other	222,974	-	0
		Total Expenses	1,320,841	16.1	21,225,326

Calculation of Working Cash Factor:	
Revenue Lag Days	35.1
Expense Lag Days	16.1
Excess Lag	19.0
WC Factor	5.20%

PGE Exhibit 212
Unbundled Results of Operations Summary
2007 Results at Reasonable Return, Before Port Westward
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,086,044	28,616	423,837	5,421	18,118	33,095	49,493	1,644,624
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	7,056	5,645	7,760	(5,421)	13	17	2,658	17,728
Total Operating Revenues	1,093,100	34,261	431,597	-	18,130	33,112	52,151	1,662,352
Operation & Maintenance								
Net Variable Power Cost	856,968	-	-	-	-	-	-	856,968
Total Fixed O&M	69,056	9,725	64,022	-	-	-	-	142,803
Other O&M	39,734	4,079	49,382	-	15,951	25,392	43,979	178,517
Total Operation & Maintenance	965,759	13,804	113,404	-	15,951	25,392	43,979	1,178,288
Depreciation & Amortization	43,336	6,168	112,946	-	1,041	4,923	4,818	173,232
Other Taxes / Franchise Fee	17,816	2,165	62,518	-	659	1,075	1,749	85,981
Income Taxes	20,050	3,673	43,235	-	145	522	486	68,111
Total Oper. Expenses & Taxes	1,046,961	25,809	332,103	-	17,796	31,911	51,032	1,505,612
Utility Operating Income	46,140	8,452	99,494	-	334	1,201	1,119	156,740
Rate of Return	8.97%	8.97%	8.97%	N/A	8.97%	8.97%	8.97%	8.97%
Return on Equity	10.75%	10.75%	10.75%	N/A	10.75%	10.75%	10.75%	10.75%
Average Rate Base								
Utility Plant in Service	1,613,003	206,931	2,380,775	-	13,207	51,688	51,176	4,316,780
Accumulated Depreciation	1,105,447	99,800	1,186,772	-	7,256	31,951	31,885	2,463,112
Accumulated Def. Income Taxes	83,294	13,388	91,711	-	2,139	7,205	7,941	205,677
Accumulated Def. Inv. Tax Credit	3,312	220	1,474	-	-	-	-	5,005
Net Utility Plant	420,949	93,524	1,100,819	-	3,812	12,532	11,350	1,642,987
Operating Materials & Fuel	45,554	178	4,444	-	-	-	-	50,176
Misc Deferred Debits	4,689	-	-	-	-	-	-	4,689
Misc. Deferred Credits	(11,055)	(783)	(12,909)	-	(1,012)	(801)	(1,521)	(28,082)
Working Cash	54,442	1,342	17,269	-	925	1,659	2,654	78,292
Total Average Rate Base	514,578	94,261	1,109,623	-	3,726	13,390	12,483	1,748,061

PGE Exhibit 212
Unbundled Results of Operations Summary
2007 Results at Reasonable Return, With Port Westward
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,127,423	31,062	424,923	5,421	18,118	33,095	49,494	1,689,536
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	7,056	5,645	7,760	(5,421)	13	17	2,658	17,728
Total Operating Revenues	1,134,479	36,707	432,683	-	18,131	33,112	52,152	1,707,263
Operation & Maintenance								
Net Variable Power Cost	845,222	-	-	-	-	-	-	845,222
Total Fixed O&M	77,497	9,725	64,022	-	-	-	-	151,243
Other O&M	40,268	4,092	49,389	-	15,951	25,392	43,979	179,070
Total Operation & Maintenance	962,987	13,817	113,410	-	15,951	25,392	43,979	1,175,536
Depreciation & Amortization	54,002	6,168	112,946	-	1,041	4,923	4,818	183,899
Other Taxes / Franchise Fee	17,816	2,165	63,568	-	659	1,075	1,749	87,032
Income Taxes	30,203	4,411	43,259	-	145	522	487	79,027
Total Oper. Expenses & Taxes	1,065,009	26,561	333,184	-	17,796	31,911	51,032	1,525,494
Utility Operating Income	69,470	10,146	99,499	-	334	1,201	1,119	181,769
Rate of Return	8.97%	8.97%	8.97%	N/A	8.97%	8.97%	8.97%	8.97%
Return on Equity	10.75%	10.75%	10.75%	N/A	10.75%	10.75%	10.75%	10.75%
Average Rate Base								
Utility Plant in Service	1,878,870	226,269	2,380,775	-	13,207	51,688	51,176	4,601,985
Accumulated Depreciation	1,110,419	100,162	1,186,772	-	7,256	31,951	31,885	2,468,445
Accumulated Def. Income Taxes	84,933	13,507	91,711	-	2,139	7,205	7,941	207,435
Accumulated Def. Inv. Tax Credit	3,312	220	1,474	-	-	-	-	5,005
Net Utility Plant	680,205	112,381	1,100,819	-	3,812	12,532	11,350	1,921,100
Operating Materials & Fuel	45,554	178	4,444	-	-	-	-	50,176
Misc Deferred Debits	4,689	-	-	-	-	-	-	4,689
Misc. Deferred Credits	(11,055)	(783)	(12,909)	-	(1,012)	(801)	(1,521)	(28,082)
Working Cash	55,380	1,381	17,326	-	925	1,659	2,654	79,326
Total Average Rate Base	774,773	113,157	1,109,680	-	3,726	13,390	12,483	2,027,208

UE 180 / PGE / 300
QUENNOZ – SCHUE

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Fixed Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz
Stephen Schue

March 15, 2006

Fixed Power Costs

Table of Contents

I. Introduction and Long-Term Supply Resource Summary

Q. Please state your names and positions with PGE?

A. My name is Stephen Quennoz. My position at PGE is Vice President, Supply. I am responsible for all aspects of PGE's power supply and for decommissioning the Trojan nuclear plant.

My name is Stephen Schue. I am a Senior Analyst in the Rates and Regulatory Affairs Department. I provide analyses for various aspects of PGE's overall resource planning activities.

We provide our qualifications at the end of our testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support rate base, O&M, and other costs associated with PGE's long-term power supply resources, both owned plants and contracts. We provide detailed testimony for Port Westward and other new resources acquired pursuant to the 2002 IRP Final Action Plan, recently or soon to be relicensed hydro facilities, and Beaver 8.

Q. How do you organize your testimony?

A. Our testimony is organized into the following sections:

- Section I: Introduction and Resource Summary (Plants, Contracts, and Transmission)
- Section II: Plant and Power Operations O&M and Capital Additions
- Section III: Hydro Relicensing
- Section IV: Port Westward
- Section V: Qualifications

Q. What are the test year O&M and capital additions for PGE's plant and power operations areas and how have they changed in recent years?

A. Summary figures ($million) are:

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast *W/O PW*	2007 Forecast *With PW*
Plant/ Power Oper. O&M	61.4	60.1	67.0	61.9	67.6	72.0	80.4
Plant/Pow. Oper. Cap. Adds.	17.3	29.2	25.2	12.9	17.9	16.4	16.4

Although there are some year-to-year changes, we project O&M expenses to generally increase at a rate somewhat less than that of general inflation over the 2002-2007 period. In addition, hydro relicensing expenses increase from less than $1 million to approximately $3 million over the 2002-2007 period and Port Westward adds more than $8 million to O&M expenses in 2007. Capital additions were high in 2003 and 2004 because of major work at Beaver, Boardman, and Coyote Springs. We explain these changes in more detail in Section II.

Q. What are the test year revenue requirement components related to PGE's recently relicensed or soon to be relicensed hydro facilities?

A. The average test year rate base (net of accumulated depreciation and deferred taxes) associated with activities required by relicensing is approximately $41.7 million. Given a pre-tax cost of capital of slightly less than 13%, the return requirement is approximately $5.4 million. Depreciation and O&M expenses are approximately $1.0 million and $2.9 million respectively, resulting in an overall hydro relicensing test year revenue requirement of approximately $9.3 million.

Q. What are the test year O&M and rate base figures related to the new Port Westward plant?

A. Port Westward will increase our average test year rate base by more than $278 million. Given a grossed up cost of capital of slightly less than 13%, the "return on" component of revenue requirement is approximately $36 million. Depreciation and O&M expenses will also increase by more than $10 million and $8 million respectively, and related costs for A&G and revenue sensitive costs will increase by more than $1 million, resulting in total cost increases of approximately $57 million. These increases and a decrease in net variable power costs (dispatch benefit, net of fixed gas transportation costs) of approximately $12 million then result in a net revenue requirement increase of approximately $45 million.

Q. What are the fixed costs of PGE's long-term contracts in the test year?

A. PGE's long-term contractual resources, including transmission, have 2007 fixed costs of approximately $159 million.

Q. Do you discuss short-term contracts in your testimony?

A. No. We include short-term contracts that affect 2007 net variable power costs in the MONET model runs discussed in PGE Exhibit 400.

Q. Please describe PGE's thermal generating resources.

A. In 2007 we will own four gas-fired plants and shares of two coal-fired plants. The gas-fired facilities are:

Gas-Fired Plant	Capacity (MW)	Location	In-Service Date
Port Westward	417	Clatskanie, OR	2007
Coyote Springs I	244	Boardman, OR	1995
Beaver	521	Clatskanie, OR	1976
Beaver 8	24	Clatskanie, OR	2001
Total Gas-Fired	1,206		

Port Westward is a new G-class combined cycle combustion turbine (CCCT), with 400 MW[1] available at a very low heat rate, approximately 6,700 Btu/kWh when new.[2] An additional 25 MW of "duct firing" is also available, but at a heat rate somewhat greater than 9,000 Btu/kWh. Section IV provides a complete discussion of the new Port Westward facility, including duct firing. Coyote is also a relatively new CCCT, and provides 240 MW at a low heat rate, 7,128 Btu/kWh, as well as 4 MW of duct firing at a higher heat rate of 8,900 Btu/kWh. Beaver is a relatively old CCCT, and has a higher heat rate, 9,299 Btu/kWh. Finally, Beaver 8 is a simple cycle unit, with a heat rate of 11,660 Btu/kWh. We discuss Beaver 8 in more detail later in this section and PGE Exhibit 200 discusses the UM 1014 Stipulation, which governs how we include Beaver 8 in the revenue requirement.

Our coal-fired facilities in 2007 will be:

Coal-Fired Plant	Capacity (MW)	Location	In-Service Date
Boardman	380	Boardman, OR	1980
Colstrip 3&4	296	Colstrip, MT	1985
Total Coal-Fired	676		

Boardman and Colstrip currently have heat rates of 9,725 Btu/kWh and 10,842 Btu/kWh respectively. However, with planned upgrades, the heat rates of Colstrip Units 4 and 3 will decrease to 10,490 Btu/kWh in July 2006 and July 2007 respectively. The capacity figures cited, 380 MW and 296 MW, are for our 65% and 20% shares of Boardman and Colstrip 3 and 4 respectively. PGE manages Boardman and PPL Montana manages the Colstrip Units.

[1] Gas-fired capacity figures are for January. Output is somewhat lower in warmer months, as maximum capacity varies inversely with temperature.

[2] Degradation will increase Port Westward's heat rate by approximately 2% soon after the plant goes on-line. The same fuel input will result in less output. This is a normal occurrence with gas-fired plants; we expect no further increases in heat rates.

Q. Please summarize PGE's major hydro resources.

A. We fully own six hydro plants plus we own shares in two others. We also have long-term contracts for output shares of four mid-Columbia (Mid-C) hydro facilities, as well as contracts with the City of Portland and the Confederated Tribes of the Warm Springs Reservation.

Q. Please describe PGE's owned hydro resources in more detail.

A. We own four hydro facilities on the Clackamas River, referred to as the Clackamas River Project. We are currently in the relicensing process for this project, but it is impossible to predict at this time when we will receive a new long-term license. For analysis purposes, we have assumed that it will be granted in early 2008.

We also own two-thirds shares of two facilities located on the Deschutes River (Pelton and Round Butte). The Confederated Tribes of the Warm Springs Reservation (Tribes) currently own one-third shares in these plants and have the option to increase their shares to one-half in 2022. We received a new 50-year license for the Pelton Round Butte Project, which contains these facilities, on June 21, 2005.

In addition, we own the Sullivan plant on the Willamette River. On December 8, 2005, we received a new 30-year license for the Willamette Falls Project, which essentially is our Sullivan plant. In Section III we discuss the Clackamas River, Pelton Round Butte, and Willamette Falls relicensing processes in more detail.

Finally, we own the Bull Run facility, whose long-term license expired in 2004. We are not seeking a new long-term license for Bull Run because it would not be cost-effective to do so. We expect to begin decommissioning this plant during the test year. The net variable power cost estimate we provide in PGE Exhibit 400 reflects corresponding decreases in Bull

Run output of approximately two thirds in November and December 2007. In summary, our owned hydro facilities are:

Owned-Hydro Plant	Capacity (MW)	Energy (MWa)	Location
Oak Grove	44	27	Clackamas River
North Fork	58	27	Clackamas River
Faraday	46	26	Clackamas River
River Mill	25	14	Clackamas River
Pelton	73	35	Deschutes River
Round Butte	225	76	Deschutes River
Sullivan	16	13	Willamette River
Bull Run	22	11	Bull Run River
Total Owned-Hydro	509	229	

Energy figures are on an average water basis.

Q. Please summarize PGE's long-term contractual hydro resources.

A. Our hydro contracts include:

Hydro Contract	Capacity (MW)	Energy (MWa)	Location
Wells	171	88	Columbia River
Rocky Reach	152	84	Columbia River
Grant Settlement	292	167	Columbia River
Tribes	161	65	Deschutes River
Canadian Entitlement	(29)	(16)	Columbia River
Portland Hydro	36	10	Bull Run River
Total Hydro Contracts	783	398	

Energy figures are on an average water basis.

Q. Please describe PGE's Mid-C contracts in more detail.

A. We have long-term contracts for output from four hydro plants located on the middle section of the Columbia River. Under the Wells and Rocky Reach agreements we simply pay percentage shares of the plants' costs in return for equal percentage shares of the output. The Wells agreement is with Douglas County PUD and expires in 2018. The Rocky Reach agreement is with Chelan County PUD and expires in 2011.

The other two Mid-C hydro facilities are covered by one contract, a Settlement Agreement with the owner, Grant County PUD. PGE had contracts for percentage output shares of the Priest Rapids and Wanapum plants, which expired or will expire on October 31, 2005, and October 31, 2009, respectively. Extensive negotiations with Grant County PUD resulted in a Settlement Agreement concerning various parties' rights to power from Priest Rapids and Wanapum after the 2005 and 2009 contract expiration dates. During a transition period through October 2009, we will continue to pay a percentage share of Wanapum's costs in exchange for an equal percentage share of the output. The Settlement Agreement also includes other products – surplus firm, conversion, meaningful priority, and displacement – based in part on Grant's needs, which will grow over time, and on a 1998 FERC ruling. The figures above are the capacity and energy-related sums of all products covered under the Settlement Agreement for the 2007 test year. PGE Exhibit 301 shows projected Settlement Agreement quantities over time.

Q. Does PGE have a contract to purchase the Tribes' Pelton and Round Butte output shares?

A. Yes. As discussed above, the Tribes have one-third shares of the output from the Pelton and Round Butte facilities. In addition, the Tribes control the output of the Pelton re-regulating dam. Under an agreement covering the period from January 2007 through February 2012, PGE will purchase the Tribes' Pelton and Round Butte output shares and the entire output of the re-regulating dam. This is essentially an extension of a current contract that runs through 2006. Under the new agreement, 25 MWa during peak hours is at fixed prices. All other power is priced at the Dow Jones Mid-Columbia daily on- and off-peak indices. This agreement is beneficial to both PGE and the Tribes. First, it provides the Tribes with a mechanism to sell all of their power. Second, it eliminates any potential conflict of interest in how to operate Pelton and Round Butte. Finally, it provides both parties with price certainty on 25 MWa of peak hour output.

Q. What are PGE's other hydro contracts?

A. The Canadian Entitlement Allocation Extension Agreement relates to the Mid-C contracts. Columbia River storage reservoirs located in Canada are operated so as to increase the value of the Mid-C plants. These benefits must be shared with Canada under a complex formula, resulting in the obligations listed above. We also have a contract under which we purchase the entire output of the Portland Hydro Project, located on the Bull Run River.

Q. Does PGE have wind-powered supply resources?

A. Yes. We have two wind contracts. These are:

Wind Resource	Nameplate (MW)	Energy (MWa)	Location
Vansycle Ridge	25	8	Eastern Oregon
Klondike II	75	27	Eastern Oregon
Total Wind Resources	100	35	

Energy figures are on an expected annual basis.

Q. Please describe these wind resources in more detail.

A. We are under contract to purchase the entire output of Vansycle Ridge through 2027. The Klondike II contract is with PPM Energy, and runs through 2035. This contract is also part of the Final Action Plan that resulted from PGE's 2002 Integrated Resource Planning (IRP) process. The Commission acknowledged the Final Action Plan in Order No. 04-375.

Q. Does PGE have other major long-term supply contracts?

A. Yes. We have three major energy contracts and three major capacity contracts.

Q. Please describe the energy contracts in more detail.

A. PGE's other major energy contracts are:

Energy Contract	Capacity (MW)	Energy (MWa)	Counterparty
Power Purchase	100	93	TransAlta
Power Purchase	25	25	Morgan Stanley
Tolling Agreement	25	On-Peak Option	Morgan Stanley
Total Energy Contracts	150	118	

The TransAlta agreement covers a ten-year purchase of output from the Centralia coal-fired facility and commences in October 2006. The Morgan Stanley Power Purchase Agreement will run for five years, beginning in October 2006. The Morgan Stanley Tolling Agreement has a financial gas for physical electricity structure and will run for five years. It commenced in January 2005. All three contracts are part of the IRP Final Action Plan. We selected these contracts for the Final Action Plan because they provide good value to customers. They competed favorably against approximately 100 other bids we received in response to a Request for Proposals (RFP). They also competed favorably in a portfolio evaluation process, which included other potential Final Action Plan resources, as well as PGE's then existing resources.

Q. Please describe the capacity contracts in more detail.

A. PGE's major capacity contracts are:

Capacity Contract	Capacity (MW)	Counterparty
Long-Term Capacity Storage Contract	150	Spokane Energy
Winter Super-Peak Option	100	PPM
Limited Exercise Winter-Peaking Option	300	PPM
Total Capacity Contracts	550	

The contract with Spokane Energy, formerly with Washington Water Power, expires in 2016. The two PPM Options are part of the Final Action Plan and have financial gas for physical electricity structures. The Super-Peak Option commenced in December 2005 and runs for five winter (December through February) seasons. The Exercise Limited Option commenced in January 2005 and runs for six winter (generally November through April) seasons. As the name implies, total quantities taken over any one season are limited.

Q. Please summarize PGE's other supply resources.

A. Other supply resources include:

- Eugene Water and Electric Board (EWEB) capacity contract – 10 MW, expires in 2014.
- Covanta Solid Waste-To-Energy facility – 10 MW effective usable capacity and 10 MWa expected energy, under a PURPA contract that expires mid-2014.
- City of Glendale Exchange – PGE receives 30 MW of capacity and 11 MWa of energy during November-February winter seasons in exchange for similar obligations from PGE to Glendale during June-September summer seasons under a contract that runs through February 2012.
- Chelan Exchange – PGE receives up to 50 MW of summer capacity, with energy returns which are in excess of receipts possible in both summer and winter, under an agreement with Chelan County PUD that expires in February 2011.
- Wells Settlement Agreement – quantities vary across the year with Wells output, 21 MW of capacity in January and 27 MWa annual average energy, under agreement that runs through August 2018.

Q. Which of PGE's long-term supply resources are focused on meeting capacity requirements?

A. PGE's long-term capacity resources during the 2007 test year will be:

A. PGE's long-term capacity resources during the 2007 test year will be:

Long-Term Capacity Resource	Capacity (MW)
Long-Term Capacity Storage Contract	150
Winter Super-Peak Option	100
Limited Exercise Winter-Peaking Option	300
EWEB Capacity Contract	10
Beaver 8	24
Total Long-Term Capacity Resources	584

Q. What is the Beaver 8 facility?

A. Beaver 8 is a 24.7 MW Alstom simple-cycle gas-fired combustion turbine that PGE purchased and installed at the site of its existing Beaver generating facility. Its heat rate is 11,600 MMBtu per MWh, and it became operational concurrent with the August 1, 2001, starting date of a stipulated three-year agreement between PGE, Commission Staff, and the Citizens' Utility Board.

Q. Do you have another source of capacity resources?

A. Yes. We now have 15 dispatchable standby generation projects, which provide more than 26 MW of reliable diesel-fired capacity at peak times. This is a substantial increase from the end of 2002, at which time we had completed four projects with combined capacities of nine MW. We also have six projects with combined capacities of 13 MW under construction. According to current schedules, all of these projects will come on-line by the end of this year. In addition, we have authorization for a four MW project, which would come on line late this year or early in 2007. The capacities of these dispatchable standby facilities – existing, under construction, and authorized – sum to 43 MW.

We have smaller scale distributed generation projects based on other fuel sources – biogas, fuel cells, and micro-turbines. We also support net metering, which is primarily photovoltaic-based.

Q. Do the dispatchable standby generators provide other benefits to customers?

A. Yes. We can start these resources simultaneously within ten seconds, thereby providing a block of reserve power for our system. Reserve requirements for thermal and hydro resources are 7% and 5% respectively, of which half must be spinning. Dispatchable stand-by generators do not qualify as spinning reserves, but they can provide the remainder – 3.5% for thermal, 2.5% for hydro. Thus, 43 MW can provide non-spinning reserves for more than 1,200 MW of thermal resources or more than 1,700 MW of hydro resources. In addition, dispatchable standby generation, when operating, acts like a demand response program, in that it supplies most or all of dispatchable standby generation customers' loads, removing these loads from the grid. This frees up transmission, which can then be used to supply other customers' peak demands or reduce transmission system congestion. Finally, dispatchable standby generation adds fuel diversity to PGE's resource mix.

Q. What is the purpose of your capacity resources?

A. Capacity resources enable a utility to meet its obligation to provide safe reliable power to customers. Specifically, these resources meet customer loads under conditions which are extreme, but of short duration. For example, we might have an immediate need for power if one of our major thermal resources suddenly went offline. In other words, capacity resources "keep the lights on."

Q. What criteria does PGE use in its selection of capacity resources?

A. The most important criterion is that the resources will meet extreme situations when called upon. The second most important criterion is fixed costs. We look for capacity resources that can provide reliability at lower fixed costs for customers. Possible margins are not an important criterion because capacity resources generally have high variable costs, making them uneconomical to run except in emergencies. Expected margins over variable costs are very small, and can even be negative. (See PGE Exhibit 200 describing how, according to a stipulated methodology, Beaver 8's margins in 2005 were slightly negative.)

Q. What has PGE done to ensure that the fixed costs of its capacity resources are as low as possible?

A. We selected the two PPM Option contracts through the RFP process related to our 2002 IRP. These contracts competed with nine other capacity resource bids and are part of the IRP Final Action Plan. PGE Exhibit 200 discusses the UM 1014 Stipulation that governs how we include Beaver 8 in the revenue requirement. This Stipulation includes a cost-benefit test.

Q. Have you prepared an exhibit that summarizes all of PGE's long-term supply resources?

A. Yes. PGE Exhibit 302 provides this summary.

Q. Does PGE have any long-term transmission contracts?

A. Yes. We need long-term transmission to deliver power from our generating resources and long-term contracts to our service territory. In addition, even with major resource additions such as Port Westward, PGE can often lower costs for customers by making wholesale market purchases that we also have to deliver to our service territory. Since we do not own enough transmission to make all of these deliveries, we must purchase adequate transmission capacity from third parties to reliably and cost-effectively meet our load obligations.

Q. What major transmission agreements does PGE have?

A. PGE maintains four major transmission agreements with BPA. These are:

- Integration of Resources (IR) agreement
- Point to Point (PTP) agreements
- AC/DC Intertie agreement (also involves PGE Transmission Services)
- Montana Intertie agreement

Q. Please describe the IR agreement.

A. The IR agreement allows PGE to deliver power from our thermal resources, Mid-C hydro contracts, and a system (capacity) purchase from Spokane Energy to the PGE system. This agreement, which expires on December 31, 2009, also allows PGE to deliver power from these resources to the head of the AC/DC Intertie at John Day/Big Eddy. Table 1 below summarizes the delivery capacities.

Table 1
IR Contract Summary

Point of Receipt	Max Capacity
Beaver	531 MW
Coyote Springs	250 MW
Colstrip	270 MW
Boardman	379 MW
Wells	169 MW
Priest Rapids	131 MW
Rocky Reach	177 MW
Wanapum	161 MW
Spokane Energy	150 MW
Total IR	**2,218 MW**

Q. Please describe the PTP agreements.

A. The PTP agreements provide PGE with firm transmission rights across BPA's transmission system from one point of receipt (POR) to one point of delivery (POD). This transmission can also be used non-firm from alternative PORs to alternative PODs. Table 2 below summarizes the current agreements, all of which last at least into 2010 and then have rollover rights.

Table 2

PTP Agreement Summary

Point of Receipt	Point of Delivery	Max Capacity	Term
John Day	PGE System	300 MW	5 yrs ending 9/2010
Big Eddy	PGE System	100 MW	5 yrs ending 9/2010
Mid-Columbia (Rocky Reach)	PGE System	750 MW	5 yrs ending 6/2010
Federal System (Vansycle Ridge)	PGE System	25 MW	15 yrs ending 11/2016

Q. Please describe the AC/DC Intertie Agreement.

A. PGE's AC/DC Intertie rights are defined in the BPA/PGE Intertie Agreement. Under this Agreement, PGE Transmission Services (PGE Transmission) controls 850 MW of southbound rights on the AC line from John Day to the California-Oregon border (COB). PGE's power operations[3] group has purchased 200 MW of rights on the southbound line to maximize value to retail customers by providing opportunities to sell excess power in California markets. This 200 MW purchase was pursuant to PGE Transmission's open access tariff. In addition, under the Network Transmission Services Agreement with PGE Transmission, our power operations group has rights to 300 MW south to north to integrate

[3] PGE's power operations group can also be thought of as PGE Merchant, to distinguish it from PGE Transmission under FERC's open access policies.

the PPM Exercise Limited Winter Peaking Option. Finally, the power operations group has rights to 100 MW of DC Intertie pursuant to an exchange of AC for DC (resulting in a decrease in AC rights from 950 MW to 850 MW) under the BPA/PGE Intertie Agreement.

Q. Please describe the Montana Intertie agreement.

A. This agreement operates in tandem with the IR agreement to allow PGE to take energy from our share of Colstrip Units 3 and 4 and deliver it to the PGE system. The Colstrip owners, including PGE, built transmission lines from Colstrip to Townsend. PGE's power operations group has purchased transmission from Colstrip to Townsend from PGE Transmission under the latter's open access tariff. From Townsend, BPA delivers power to Garrison pursuant to the Montana Intertie agreement. From Garrison to the PGE system, BPA delivers the power pursuant to the IR agreement. Most of this transmission is firm. However, we only have 280 MW of firm transmission from Townsend to Garrison, and must schedule generation above this limit non-firm over Montana's system or sell the power in Montana, generally at adiscount to Mid-C prices. From Garrison to our service territory, we have 270 MW of firm rights under the IR agreement, but can schedule generation above this limit non-firm over BPA's system at no additional cost.

Q. Where do you discuss the O&M expenses and capital additions associated with PGE's owned transmission resources?

A. We discuss these revenue requirement elements in PGE Exhibit 600.

II. Plant and Power Operations O&M and Capital Addition Expenses

Q. In summary, what are PGE's plant and power operations-related O&M costs, full-time employees (FTE), and capital expenditures from 2002 through the 2007 test year?

A. Table 3 below provides this information.

Table 3
Summary Plant-Related Statistics
($000)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast *W/O PW*	2007 Forecast *With PW*
Hydro O&M	6.5	7.5	7.2	8.3	9.4	10.7	NA
Coal O&M	26.2	26.6	34.8	25.9	27.7	28.6	NA
Gas O&M	14.7	13.5	10.5	14.4	15.3	16.4	24.9
General Plant O&M	3.2	1.7	2.8	2.9	3.1	3.7	NA
Power Operations O&M	10.8	10.8	11.7	10.4	12.1	12.5	NA
Hydro FTEs	82	77	79	83	83	84	NA
Coal FTEs	67	67	69	72	73	73	NA
Gas FTEs	91	82	79	81	78	77	94
General Plant FTEs	65	64	66	76	78	79	NA
Power Operations FTEs	73	74	72	74	87	77	NA
Hydro Cap. Add's - Not Relicens.	9.6	4.5	5.2	3.6	4.4	2.9	NA
Coal Capital Additions	4.2	7.0	17.1	4.6	8.8	9.4	NA
Gas Cap. Additions	3.5	17.7	2.4	1.9	1.5	2.3	NA
General Plant Capital Additions	0.0	0.0	0.5	1.1	1.8	1.8	NA
Power Operations Cap. Additions	0.0	0.0	0.0	1.7	1.4	0.0	NA

Hydro O&M expenses include relicensing-related costs, whereas hydro capital additions do not. We discuss relicensing-related capital expenditures in Section III. Table 3 provides both with and without Port Westward figures for 2007, the difference being 17 FTEs and $8.4 million in O&M expenses. Employees listed as general plant FTEs bill much of their time to individual plants, although they are not assigned to any one facility. General plant capital additions are related to our dispatchable standby generation program.

Q. What does Table 3 broadly imply about plant and power operations-related expenses over the 2002-2007 period?

A. Table 3 indicates that PGE's plant-related costs have not changed very much over the five years. Considering Port Westward's $8.4 million O&M expenses, which apply only to 2007, our thermal O&M expenses can vary from year to year, but are projected to increase at less than the inflation rate in the overall economy. Projected general economy inflation over the five-year period is approximately 13%, implying that, had coal and gas-fired plant O&M expenses gone up with overall inflation, they would be about $29.6 million and $16.6 million respectively in 2007. Instead, comparable 2007 test year figures are $28.6 million and $16.4 million.

We are constantly looking for ways to increase productivity, and effectively offset wage and other cost pressures. Although we project hydro O&M expenses to rise somewhat more than wage and other cost pressures would imply, a substantial portion of this increase relates to new or expanded activities. For example, 2002 O&M costs associated with relicensing totaled less than $0.7 million, as fish ladder maintenance was the only activity included. In 2007, we expect relicensing O&M costs to increase to approximately $3 million. Increases in general plant and power operations O&M expenses are less than $0.5 million and $2 million respectively over the five-year period.

Q. What primary drivers explain the changes in plant-related costs over the 2002-2007 period?

A. Primary drivers are:

- Hydro relicensing costs classified as O&M have increased over the period – approximately $3 million of $4 million hydro O&M increase.

- Port Westward will come on line in 2007, resulting in higher FTE and O&M cost levels – nearly all of $8 million gas O&M increase.
- Generator rewinds and runner replacements at several hydro facilities were completed early in this period, resulting in declining hydro capital addition levels over the period – nearly all of the more than $6 million decrease in hydro capital additions.
- Thermal capital additions were high during 2003-2004 – major work at Beaver ($7 million for heat-recover steam generator), Boardman ($10 million, primarily for turbine upgrade), and Coyote Springs ($5 million for rotor replacement).

Q. What is PGE's overall strategy for operating, maintaining, and upgrading its generating resources?

A. We operate, maintain, and upgrade our generating resources to achieve high availability and reliability. Ensuring that these resources are available to serve customers reduces our power costs because most of our plants' variable costs (mostly fuel) are less than the market price of electricity.

Q. Have you achieved this strategy over the last few years?

A. Yes. PGE has experienced good thermal plant availability, as demonstrated by Table 4, although recent problems at the Boardman plant negatively affected availability in 2005. Each figure is the percentage of the "not scheduled for maintenance or economic outages" portion a year that a plant really is available. In other words, the table is driven by forced (or unplanned) outages. For example, a plant might be scheduled for major maintenance work for 10% of a particular year, leaving it 90% available if no forced outages occur. If forced outages occur during 5% of the (90% of all) hours during which the plant "should be" available, then the plant's forced outage rate is simply 5%, and Table 4 would list its availability as 95%.[4]

Table 4

PGE Actual Thermal Plant Availability Factors

Plant:	2001	2002	2003	2004	2005
Boardman	97.11 %	91.88 %	95.79 %	88.49 %	75.89 %
Colstrip	90.60 %	76.95 %	90.81 %	90.64 %	92.48 %
Coyote	98.91 %	98.40 %	72.79 %	99.24 %	98.99 %
Beaver	96.91 %	69.61 %	81.98 %	85.28 %	85.51 %

Q. Are PGE's capital expenditures on thermal resources consistent with the goal of incurring reasonable costs to operate, maintain, and upgrade PGE's thermal plants to provide safe reliable power to customers at a reasonable price?

A. Yes. Work at Colstrip in 2006 and 2007 will increase the capacity of our shares by 10 MW, off-setting degradation over the last two years, and decrease the plants' heat rate by 352 Btu/kWh. The 2004 turbine upgrade resulted in a 19 MW increase in output for our share of Boardman, along with a 265 Btu/kWh decrease in heat rate. The 2002 HRSG work at our Beaver plant resulted in a 16 MW increase in output and a significant decrease in heat rate. The increases at Boardman and Colstrip provide more generation fired by coal, a relatively inexpensive fuel. Other capital expenditures are necessary to keep our thermal resources in good condition so that they are available to run when their fuel costs are lower than the value of the electricity they provide.

[4] Our net variable power cost modeling is somewhat more complex, as MONET considers both planned and forced outages, the latter based on the last four years of data. See PGE Exhibit 400 for details.

III. Hydro Relicensing

A. Introduction

Q. Why are you addressing hydro relicensing in this filing?

A. The 2007 test year is the first to include costs related to this effort, which PGE began in 1995. This test year includes some O&M associated with new licensing requirements, as well as some capital expenditures, including those associated with obtaining new licenses for Pelton, Round Butte, and Sullivan. Our new licenses will require capital expenditures of approximately $370 million. Although we have already incurred some of these costs, most are for activities that will occur between now and 2020. O&M expenses will also increase. Using a collaborative process, however, we preserved the cost-effective status of these resources and avoided any significant decrease in their performance. The latter is important because, at zero variable fuel cost, production capability is the key to the value of these resources.

Q. How is this section organized?

A. Part B summarizes the hydro projects PGE decided to relicense and the related costs, test year revenue requirement, and measures of cost effectiveness. Part C describes the approach to relicensing that PGE took under the Federal Energy Regulatory Commission's (FERC) general licensing procedures.

B. Relicensing and Related Revenue Requirement

Q. Which hydro projects has PGE recently relicensed or is PGE in the process of relicensing?

A. On June 21, 2005, PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) jointly received a new 50-year FERC license for the Pelton Round Butte Project, which consists of three developments located on the Deschutes River. PGE has majority ownership shares in two of these developments, Pelton and Round Butte. The third facility, the re-regulation dam (and associated powerhouse), is completely owned and operated by the Tribes. On December 8, 2005, PGE received a new 30-year FERC license for the Willamette Falls Project, which includes our Sullivan facility, located on the Willamette River. PGE is currently in the process of obtaining a new long-term license for the Clackamas River Hydroelectric Project, which is also under FERC jurisdiction. This Project consists of four developments – Oak Grove, North Fork, Faraday, and River Mill – all owned by PGE.

Q. Overall, what relicensing costs has PGE incurred and does PGE expect to incur in the future?

A. These costs fall into three primary categories: capital additions, relicensing process costs, and O&M. First, we expect to invest approximately $301 million for fish ladders, a water intake structure, and other capital additions. Second, we will capitalize approximately $70 million in relicensing process and studies costs. Third, protection, mitigation, and enhancement (PME) measures required by the licenses will increase O&M costs for the projects. The new licenses and related settlements require several measures. For Pelton Round Butte, these include road maintenance and improvements to recreation sites. For

Willamette Falls, PME measures include the responsibility for fish ladder maintenance. Our Clackamas Project will likely require similar PME measures. We project total relicensing-related O&M costs to be approximately $3 million in 2007 increasing to approximately $7 million in 2009, then decreasing to approximately $3 million in 2015, and generally increasing at 2.5% per year thereafter.

Q. Have you prepared a summary table of costs – both actually incurred and projected – by year and by project?

A. Yes. PGE Exhibit 303 provides this information. Pages 1 and 2 of that Exhibit cover capital and O&M costs respectively.

Q. How do these costs affect the test year revenue requirement?

A. The test year net rate base includes approximately $41.7 million related to relicensing. Given the pre-tax cost of capital of slightly less than 13%, the return requirement is approximately $5.4 million. The test year revenue requirement also includes relicensing-related depreciation and O&M expenses of approximately $1.0 million and $2.9 million respectively, resulting in a total hydro relicensing-related revenue requirement of approximately $9.3 million.

Q. Has PGE decided not to relicense any of its hydro projects?

A. Yes. We decided not to seek a new long-term license for Bull Run, our 22 MW hydro facility located on the Bull Run River, just upstream from its confluence with the Sandy River. We determined that the costs associated with measures necessary to obtain a new long-term license would likely exceed the value of the associated power output.

Q. Have you calculated "per MWh" costs for power to be produced by the relicensed plants?

A. Yes. Our calculations reflect the amounts and timing of all costs – both relicensing and other – related to running the hydro facilities covered by the Pelton Round Butte, Clackamas River, and Willamette Falls Projects through the end of the new license terms. We know that the new Pelton Round Butte and Willamette Falls licenses end in 2055 and 2035 respectively. We assume that the new Clackamas River license will run through 2052.

Using "average water," as explained in PGE Exhibit 400, and on a real levelized 2006 dollar basis, these costs are:

- Pelton $21.83/MWh
- Round Butte $22.66
- Clackamas Project $41.90
- Sullivan $45.26

These are substantially lower than comparable levelized market prices of more than $53/MWh.

Q. What net present values result from your calculations?

A. We expect relicensing to provide customers with the following net present value benefits ($2006 Million):

- Pelton $165
- Round Butte $375
- Clackamas Project $143
- Sullivan $ 14
- Total $697

Q. How does the cost of relicensing hydro resources compare to the cost of other resource alternatives?

A. It compares very favorably. The average cost of the resources that are part of PGE's most recent Commission-acknowledged Final Action Plan is more than $40/MWh, even assuming the gas forward curves used to evaluate the RFP bids and the Port Westward alternative. This average would be substantially greater using current forward curves. We base the net present value calculations on an expected long-term 2006 real levelized market power price of more than $53/MWh.

C. Hydro Relicensing Process

Q. Please describe the new long-term licenses that PGE has obtained or is pursuing.

A. FERC issues licenses for hydro facilities with terms ranging from 30 to 50 years.

Our two Deschutes River developments, Pelton and Round Butte, operated under one long-term license for the Pelton Round Butte Project, which expired at the end of 2001. After expiration of the long-term license, the project operated under "annual licenses." On June 21, 2005, FERC issued a new long-term (50-year) license.

For FERC licensing purposes, PGE's Sullivan facility was designated as the Willamette Falls Project. This project, whose long-term license expired on December 31, 2004, was operating under an "annual license" until December 8, 2005, when FERC issued a new long term (30-year) license.

With respect to the Clackamas River, we plan to renew the long-term license for our Oak Grove, North Fork, Faraday, and River Mill developments. These facilities were originally covered by two licenses, one for the Oak Grove Project, the other for the North Fork Project which includes our North Fork, Faraday, and River Mill plants. The two licenses were recently combined and designated as the Clackamas River Project. The current license expires on August 31, 2006, and we have requested a 45-year license. It is impossible to predict when FERC will act on our pending Clackamas application.

Q. What is the relicensing process like in general?

A. The FERC relicensing process is complex and time consuming (usually a minimum of five years). In making relicensing decisions, FERC must consider fish and wildlife, recreational, land use, cultural, and aesthetics issues equally with energy production. Certain federal and state resource agencies, known as "mandatory conditioning agencies," have specific authority to include requirements in FERC issued licenses. These requirements are often expensive, and can limit hydro plants' operational flexibility. Examples are mandatory measures for fish passage and minimum in-stream flows. Often there is insufficient scientific knowledge to objectively determine the environmental effectiveness of some proposed mandatory conditions. Moreover, the FERC relicensing process can become extremely contentious and political. Given this environment, PGE used a collaborative approach to reduce costs and uncertainties wherever possible.

Q. Please describe the relicensing process for the Pelton Round Butte Project.

A. PGE began the relicensing process for the Pelton Round Butte Project in 1995. Following several years of relicensing discussion, PGE and the Tribes filed their Final Joint Application Amendment in June 2001. On August 11, 2002, FERC issued the Ready for Environmental Analysis Notice. This is essentially a determination that FERC has sufficient information to analyze the environmental impacts of relicensing the project. To resolve remaining issues, PGE and the Tribes began a multiparty, facilitated negotiation process in January 2003. Negotiations concerning fish passage, minimum flows below the plants, and associated operational issues, were complex and time consuming. In addition, discussions of the plants' water rights related to future municipal and other water use demands involved many parties. Reaching consensus required a lot of time.

On August 29, 2003, FERC issued its Draft Environmental Impact Statement. In December 2003, PGE and the Tribes filed a description of the Proposed Preferred Alternative with FERC. FERC issued its Final Environmental Impact Statement in June 2004. Parties signed the Settlement Agreement on July 13, 2004, and PGE filed the agreement with FERC on July 30, 2004. FERC issued a new long term license for the project on June 21, 2005.

Q. What were the advantages of PGE's decision to use a multi-party, facilitated negotiation process to relicense the Pelton Round Butte Project?

A. Thirteen agencies claimed some form of mandatory conditioning authority in the relicensing of the Pelton Round Butte Project. A collaborative settlement process provided the best opportunity to reconcile potentially inconsistent demands from these agencies and to maintain the economic benefits of the project for customers. The negotiated settlement involving all parties also greatly reduced the risk of litigation. Litigation over licenses increases costs to customers and raises uncertainty. Moreover, PGE believes that facilitated settlement processes involving all parties create the best opportunity for creative problem solving. We also expect the negotiated settlement to reduce controversy during the implementation of license terms, resulting in more efficient and lower cost implementation of programs.

Q. What must PGE do to meet the conditions of the Settlement Agreement that was part of the Pelton Round Butte Project relicensing process?

A. The Settlement Agreement and the new license, which largely adopts the terms of the agreement, have numerous requirements. The license terms address both project operations and measures to address all resource categories impacted by the project. These categories include wildlife and botanical resources, fisheries, water quality, recreation, culture, road maintenance, and other land uses.

Of particular significance, the new license contains an aggressive fish passage plan, which aims to reintroduce salmon and steelhead above the Round Butte Dam through construction of a new intake tower at the dam.

Q. How will the new intake tower at Round Butte work?

A. The new intake tower, also designated as the Selective Water Withdrawal Tower (Tower), will have two functions. First, by allowing water to be withdrawn from the Round Butte reservoir at a variety of depths, the Tower will create more distinct currents through the reservoir. These currents will guide downstream migrating juvenile salmonids to new fish collection facilities. Second, the Tower will improve water quality, both in the project reservoirs and downstream of the project.

Q. Will the changes made to meet the conditions of the Settlement Agreement alter the output and availability characteristics of Pelton and Round Butte?

A. No. Although the project will operate under a clearer and somewhat more restrictive set of target flows and reservoir levels, the key components of project operations, average energy, and peaking capability, remain intact.

Q. Will the changes made to meet the conditions of the Settlement Agreement change the O&M costs of Pelton and Round Butte?

A. Yes. Many of the requirements of the Settlement Agreement will increase O&M costs. In particular, PGE will pay various entities for road maintenance and law enforcement costs. Also, we will increase the biological staff dedicated to the project and to license implementation. Finally, annual charges paid to the State of Oregon and FERC will increase. Pelton and Round Butte PME-related O&M costs are approximately $2.3 million for the 2007 test year.

Q. Are all hydro relicensing costs directly related to license articles?

A. No. Although it is in all parties' interest to agree on the PME measures that FERC will enforce, there are instances in which the relatively narrow nature of FERC's jurisdiction over licensees does not cover all measures requested by the different parties. In these instances, PGE's negotiating team calculates the cost of these measures and compares those costs to the costs that PGE could incur if we did not achieve settlement.

Q. What are the primary settlement-related costs for Pelton Round Butte that do not directly relate to license articles?

A. In its order issuing a new license for Pelton Round Butte, FERC omitted two elements to which the settling parties had agreed:

1. Support for improvements of Forest Service facilities at Haystack Reservoir. This portion of the agreement requires PGE to pay $10,000 to the Forest Service in the fifth year of the new license. Additional payments of $15,000 each follow in years 20 and 40 of the new license.
2. Improvements to recreation sites on the lower Deschutes. This group of measures requires PGE to support a variety of upgrades to heavily used camp sites along the

Deschutes River below the project. The agreed upon level of support is $87,000 in the fifth year of the license and an additional $49,500 in the seventh year.

Q. What risks did PGE avoid by reaching settlement with all parties?

A. Had we not reached an agreement with all parties, federal and state agencies would have been free, within the limits of their statutory authorities, to mandate mitigation measures that FERC would have been obliged to include in the license. At that point, PGE's only practical recourse would have been to appeal issuance of the license to the federal Court of Appeals. It was PGE's judgment that the outcome of such litigation would have been a license which was, on its face, more expensive for customers than the settlement alternative, and could have involved significant litigation costs as well.

Q. Please describe the process PGE used to relicense the Willamette Falls Project.

A. In relicensing the Willamette Falls Project, we used a variant of FERC's Alternative Licensing Process, under which PGE prepares the environmental assessment on FERC's behalf. Participants in the relicensing process worked in a collaborative fashion, tackling issues incrementally in small technical work groups. This process was successful and resulted in the filing of a Settlement Agreement with FERC in January 2004. All parties have signed this agreement.

The most prominent issue at Willamette Falls was downstream passage of salmonids. Concerns also arose about safe passage of lamprey, a species of cultural significance to the Grand Ronde, Siletz, and Warm Springs Tribes. Petitions were submitted for listing lamprey under the Endangered Species Act. There were also issues regarding traditional tribal uses in the area of the falls. Finally, some parties requested increased public access to the falls through the project and adjacent paper mills. PGE could not meet these requests because of project and paper mill safety concerns and FERC's recent increased emphasis on project security.

PGE filed the Final License Application in December 2002. FERC issued its Draft Environmental Assessment in January 2004, the same month in which PGE filed the Settlement Agreement with FERC. FERC issued its Final Environmental Assessment in October 2004 and a new 30-year license in December 2005.

Q. What must PGE do to meet the conditions of the Willamette Falls relicensing-related Settlement Agreement?

A. PGE must operate the project in accordance with a more restrictive set of license articles. In addition, PGE will upgrade the turbines at Sullivan to improve the units' operating efficiencies and to make them more "fish-friendly." The Settlement Agreement also requires the decommissioning of a small powerhouse previously owned by Blue Heron Paper Company. Finally, the Agreement requires a phased program of improvements to the fish passage facilities at Sullivan and at Willamette Falls themselves.

Q. Will the changes made to meet the conditions of the Settlement Agreement alter Sullivan's output and availability characteristics?

A. No. The Settlement Agreement conditions will leave availability characteristics virtually unchanged.

Q. Will the changes made to meet the conditions of the Settlement Agreement change Sullivan's O&M costs?

A. Yes. The O&M costs at Sullivan will increase, largely for PGE responsibility for maintenance of the Oregon Department of Fish and Wildlife fish ladder located at the site. Sullivan PME-related O&M costs are approximately $200,000 for the 2007 test year.

Q. What process has PGE used to relicense the Clackamas River Hydroelectric Project?

A. For the Clackamas River Project we are using a variant of FERC's Alternative Licensing Process. Under this process, FERC's National Environmental Policy Act (NEPA) contractor, the firm that will eventually write the Environmental Impact Statement for FERC, participates in the process from the beginning, working with the applicant and relevant agencies. Relicensing participants work in a collaborative fashion, tackling issues incrementally in small technical work groups.

Much of the Oak Grove portion of the project is on Forest Service lands, which gives the Forest Service broad authority to mandate license conditions. Flow below the Harriet Lake diversion dam is a significant issue. Proximity to the Portland metropolitan area makes recreational use of the Clackamas Basin a major factor. Finally, most portions of the project have some form of up- and down-stream fish passage. The efficiency and appropriateness of the fish passage system is a major concern.

Relicensing participants completed scoping, the first phase of the collaborative process, and PGE issued a revised Scoping Document in April 2003. Concurrent with relicensing, PGE asked for a license amendment as part of its Endangered Species Act (ESA) compliance strategy. In June 2003, FERC granted this amendment, which included several fishery conservation measures and authorized new turbine runners at North Fork and Faraday #6. PGE issued the initial draft of its Preliminary Draft Environmental Impact Statement at the end of September 2003 and filed its Final License Application and associated Preliminary Draft Environmental Impact Statement in August 2004. With the completion of the Final License Application, PGE convened a settlement group, whose goal was to resolve the licensing issues via a collaborative settlement.

Q. Was the settlement group successful?

A. Yes. The group reached consensus on the outstanding issues. This resulted in an Agreement in Principle, which was filed with FERC on June 30, 2005.

Q. What must PGE do to meet the conditions of the Agreement in Principle?

A. As with the Pelton Round Butte Project, the Agreement for relicensing the Clackamas River Project contains significant measures to improve the survival of salmon and steelhead passing through the project. Of greatest significance, the agreement contains minimum flows in the Oak Grove Fork of the Clackamas River below Harriet Dam and requires new fish passage facilities to be constructed at PGE's North Fork and River Mill facilities. The agreement also contains measures to improve recreation in the project area, and to protect wildlife habitat and species, cultural and historical resources, and water quality.

Q. Will the changes made to meet the conditions of the Agreement in Principle alter the output and availability characteristics of PGE's Clackamas River hydro facilities?

A. The availability characteristics of the four facilities included in the Clackamas River Hydroelectric Project will remain largely unchanged. The combined energy output of these three plants will fall by approximately seven MWa because of increased minimum flow requirements at Oak Grove and Faraday, and head loss at North Fork.

Q. Will the changes made to meet the conditions of the Agreement in Principle change the O&M costs of PGE's Clackamas River facilities?

A. Yes. Staffing requirements to fulfill license obligations, increased operational requirements for campgrounds, and payments for road maintenance and law enforcement will increase O&M. Clackamas PME-related O&M costs are approximately $400,000 for the 2007 test year.

Q. Why did PGE decide to use a collaborative variant of FERC's Alternative Licensing Process for its Clackamas River and Willamette Falls Projects?

A. This choice provided the best chance of creating firm information bases and preliminary agreements, which could then serve as the foundations for comprehensive settlements. The collaborative process resulted in negotiated settlements, which will likely reduce both the controversy during license term implementation and the possibility of litigation. This reduction of conflict is likely to reduce costs and uncertainties for customers.

IV. Port Westward

A. Introduction

Q. Is Port Westward the first generating plant PGE has added to its system in more than 10 years?

A. Yes. We selected Port Westward through an Integrated Resource Plan (IRP)/Request for Proposals (RFP) process. This supply resource, a combined cycle combustion turbine (CCCT) plant, competed with more than 100 bids. Commission Order No. 04-376 approved inclusion of Port Westward in the revenue requirement on a cost basis. This filing includes capital and O&M costs for the 2007 test year, as well as Port Westward's effect on test year net variable power costs.

Q. How do you organize this section of your testimony?

A. This section is organized as follows:

- Part B develops the Port Westward test year revenue requirement elements.
- Part C describes the Port Westward plant.
- Part D explains how Port Westward is an integral part of the PGE's Commission-acknowledged Final Action Plan.
- Part E demonstrates that PGE has prudently implemented the Final Action Plan-based decision to develop the Port Westward plant.

B. Port Westward Revenue Requirement Elements

Q. What are the test year revenue requirements for Port Westward?

A. Port Westward test year net rate base is approximately $278 million, which, when multiplied by our pre-tax cost of capital of slightly less than 13%, has a revenue requirement effect of approximately $36 million. Test year depreciation and O&M expenses are more than $10 million and $8 million respectively, and related costs for A&G and revenue sensitive costs will increase by more than $1 million, resulting in an overall test year revenue requirement of approximately $57 million. These increases and a decrease in net variable power costs (dispatch benefit, net of fixed gas transportation costs) of approximately $12 million then result in a net revenue requirement increase of approximately $45 million.

Q. In detail, what does the rate base calculation include?

A. Port Westward rate base elements are the following ($000):

Gross Plant	285,205
Average Accumulated Depreciation	(5,333)
Average Accumulated Def. Taxes	(1,758)
Average Working Cash	76
Total	278,189

Q. What is the capital cost included in the rate base figures?

A. The capital cost is $285.2 million. It includes allowance for funds used during construction and approximately $3.0 million in capitalized firm gas transportation costs.

Q. How does this compare with the G-class capital cost estimate provided to Staff during PGE's RFP process?

A. In our response to Staff Data Request No. 007 in Docket LC 33 (for the IRP / RFP process), we provided an estimate of $295.2 million, which did not include capitalized gas transportation costs. Therefore, an estimate of $298.2 million (295.2 + 3.0 = 298.2) is comparable to the $285.2 million included in the test year revenue requirement. In other words, our current best estimate of capital costs is $13 million lower than the estimate we provided in LC 33.

Q. What are the capitalized gas transportation costs included above?

A. Pursuant to Order No. 04-686, in computing the test year rate base, PGE will capitalize approximately $3 million for 11,000 Dth/day of firm gas transportation acquired for the period November 1, 2004, through the start of Port Westward's operation. PGE bought gas transportation prior to completion of Port Westward to secure cheaper released capacity from existing Northwest Pipeline shippers. Waiting until late 2006 or early 2007 presented a risk of delay and likely cost increases related to pipeline expansion.

Q. Did PGE take actions to lower the net costs of this firm gas transportation to customers?

A. Yes. As noted in the order, PGE has been offering the unused firm gas transportation capacity for sale to other users. We have also used the capacity for arbitrage gains when gas prices at Stanfield and Sumas differed significantly. Both of these uses lower the net amount requiring capitalization. As of December 31, 2005, these revenues have been low, about $30,000, but we will continue to look for opportunities and will update these figures as the ratecase proceeding progresses.

Q. What is the depreciation life of the Port Westward plant?

A. Port Westward's depreciation life is approximately 28 years.

Q. Please describe the test year O&M costs associated with Port Westward.

A. Test year O&M costs (on a 12-month basis) are approximately $8.4 million, and include an addition of 17 full-time employees and a long-term service agreement (LTSA). We describe the LTSA in more detail later in this section.

Q. How do you incorporate Port Westward into net variable power costs?

A. PGE Exhibit 200 discusses the test year revenue requirement, both before and after Port Westward comes on-line. The revenue requirement with Port Westward includes an annualized decrease of approximately $11.7 million in net variable power costs attributed to the new plant.

C. Description of Port Westward

Q. Please describe the Port Westward Generating Plant.

A. Port Westward is a new G-class combined-cycle combustion turbine (CCCT), with an overall (January) capacity of 425 MW when new.[5] The CCCT configuration combines the output of two turbines. The first turbine uses natural gas to produce electricity and very hot exhaust gas. The exhaust gas is then directed to a heat recovery steam generator (HRSG). The HRSG uses the heat from the exhaust gas to turn water into steam, which a steam turbine then uses to produce additional electricity. Port Westward's natural gas combustion turbine is a Mitsubishi G-1 class unit with duct firing capability. Duct firing increases the temperature of the exhaust gas by adding and igniting additional gas. The higher exhaust gas temperatures allow the HRSG to produce more steam and hence more additional electricity via the steam generator, although at lower efficiency. Operating characteristics of a gas-fired plant vary somewhat with temperature and humidity. At 51° F ambient design temperature and 78% relative humidity, the heat rate for Port Westward in combined cycle mode will be approximately 6,700 Btu/kWh when the plant is new and all parts are in perfect condition. Under these same conditions, duct firing will have a heat rate of slightly more than 9,000 Btu/kWh.

[5] 400 of this is combined cycle; the remaining 25 duct firing. See Footnote 2 on degradation.

PGE selected Black and Veatch Construction, Inc. as the Engineering, Procurement and Construction (EPC) contractor. The site, located adjacent to the Columbia River in Columbia County, has excellent access to the Kelso-Beaver (K-B) Pipeline for fuel supply. Construction of a 19-mile-long transmission line will connect the plant to PGE's transmission system at our Trojan Station. Finally, PGE holds a long-term lease from the Port of St. Helens for the Port Westward site.

D. Integrated Resource Planning Context

Q. How did PGE decide to build Port Westward?

A. The decision to build Port Westward was a result of PGE's 2002 Integrated Resource Plan (IRP) process, which included an RFP and a Final Action Plan. Development of an approximately 400 MW G-class combined-cycle combustion turbine (CCCT) facility was a major element of the Final Action Plan, which the Commission acknowledged in Order 04-375.

After a public process, which included six public meetings and workshops, and an internal process, which included extensive modeling and analysis of alternative resource strategies, PGE filed its 2002 IRP in August 2002 (OPUC Docket No. LC 33). PGE updated the IRP with the 2002 IRP Supplement in February 2003. The IRP and Supplement called for various quantities of specific generic resource types, including a new gas-fired resource. As one option, PGE contemplated building a new CCCT at its Port Westward site. Parties to LC 33, however, noted that a considerable number of CCCT plants had been planned or built in response to high electricity prices during the energy crisis, and that the owners might be willing to sell these plants to PGE at reduced prices or offer attractively-priced tolling contracts, given that expected margins had decreased substantially. If these plants' owners were willing to sell for less than they had paid, then purchasing one or more of these plants under either ownership or tolling arrangements might well be the best option for customers. One way to solicit offers from plant owners was to issue an RFP, which we did.

Q. How did PGE conduct the RFP process?

A. After conducting a workshop for potential bidders, PGE issued its RFP, which the Commission approved (with conditions) in Order No. 03-387, issued on July 3, 2003. This RFP followed the framework of the OPUC Competitive Bidding Order (No. 91-1383), and was for "all sources," as we wanted the ability to consider all options for our Final Action Plan. In response, we received more than 100 bids involving approximately 14,000 MW of potential supply resources.[6] Our threshold requirements were modest, and we eliminated only 15 bids from consideration. Merrimack Energy was engaged as an independent observer for the RFP process, and submitted both interim and final reports. In its Final Report, submitted on September 6, 2004, Merrimack stated that PGE had fairly evaluated all of the RFP bids *and* its own self-build option, Port Westward.

Q. Did Merrimack independently score bids to PGE's RFP?

A. Yes. Using PGE's scoring methodology, Merrimack independently scored approximately 40% of the RFP bids. Merrimack and PGE's scorers then discussed differences in their results, which in most cases were very small. As a result of these discussions, PGE changed some of its scoring results as appropriate.

Q. How did PGE evaluate the RFP bids?

A. PGE developed a scoring methodology with input from the independent observer and parties to LC 33. This methodology was weighted 60% towards price (on a real, levelized $/MWh

[6] Note that bidders sometimes submitted multiple bids for the same project – ownership or tolling, entire project or a share thereof, etc.

basis), and 40% towards non-price factors, the latter including 10% for environmental considerations. We placed the highest scoring bids on a short list and then analyzed more than 20 portfolios made up of various combinations of short-listed bids and PGE's existing resources. This analysis included both price and risk elements. The portfolios that performed best from a price perspective also generally performed best from a risk perspective. That made the selection of our recommended supply actions, included in our March 2004 Final Action Plan, relatively straightforward.

Q. Did other parties to LC 33 participate in the evaluation and analysis process?

A. Yes. PGE held workshops to explain how we applied the scoring methodology to actual RFP bids and responded to approximately 100 data requests from OPUC Staff and other parties. These requests covered a wide range of topics. Of particular interest were the possibility of delaying Port Westward for a few years and alternative methodologies for comparing bids of differing durations. We also responded to questions received at a January 28, 2004, workshop, and to comments on our Proposed Action Plan.

Q. How did PGE's Port Westward self-build opportunity enter the RFP process?

A. Prior to receipt of RFP bids, PGE submitted to OPUC Staff a package of materials on Port Westward, which included application materials required of all RFP bidders, as well as a scorecard. The scorecard included the detailed results of applying our RFP bid scoring criteria to Port Westward, as well as an overall score.

Q. What PGE Final Action Plan did the Commission acknowledge?

A. In Order No. 04-375, the Commission acknowledged the following action items:

- Build or acquire 350 MWa of a high efficiency gas-fired resource.
- Acquire 25 MW of duct firing capability for peak loads and economic dispatch.

- Acquire approximately 65 MWa (195 MW) of wind generation, provided that the necessary transmission and integration services can be obtained, and that Energy Trust of Oregon (ETO) funds permit a price within the range of other alternatives.
- Acquire 135 MWa in fixed price PPAs for durations of five to ten years.
- Acquire up to 50 MWa of baseload energy tolling in place of fixed price PPAs if required, and 400 MW of tolling capability for peak purposes.
- Rely on the ETO to achieve 55 MWa of energy efficiency in PGE's service territory by 2007.
- Evaluate the market potential for combined heat and power systems at customer sites.
- Build a "virtual" peaking plant from 30 MW of dispatchable standby generation.
- Acquire capacity through customer demand reduction programs.
- Acquire short-term energy supply to meet the average annual energy need for direct access customers.

Q. Why did PGE select Port Westward?

A. Based on analyzing more than twenty combinations of short-listed RFP bids and the Port Westward self-build alternative, Port Westward was part of the portfolio that had the best combination of expected costs and associated risks and uncertainties. Portfolios that contained either lower proportions of CCCTs or CCCT options other than Port Westward were more expensive on an expected net present value of revenue requirement basis, or riskier, or both.

In addition to being part of the best portfolio, on a stand-alone basis Port Westward scored higher than any of the CCCT-based bids we received in our RFP.[7] Although our analysis also included detailed non-price factors, Port Westward scored better primarily because it provides lower expected costs for customers.

Q. Why was Port Westward cheaper than other CCCT-based alternatives?

A. Port Westward's location results in cost advantages over other gas-fired resource alternatives. This location has access to the existing K-B gas pipeline, whereas some of the gas-fired resources bid into our RFP would require fuel infrastructure construction. Gas-fired resources located in Washington are also more expensive because of that state's natural gas tax.

In addition to overall fuel cost advantages, Port Westward's location gives it a transmission cost advantage. Many of the gas-fired resources bid into our RFP could not guarantee firm transmission to PGE's service territory, and, to the extent they could provide such transmission, it was generally subject to BPA's rates and imputed line losses. In contrast, PGE can build a relatively inexpensive 19-mile line from Port Westward to PGE's Trojan Station. This line will avoid the fixed transmission charges and imputed line losses associated with BPA transmission.

Q. Have you performed calculations showing that building a new transmission line is beneficial for customers?

A. Yes. The customer benefit is almost $6 million per year. Building the new transmission line will cost less than $20 million and have an annualized test year revenue requirement of approximately $3.2 million. A return requirement of approximately $2.4 million and

[7] In fact, Port Westward with one F-class turbine scored higher than all but one bid, which was later withdrawn. Port Westward with one G-class turbine scored higher than any bid received.

depreciation expense of approximately \$0.7 million comprise most of this total, as the increase in O&M costs is very small. However, the new line will result in savings due to several factors. First, at the current BPA IR tariff rate of \$1.51/kW-mo., the new line will allow PGE to avoid annual BPA direct transmission charges of almost \$7.5 million (1.51 x 12 x 417 x 1000). Second, we expect actual line losses to be approximately 0.75%, substantially lower than the 1.9% rate charged by BPA. On the basis of a MONET model run assuming hypothetical Port Westward availability for all 12 months of 2007, this saving is almost \$1.5 million on an annualized basis. Netting the transmission and line loss savings against the annual revenue requirement results in an annual net benefit of approximately \$5.9 million.

Q. What is the primary advantage of a G-class rather than an F-class turbine?

A. It is a cheaper alternative for customers. We submitted to Commission Staff a complete scorecard and cost estimate for an F-class CCCT at our Port Westward site. As discussed above, this alternative was part of our best portfolio and also scored higher than all but one of the RFP bids on a stand-alone basis. However, subsequent analysis showed that the G-class option was an even lower-cost alternative for customers. This cost advantage is primarily due to two factors. The G-class option has scale advantages, as it is approximately 100 MW larger than the F-class option, and it has a three to five percent heat-rate advantage.

E. Prudent Project Execution

Q. Why did PGE choose to purchase the Port Westward G-class turbine from Mitsubishi?

A. There are only two G-class turbine manufacturers in the world – Mitsubishi and Siemens Power Corp. (known as Siemens-Westinghouse at the time we made our decision). We considered these two options based on the following criteria:

- Technology attributes
- Cost
- O&M considerations
- Number of operating plants
- Units deployed
- Units on order
- Reliability

Our engineers analyzed the two possibilities according to the selection criteria. In addition, we retained consultants who completed a detailed analysis of the two options' abilities to meet the selection criteria. After consideration of both the internal and external analyses, we selected the Mitsubishi alternative.

Q. Does the purchase of a newer-technology G-class, rather than an F-class turbine, increase technology risk?

A. No, for three reasons. First, G-class turbines have been in commercial use for eight years. Thirty-five Mitsubishi G-class machines are now in operation. Second, we negotiated with Mitsubishi Power Systems (MPS) a Power Island Equipment Purchase Agreement. The Agreement, which we assigned to Black & Veatch, the engineering, procurement, and construction (EPC) contractor, provides a one-year[8] warranty on equipment and guarantees for output, heat rate, and substantial completion, with liquidated damages for non-conforming performance. Finally, PGE and MPS signed a Long-Term Service Agreement (LTSA) which provides long-term major maintenance services to ensure

[8] Specifically the warranty is for one year or 8,000 operating hours, whichever comes first. Given expected dispatch, we expect one year to be the operative limit.

ongoing plant reliability. The LTSA provides assurance and predictability of turbine maintenance.

Q. What does the LTSA provide?

A. The LTSA is a 12-year contract, which also includes an additional two-year warranty on the hot gas components of the gas turbine, including the compressor. It has a fee structure based on equivalent operating hours (EOH), under which PGE will make quarterly payments and, in return, MPS will provide periodic EOH-based maintenance inspections. These inspections will include component repair and replacement.

Hot gas path components carry a warranty and the LTSA addresses all warranty-related work. PGE will also receive 24-hour online monitoring of the Port Westward plant from MPS's Orlando Service Center. In addition, the LTSA covers unplanned work that PGE, at its discretion, may ask MPS to perform. The agreement has a known escalation clause based on published labor and materials indices and an early termination clause which allows PGE to pay a fee to discontinue the arrangement after the first major inspection. We expect the first major inspection to occur after approximately six years, and could opt for early termination if the market changes significantly. The LTSA also has a fee-based termination for cause provision.

Q. Does PGE propose a major maintenance accrual mechanism for Port Westward, similar to the one currently used for Coyote?

A. No. Under the structure of the LTSA, MPS will perform periodic maintenance, the scope of which will vary considerably from year to year. However, PGE's annual payments will be almost flat, at approximately $4.5 million per year. Under this structure, an accrual mechanism is not needed.

Q. What process did PGE use to select Black & Veatch as the EPC contractor?

A. We sent a Request for Proposals (RFP) to six potential bidders, four of whom decided to submit bids. The RFP contained information on required plant characteristics, permitting status, and the target on-line date. We evaluated responses according to both price and non-price factors, the latter including experience with G-class turbines and CCCTs in an EPC contract arrangement.

Q. Why did PGE select Black & Veatch?

A. The Black & Veatch bid provided a good combination of guaranteed price, experience, and performance guarantees. Black & Veatch is a major international engineering construction and consulting firm headquartered in Kansas City. It is employee-owned and works in a variety of fields including power generation, power delivery, gas, oil, and chemicals.

Q. What plant performance guarantees has Black & Veatch provided?

A. The plant must meet both output and heat rate guarantees. Black & Veatch must physically remedy any problems that cause performance to deviate more than two percent from the guarantees, regardless of cost (to Black & Veatch). For deviations within two percent of the guarantees, Black & Veatch can either provide physical remedies or pay damages on a sliding scale, so that larger deviations result in larger damages.

Q. Has Black & Veatch provided a guaranteed completion date for the Port Westward project?

A. Yes. The planned completion date is March 1, 2007, and the guaranteed completion date is May 1, 2007. Black & Veatch must pay liquidated damages if the work is not completed by the guaranteed date. These damages are on a sliding scale, so that longer delays result in higher penalties.

Q. Is the project on time and within budget so far?

A. Yes. The project is currently within budget and on schedule to be on line on March 1, 2007.

Q. How far along is construction at this time?

A. Construction of the plant is proceeding on schedule. We have completed concrete foundations for the combustion turbine and steam turbine, and erection of structural steel for the generation building is nearly complete. We have also commenced installation of the combustion and steam turbines, which were delivered to the site in January 2006. Construction of the heat recovery steam generator commenced in November 2005 and continues. Concrete has been placed for the cooling tower basin and circulating water pump structure. We will begin construction of the cooling tower in February 2006. Erection of the plant services building continues. We have completed transmission line right-of-way clearing and the construction of concrete footings. Installation of the monopole transmission structures continues.

Q. What are the construction and testing milestones associated with Port Westward?

A. Table 5 lists construction and testing milestones, both completed and forecasted.

Table 5

Port Westward Milestones

Milestone	Contract Completion	Actual/Forecasted Completion
Start construction of stone columns.	Feb. 1, 2005	Feb. 15, 2005
Start construction of foundations.	June 1, 2005	May 2, 2005
Start HRSG deliveries.	Nov. 15, 2005	Oct. 17, 2005
Combustion and steam turbine delivery.	Jan. 15, 2006	Jan. 22, 2006
Back-up power from Beaver plant constructed.	April 1, 2006	April 1, 2006
Demineralized water available from Beaver plant.	July 1, 2006	July 1, 2006
Fuel gas available.	Aug. 1, 2006	Aug. 1, 2006
Wastewater system available.	Aug. 1, 2006	Aug. 1, 2006
Switchyard available.	Oct. 8, 2006	Oct. 8, 2006
Transmission lines available.	Oct. 8, 2006	Oct. 8, 2006
First fire of the combustion turbine.	Nov. 15, 2006	Nov. 15, 2006
Planned commercial operation.	March 1, 2007	March 1, 2007
Guaranteed commercial operation.	May 1, 2007	May 1, 2007

Q. How does the Port Westward plant work with the Port of St. Helens water supply and discharge system?

A. The Port of St. Helens, in cooperation with the Columbia County Urban Renewal District, secured a loan through the Oregon Economic Development Department to make infrastructure improvements for the Port Westward industrial site. The Port will repay this loan by tax increment financing, i.e. the property taxes from projects built at the Port Westward Industrial Site will provide funds to repay the loan. The site improvements include a new water supply distribution and discharge system, whose scheduled completion date is July 2006. PGE plans to connect the Port Westward generating plant to the discharge system in August 2006. The water distribution system will also serve other industrial customers.

Q. When will PGE begin paying property taxes related to the Port Westward plant?

A. PGE is making property tax payments during the construction phase, but will have a five-year property tax "holiday" beginning at the plant's commercial operation date. We include no Port Westward property tax payments in the 2007 test year revenue requirement.

V. Qualifications

Q. Mr. Quennoz, please describe your qualifications.

A. I hold a Bachelor of Science degree in Applied Science from the U. S. Naval Academy and hold Masters Degrees in Operations Analysis from the University of Arkansas, Mechanical Engineering from the University of Connecticut, Nuclear Engineering from North Carolina State University, and an MBA from the University of Toledo. Prior to working for PGE, I held positions as Plant Superintendent at the Davis-Besse Nuclear Station for Toledo Edison and General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light. I also coordinated restart of the Turkey Point Nuclear Station for Florida Power and Light. I joined PGE in 1991 and served as Trojan Plant General Manager and Site Executive. I assumed responsibilities for thermal operations in 1994 and hydro operations in 2000. I was appointed Vice President, Nuclear and Thermal Operations in 1998, and Vice President, Generation in 2000. I've held my current position of Vice President, Supply since August 2004. My responsibilities include overseeing all aspects of PGE's power supply, as well as the decommissioning of the Trojan nuclear plant. I am a registered Professional Engineer (P.E.) in the State of Ohio.

Q. Mr. Schue, please describe your qualifications.

A. I received a Bachelor of Science degree in Economics from the University of Oregon, a Master of Arts degree in Economics from the University of Minnesota, and a Master of Business Administration degree from the University of Louvain (Belgium). I have taught beginning and intermediate level economics courses at the University of Minnesota, particularly in the area of public finance.

I have been employed at PGE in a variety of positions beginning in 1984, primarily in the Rates and Regulatory Affairs Department. I have worked on Bonneville Power Administration rate cases, particularly in transmission rate design. I was the Project Manager for PGE's 2000 Integrated Resource Plan (IRP), and worked on PGE's 2002 IRP and related Request for Proposals. I also co-sponsored testimony and provided analytical support in the Trojan-related UE 88 Remand docket. In addition, I worked at the Oregon Public Utility Commission during 1986 and 1987, where my primary assignment was economic evaluation of conservation programs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	Grant County Settlement Agreement
302	PGE's 2007 Supply Resources
303	Relicensing Capital Expenditures

Grant County Settlement Agreement

Existing Wanapum Contract and Settlement Per Se
(MWa at Average Water)

Year	Wanapum Contract	Settlement Agreement	Total
2006	82.3	84.5	166.8
2007	82.3	84.5	166.8
2008	82.3	84.5	166.8
2009	68.6	92.2	160.8
2010		138.9	138.9
2011		127.7	127.7
2012		80.8	80.8
2013		78.4	78.4
2014		76.0	76.0
2015		73.6	73.6
2016		72.8	72.8
2017		72.8	72.8
2018		72.8	72.8
2019		72.8	72.8
2020		72.8	72.8
All Future Years *		72.8	72.8

* To continue over term of new long-term license, expected to be through approximately 2055

PGE's 2007 Supply Resources

Resources	Capacity (1) (MW)	Energy (2) (MWa)
Plants		
Boardman	380	278
Colstrip	296	243
Port Westward	417	305
Coyote I	244	151
Beaver	521	34
Beaver 8	24	0
Round Butte	225	76
Pelton	73	35
Oak Grove	44	27
North Fork	58	27
Faraday	46	26
River Mill	25	14
Sullivan	16	13
Bull Run	22	11
Plant Total	2,391	1,239
Contracts		
Wells	171	88.0
Rocky Reach	152	84.0
Grant County Settlement	292	167.0
Tribes	161	65.0
Canadian Entitlement	(29)	-16.0
Portland Hydro	36	10.0
Vansycle Ridge	25	8.0
Klondike II (3)	27	27.0
TransAlta Power Purchase	100	93.0
Morgan Stanley Power Purchase	25	25.0
Morgan Stanley Tolling	25	12.7
Spokane Energy Capacity	150	0.0
PPM Winter Super-Peak Option	100	0.0
PPM Exercise Limited Option	300	0.0
EWEB Capacity	10	0.0
Covanta PURPA Contract	10	10.0
Glendale Sale	(20)	-12.7
Glendale Exchange	30	0.0
Chelan Exchange (4)	0	0.0
Wells Settlement Agreement	21	27.0
Contract Total	1,586	588
All Resource Total	3,977	1,827

(1) Capacity measures are for January. Note that the capacities of gas-fired plants are inversely related to temperature. Figures for Boardman, Colstrip, Pelton, and Round Butte are PGE shares.

(2) Some resources, particularly thermal plants, are subject to economic dispatch; hence annual output varies from year to year. Figures in the table for Boardman, Colstrip, Coyote I, and Beaver are annual averages for the 2002-05 period. The figure for Port Westward is based on relative hypothetical 2007 dispatch of Port Westward and Coyote. The Morgan Stanley Tolling and the Glendale Sale figures are 2005 actuals. Energy output for hydro resources is on an expected water basis.

(3) Klondike II has 75 MW of nameplate capacity, but this is not the same as reliable capacity. We set capacity equal to average energy for wind resources in our 2002 IRP Final Action Plan, but will revisit this issue in our 2006 IRP.

(4) The Chelan Exchange provides 50 MW of summer capacity.

Relicensing Capital Expenditures ($000)

Year	Pelton	Round Butte	Sullivan	Clackamas	Total
Through 2003	6,173	15,432	9,178	21,366	52,149
2004	850	2,125	3,223	7,388	13,586
2005	1,897	4,744	4,916	14,503	26,060
2006	942	2,356	4,458	16,690	24,446
2007	4,138	10,344	4,861	19,629	38,972
2008	11,815	29,538	1,589	21,248	64,191
2009	2,912	7,279	894	28,928	40,013
2010	395	987	339	10,868	12,589
2011	1,673	4,182	-	31,297	37,151
2012	1,053	2,632	-	36,019	39,704
2013	4,687	11,717	-	-	16,404
2014	53	131	-	-	184
2015	-	-	-	-	-
2016	-	-	-	-	-
2017	-	-	-	-	-
2018	-	-	-	-	-
2019	-	-	-	-	-
2020	1,612	4,031	-	-	5,643
Total	38,199	95,499	29,459	207,936	371,093

Relicensing O&M Expenses ($000)

Year	Pelton	Round Butte	Sullivan	Clackamas	Total
2005	369	922	-	-	1,291
2006	590	1,475	-	-	2,065
2007	654	1,635	214	407	2,910
2008	799	1,997	220	586	3,601
2009	1,166	2,916	225	601	4,908
2010	1,033	2,582	231	616	4,461
2011	863	2,156	236	631	3,887
2012	826	2,065	242	647	3,780
2013	844	2,111	248	663	3,867
2014	836	2,091	255	680	3,861
2015	490	1,224	261	697	2,672
2016	494	1,234	267	714	2,710
2017	498	1,245	274	732	2,750
2018	507	1,267	281	750	2,805
2019	540	1,350	288	769	2,947
2020	543	1,358	295	788	2,985
2021	545	1,362	303	808	3,018
2022	578	1,444	310	828	3,160
2023	579	1,448	318	849	3,194
2024	590	1,475	326	870	3,262
2025	618	1,545	334	892	3,389
2026	612	1,529	342	914	3,397
2027	634	1,585	351	937	3,508
2028	668	1,670	360	961	3,658
2029	672	1,680	369	985	3,706
2030	688	1,721	378	1,009	3,796
2031	732	1,829	387	1,035	3,982
2032	737	1,843	397	1,060	4,038
2033	754	1,886	407	1,087	4,135
2034	798	1,995	417	1,114	4,325
2035	747	1,869	-	1,142	3,758
2036	768	1,919	-	1,171	3,857
2037	826	2,065	-	1,200	4,091
2038	815	2,036	-	1,230	4,081
2039	844	2,109	-	1,261	4,213
2040	892	2,230	-	1,292	4,414
2041	904	2,261	-	1,324	4,489
2042	922	2,306	-	1,357	4,586
2043	977	2,444	-	1,391	4,812
2044	976	2,440	-	1,426	4,841
2045	1,010	2,526	-	1,462	4,998
2046	1,067	2,667	-	1,498	5,232
2047	1,073	2,683	-	1,536	5,292
2048	1,097	2,742	-	1,574	5,413
2049	1,176	2,939	-	1,614	5,729
2050	1,175	2,937	-	1,654	5,766
2051	1,204	3,011	-	1,695	5,911
2052	1,280	3,200	-	1,738	6,218
2053	1,283	3,207	-	-	4,490
2054	1,315	3,287	-	-	4,602

UE 180 / PGE / 400
LESH – NIMAN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Power Cost Framework

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Pamela G. Lesh
Michael A. Niman

March 15, 2006

Power Cost Framework

Table of Contents

I. Introduction

Q. Please state your names and positions at PGE.

A. My name is Pamela G. Lesh and my position is Vice-President, Regulatory Affairs and Strategic Planning. I am responsible for all aspects of regulatory affairs and for overall strategic planning at PGE. My qualifications are in PGE Exhibit 100.

My name is Michael A. Niman and my position is Manager, Financial Analysis. I am responsible for power cost, project, and other financial analyses at PGE. My qualifications are in Section VI of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support PGE's forecast of net variable power costs (NVPC) for the purpose of setting cost of service rates for 2007 and to propose a fair methodology for reflecting power costs in PGE's cost of service rates. We propose a framework for power costs that uses three major regulatory tools – a general rate case (GRC), a forward-looking automatic adjustment clause (AAC), and a retrospective automatic adjustment clause – to achieve rates reasonably reflective of actual cost, and to allocate (between PGE and our customers) the risk of variances between the forecast used to set rates and the actual costs experienced. Our proposal includes not only methodologies and allocations, but also process and timing.

In brief, we propose to use a GRC much as we do now. Filed as needed by PGE, or initiated by the Commission or a complainant, the GRC would establish – for a test period and the indefinite future until the next GRC – the following:

- Capital recovery costs for generation investments (return of and return on)
- O&M for plants and power operations

- Operating parameters for PGE resources (or contracts that resemble resources) such as heat rate, maximum capacity, and environmental constraints
- MONET (the PGE power cost model) logic or other changes not specifically included in the annual update

We further propose to replace the Resource Valuation Mechanism (RVM) with Annual Power Cost Update (Annual Update – see Schedule 125). The RVM served two purposes: updating NVPC and providing the methodology for calculating transition adjustments for customers choosing direct access or market-based rate offers. PGE Exhibit 1300 explains the mechanism by which we propose to calculate transition charges in the future. For the Annual Update, each year, PGE will produce a new NVPC forecast by inputting to MONET:

- New power, fuel and transmission contracts (physical and financial) entered into by PGE;
- A load forecast for the following calendar year;
- Forward curves for power and fuel to value any short or long positions;
- Updated forced outage rates, using the traditional four-year rolling average methodology; and
- Planned maintenance outages for the following calendar year.

Unlike the RVM, the Annual Update will not re-spread fixed power costs (developed through unbundling) for the new load forecast. This feature of the RVM related primarily to its use as a transition cost mechanism.

Last, we propose an automatic adjustment clause – the Annual Power Cost Variance (Annual Variance – see Schedule 126) that compares the difference between the forecast

NVPC for a given year with the actual NVPC that PGE incurred, and allocates that difference between PGE and customers according to the following parameters:

- Variances shared 90% to customers and 10% to PGE
- Portion of variance related to changes in load from the forecast neutralized by comparing forecast average NVPC to actual average NVPC
- Prudence review

Both the Annual Update and Annual Variance would be subject to an earnings test, which we modeled on the Commission's 1999 policy ruling relating to Purchased Gas Adjustment (PGA) clauses, Order No. 99-272. Once a year, a proceeding would occur to enable a Commission finding whether the effects of the Annual Update and Annual Variance mechanisms in the prior calendar year, combined with the results of risk allocations from the last general rate case and any other regulatory actions for that year, resulted in reasonable rates. PGE would share equally (50-50) with customers any earnings for that prior calendar year above a threshold, which we propose as 100 basis points above our authorized return on common equity (ROE), adjusted for years between GRCs.

Q. Will PGE make an RVM filing for 2007?

A. Yes. PGE's current Schedule 125 remains effective until the Commission approves its modification. Accordingly, we have included with this filing an RVM estimate, similar to those we have provided over the last several years, and we will file the 2007 RVM by April 1, 2006, per the usual schedule. The RVM estimate differs from the GRC NVPC forecast in two respects:

- It reflects no changes to the MONET model

- The load excludes those customers who have given us notice "not to plan" for them under Part B of Schedule 125. As explained in PGE Exhibit 1300 we propose to eliminate this option beginning in 2007.

The 2007 RVM preliminary estimate is $813.8 million, a 29% increase from 2006. Continued high projected electric and natural gas prices and large unfilled positions are the primary causes of the increase. The forward curves in the final 2006 RVM filing were $67.44 per MWh and $9.35 per DT, respectively. However, at that time we had already filled most of our needs, either on physical or financial bases. The average cost to pay for short-term electric contracts and cover a small open electric position at forward curve prices was $49.76/MWh, and the value of our gas financials was more than $57 million. On the other hand, as of 2/23/06, forward curves for 2007 were $61.49 per MWh and $8.48 per DT, only somewhat lower than those in the final 2006 RVM filing, and we had large unfilled electric and gas needs. The average cost to pay for short-term electric contracts and cover a large open electric position was $60.63/MWh, and the value of our gas financials was less than $10 million. Our confidential workpapers provide detailed MONET model output for our 2007 RVM and GRC NVPC forecasts.

Q. What is your GRC NVPC forecast?

A. Our GRC NVPC forecast is $857 million. Both this forecast and the RVM estimate include:

- Forced outages rates based on the years 2002 through 2005
- Planned maintenance outages for 2007
- Power and fuel contracts entered into through 2/23/06
- Forward electricity and natural gas curves on 2/23/06
- Updated cost and performance parameters for thermal plants

- Updated hydro generation forecast based on the average of 69 years of hydro conditions
- Updated transmission and wheeling assumptions

Q. How do you propose to update your RVM estimate and GRC NVPC forecast?

A. We propose to do this according to the schedule adopted in the 2007 RVM, using that schedule for updating the GRC NVPC forecast as well. We intend to propose a schedule for this GRC docket that enables resolution of PGE's proposed changes to direct access by the end of August, in time for the September Schedule 483 and 489 elections. Assuming this resolution includes the disposition of Schedule 125 Part B opt-out as well, there will be no difference between the GRC NVPC and RVM NVPC forecasts except for any contested MONET changes. The RVM estimated rate change would, however, continue to reflect re-spreading the UE 115 supply function fixed costs over 2007 RVM loads.

Q. How does the Boardman outage that begin briefly in October 2005, and PGE's pending deferral for part of the outage period, affect your RVM and GRC estimates and your proposed framework?

A. In this filing, both the 2007 RVM and GRC NVPC forecasts include the days starting October 23 through December 31, 2005, in the rolling four-year average calculation of Boardman's forced outage rate. We stated in our application for deferred accounting that, to the extent that PGE receives recovery of the cost of replacing Boardman, the forced outage rate calculation should not reflect days included in that recovery. If the deferral proceeding results in a Commission order by October or November, we can reflect the outcome in the RVM and GRC NVPC forecasts.

The effect of the outage and the potential deferral on the Annual Variance component of our proposed NVPC framework is more complex. As we summarized above, the Annual

Variance tariff puts in place a sharing of variances, positive and negative. All else being equal, including Boardman's unexpected forced outage days in the rolling average used for forecasting increases the likelihood of a negative variance; i.e., actual NVPC would be lower because Boardman would produce more electricity at its variable cost of approximately $13/MWh, compared to a market price that may be approximately $60/MWh. Under our proposal, customers would receive 90% of such negative variances. This result would deprive PGE of the opportunity to recoup our loss from the outage period, to the extent that the Commission did not allow us direct recovery of the costs through deferral. The reverse could happen as well if, for example, Colstrip or Coyote Springs had performed particularly well in 2004 or 2005. Transition to the Annual Variance tariff could deprive customers of some of the expected compensation for the extraordinary performance that did not benefit them because no variance mechanism was in place.

To address this transition issue, which occurs both at the start and at the eventual end of the Annual Variance tariff, we have included language in the tariff to preserve the "benefit of the bargain" for customers and for PGE of variances related to how we forecast forced outage rates.

Q. How have you organized your testimony?

A. In the remainder of this introduction, we review the regulatory tools available for including power costs in cost of service rates and summarize a study PGE has prepared regarding how regulatory agencies in other states have applied these tools for electric utilities under their jurisdictions. We drew upon our review and this study, as well as the Commission's Order No. 05-1261, Oregon's regulatory treatment of natural gas utilities' purchased gas, and our interactions with expected parties to this case, in developing our proposed framework. We also briefly review the definition of net variable power costs (NVPC) and how we use our MONET model to produce a forecast of NVPC.

Section II discusses the GRC portion of our framework. We explain why we believe it appropriate to address the selected components of power costs in that forum, rather than in an annual update or a retrospective automatic adjustment clause, and the risk allocation reflected by the proposed treatment of those components.

Section III explains why we included the Annual Update mechanism in our framework. We also support our short list of items eligible for the Annual Update and describe the process and timing we propose to apply to the proceeding. As with Section II, we identify the risk allocation contained within this part of the framework.

Section IV explains why we included a retrospective mechanism in our proposed power cost framework, describes the parameters and process we propose for the Annual Variance tariff and why we chose or designed them and rejected others. We address the guidelines the Commission suggested in Docket UE 165 for the SD-PCAM as well as parameters currently in place for similar mechanisms or used in the past.

In Section V, we discuss the MONET changes that we propose the Commission adopt either for use in a continued RVM or for use in the proposed Annual Update. We present a preliminary estimate of the amount by which each change will affect NVPC.

Q. What regulatory tools are available for handling power costs in cost of service rates in Oregon?

A. Oregon has at least four regulatory tools that it can employ to reflect power costs properly in cost-of-service prices. These are:

- GRCs, which are a comprehensive review of all of a utility's costs, including the cost of capital;

- Forward-looking automatic adjustment clauses, for which the Commission may by statute suspend some of the procedural requirements for processing rates and which generally focus on components of cost of service that change more frequently than most;
- Retrospective-looking automatic adjustment clauses, which by using deferred accounting authority can adjust rates for components of cost of service that change frequently but are difficult or impossible to forecast accurately; and
- Deferred accounting, presently governed by the guidelines the Commission adopted in Docket UM 1147 and which is best suited for unexpected and short-term changes in a utility's costs.

All of the regulatory tools other than the GRC require features that ensure that the prices resulting from their application still meet U.S. Constitutional and statutory requirements. Commonly, this occurs through a prospective or retrospective review of earnings that will or have resulted from the approved cost changes.

Q. What are the characteristics of a GRC that you considered in deciding how to use this tool in the framework?

A. A GRC is the most thorough of all the tools, with a process that provides ample access to information and time to ensure understanding. The inclusion of all costs and revenues allows exploration of all linkages, direct and indirect. Determining whether the resulting prices meet Constitutional and statutory requirements is intrinsic to the proceeding, because the Commission determines the authorized rate of return based upon its application of the requirements to the record developed in the GRC. This is the proceeding in which the Commission can best address the alignment of risk allocation and cost of capital and this is why PGE is proposing a comprehensive regulatory framework for power costs in this filing.

A GRC, with its "test year" core, is not well suited, however, to highly dynamic information, such as near-term power and fuel purchase contracts, and forward curves. Depending on the process, it can become questionable whether the forecasts of such dynamic costs or revenues will be an acceptable representation of what will happen in the test year, let alone subsequent years. In addition, initiation of GRCs in Oregon has been one-sided in practice although not in right: the Commission or a customer can initiate a GRC. The slowness and initiation characteristics make a GRC ill-suited to cost components that can change significantly, up or down, from year to year (e.g., NVPC). This tool is best for cost components that slowly rise or slowly fall over time, such as most fixed costs.

Q. Which characteristics of an automatic adjustment clause (AAC) did you consider important in deciding how to use this tool in the framework?

A. Based on Oregon's experience with PGA clauses and PGE's power cost adjustment clause in the 1980s (1980s PCA) and RVM since 2001, we conclude that AACs are a good regulatory tool for cost of service rates if the cost (or revenue) to which the AAC applies:

- Changes frequently and in ways that could both increase or decrease prices, such that removing the utility's information advantage helps ensure fairness over time;
- Implements an already-decided risk allocation, rather than changing that allocation or revising it to reflect a new risk (such as a major new investment); and
- Generally is actually incurred, third-party generated, per a previously-agreed methodology, or verifiable.

Two items on this list are similar to those mentioned by the Commission in its 1989 order modifying PGA clauses in Oregon, Order No. 89-1046, which noted the standards of: (1) a cost that changes frequently so that tracking is useful to avoid numerous rate proceedings; (2) the significance of the cost in relation to the utility's total expenses; and (3) the degree of control the utility has over the cost. In 1989, gas costs were over 56% of Northwest Natural's total expenses; in 2007, we expect NVPC to be over 50% of our total revenue requirement.

AACs based on the above criteria can proceed rapidly and consume relatively few regulatory resources. The tool works less well if the underlying information is complex or involves choices about which disagreement might exist or if the AAC's timing does not permit review of all information used in adjusting prices.

The primary difference between forward-looking and retrospective AACs is the nature of the cost or revenue change involved. AACs for costs already incurred to serve a future period (e.g. gas purchase contracts) or capable of accurate forecasting can easily be forward-looking. AACs for costs not yet incurred and subject to uncertainty (e.g., energy efficiency program incentives that will depend on how many customers choose the program) require a retrospective AAC.

Q. Why do you believe that AACs, forward-looking or retrospective, and deferred accounting require features to ensure that the prices resulting from their application still meet U.S. Constitutional and statutory requirements?

A. Any time the Commission rules on utility prices, its decision must meet these tests. As we noted above, this happens in a GRC as an intrinsic function of the scope of the proceeding. By their very nature, however, AACs or deferred accounting matters do not involve all costs and revenues and unreasonable prices could result if, for example:

- The cost or revenue adjusted through the AAC or deferred accounting relates integrally to another cost or revenue that is not adjusted; or
- Unrelated costs or revenues have changed significantly.

The Commission typically does this through an earnings test of some sort. In the PGAs, for example, the earnings test generally does not directly relate to the ways in which the AACs update the forecast of future natural gas costs or the variance between forecast and incurred gas costs for a prior period (this is slightly different for Avista). Rather, once a year, the Commission checks whether the complete regulatory framework for the gas utilities (GRCs and PGAs) has resulted in reasonable rates. Earnings above a certain threshold are subject to sharing. See Order No. 99-272 and OAR 860-022-0070. With respect to deferred accounting, the Commission has explained that "the sole issue is whether a utility's earnings for the test period enable it to absorb a cost that has been approved for deferral." Order No. 93-257 at 7.

Q. Did PGE conduct a study of how other states handled power costs for purposes of setting cost of service rates?

A. Yes, PGE engaged NERA Economic Consulting, formerly National Economic Research Associates, to conduct this study on our behalf. NERA completed the study in August 2005. PGE includes the full study entitled The Continuing Role of Power Cost Adjustments in the Electric Utility Industry as PGE Exhibit 401. In addition, PGE routinely tracks how other Northwest states address power cost recovery.

Q. What states and utilities did NERA include in the study?

A. NERA began with the fifty states as well as the District of Columbia and divided them into traditionally regulated states and states that had restructured their electric industry. (Nebraska and Alaska do not have any investor owned utilities.) PGE Exhibit 402 shows the types of states as defined by NERA and the states that have long standing Power Cost Adjustments (PCAs). The study excludes the restructured states and focuses on the traditionally regulated states outside the Northwest (30). Although NERA excluded Arizona as a restructured state, it should probably be included because restructuring is largely halted and the Arizona Corporate Commission has reinstituted a PCA for Arizona Public Service. Tucson Electric Power has not yet filed a rate case because of a prolonged rate freeze associated with the now halted restructuring.

Q. At a high level, what were the results of this study?

A. Of the states and utilities reviewed, the overwhelming majority track through to retail prices 100% of a utility's prudently-incurred NVPC, both power and fuel. This occurs through periodic filings for forward-looking rate adjustments and true-up mechanisms to reconcile past variances. Rate adjustments are usually accompanied by requirements for a regulatory hearing or report to the Commission. The frequency of adjustments varies from state to state, ranging from monthly to annually. Of the 28 states that authorize their utilities to have a power cost adjustment clause, 25 include some form of true-up. The time-lag for full cost recovery of forward-looking adjustments and true-up reconciliation varies from 1 month to 12 months.

Some states include purchased capacity costs in their PCAs. These states include Hawaii, Montana, Oklahoma, South Carolina and South Dakota. Others address capacity in separate clauses (AR, FL, WI) or the utilities' base rate (GA, IA). Some states allow utilities to recover the cost of financial hedges (AL, GA, MS, NV, ND, SD). Utilities may include some or all of the gains/losses from financial hedging aimed at reducing energy costs in the PCA. Distinct geographic characteristics exist. PGE Exhibit 403 provides details of the state process.

Q. What did the survey show regarding the use of dead-bands and sharing?

A. Only Washington has had a dead-band of the nature applied in Oregon to two recent deferred accounting requests and proposed by various parties for ongoing AACs. Sharing mechanisms are infrequent and, where they exist, generally relate to the true-up or retrospective portion of the mechanism. These mechanisms take on a variety of forms. We discuss dead-bands and sharing further in Section IV.

Q. What did NERA do to ensure full understanding of the power cost framework in place in the various states?

A. NERA contacted both the Commissions and the utilities listed in the study. NERA solicited information about the framework of each PCA so that we could understand the mechanics and rationale. Appendix 1 of PGE Exhibit 401 presents the detailed information.

Q. What are your conclusions from the NERA study?

A. We conclude that, among states that continue to regulate utilities on a cost of service basis:

- The use of regulatory tools that allow frequent resetting of rates for power cost components, outside of a general rate case, is common;
- The use of regulatory tools that adjust rates for differences between the forecasted power cost components and actual power costs incurred, is common; and
- Commissions in the Western states tend to allocate more risk of variance to utilities than those in the Southern or Midwestern states.

PGE's current lack of a retrospective tool for variances between forecasted and actual power costs places us in an "outlier" status among cost of service electric (or combination) utilities. This is why our framework includes the Annual Variance tariff.

Q. How does PGE define "net variable power costs" (NVPC)?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs of power that generally change as power output changes, such as transmission payments to third parties. PGE records its variable power costs to FERC accounts 501, 547, 555, 565, and 447. Based on historical decisions, we include some fixed power costs, such as Boardman taxes. These items, such as transportation charges and excise taxes, relate to fuel used to produce electricity. We "amortize" these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (151). We also exclude some variable power costs, such as variable operation and maintenance costs, because they are already included elsewhere in PGE's accounting. The "net" refers to net of assumed wholesale sales.

Q. How does PGE produce a forecast of NVPC?

A. PGE uses a model to forecast NVPC. The primary purpose of the model is to reflect in estimating NVPC the principles of economic dispatch; i.e., a utility should use lowest variable cost resources to serve customers first, moving up the price/supply curve as load requires. PGE uses a combination of known future costs, forecast cost inputs, and a model to produce a forecast of net variable power costs, built around the principle of economic dispatch. In other words, for PGE and the region, resources such as hydro plants, coal plants, and combustion turbines run to meet load in order of lowest (variable) cost first, and highest cost last. We use a model called MONET that we first built in the mid-1990s and have since refined.

Q. How does PGE use MONET to forecast net variable power costs?

A. PGE uses MONET to "dispatch" PGE's resources against forward curves for purchased power and gas. To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, and any variable operating and

maintenance costs (although not part of net variable power costs for ratemaking purposes);

- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Transmission (wheeling) contract costs;
- Physical and financial electric contract purchases and sales; and
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET dispatches PGE resources to meet customer loads based on the principle of economic dispatch. Thus, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Any plant can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with market purchases (or sales) based on the forward market price curve.

II. Power Cost Framework – General Rate Case Role

Q. What components of PGE's power costs do you propose that the Commission reflect in rates only through a GRC?

A. As has historically occurred, we propose that the Commission reflect the following in rates through a GRC:

- Capital recovery costs for generation investments (return of and return on), whether new or capital additions;
- O&M for plants and power operations;
- Operating parameters for PGE resources (or contracts that resemble resources) such as heat rate, maximum capacity, and environmental constraints; and
- MONET logic or other changes not specifically included in the annual update.

Q. Why are capital recovery costs on this list?

A. Oregon's practice for many years has been to change cost of capital only in a GRC, at which time the Commission can ensure that the rate of return (reflecting cost of debt, equity, preferred and cap structure) produces an end result that meets Constitutional and statutory requirements. Similarly, Oregon has, for many years, required that utilities update their depreciation studies every five years, a time frame more suitable to addressing these "return of" issues in a GRC. For major new investment or capital additions, PGE generally knows in advance and a GRC schedule is workable. In addition, a proposed addition to rate base is not a highly variable number that requires frequent updating throughout the process.

Q. Are there circumstances under which PGE and participants in your rate cases might not want to do a full GRC to update power supply capital recovery costs?

A. Yes. We have one instance in this case. PGE plans to complete Port Westward shortly after concluding a GRC for the 2007 test year. PGE could almost simultaneously run a GRC for a test period that ends on Port Westward's on-line date but it makes more sense simply to "track" the plant into the already approved test year when it becomes available. The Commission previously used this procedure for PGE's Coyote Springs plant, and there are other examples as well. In essence, these "tracker" cases operate on the implicit assumption that nothing else requires review to ensure that the end result of the rates is reasonable. As we think ahead to the next five to ten years, it is probable that PGE will have more frequent generation-related major investments or capital additions than in the past 10 years. PGE is open to adapting this framework to accommodate a "tracker" concept for certain resource investments or capital additions.

Q. Why do you propose to address plant-related and power operations O&M in a GRC?

A. We propose this for two reasons. First, costs incurred in other areas, such as information technology, affect plant or power supply O&M costs making it difficult to address only O&M. For example, in this case, IT costs allocable to generation are $3.7 million. Second, these costs are not highly variable, either during a GRC process or after the case's conclusion.

Q. What do you mean by the term "plant operating parameters" that you use to describe the next category of power cost components you propose to address in a GRC?

A. The two main parameters we have in mind here are heat rate (for thermal plants) and maximum output capability (for hydro and thermal plants). Specifically for hydro, we include environmental operating constraints as a parameter matter, but updating "average water" for additional years of data would not be. These are characteristics that change from time to time because of reasons such as capital investments or environmental issues (permits etc.).

Q. Why do you propose to update these plant operating parameters in a GRC?

A. We propose this primarily for two reasons. First, the reasons for changes in these parameters can be complex, such as a new biological opinion affecting Columbia River hydro operations or air quality issues that constrain a given plant's operation during certain hours of the year. Handling such issues in a GRC allows all parties more time to understand the change. Second, particularly for improvements in heat rate or maximum capability, capital additions and higher O&M may be integrally related with the change. It seems unbalanced to reflect the parameter changes without recognizing the capital additions or higher O&M. On the other hand, a planned maintenance outage – which we do intend to reflect in the annual update – may be particularly long in a given year because of the work that is required to improve heat rate or increase maximum capability. This actually occurred with Boardman in 2004 and is underway for Colstrip 4 and 3 in 2006 and 2007, respectively.

In the RVM, we did change operating parameters for these matters. At times, however, our proposed changes generated controversy for a variety of reasons. We are open to discussing this part of the proposal during the process of this case. Solutions to the complexity and linkage issues may appear that we are not aware of right now.

Q. Why do you propose to handle MONET logic and other types of changes not specifically allowed by the Annual Update process in a GRC?

A. We make this proposal primarily because of our experience with the RVM and feedback from parties about the RVM process. The range of logic, data, and other modeling changes that can occur, as we attempt to produce as accurate a forecast as possible, is large. The effect of most such changes, however, is generally small. We may gain some process efficiency by gathering these together for handling in a GRC and parties will gain time to evaluate these changes.

Q. How would your proposed framework operate in a year in which you had a GRC?

A. Much as we are doing in this filing, we would provide an estimate of the upcoming Annual Update with the GRC so that customers understood the combined possible rate change and we would include in the GRC any MONET or operating parameter changes not allowed by the Annual Update process. On the date contained in the Annual Update tariff, we would file the Annual Update for the following year, without the effects of the proposed model changes in the GRC. Once the Commission acted on the GRC, we would include those decisions in the final Annual Update model run for the upcoming year.

Q. What risk allocations does this part of your proposed framework embody?

A. This part of the framework allocates to PGE the following risks:

- Regulatory lag and prudence on the recovery of generation capital investments;
- Changes in load that affect the recovery of these fixed capital recovery and O&M costs;
- Changes in and prudence of fixed O&M costs;
- Regulatory lag on changes in costs related to changes in plant/contract operations; parameters, to the extent of PGE's share per the Annual Variance mechanism; and
- Modeling choices, to the extent of PGE's share per the Annual Variance.

Q. What modeling choices allocate risk to PGE?

A. Two of our inputs to MONET embody significant risk allocations:

- The four-year rolling average methodology used to create a forecast forced outage rate for generating plants; and
- The methodology used to forecast the amount of hydro-electric power PGE's plants and Mid-C contracts will produce.

For both of these, we use a methodology because we have no way of knowing for certain what a given plant's forced outage rate for a year will be or what hydro-electric power we will receive from our projects or contracts. Only by fluke will the methodology result in a forecast that is the same as what actually occurs.

Q. How does the four-year rolling average for forced outages work?

A. We use a four-year rolling average, incorporating data from the four most recent calendar years for which data are available. For the 2007 net variable power cost estimate in this filing, we use data from 2002-2005. For example, if a plant had experienced forced outage rates of 5%, 12%, 3%, and 8% for the years 2002, 2003, 2004, and 2005 respectively, we would assume a 7% forced outage rate in our 2007 power cost estimate. This simple example assumes equal weighting of the forced outage rates. The actual calculation is effectively a weighted average, however, using the total unit forced outage hours, equivalent derated hours, service hours, etc. as applicable over the four calendar year period.

This produces a point forecast for a given year. If the actual forced outage rate for the year is less than this, PGE may experience the benefit of the additional plant availability, subject to the Annual Variance tariff. Customers will receive this benefit, however, over the following four years, as the increased availability lowers the forecast forced outage rate below what would otherwise have been forecast. The reverse occurs also.

Over the last seven years, the actual forced outage rates for PGE's coal generating plants have varied between 2.9% and 24.1%. The range is slightly larger for the gas-fired generating plants: between 0.6% and 30.4%. The financial effects can be significant, however, particularly for the coal-fired resources because of the differences between a given plant's variable cost and the market value of a MWh. The financial effect of forced outage rate changes at Coyote Springs and Beaver (and Port Westward, when it begins operation) are smaller because the natural gas-driven variable costs are often close to market on a given day.

Q. Is this an acceptable risk allocation?

A. Yes, when matched with the Annual Variance tariff we propose. The Annual Variance tariff will ensure that customers see most of the benefit of good plant performance and that PGE recovers most of its costs to provide power despite prudently-incurred plant outages. PGE will, of course, remain subject to bearing the cost of outages caused by imprudence. As we noted in Section I and explain in Section IV, the Annual Variance tariff must include a transition mechanism, however, because the four-year rolling average methodology includes in the mechanism the effects of years before it was in place.

Q. How do you forecast the amount of hydro-electric power production PGE will have available to it?

A. We use the Pacific Northwest Coordination Agreement (PNCA) hydro regulation model to develop an average monthly generation for each hydro resource, based on the historical stream-flows over the period 1929 through 1997, with in-board and out-board adjustments to the model. This produces a point forecast for a given year. If the actual production for the year is less or more than this, PGE will experience the cost of replacing the expected production (subject to the APCV mechanism). Generally speaking, over the last 10 years, actual hydro production has varied between a low of 428 MWa to a high of 708 MWa. This is a large range. Moreover, a swing of 20% or more from one year to the next is not uncommon. The financial effects are also large, because of the difference between the variable cost of hydro power, which is close to zero, and the market value of the power produced. For example, if the market electric price is $60/MWh, and hydro production is 100 MWa different than expected, the financial effect is more than $50 million (60 x 100 x 8,760 > 50,000,000).

Q. Is this similar to the rolling four-year average you use for forced outage rates?

A. No. It is different in a critical respect. Except for periods of highly volatile power markets, the rolling four-year average will roughly ensure an even risk allocation between PGE and customers over a five-year period. The shape of effect to each differs, but the totals should be close. This is NOT the case for how we forecast hydro production. Every year's forecast is a new look, unaffected by the year (or four) that just occurred. Moreover, the vast range of years covers an even larger range of wholesale electricity power prices (or no wholesale power prices, as there likely was little in the nature of a wholesale power market in many of the early decades included in the 69 years). It is doubtful (although we do not have records) that hydro production variations up to and as late as the 1950s had as much financial effect on utilities as they do today.

Thus, only at the end of 69 years could customers and PGE know whether this risk allocation resulted in revenue and cost neutrality and, of that, we have no certainty because we have no way of knowing whether the same distribution of water years will occur over a given sixty-nine years. And, of course, from 2007 forward, it is uncertain whether PGE will have access to production from the Mid-C hydro plants for 69 years and somewhat doubtful even for production from PGE's own hydro facilities, the longest license for which now expires in 2055.

Q. Is this an acceptable risk allocation?

A. No, not without a retrospective AAC of some sort. The Commission has recognized this, encouraging the development of an ongoing mechanism in Dockets UM 1077 and UE 165.

Q. Is there any other methodology PGE could use to create a point forecast of hydro production for purposes of creating a NVPC forecast?

A. Some have suggested that developing "expected value power costs" could produce a point NVPC forecast that reflects an even chance of positive or negative variances and an even size of such variances.

Q. What is expected value power cost?

A. Assuming all relevant variables are defined accurately, it represents a "fair roll of the dice" with respect to expected power cost recovery for the next year. If you roll the dice many times (i.e., many simulations of next year), the deviations between the simulations and Expected Value Power Costs for next year will tend to even out. The method simulates individual or aggregated draws of possible hydro conditions from the period 1929-1997, simulated to occur in the next year. It simulates next year only and not years into the future. In other words, whether one uses Average Hydro Power Cost or Expected Value Power Cost, there can be no reason to expect an inter-temporal matching of the costs and benefits.

Q. What are your concerns with developing Expected Value Power Cost?

A. One of the difficulties in developing Expected Value Power Cost is developing reasonable parameters for the relationship between hydro generation and market electric prices. Moreover, Expected Value Power Cost does not represent a ratemaking response for treating the volatility of power costs around the baseline forecast. It does not simulate hydro conditions outside of the 1929-1997 period or other more extreme hydro conditions. It does not handle unanticipated events (e.g., the 2000-2001 California Power Crisis), and generally is very poor at reflecting non-fundamental factors such as market psychology. It also does not simulate the next 69 years into the future. This is because:

- Hydro system non-power constraints change over time into the future.
- Hydro resource shares change over time into the future.

- The distribution of potential hydro production outcomes may not be represented by the 69 years because of climate change or changes in environmental requirements.
- The relevant parameters (e.g., hydro/market price relationship, gas/electric price relationship) are not static. As a result, even if the parameters are defined correctly for one year, they will tend to change over time. Thus, a deviation in power cost that is consistent with a distribution of potential outcomes in year 1 could not be expected to be offset with a deviation in power cost in year 2 (or some other future year) that is consistent with a different distribution of potential outcomes.

III. Power Cost Framework – Annual Update Role

Q. What components of PGE's power costs do you propose to address through the Annual Update?

A. We propose to establish a forecast of NVPC – which we defined in Section I – for ratemaking purposes each year through the Annual Update tariff. To create this forecast, we propose to use MONET, updating only for:

- Hourly loads for the forecast year;
- New physical and financial contracts and changes to existing contracts for power, fuel, fuel transportation, or transmission/wheeling;
- Forced outage rates, using the traditional four-year weighted, rolling-average methodology;
- Planned maintenance outage days for the forecast year; and
- Forward curves for long or short open power, natural gas, oil, or U.S./Canadian foreign exchange rate positions.

As we stated in Section II, any model change or data input not on this list would not occur in the Annual Update process.

Q. Why have you included an annual NVPC update in your proposed framework?

A. The primary driver of changes in our NVPC is power and fuel contracts that we purchase in advance for a given future year or years.

With the advent of markets for both power and fuel, and the shift away from long-term (15-year plus) agreements, neither PGE nor customers can have confidence that forecasts created for one year will be even approximately representative for a subsequent year. For example, just from 2002 to 2003, the average price of our power contracts fell by almost 49%; our 2003 RVM passed this cost decrease through to customers with no lag. An even larger drop in natural gas prices occurred after prices based on the UE 88 test year took effect in early 1995. PGE adjusted prices for this decrease at the end of 1996 in UE 100. Without an AAC, reflecting these market-driven changes in PGE's prices may not occur on a timely basis. PGE would have to evaluate whether to file a GRC based on the overall change in our revenue requirements and our belief about how long the changed power and fuel prices would persist.

Q. Doesn't an annual NVPC update eliminate regulatory lag as a risk the utility bears?

A. First, it is important to note that regulatory lag is a two-way risk: a utility has the risk of not receiving timely (via either load growth or rate increases) revenue increases to cover rising costs and customers have the risk of not receiving timely rate decreases as load growth and/or falling costs increase a utility's earnings. The Annual Update eliminates this risk for both PGE and our customers. Moreover, it does so only for this limited set of costs. The framework we are proposing allocates to PGE the regulatory lag risk for several power cost-related components.

Second, one of the traditional purposes of regulatory lag – to create an incentive for prudent decision making – may be less needed for the costs we propose to include in the Annual Update. One of the benefits of regulatory lag in the past was to encourage prudence by aligning interests between the utility and customers; i.e., the lag assured that the utility experienced either the benefits or detriments of the particular decision. For power and fuel contracts entered into in a competitive market, this assurance of prudence is less necessary because the Commission can judge the prudence of decisions according to other available decisions. Even for structured contracts, which may not have directly comparable alternatives, the market will provide enough information to construct a cost-benefit analysis. And, as with the purchased gas costs for which gas utilities also do not experience regulatory lag, PGE earns nothing on its power and fuel contracts. These are not rate base investments.

Q. Does an annual update discourage PGE from entering into multiple-year contracts?

A. No. PGE entered into several multiple-year (five years and longer) power contracts as part of the 2002 IRP Action Plan and RFP process. As market liquidity improves for contracts in the three-to-five year range, we will evaluate entering into these as well.

Q. Why does your proposal update hourly loads?

A. NVPC relates directly to loads. It would make no sense to update the costs without updating the loads.

Q. What model will you use for load forecasting in the Annual Update?

A. We propose to use the same model as we use in a GRC but, as explained in PGE Exhibit 1200, we will need to re-estimate the parameters with current external data. Load forecasts for the annual update process will incorporate the most recent data available for key inputs such as employment, GDP, building permits, and interest rates.

Q. Why will you include updates to power, fuel and transmission contracts in the Annual Update mechanism?

A. Again, these are the drivers of year-to-year changes in forecast NVPC. Chart 1 below shows, in $/MWh the average variable cost of gas resources and of power contracts during the last five years and in millions the total dollars spent. The total results from both the average cost and the volume, which can vary from year-to-year both because of load and because of trade-offs between gas and electricity.

Chart 1

		2001/2	2003	2004	2005	2006
Gas Resources	$/MWh	38.5	38.3	40.9	37.6	50.6
	Total $'s	201M*	98M	91M	51M	103M
Contract Resources	$/MWh	74.8	38.4	42.8	46.1	52.6
	Total $'s	508M*	204M	221M	299M	381M

* indicates 15-month number, from October 1, 2001 through December 31, 2002

Q. Why will you update forced outage rates in the Annual Update?

A. As we explained in Section II, the methodology we use for forecasting a forced outage rate allocates the risk that this forecast is wrong very specifically: the in-year effect goes to PGE and customers experience the variance in the following four years. To make this risk allocation methodology work fairly requires an annual update.

Q. What is the reason you update planned maintenance outages in the Annual Update?

A. These specific plans to perform, or not perform, maintenance vary significantly every year. PGE will purchase power to cover these periods and customers should pay that expected cost, which will change from year to year as maintenance needs change. If we set this only in a GRC, both sides would run a significant risk that the test year estimate was not representative in later years.

In contrast to the current RVM process, we propose to update the planned maintenance outage forecast in October of each year. By October, plant managers have largely completed their budgets, committing dollars to the planned maintenance and firming the timing. This should decrease the chance for variance over the current RVM process, in which we set the planned maintenance outage forecast in March.

Q. Even if you lock your forecasts of planned maintenance outages in October, is there a chance that the outages do not occur as planned?

A. Yes. We experienced this with our Sullivan plant. As of March 2004, we expected to take Sullivan out of service from July through October, 2005. In February 2005, we learned that we could not obtain all the necessary permits in time and would need to reschedule the outage for the following year – 2006. There is also a chance the outages go longer than expected. For example, in 2000, the Boardman outage lasted almost 54 days, rather than the 15 planned.

Q. How will you address this in the Annual Update mechanism?

A. We are open to discussing with the parties means of adjusting for changes between actual and planned maintenance outages. One approach might be to spread the missing or extra days over the following 2-3 years. Other approaches may exist as well.

Q. You noted above that some planned maintenance outages include work to increase the output or decrease the heat rate of a generating plant. Since customers "pay" for the variable cost effects, shouldn't they receive the benefits of the increase in capacity or decrease in heat rate?

A. It is reasonable that customers should get some benefit but, unless we also include the investment and additional O&M costs, it is not fair that customers receive the entire benefit. We are willing to explore allocating the benefits according the proportions represented by capital carrying costs (return of and on), one-time O&M, and foregone power production. As with the potential mismatch between forecasted and actual planned maintenance outages, we have not included a solution in the Annual Update tariff but are open to discussing the issue with the parties.

Q. Why do you need forward gas and electric curves for the Annual Update mechanism?

A. MONET meets load and dispatches PGE's resources on an hourly basis. As we begin a given calendar year, there are always some hours for which we have not purchased power or natural gas as MONET would indicate or have, in fact, purchased more power or gas than MONET calculates that we need to meet load. We input forward curves in MONET to value both what we need to buy and what we need to sell.

Q. What forward curves do you propose to use for the Annual Update?

A. We propose to use the average of five daily forward curves that we generate internally in early November.

Q. Is this a change from the RVM?

A. Yes. In the RVM, we have used PGE's internally-generated curve from just one day.

Q. Why do you propose to average the curves over a five-day period?

A. We have two reasons. First, an average over five days will smooth daily fluctuations from the forward look. Although uncommon, we have seen some extreme one-day moves in the forward curve that would cause us to have significant reservations about using that single day in ratemaking. Second, the use of five days' curves should ease concerns that PGE is proposing an unrealistic curve for purposes of the Annual Update. These are the same curves that we use to adjust our positions on a daily basis. Using an inaccurate curve for five days could have a significant adverse financial effect.

Q. Are externally-generated curves available?

A. We are aware of several external sources for forward curves, including ICE, brokers, and Energy Market Report. The difficulty with any of these is that we do not have direct access to their sources. We cannot validate their projections. We base our curve on actual conversations with trusted sources and document those. We do validate our curve against the externally-generated curves.

Q. Is it feasible for parties to the Annual Update process to audit PGE's internally generated gas and power curves?

A. Yes. We could make available to parties our documentation and the externally-generated curves from the same period. Review of these materials would not take much time.

Q. What process and timing do you propose for the Annual Update process?

A. We would initiate the process each July 1, providing an estimate of NVPC for the following calendar year, along with projected rate changes. This filing would include final forced outage rate calculations and all structured (including capacity) or multi-year power or fuel contracts that PGE intended to include. For the latter, the filing would include the basis on which we determined that the price of the structured contracts was reasonable. The estimate would also reflect preliminary planned maintenance outages, market contracts, pricing changes under old contracts, such as long-term transmission/wheeling agreements, and forward curves as of a certain date before July 1. For this initial filing, we would use just one-day curves. We chose this timing to allow parties ample time to review the support behind our structured contracts and verify the forced outage rate calculations. Parties could also review market contracts and old contract pricing updates included in this estimate and preliminarily review the load forecast.

On or before October 1, we would provide a final load forecast and the final planned maintenance outages. As noted above, by early Fall, plant managers generally have firmed their plans for maintenance work in the following year. The only load change allowed after this date would be that necessary to reflect customer elections in September under Schedules 483 and 489. We envision that the parties would use the following six weeks to verify the load forecast and engage in any necessary review of the planned maintenance outages.

On or before November 15, we would provide a final MONET run for the following calendar year, updating market contracts through early November, any short-term transmission pricing, and using the averaged forward curves described above. This run would include any load changes resulting from Schedule 483 and 489 elections. During the following three weeks, parties could audit the forward curve calculations and review the final market contracts and transmission pricing included.

We anticipate a Commission order on rates for the Annual Update tariff on or around December 15.

Q. Does your proposed Annual Update change any of the risk allocations you discussed in Section II or create any new risk allocations?

A. We discussed above how this mechanism interacts with the risk of regulatory lag, with respect to power and fuel contracts. The cut-off of structured contracts as of July 1 heightens somewhat the risk of regulatory lag for PGE for any such contracts. For forced outages rates and planned maintenance outages, the Annual Update simply implements the risk allocation stemming from the methodology choice made in a GRC.

IV. Proposed Annual Variance Tariff

Q. What are the parameters of your proposed APCV mechanism?

A. Under the proposed APCV mechanism, PGE would:

- Track the difference between its actual NVPC for a given year and its forecast NVPC, resulting from the Annual Update;
- Neutralize the effects of load changes (increases or decreases) on that variance;
- Absorb 10% of the variance and design the remaining 90% into a per kWh rider per an amortization schedule set by the Commission; and
- Demonstrate each year that earnings in the prior year, with the effects of the Annual Update and Annual Variance tariffs, do not exceed a reasonable amount, sharing any earnings above a threshold ROE 50-50 between PGE and customers.

Q. Why have you included a retrospective AAC in your power cost framework?

A. We believe that, notwithstanding an annual update of forecast NVPC, a substantial probability remains that the actual incurred NVPC will differ significantly from the forecast most years and will do so in both a positive and negative manner, resulting in lower NVPC one year and higher NVPC another year. Without a retrospective mechanism in the framework, neither PGE nor customers will have the assurance they should have that prices reflect cost of service.

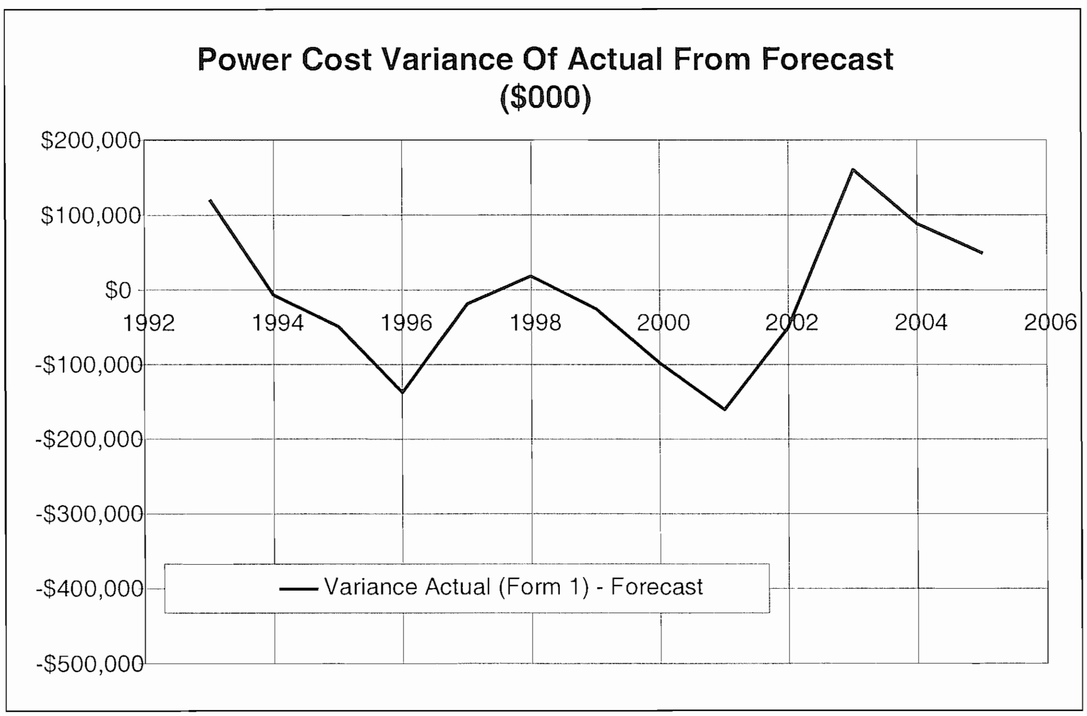
Q. Why does the Annual Variance tariff track variances between actual NVPC and forecast NVPC?

A. We have several reasons for proposing this construct. First, it is most consistent with the nature of our resource portfolio and how we operate the system. We work hard to minimize costs across the entire system and engage in much day-to-day activity to this end. Isolating the variance mechanism to a couple of cost components eliminates much of this activity from the mechanism and may distort the result. Second, and related, although we certainly know the uncertainty associated with hydro production, uncertainty – positive and negative – exists with respect to many other inputs to the MONET forecast even if hydro variations can swamp their effect. Third, during the last several years that we have wrestled with this issue with CUB, ICNU and OPUC Staff, we understand most have come to believe that a comprehensive mechanism is best. The disagreement lies in use of a dead-band and sharing, not in the scope of the mechanism.

Q. What has been the historical variance between forecast and actual NVPC?

A. Graph 1 below illustrates the variance between actual and forecasted net variable power costs from 1993 through 2005.

Graph 1



Graph 1 indicates that variances can be more than $150 million, both positive and negative.

Q. What do you cover in this section?

A. We first address, in Section A, how we propose to neutralize the outcome of the Annual Variance calculations to changes in load. Section B discusses why we included a sharing element in the proposal; Section C addresses why we did not, however, include a dead-band. In Section D we address the requirement of revenue neutrality the Commission suggested in its Order in UE 165. Section D discusses earnings tests, why we chose the form we did and how it would work. Last, in Section F, we address the process we would follow for the Annual Variance tariff.

A. Neutralizing Load Effects

Q. Why is it necessary to neutralize the effects of load changes on the variance tracked by the mechanism?

A. To fail to do so would create a mismatch between the NVPC component of rates and the actual costs incurred to serve customers.

Q. How will you neutralize these effects?

A. Because variable power costs are: 1) direct costs, 2) allocated to rate schedules on a kWh basis, and 3) included in energy charges that are billed on a kWh basis, it is relatively straightforward to determine the rate component associated with NVPC. In simple terms, it is the forecast NVPC divided by the forecast loads which we will call forecast unit NVPC. If actual load increases over forecast, NVPC will also increase, all else being equal. Likewise revenue associated with NVPC will increase by the forecast unit NVPC per kWh of load change. If loads decrease, the opposite will happen. Therefore, it is necessary to adjust for changes in loads by multiplying the load difference by the forecast unit NVPC.

Q. Are there other methodologies to achieve this neutralization?

A. There may be others, but they do not align actual NVPC incurred with revenues received.

Q. If customers respond to a prolonged period of tight power supply by reducing load, are they helped or hurt by this mechanism?

A. They are helped. In general, but especially during time of power shortage (e.g., a drought condition), we would expect the market value of power to exceed the forecast unit NVPC. Thus, a reduction in load would reduce what we call the "Power Cost Variance" (the difference between actual and forecast NVPC adjusted for load differences at the average unit NVPC) from what it would otherwise be.

Q. Please describe the Power Cost Variance as a formula.

A. The Power Cost Variance is equal to:

Actual NVPC - Forecast NVPC - (Actual Load - Forecast Load) * Forecast Unit NVPC

An algebraically equivalent way to express this is:

(Actual Unit NVPC - Forecast Unit NVPC) * Actual Load

(The proof is left to the reader.) This is the formulation included in our proposed tariff (PGE Exhibit 1302) and is the same as that used in our 1979-1987 PCA.

B. Sharing

Q. What purpose does a sharing feature serve?

A. To the extent the AAC is capturing variances between a forecast cost and an actual cost, the sharing percentages serve to align interests between the utility and customers, much as regulatory lag does. In other words, the utility experiences a direct financial effect of every decision made and action taken during the period over which the AAC is capturing the variance. This alignment of interests allows an assumption that the utility is acting prudently. Thus, while to some extent this feature works – as a dead-band does – to preclude the utility from recovery of some level of prudently incurred cost, it serves a regulatory purpose of aligning interests on decision-making and easing regulatory burdens associated with establishing prudence.

Q. What other states have used sharing as a feature of AACs for NVPC?

A. Colorado recently adopted a stipulated AAC that included sharing for Public Service Company of Colorado. Docket No. 02S-315EG. This AAC, in effect for 2004 through 2006, shares the first $15 million difference 50-50, the next $15 million is allocated 75% to customers and 25% to the utility and variances beyond that are 100% to customers. Order No. CO3-0670. The Commission explained in adopting the stipulation that: "This mechanism insures that the difference between ECA [energy cost adjustment] revenue paid by customers and prudently-incurred CPUC jurisdictional energy costs will never vary more that $11.25 million, either positive or negative." [p. 60.] The Order also notes that "[m]any parties filed testimony urging the Commission to adopt a 100% pass-through mechanism." [p. 59.]

Idaho uses a 90-10 sharing parameter in long-standing AACs in place for Avista and Idaho Power Company. Similarly, in 2005, Arizona approved an AAC for Arizona Public Service Company (APS) that includes 90-10 sharing. Docket No. E-01345A-03-0437. The Arizona Commission stated that it "agree[d] that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating." [p. 16-17.] Because testimony indicated that APS required the AAC primarily for the cost of power purchased to serve load growth, however, rather than price volatility, the Commission limited the annual amount of NVPC that APS could use to calculate the AAC, thus requiring that APS file a rate case to reset the base if it deems necessary because the cap was reached. [p. 17.]

Sharing is also a parameter in Washington. We discuss this in Section C. below, on dead-bands.

Q. Has Oregon used sharing in AACs?

A. Yes, frequently. PGE's early PCA included sharing of the variances between the quarterly forecast NVPC and the actual NVPC 80% to customers and 20% to PGE. Since 1989, Oregon's PGAs also have included sharing. Historically, the PGA passed through 100% of any variances in the cost of purchased gas which, at that time, was typically from a sole interstate pipeline supplier. In 1989, it became possible for gas utilities to purchase from multiple suppliers. Gas costs were then approximately 56% of Northwest Natural Gas Company's total expenses. The Commission stated: "[I]t is obvious that changes in gas costs can have a significant effect on LDC earnings. The determinations in this order demonstrate that it is the intention of the Commission to continue to provide safeguards to LDCs and their customers regarding gas cost changes." Order No. 89-1046. The Commission adopted 80-20 sharing for the retrospective aspect of the PGA.

Q. How do the PGA's work?

A. Our understanding is that a PGA has two components, similar to those we propose for PGE: a forward-looking mechanism to reset base natural gas costs for a coming year and a retrospective mechanism which defers, for later inclusion in rates, 100% of the monthly difference between actual fixed costs and the base level and a portion of the monthly differences between actual commodity-related costs and the base level in rates. See Order No. 99-272 at 2. As indicted above, this portion was 80-20 for all gas utilities starting in 1989. In the late 1990s, two of the Oregon gas utilities moved to 67-33 sharing, while one remains at 80-20. The sharing percentage triggers different applications of an earnings test. Order No. 99-272.

The base is set according to the cost of gas for a given gas utility for twelve months ending June 30 of each year. Volumes are not normalized to a prior rate case or for weather.

This historical period can be adjusted for known and measurable changes in purchase contracts. See Order No. 89-1046. In other words, the base includes forward contracts. Only projected volumes not covered by forward contracts would be priced at the historical cost.

Based on this understanding, we perceive that the risk allocated between gas utilities and their customers is as follows:

1. Regulatory lag in adjusting the price of any "base" gas required for the following year and not purchased in advance. Gas utilities have this risk, but it is also largely within their control.

2. Variance risk between the volume of gas used in the prior year and, thus, used to set the base and the volume of gas actually needed. This risk is shared, either 67-33 or 80-20.

3. Variance risk between the price of gas needed to serve load greater than that in the base forecast and the price included in rates and, thus, recovered for the additional sales. This risk is also shared, either 67-33, or 80-20.

Q. Is the process of setting the forward-looking base for the PGA the same as you propose for the Annual Update?

A. No. There are two significant differences. First, we currently, and would in the future, use a normalized, forecasted load, not historical volumes. Second, both the Annual Update and Annual Variance mechanisms concern **net** variable power costs: we forecast sales of any power or fuel purchased in excess of the forecasted, normalized load and generating plant needs and would track the variance in sales as they actually occurred.

Q. Is there any other difference between natural gas and PGAs and NVPC and your proposed mechanisms that is worth noting?

A. Yes. PGE faces a much larger price variance that is not related to volume/load variance. Our NVPC is based on a resource stack at the bottom of which are resources with very low or zero variable costs. Changes in the delivery from these resources can profoundly affect our actual NVPC. It would be analogous to the gas utilities having access to natural gas supplies priced at nothing or very low prices – say, $0.50/MMBtu – but being unsure, day-to-day just how much of this gas they will receive in their system. In addition, we have single-source risk for both some of our plants and our purchases. In other words, we expect significant volumes from these sources raising the risks of default or production variations. Examples would be the Mid-C contracts, the Trans Alta contract, and our coal-fired generating plants.

Q. How did you choose the sharing percentage?

A. The sharing percentage is the same as used in Arizona and Idaho. It is also the same as being proposed by Avista for Washington, to match what is in place for them in Idaho.

C. Dead-bands

Q. Does your proposed Annual Variance tariff use a dead-band?

A. No.

Q. What has been Oregon's application of a dead-band to an AAC?

A. Oregon has applied a dead-band to an AAC only once: in the stipulated power cost adjustment mechanism adopted in UE 115. Because the tariff for this mechanism expired 15 months following its effective date, however, it is arguable that this tariff was more in the nature of a deferral than an AAC. Oregon does not apply any dead-band to the regulatory framework used for purchased gas adjustments (PGAs) for natural gas utilities nor did Oregon apply a dead-band to PGE 's 1980s PCA.

The Commission has also imposed a dead-band in one instance of a deferred accounting request.[1] Such requests are markedly different from AACs, however, because of their sporadic nature.

Q. What other states use a dead-band for AACs that apply to electric utility power costs?

A. Washington (through the Washington Utilities and Transportation Commission) has approved, in the instance of two stipulations offered to it, a dead-band for AACs that apply to NVPC. Within the last month, Wyoming also approved a stipulation filed with it in a PacifiCorp case that includes a power cost adjustment clause with a dead-band.

A dead-band parameter –$20 million plus or minus – appears in the AAC stipulated to by Puget Sound Energy (PSE) Company in 2002, along with sharing tiers of 50% for the next $20 million, 90%/10% for the next $80 million and anything over $120 million shared 95% to customers and 5% to PSE. Twelfth Supplemental Order Docket No. UE-011570. That stipulation also placed a cumulative $40 million, 4-year limit (7/1/02 through 6/30/06) on the amount of NVPC variances allocated either to customers or PSE, with sharing moving to 99% to customers and 1% to PSE for amounts over this. A dead-band – $9 million plus or minus – also appears in the AAC stipulated to by Avista in 2002, with 90-10 sharing of all amounts outside of that. Fifth Supplemental Order, Docket No. UE-011195.

Q. Will Washington be reviewing the appropriateness of dead-bands in AACs for NVPC?

A. Yes. Both Avista (Docket No UE-060181) and PSE (Docket No. UE-060266) have filed cases requesting removal of the dead-bands from their power-cost related AACs. Avista proposes an AAC with 90-10 sharing. PSE proposes an AAC with 50-50 sharing of the first $25 million in positive or negative variance, with 90-10 sharing of the next $95 million in variance and 95-5 sharing of any remainder.

[1] PGE stipulated to a dead-band in another deferred accounting request (Docket UM 1008/1009).

Q. Has Wyoming applied a dead-band parameter to an AAC for NVPC?

A. As noted above, Wyoming just approved a stipulation that included one for PacifiCorp. The NERA report indicates that Wyoming had previously approved a dead-band mechanism for Cheyenne Light, Fuel and Power Company (Cheyenne) but, based on our review of the matter, it is not clear that is the case. The August 2001 Order describes a stipulation regarding a long-standing NVPC AAC for Cheyenne. Docket No. 20003-ES-01-58. Because of costs incurred during the Western power market crisis, Cheyenne was proposing rate increases from 57.1% to 88.2%. In the Stipulation, the parties agreed to spread recovery of some of the already-incurred costs included in those increases over future years (through 2005) and Cheyenne agreed to fix capacity and energy prices for purposes of the AAC from February 24, 2001 through the end of 2002. After the end of 2002, the AAC would revert to passing through 100% of actual NVPC. This plan allowed Cheyenne to drop the proposed rate increases by about a half in 2001 with an additional round of increases in 2002.

Q. Does the NERA report also show Kansas as a state that has used a dead-band for utility power-cost related AACs?

A. Yes. Again, we reviewed the material and would not classify the approach as a dead-band. The state-wide policy, adopted in 1977, puts limits on certain costs, such as line losses.

Q. Why haven't you included a dead-band in your mechanism?

A. We have several reasons.

First, as noted above, Oregon has only applied a dead-band in a non-settlement matter for a deferred accounting request. A dead-band applied to PGE's stipulated 15-month PCA, but this was not an ongoing AAC. Oregon has never applied the dead-band concept to an indefinite AAC, of which the most comparable example is the PGA mechanisms.

Second, a dead-band interferes with the risk allocation of the forced outage rate methodology. This occurs because the dead-band, for positive or negative variances, will consume some of the amounts the methodology would otherwise allocate to PGE or to customers, depending on what other factors are causing NVPC to vary. Applying sharing does not cause this because the sharing is consistent across the five years the forced outage rate methodology requires to reach parity.

Third, a dead-band suggests that a utility's earnings opportunity must, first and foremost, be at risk to variances in costs over which the utility has little or no control and must incur to meet its obligation to serve. NVPC differ from fixed O&M both in the size of potential variance, which is much higher for NVPC, and the ability to delay or avoid expenditures, which is much greater for fixed O&M. Delaying significant amounts of fixed O&M can threaten the quality of customer service and, over some period, the health of the utility's system. Delaying the purchase of power customers demand could threaten the stability of the system, causing widespread outages.

Last, a dead-band is not necessary to prevent undue rate volatility. The Commission has control over the amortization of any variances accumulated through the mechanism. Small variances need not trigger a rate change and the Commission may spread large variances over several years.

Q. Are you aware of any regulatory policy reason for applying a dead-band?

A. No. Some argue that a retrospective AAC must include a dead-band to ensure that the utility bears some risk. However, most aspects of regulation, such as the concept of administratively-determined prudence, allocate risk to a utility. A dead-band that automatically works to preclude recovery of prudently-incurred costs a utility must incur, or to prevent customers from benefiting from the characteristics of resources such as hydro generation, is not a necessary step to ensure that a utility bears risk.

Q. Doesn't the Commission's Order in UE 165 suggest that an AAC for hydro variances include a dead-band?

A. The Commission stated that "unusual, but not necessarily extraordinary, events – should be used for hydro-related PCAs." Order No. 05-1261. It is not clear what the Commission would conclude with respect to a retrospective adjustment for all NVPC variances, as opposed to hydro-generation variances only. If this conclusion applied to a retrospective adjustment for comprehensive NVPC variances, it would suggest that there is some level of "usual" prudently incurred cost that a utility may not have an opportunity to recover. Moreover, this policy would preclude recovery simply because the cost is uncertain and, thereby, difficult to forecast. While utilities have traditionally borne responsibility for managing costs within their control, they have not borne responsibility for uncertainty. In some circumstances, a utility's NVPC may not be uncertain and such circumstances would support a regulatory framework that did not include a retrospective adjustment. That is not the case, however, for PGE.

Q. Has the Commission required a dead-band as described in UE 165 to Oregon PGA clauses?

A. No.

D. Revenue Neutrality

Q. What is your understanding of "revenue neutrality," a guideline the Commission recently suggested apply to a hydro-related AAC in UE 165?

A. We understand that the Commission's goal was "that operation of a hydro-related PCA should not bias the overall expected level of power cost recovery; i.e., the mechanism should be revenue neutral over time." Order No. 05-1261 at 10. We find this difficult to apply, however.

The reason regulatory practice has included AACs over the years is that some costs defy accurate forecasting. NVPC are such, both for individual components, such as hydro production, and overall. This is particularly the case in a resource portfolio that has resources with significantly different dispatch costs and in a region in which there is an active wholesale market in which utilities participate to achieve lower overall NVPC as the market-clearing heat rate changes, affecting planned dispatch decisions.

Thus, it is impossible to determine whether a given AAC will result in the same collection of costs from customers – revenue neutrality – whether it existed or not. This goal appears to suggest a long-term backward look, limiting recoveries from or refund to customers to equalize them over the period chosen. Such a practice, however, setting aside legal concerns, suggests that we know the costs covered by the AAC will distribute themselves over the period of years chosen in a manner that provides the utility and customers equal probabilities of the same amount of economic variance. We can think of no cost included within NVPC that meets such criteria, let alone that the overall resulting NVPC over a period of years would meet such criteria.

Until we can achieve a fuller understanding of the steps and pre-conditions necessary to apply this parameter, we will not attempt to do so. We cannot "show" that the retrospective APCV we propose, and the alternate, are "revenue neutral." We can assure, however, that customers pay no more than the actual cost of service related to NVPC as those rise and fall.

E. Earnings Tests

Q. How has Oregon applied earnings tests to AACs?

A. At some point in the 1990s, Oregon began to apply an earnings test to natural gas utilities' PGA mechanisms. Our understanding of how this earnings test works is as follows. In the Spring of each year, once audited results are available for the prior calendar year, the gas utilities make a filing of regulated earnings for that prior year. Using a formula, the parties derive an updated "allowed" ROE for the prior year. A portion of actual earnings a given number of basis points above the updated ROE are shared with customers. For example, it appears that this is 33% of earnings more than 300 basis points above the updated ROE for Northwest Natural. If a gas utility chooses 67-33, rather than 80-20, sharing for the retrospective portion of the PGC, the earnings test does not apply to deferred amounts. That the earnings test triggers, does not limit applying the PGA to create a new base natural gas cost for the following year, it simply generates a credit to customers that the utility amortizes in that following year. If an earnings test applies to the deferred amounts, and if adjusted earnings are above the threshold earnings levels and the deferrals would result in a surcharge to customers, the gas utility will return to customers the lesser of: (a) the amount of revenue in the readjusted test year representing 80% of the earnings above the threshold, or (b) the amount of revenue related to offsetting the purchased gas cost deferrals.

An earnings test did not apply to PGE's old PCA, nor did one apply to the SAVE mechanism.

Q. Has Oregon applied earnings tests to deferred accounting requests?

A. Yes. The statute that gives the Commission authority to use deferred accounting requires an earnings test in most instances. Nonetheless, in practice an earnings test is not always a factor. For example, the Commission did not perform an earnings test in passing through property tax reductions to customers (UM 374), the amount by which actual IT expenditures were less than its forecast (UE 115), or in allowing PGE to recover certain conservation expenses (UM 784).

During the early 1990s, when PGE's Trojan plant experienced prolonged outages and then we permanently closed it to achieve long-term lower costs for customers, the Commission authorized PGE to defer replacement power costs four times. Table 1 below shows the dockets, amount deferred, earnings test applied, and resulting recovery for each deferral.

Table 1
Trojan-Related Deferrals ($000)

Dockets	Period Covered	Customer Share	Earnings Test Year Ending	Power Cost Variance	Customer Share Before Earnings Test	Customer Share After Earnings Test	Effective Customer Share Percentage
UE 81, UE 82, UM 445	11/01/91 - 03/31/92	90%	04/01/92	26,112	23,501	23,501	90%
UM 529, UE 85	12/04/92 - 03/31/93	80%	04/01/93	56,714	45,371	45,371	80%
UM 594, UM 571, UE 93	07/01/93 - 03/31/94	50%	04/01/94	98,360	49,180	9,100	9%
UM 692, UE 93	01/01/95 - 03/31/95	40%	04/01/95	29,000	11,600	11,600	40%

Q. As a matter of regulatory policy, should earnings test considerations used for deferred accounting requests apply to AACs?

A. In general, no[2]. The two regulatory tools are different. As we noted above, the use of deferred accounting is infrequent and limited to temporary and extraordinary cost or revenue changes. Most AACs, in contrast, are an ongoing regulatory mechanism and features included in them directly affect the probability of cost recovery a utility can expect and that is important to determining whether the approved prices meet Constitutional and statutory requirements. For example, an AAC earnings test that routinely cut-off recovery of incurred costs at a point below a utility's authorized return on common equity (ROE) would affect the risk profile for the utility's entire cost structure. With such an earnings test, it could be impossible to conclude that the prices allowed the utility an opportunity to recover its costs and earn a return commensurate with firms facing comparable risks. It would lower investors' expected ROE, driving down the utility's market value and, ultimately, increasing its cost of raising capital. See PGE Exhibit 1100. Such an earnings test is a penalty, rather than a means of assuring reasonable prices.

An AAC should not, by its operation, cause prices to become unreasonable. The earnings test used for PGAs accomplishes that purpose. For an electric utility, however, because of the amounts involved in NVPC, sharing of earnings more than 100 basis points above an updated ROE may be more appropriate than the 300 basis points used for gas utilities.

Q. How would the earnings test apply?

A. PGE proposes to share evenly with customers the amount by which PGE's normalized actual ROE exceeds a threshold ROE. The threshold ROE is 100 basis points over a baseline ROE, calculated as follows:

- The baseline ROE for each year that is also a GRC test year will be the Commission authorized ROE as determined in that GRC.
- The baseline ROE for each year that is not a test year will be based on the difference between the risk free rate used to derive the Commission authorized ROE in the most recent GRC case and the actual risk free rate, based on actual

[2] An exception may be applying an earnings test to the AACs adopted as a result of SB 408. Because various interpretations of SB 408 needed for the AACs could cause utilities severe financial harm, an earnings test may be the only means of achieving a reasonable result under the *Hope* test.

Treasury yield data and applying the same methods used to determine the risk free rate in the GRC.

The annual update to ROE will ensure that if interest rates change (up or down), the baseline ROE (and hence, threshold ROE) will move accordingly.

The normalized actual ROE will be determined based on PGE's actual financial results as reported in the Results of Operations report filed annually with the OPUC, adjusted for the following:

- Costs explicitly disallowed for recovery by the Commission in our last GRC, such as Category C advertising expenditures (these are not adjustments to forecasted expenditures).
- Removal of any non-utility costs inappropriately included in utility accounts.
- Removal of any prior period costs or revenues.
- Coordination of the interest deduction for tax purposes to reconcile to the cost of long-term debt financing of PGE's rate base.

Q. Does your proposed Annual Variance tariff use the earnings test the Commission suggested in its order in Docket UE 165?

A. No. The Commission's suggested earnings test mechanism would constrain any recovery by PGE to that which brought our earnings up to the bottom of a range calculated by subtracting 100 basis points from our authorized ROE and limit any refund by PGE to that which brought our earnings down to the top of a range calculated by adding 100 basis points to our authorized ROE. In other words, if PGE had experienced higher NVPC and managed to control other expenses or receive revenue to offset some of this loss, the earnings test would commensurately preclude recovery of the increased NVPC, ensuring that, at a minimum, PGE had to absorb all (or more – depending on net rate base) of the $15 million dead-band the Commission also suggested to be appropriate.

Even assuming an equal probability that NVPC will be lower or higher than the forecast, with an equal probability that the positive or negative variance will be the same, this unprecedented version of an earnings test would systematically and negatively interfere with the other risk allocations already made to the utility by the overall regulatory framework. Compounding this problem is what PGE has demonstrated in Docket UE 165: the variance between forecast and actual NVPC is not symmetric in probability and amount. Given the amount of hydro power in the NW, hydro conditions have the ability to move the market clearing heat rate across the WECC, with lower than average hydro raising the market clearing heat rate and higher than average hydro lowering it. Even if water conditions, over some period of years, produced a symmetric distribution of lower and higher than average production, the financial effects would not be symmetric because of how hydro affects the market.

Q. Has the Commission applied an earnings test such as the one suggested in UE 165 to Oregon PGA clauses or in any other instance?

A. No, not to our knowledge.

F. Process

Q. What process do you propose for the Annual Variance mechanism?

A. We propose to initiate the mechanism in June with a filing that contains:

- Calculation of the variance
- The earnings test
- Proposed rate adjustments

Assuming that the Commission could complete any necessary process with six months, PGE can make the price change on January 1 of the following year with ample advance notice to customers.

Q. Is it possible to make more timely rate changes for results of the Annual Variance mechanism?

A. Yes. PGE could estimate the result of the Annual Variance mechanism (although not the earnings test) for a given calendar year as of October of that year and include this estimate in the final stages of the Annual Update for the following year. As long as the Commission had authorized us to maintain a balancing account for this mechanism that we could credit or debit as need be for any reconciliation of the final to the estimate, PGE would be willing to do this.

Q. Would prudence be an issue in the Annual Variance proceeding?

A. Yes, actions or decisions that pre-date but affect the period of the variance and that were not the subject of regulatory scrutiny in the Annual Update process would be subject to a prudence review. An example of this would be maintenance decisions on PGE's generating facilities and forced outage rates. While a party could raise prudence issues with respect to decisions and actions during the period of the variance, the alignment produced by the sharing mechanism should limit such issues to a minimum.

V. MONET Changes

Q. What model changes have you made to MONET since your 2006 RVM (UE 172) filing?

A. We have made the following modeling changes:

- Inclusion of Boardman coal losses
- Change in definition of electric market from the PGE system to the Mid-C trading curve
- Inclusion of an electric exchange option
- Increase in stand-by generator ratings to full capacity
- Inclusion of net costs of Troutdale-Linneman wheeling
- Inclusion of wheeling cost for "excess" Montana Colstrip power

Q. Why have you changed the model to include consideration of the loss of coal during its transportation from Wyoming to Boardman?

A. We have documented (over the period 1999 through 2002) that we lose approximately 1% of the coal between the point where it is loaded in Wyoming to where it is fed into the Boardman boiler. The trip is approximately 1,121 miles. During transit, strong winds attack the coal from the cumulative effects of train speed, headwinds, and crosswinds. These winds blow coal out of the rail cars, which is called in-transit wind erosion. In the coal industry, in-transit wind erosion is a commonly accepted fact, much like the loss of electrical energy over transmission lines. Studies in the 1970s and early 1980s reported losses of up to 3%. The studies used several methods of measuring the amount of coal lost, including both measuring the change in the depth of the coal and the weight of the coal, before and after transit and wind tunnel tests. A study by K.H. Nimerick and O.P Laflin, "In-transit Wind Erosion Losses of Coal and Methods of Control", *Mining Engineering*, August (1979), 1236-1240, reported that coal loss can be as high as 1.675 tons (3,350 lbs.) per rail car when subjected to 58 mph winds for six hours.

We calculated our estimate of 1% by comparing the difference between coal purchased and coal burned and the actual physical change in our coal pile. In equation form:

Coal Loss = (Coal Purchased – Coal Burned) – (Change in Actual Coal Pile)

Our 1% coal loss figure is then total coal losses over 1999-2002 divided by total coal purchases over that same period.

Q. How does the inclusion of coal losses affect 2007 NVPC?

A. We presently estimate that this model change will increase NVPC by approximately $354,000 but this number will likely change as we update MONET.

Q. Why isn't PGE proposing a similar model change for coal transported to Colstrip?

A. Colstrip is located only six miles from the mine, so any coal loss due to in-transit wind erosion is minor. In fact, our study found that the coal losses were only 0.1%, which is insignificant.

Q. Why have you changed MONET's definition of the electric market from PGE system price to Mid-C prices?

A. Using Mid-C prices, rather than PGE system prices, removes the 1.9% adder for contractual losses over BPA's transmission system that we previously applied to purchases we forecasted we would make at Mid-C. We include losses in our load forecast, so this adder caused double-counting. Removing it is consistent with how we model losses from our thermal plants. This enhancement also removes a minor inconsistency in MONET's treatment of contract purchases vs. market purchases. Previously, when PGE purchased a contract at the current Mid-C price, the power incrementally displaced assumed forward market purchases in MONET at the PGE system price. In theory, there should be no change in power costs because both the contract and the market purchase were at the market price. This displacement did create a change in power costs in MONET, however, because of the loss adder on the forward market purchases. Suppose, for example, that PGE purchased a 100 MWa flat contract at the Mid-C for $50/MWh. We would input that contract into MONET, and MONET would reduce forward market purchases by 100 MWa, but at a PGE market curve price of approximately $51/MWh ($50 x 1.019 = 50.95). Forecasted power costs would fall because the adder did not apply to the contract.

Q. What effect does using Mid-C prices instead of PGE's system prices have on 2007 NVPC?

A. We currently estimate that using Mid-C prices decreases net variable power costs by approximately $7.0 million. This effect will diminish as we replace assumed forward market purchases with contracts through the year.

Q. How have you included the electric exchange option contract in MONET?

A. This contract is what we would call a structured contract, which is designed to achieve a particular result between the contracting parties. In this structured contract, the counterparty pays PGE an annual fee, and, in return, when the option is exercised by the counterparty, PGE must transmit (wheel) the counterparty's generation for them. Under normal conditions, we expect to use our existing BPA Point-To-Point transmission capacity with no incremental cost to PGE. However, we expect to incur incremental wheeling costs when simultaneously: (a) the counterparty exercises its option and (b) certain transmission paths are curtailed. This contract makes use of otherwise available capability on PGE's system. To include this contract in MONET, we modeled the incremental wheeling cost PGE expects to incur based on our expectation of how often the two conditions will occur simultaneously and included this estimate as well as the annual fee PGE receives from the counterparty. The forecasted net benefit to customers is approximately $1.1 million in 2007.

Q. Why did you change the stand-by generator ratings in MONET from partial-capacity to full capacity?

A. In prior MONET model runs, we significantly de-rated the capacities of the distributed standby generation (DSG) units at PGE customers' sites because of the annual run-time limits in their operating permits, which are typically a few hundred hours. Based on our observations of how PGE actually dispatches these DSG units, however, we believe this is too conservative. There might be only a few high-priced hours in a year when MONET dispatches a standby generator, and in reality the standby generator would then typically operate at its full capacity.

Going forward, we will monitor each DSG unit's run time to ensure that it stays within its annual limit. If a unit begins to exceed its annual limit, we will need to modify MONET to constrain its dispatch, probably by using a de-ration for certain months as needed. Under current conditions, we do not expect the annual run-time limits to limit DSG generation, but we do expect this enhancement to improve our power cost modeling.

Q. Does increasing the DSG units' capacities have any effect on NVPC in this proceeding?

A. No. With current oil prices and electric prices, we do not presently forecast to run any of these units in 2007. This is consistent with their peak resource nature.

Q. What change did you make to MONET to reflect the net wheeling costs related to the Troutdale-Linneman transmission facilities?

A. These costs relate to an old transmission contract between PGE and Pacific Power, under which we pay each other for wheeling rights on each other's transmission facilities. We overlooked this contract in UE 115 and first proposed to include it in MONET in the 2004

RVM proceeding. We have added this contract to MONET. Under the contract, PacifiCorp pays PGE a fixed $20,529 per month to use PGE's 230-kV Linneman-Bethel transmission line, and PGE pays PacifiCorp a fixed $8,646 per month to use PacifiCorp's Troutdale-Linneman 230-kV transmission line. The net effect is a fixed NVPC cost reduction of approximately $140,000 for 2007.

Q. Why have you modified MONET to include wheeling costs for "excess" power generated at the Colstrip plant in Montana?

A. This change corrects an omission on our part. There are times when our share of Colstrip's generation (296 MW at the busbar in the last several RVMs) exceeds our firm contract wheeling capacity on the Townsend-Garrison line in Montana (approximately 280 MW). We pay non-firm wheeling charges to deliver this power to the Garrison Substation, from which our BPA IR Contract wheels the power the rest of the way to our system. Because we include this excess power in MONET as part of our normal generation from Colstrip, the model should also include these "excess" wheeling costs. Our 2007 estimate is based on the 2002-2005 four-year average of actual excess wheeling payments to Northwestern Energy. This increases 2007 NVPC by approximately $205,000.

Q. Has more hydro output data become available since the Commission approved PGE's 2006 RVM filing?

A. Yes. We have historically based our hydro output forecasts on data that the Northwest Power Pool (NWPP) uses in its Headwater Benefits Studies (HBS). NWPP completed an HBS in mid-2005, using data for the August 1928-July 1998 period, 70 Operating Years. The previous HBS used only 60 Operating Years, the August 1928-July 1988 period. The new HBS allowed us to construct a 69-calendar year data set.

Q. Has PGE added any new resources from the 2002 IRP Final Action Plan to MONET since the 2006 RVM filing?

A. Yes, we have added one such resource. The only new resource from the 2002 IRP Final Action Plan that is new since the 2006 RVM is Port Westward, commencing in March 2007

Q. How will Port Westward affect NVPC in 2007 when it begins commercial operation?

A. We expect that Port Westward's operation will lower NVPC because its favorable heat rate will displace higher cost contracts and assumed forward market purchases. We presently estimate these benefits, using the 2007 GRC MONET run, at approximately $11.7 million on an annualized basis.

After preparing this estimate, we became aware that the maximum operating capacity we used in MONET for Port Westward is too high and the heat rate is too low. We are working with the manufacturer to project Port Westward's operating parameters during the test year and will include heat rate and maximum capacity revisions in the updated MONET runs we do as this case proceeds. PGE Exhibit 300 discusses these parameter changes.

Q. What are your present expectations regarding 2007 planned maintenance outages (PMOs) for PGE's thermal plants?

A. Table 2 below shows both the 2006 and 2007 PMOs, the latter of which is based on the expectations of the respective PGE plant managers for Beaver, Boardman, and Coyote, and PP&L Montana, the plant operator for Colstrip.

Planned 2007 outages at Beaver include 16 days for the entire plant, and 21, 14, and 21 additional days for Units 6, 5, and 1, as we expect these units to need combustion turbine inspections and other work. Colstrip Unit 3 will be out for more than six weeks to complete an upgrade, which will increase PGE's output share by 4.8 MW. PP&L Montana does not plan a maintenance outage at Colstrip Unit 4 during 2007. The planned outage at Coyote relates to a hot gas path inspection and planned maintenance at Port Westward is for a combustion turbine inspection.

Table 2
Thermal Plant Scheduled Maintenance (Days/Year)

Plant	2006 RVM	2007 GRC
Beaver	28.5	See Text
Boardman	29	30
Colstrip 3	9	44
Colstrip 4	52	0
Coyote	16	16
Port Westward	NA	16

Q. What are your present expectations regarding 2007 PMOs for PGE's hydro plants?

A. Our planning includes the following hydro plant outages:

- Bull Run production decrease of more than two thirds in November and December – dismantlement begins
- Sullivan production decrease of approximately 15% from June 1 through November 9 – two units out for runner replacements
- River Mill production decrease of approximately 7% from April 15 through June 15, and during November – test spills for fish
- Round Butte production decrease of 10% in November – work on Selective Water Withdrawal Structure

Q. Have you changed the total capability and heat rate of Colstrip Units 3 and 4 for this filing?

A. Yes, because, consistent with our framework proposals, this type of change would appear in a GRC. We are updating for two types of changes at Colstrip for the 2007 GRC, which are updates to the existing capacity and heat rate of Units 3 and 4 and updates to reflect a turbine upgrade at each unit. Over the last 1-2 years, degradation in the capacity of Units 3 and 4 has been observed, reducing each unit's capacity from approximately 740 MW to 716

MW net. There is a minor update to the combined heat rate for Units 3 and 4, from 10,913 Btu/kWh to 10,842 Btu/kWh. Then, effective July 1, 2006 Colstrip 4 will have its high-pressure steam turbine upgraded, adding an estimated 24 MW of capacity with no additional fuel input. A year later, effective July 1, 2007, Unit 3 will be upgraded in the same manner. After the upgrade is complete, each unit's capacity will be increased by 24 MW, which is also coincidentally the approximate amount of observed capacity degradation over the last 1-2 years. Thus, after the upgrade is complete, each unit's capacity will be restored to about 740 MW net. The heat rate will also improve, to 10,490 Btu/kWh, because the upgrade capacity does not use additional fuel.

VI. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

List of Exhibits

PGE Exhibit	Description
401	Continuing Role of Power Cost Adjustments in the Electric Utility Industry
402	Status of Electric Restructuring: States Considered in Survey
403	Cost Recovery Mechanisms in Current PCA's

September 30, 2005

The Continuing Role of Power Cost Adjustments in the Electric Utility Industry

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I. EXECUTIVE SUMMARY

This report is a survey of Power Cost Adjustment (PCA) mechanisms across the United States, with a focus on traditionally regulated states. For vertically-integrated utilities in traditionally regulated states, PCAs typically cover both fuel and purchased power alike.

This report focuses primarily on the 30 states outside the Pacific Northwest that have a traditional regulatory framework. Of the 50 states and the District of Columbia (DC), sixteen states and DC have engaged in meaningful electric restructuring starting in the late 1990s (ER States),[1] two states do not have investor-owned utilities (IOU) operating in the state, and thirty-two states (including the Pacific Northwest region) are traditionally regulated (Traditional States).

The traditional bases for PCAs still hold true. The efficient allocation of resources (the principle that prices should reflect costs) requires that electric utility rates reflect the true economic costs of providing utility service to customers, while signaling future prices. PCAs, moreover, play a role in allowing utilities to attract capital at a reasonable cost. Rating agencies such as *Standard & Poor's*, *Moody's*, and *Fitch* cite the importance of adjustment clauses that support utility credit ratings. With increasing volatility in energy prices—*e.g.*, oil, natural gas, and coal prices and the wholesale price of electricity —relative to the era before restructuring, the rationale for using a PCA is becoming, if anything, more established. By ensuring that reasonably incurred and unavoidable costs can be recovered, PCAs lower utilities' financial risk and, in turn, lower the cost of capital for utilities.

This report explains how PCAs continue to be a common and accepted part of utility regulation for traditionally regulated utilities. The research for the report was conducted through interviews with Commission and utility staff as well as a detailed examination of financial reports, tariff sheets, rate case and merger orders, regulatory reports and expert testimony.

For the group of 30 Traditional States, 28 states allow some or all of their utilities to recover fuel, purchased power and certain other expenses through a PCA mechanism.[2] The Southeast and Midwestern states generally have comprehensive and flexible PCAs in terms of coverage of fuel and purchased power costs and process for recovery. In contrast, some of the Western states implement their PCA on a utility-by utility basis, which in turn creates inconsistencies and causes a lack of certainty about how fuel and purchased power costs are recovered.

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1 Utilities that are in electric restructuring states and that have an obligation to offer Provider-of-Last-Resort (POLR) service can easily justify the use of an equivalent to a PCA to pass through the full range of POLR costs to customers. **Appendix 2** provides a summary of how the costs of POLR service are passed through to customers in electric restructuring states.

2 Utah and Vermont are the traditional states that do not use PCAs.

II. PCAs ARE A COMMON AND WELL-SUPPORTED PART OF UTILITY RATEMAKING

Regulation of utility rates is necessary. An investor-owned utility has the obligation to provide the services that customers expect and the capital needed to maintain and expand the facilities that allow the public to be adequately served. In return, the regulator provides a stable regulatory environment, offers the utility a reasonable opportunity to earn a fair return on its investments and recover its prudently-incurred costs in rates, and oversees the adequacy and reliability of service. The task of utility rate regulation is to ensure that costs are prudently incurred and that rates are just and reasonable.

PCA mechanisms play an important role in this process. A key role for regulators is to signal credibly to a privately-owned utilities' investors how its costs will be recovered in regulated charges over time. Without such credible regulatory signals, privately-owned utilities cannot go to the capital markets to raise the necessary investment funds required to operate, maintain and expand the utility's infrastructure—and without access to capital markets, capital-intensive utilities cannot function. PCA mechanisms give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. Where customers' demand, fuel prices, and the wholesale cost of power are outside management's control, PCAs provide a fair and efficient means for customers to see the right price signals for the power they consume.

This section provides a brief history of the use and rationale behind PCAs in the context of administered rates. First, we identify the three eras of PCA regulation. Then, we discuss the standard rationale for PCAs, and the key constraint on PCA design: incentives. Finally, the role of PCAs in enabling utilities to attract capital is explained.

A. PCAs Have Been Widely Used for Many Years

PCAs are a standard and longstanding part of US utility ratemaking.[3] In the 1970s, with increasing energy prices, uniform PCAs that allowed for rate changes on a routine schedule became common.[4] PCAs, however, were implemented well before that date in many states. The three eras of PCA regulation are as follows:

- *Response to Specific Shocks.* Fuel adjustment clause (FAC) mechanisms, the precursor to PCAs, began to be established in the early 20th century, usually to deal with specific "shocks," such as high coal prices following World War 1. After the immediate war-related fuel cost increases diminished, state commissions decreased their use of FACs. Inflationary

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3 Michael Schmidt provides a useful summary of the early history of PCAs. *See*: Michael Schmidt, *Automatic Adjustment Clauses: Theory and Application,* (East Lansing, MI: MSU, 1980), pp. 10-11.

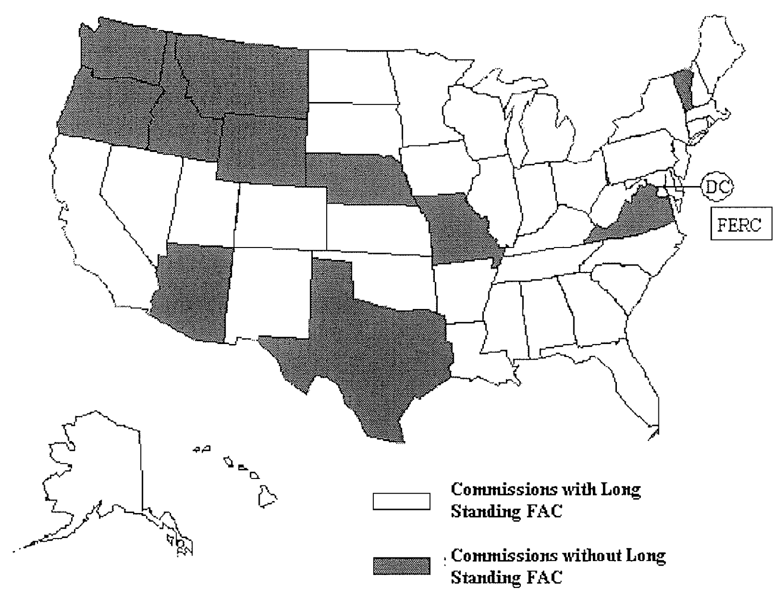
4 Schmidt explains that "[t]he purpose of an automatic adjustment clause is to allow a utility to adjust its revenues to accommodate changes in actual costs for a major expense item(s) *over which it generally has little or no control*. The objective is to mitigate the effect of relatively volatile cost items the firm purchases on a continuous basis." *Id.*, pp. 10-11.

pressures during and immediately following World War II created a renewed need for FACs to be applied during rate cases.

- *FACs Frequently in Place.* As early as the late-1950s, FACs were found to "have been incorporated in retail electric rate tariffs in forty-four states."[5] By this period, many FACs were in place, although actual FAC-related rate changes were infrequent.
- *Uniform FACs.* Following the energy crisis of 1972-73, state Commissions paid increased attention to FACs. In terms of FAC design issues, the focus of "at least twenty-nine" states was on uniformity so that all utilities in a state would be able to change their fuel rates.[6] The energy crisis of the 1970s and resulting high oil prices caused Commissions in many states to increase the frequency of rate changes by using a PCA.

In a survey conducted in 1990, NRRI found that 40 jurisdictions had "long-standing" PCAs in place, which they defined as having had an FAC for at least five years. **Figure 1** identifies these states.[7] Given the NRRI survey, this report focuses primarily on what has developed since 1985.

Figure 1: Commissions with Long Standing PCAs



Source: NRRI Report, p. 18.

5 R.S. Trigg, "Escalator Clauses in Public Utility Rate Schedules," *University of Pennsylvania Law Review* 106 (May 1958), p. 973.

6 Schmidt, *supra* note 3, p. 60.

7 Robert Burns, Mark Eifert and Peter Nagler. "Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets," *National Regulatory Research Institute*, November 1991, p. 9. [Hereinafter referred to as "NRRI Report."]

B. The Basic Justification of PCAs in the Context of Administered Rates

PCAs are a regulatory mechanism that accommodate timely recovery of certain categories of costs. PCAs benefit both customers and investors by helping to assure that a utility has an opportunity to charge rates that are just and reasonable, based on prudently incurred costs. Customers benefit from PCAs that improve the utility's ability to attract capital on reasonable terms in both good markets and bad. **Figure 2** summarizes the three classic rationales for a PCA, as well as a major constraint on their use.

Figure 2: Three Reasons for a PCA and a New Consideration

Three Classic Reasons

1) The item constituted a significant or large component of the utility's total operating cost.
2) The cost changes with respect to that item were volatile and unpredictable.
3) The purchased item (most commonly fuels) were entirely outside the control of the buying utility.

New Consideration

The operation of any automatic adjustment clause for fuel purchases should provide incentive compatibility in a more open market environment.

Source: Authors and Kelly et al., *Electric Fuel Adjustment Clause Design* in NRRI's report "Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets," November 1991.

1. Item constitutes a large component of total operating cost

Fuel and purchased power continue to constitute a large proportion of operating expenses for an electric utility. In its 1991 report, NRRI found that "[w]hile fuel and purchased gas costs are generally down from their peak levels, they still constitute a significant proportion of a utility's operating costs [footnotes not included]."[8] The NRRI Report goes on to state that "most other variable costs do not represent a significant proportion of a utility's operating costs, and hence, are not candidates for an automatic adjustment clause."[9]

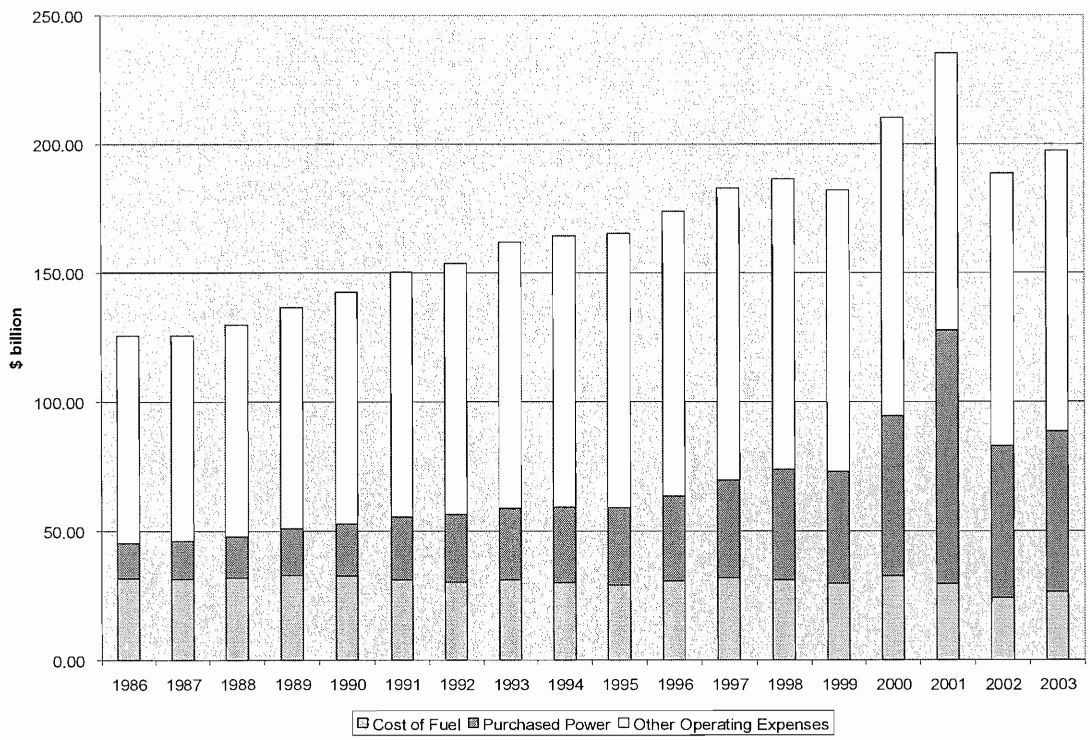
We have examined whether fuel and purchased power costs continue to be a significant component of a utility's total operating costs and found that the answer is clearly yes. For all major IOUs in the US the average proportion of fuel and net purchased power relative to total

[8] NRRI Report, *supra* note 7, p. 2.

[9] *Id.*

operating expenses ranged from 35.8 to 54.3 percent during the 1992 to 2003 period.[10] Total fuel and net purchased power averaged 41.2 percent for the 1992-2003 period, as shown in **Figure 3**. The continued high proportion of fuel and purchased power costs relative to total operating costs shows that there is a continuing role for PCAs as a tool for timely recovery of these costs.

Figure 3: Fuel and Net Purchased Power Costs and Other Operating Expenses for US Investor Owned Utilities, 1986-2003 [11]



Source*: EIA*

2. Cost changes are volatile and unpredictable

Power acquisition costs continue to be volatile and unpredictable. With wholesale (and, in some states, retail) competition, fuel prices and wholesale power costs can be volatile and unpredictable. Natural gas and wholesale electricity prices can "spike" based on market conditions; therefore, a price signal is needed to entice customers to manage their usage when that occurs. A major thrust of the focus on wholesale competition over the last 15 years is that

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[10] Energy Information Administration, Electric Power Annual 2003, p. 49, Table 8.1 Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1992 through 2003, December 2004. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf (Accessed on 8/5/2005).

[11] Energy Information Agency. *Electric Power Annual, Vol. II*. Contacted EIA and compiled from hardcopies of past editions of the Electric Power Annual report tables titled "Revenue and Expense Statistics for Selected Investor-Owned Electric Utilities": Table 8.1 (1992-2003), Table 11 (1990-1994), Table 34 (1986-1990).

market-based wholesale prices should "shine through" to retail rates, leading, over time, to better resource allocation in the economy as energy consumers receive the correct price signals.

A utility must serve its customers under all weather and power market conditions and therefore must purchase fuel and power to satisfy demand during peak periods during the year (*i.e.*, unusually cold winter days or warm summer days). A report issued by the Oklahoma Corporation Commission states that:

> the issue of fuel cost management by utilities is of ever-increasing importance. In the wake of the natural gas crisis in the winter of 2000-01, the commission formulated new rules for regulated natural gas companies in regards to this issue, and is currently examining potential new rules to more closely scrutinize the fuel purchases of electric utilities.[12]

A number of state have monthly fuel clauses, which allow a more timely reflection of fuel and wholesale power costs to be reflected in retail rates. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

> The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes. Because non-fuel expenditures are more stable than fuel expenditures, utilities were not only less likely to seek base rate adjustments, but any rising costs also provided the utility with a greater incentive to use other, less expensive fuels to generate electricity.[13]

State commissions continue to cite the unpredictable nature of fuel and purchased power costs that, if unaccounted for, would leave the utility to bear the burden and financial risk of volatility. The Louisiana Public Service Commission states that the "Fuel Adjustment Clause mechanism…has been established due to the materiality and historical and potential volatility of these costs."[14] Similarly, the Florida Public Service Commission explains that:

> [A]s a result of the severe price fluctuations in fuel costs experienced during the Organization of Petrolium Exporting Countries (OPEC) oil embargo of 1973-74, the [Florida] PSC established a separate charge for fuel that can be adjusted in proceedings that do not involve base rates. These fuel proceedings were scheduled more frequently than base rate proceedings and a new line item on customer bills was established.[15]

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[12] Oklahoma Energy Outlook 2005, Oklahoma Corporation Commission report, Summer 2005-Spring 2006, p. 3.

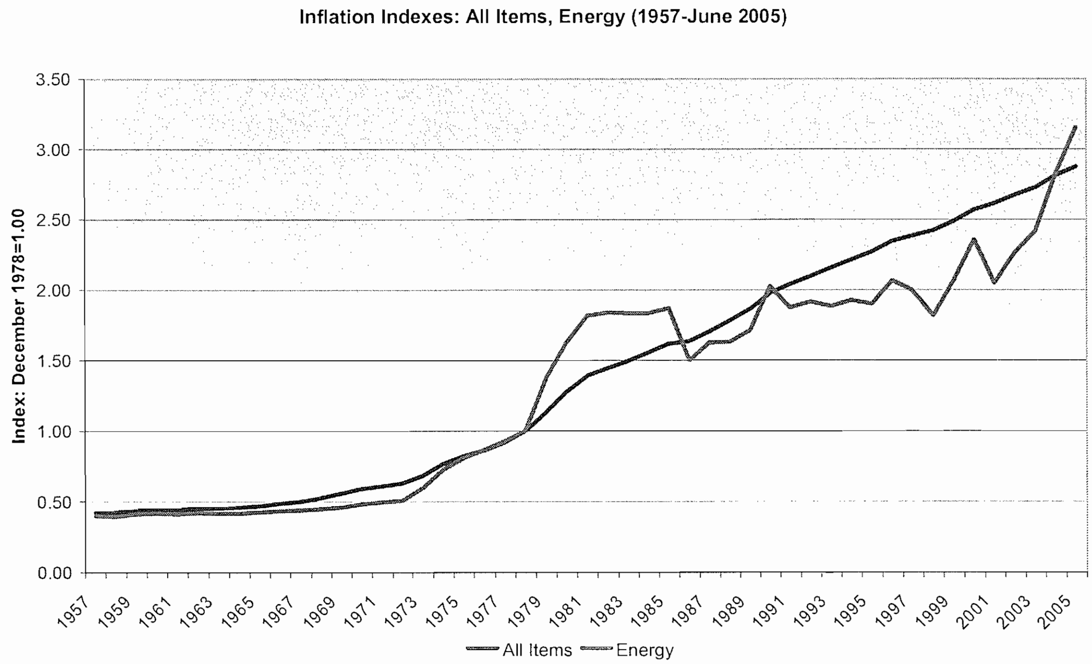
[13] Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

[14] Before the Louisiana Public Service Commission, "Development of standards governing the treatment and allocation of fuel costs by electric utility companies," General Order, Docket No. U-21497, October 1, 1997.

[15] Baez, *supra* note 13.

An analysis of energy price index from 1960 to June 2005 illustrates the volatility in energy prices relative to the general Consumer Price Index (CPI) for all items (See **Figure 4**). Energy prices have fluctuated above and below the general price index.

Figure 4: Change in CPI for All Items and Energy (1960-2005)[16]



Source: *Bureau of Labor Statistics*

Appendix 3 further illustrates the volatility of electricity, natural gas and even coal prices during the past few years. The recent past has shown that events outside a utility's control (*i.e.* geopolitical and natural disasters) has increased volatility in purchase power and fuel prices. Therefore, it is more imperative than ever for utilities to recover these costs.

3. Price and need of purchased item outside utility's control

Utilities procure fuel from markets and would normally not have the ability to control the price set in those markets. The 1991 NRRI Report notes that "[u]nless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over the cost of the fuel."[17] Similarly, the price of wholesale power is set in competitive markets. Moreover the utility does not normally have the ability to control its customers demand. It must procure the fuel and purchased power that is needed to meet customer demand as part of its obligation to serve.

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[16] U.S. Department of Labor, Bureau of Labor Statistics. "All Items" and "Energy" CPI for all urban consumers. *See*: http://www.bls.gov/cpi/home.htm (Accessed on 8/8/2005).

[17] NRRI Report, *supra* note 7, p. 4.

The utility, of course, has an obligation to *procure* its fuel and purchased power from the energy markets in a prudent manner. The NRRI Report notes that the utility is not "excused from hard-nosed, tough bargaining" and goes on to explain that "state public utility commissions often hold utilities to a standard of care of a prudent business man in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause."[18]

Regulatory oversight of the prudence of its management of its procurement activities can be accomplished while allowing for timely rate changes that accurately reflect fuel and wholesale power market prices. For example, a number of states perform periodic reviews of the reasonableness of fuel and purchased power costs and the process used to review PCA costs.

C. Incentive Compatibility

The NRRI Report identifies "incentive compatibility in a more open market environment" as the major constraint to the use of a PCA, explaining that "an automatic adjustment clause should be designed to promote, or at least not discourage, efficient behavior by the utility."[19]

Electricity rates need to accomplish two basic goals: impart information that helps customers and investors make economic decisions about their consumption and investment decisions, and ensure that regulated utilities recover their costs to serve the public. Today's electricity rates often fall short on the first count, and, in some states, current cost recovery mechanisms (*e.g.*, base rate cases and fuel adjustment clauses) do not do well on the second count. Utility PCAs can be designed to provide proper incentives to the utility and its customers.

Utility base rates should be set in ways that achieve allocative efficiency (that is, reflect its economic costs) and that provide incentives to achieve productive, or operational, efficiency. Further, rates need to encourage utilities to make the investments that are critical to maintaining reliability and increase dynamic efficiency over time. Finally, the process of utility ratemaking has costs, with administratively efficient ratemaking processes having clear benefits to customers.

1. Efficient allocation (utility rates should reflect costs)

The efficient allocation of resources concerns the price signals faced by customers. Efficient utility rates give customers the economically correct price signals to use electricity or gas or not, depending on the customer's choice. Failure to allow rates to reflect fuel and purchased power costs in a timely manner would distort this efficiency, since customers would be receiving an inappropriate price signal regarding the value in the market of the services they choose to consume. The Chairman of the Florida Public Service Commission comments that

> [o]n the consumer side, the change [removing fuel costs from base rates] not only allowed customers to receive better fuel price signals reflecting fuel price changes

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[18] *Id.*

[19] NRRI Report, *supra* note 7, p. 4.

in the marketplace, but it also gave customers an incentive to conserve electricity during periods of high fuel costs.[20]

Utility rate structures have remained largely unchanged during the past two decades. To be efficient, utility rates to end-user customers should be designed to provide better price signals by better reflecting cost causation. This will facilitate the demand response necessary to make wholesale competition work more efficiently. It will also provide a signal as to when, where, and whether to build new infrastructure or enter a market.

Commissions cite efficient allocation of resources as an important factor in establishing PCAs. For instance, in the Arizona Public Service decision that reinstated the PCA after a 16 year absence, the Commission stated that "adjustors can create price signals to consumers, but the effectiveness is reduced considerably when a band is included."[21] This can be especially true during periods of peak demand (*i.e.*, an unusually warm summer).

2. No productive efficiency lost (costs that are beyond the control of the utility can be recovered without loss of efficiency incentives).

A utility should have the incentives to operate in an efficient manner, while also continuing to provide safe, adequate, and reliable service to the public. Productive (technical) efficiency simply means that a firm operates to minimize the cost of producing a given level of output. The possibility of profit is the carrot while the risk of losses acts as a spur. Finding the right technologies, the best combinations of inputs for particular circumstances, avoiding waste, and timing investments correctly, as well as getting thousands of other details of management right, all go into achieving efficient production.

Regulation must provide a utility with the incentive to achieve productive efficiency. Costs that are beyond the control of the utility can be recovered in a timely manner without dampening efficiency incentives. If costs are not within the control of the utility, the pursuit of efficiency calls for no penalty or gain to be borne by the utility as a result of changing market conditions. These costs would be the same as the "exogenous costs" (also referred to as "Z factors" in the economic literature) that can be appropriately passed through in rates because prices in a competitive market would adjust to allow these types of costs to be recovered.[22]

Exogenous cost changes represent any change in the cost of the firm—up or down—that is beyond the control of the firm. In a competitive industry, if these costs were required to provide a service, changes in these costs would alter the long run marginal and average cost

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[20] Baez, *supra* note 13.

[21] Before the Arizona Corporation Commission, "In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract," Docket No. E-01345A-03-0437, April 7, 2005, p. 14.

[22] *See*: Tardiff, T. J. and Taylor, W.E., "Revising Price Caps: The Next Generation of Incentive Regulation Plans," in Crew, M.A (ed.), *Pricing and Regulatory Innovations Under Increasing Competition*, Kluwer Academic Publishers (1996), Boston, pp. 21-38.

curves of the industry and would directly affect the market price prevailing in the industry. Because the costs are not under the control of the firm, automatically passing such cost changes through to customers cannot affect the incentive of the firm to behave efficiently or the market price standard to which regulated policies aspire.

Rate adjustments pass through exogenous cost changes are a theoretically sound and well-recognized component of utility ratemaking. They permit cost changes for the regulated firm to affect prices in just the way that cost changes affect prices in unregulated, competitive markets without distorting the incentives of the regulated firm to reduce the costs in question.

3. Economy of administrative and rate case resources.

Some commissions have established "automatic" (*i.e.*, monthly) PCAs, in which the commission adjusts the amount that the utility recovers for fuel and net purchased power through a pre-existing formula. With a clear and relatively simple framework, utilities and customers can understand and properly manage these costs. Rate cases are appropriate for relatively stable capital cost (rate base) items, such as distribution plant. However, fuel and purchased power costs are highly variable. Therefore, another mechanism is needed that can allow for more frequent automatic changes to rates to reflect changing costs. Rate cases and PCAs must work together to address the larger issue of rates reflecting the cost to generate and deliver electricity.

Minnesota presents an example of PCAs and rate case proceedings working in concord with one another. The Commission allows an automatic PCA that permits its utilities to make monthly adjustments to its fuel and purchased power cost recoveries. Balancing accounts are used to correct for under or over recoveries with estimated forecasts from the previous month. This mechanism assures that the utility recovers its costs (and customers see refunds if these costs are lower than expected). Additionally, the Commission requires an annual report that reviews the accuracy and prudence of its PCA.[23] The annual review serves as a way to provide a forum to discuss any issues that may arise in a way that mildly resembles rate cases for capital costs.

Kentucky is another instance where the Commission conducts semi-annual public hearings to examine procurement and other practices related to fuel and purchased power cost recovery. The Commission can make adjustments to correct for any costs that are determined through the hearings to be unjustified. Additional proceedings are conducted every two years to evaluate the operating of the clause and to set the level of such charges to be included in base rates.[24]

D. PCAs Support Utilities' Ability to Attract Capital

The PCA is an important mechanism that permits the utility to recover its costs and assure the capital markets that the company can pay its obligations to shareholders and

[23] Minnesota Rule 7825.2810: Annual Report; Automatic Adjustment. http://www.revisor.leg.state.mn.us/arule/7825/2810.html (Accessed on 8/1/2005).

[24] Kentucky Code 807 KAR 5:056, "Fuel adjustment clause." *See*: http://www.lrc.state.ky.us/kar/807/005/056.htm (Accessed on 8/5/2005).

bondholders. An essential requirement for the success and sustainability of the regulation of a utility is to ensure sufficient financial integrity and access to the capital markets. Arizona and Colorado provide two examples of the Commission balancing the concerns of utility and its customers.

When approving the Arizona Public Service Company's proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."

The Colorado Public Utilities Commission explained their long-term use of PCA mechanisms by stating that they established their PCA in order to:

> permit rapid recovery of increased costs over which the utility has no control. The Commission recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings. We observed that this erosion of earnings would, in turn, jeopardize the utility's ability to provide service.[25]

Capital attraction is a basic constraint that investor ownership places on the level of regulated charges, which allows the utility to fund its operations and serve its customers. Professor James C. Bonbright, a widely referenced expert on the principles of public utility prices, describes what he called the capital attraction function of investor-owned utilities as follows:

> [Capital attraction] is one of the most prominent and most widely recognized functions of public utility rates. Public utility companies are permitted to impose charges for their services largely in order to induce and enable them to supply these services and to make provision for their continuation and for their required expansion. If denied the opportunity to levy compensatory charges, they could not long continue operation in the absence of tax-financed subsidies.
>
> ... Rates below this level are deemed deficient because, at least in the long run, they will not enable the company to live up to its obligations to serve the community.[26]

Credit rating agencies have identified recovery of fuel and purchased power costs as a significant credit consideration for BGE and other electric and gas distributors. **Appendix 4** provides a discussion by credit rating agencies (i.e. *Standard & Poor's*, *Moody's* and *Fitch*) on the importance of PCAs for electric utilities. While the presence of PCAs have always been noteworthy in ratings agency reports for the electric utility sector, the greater volatility of the

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[25] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[26] Bonbright, J.C., *Principles of Public Utility Rates*, Columbia University Press, New York (1961), pp. 49-50.

wholesale power and natural gas commodity markets has caused them generally to be more closely scrutinized by rating agencies. This heightened focus is present for both traditionally regulated utilities and for distribution utilities that provide provider-of-last-resort service.

Electricity distribution has risks. While the common held perception is that electric distribution is a low-risk sector, it is well-recognized that distributors that have a POLR obligation are riskier than distributors that do not. *Fitch Investor's Service* (formerly *Duff & Phelps*) has described two basic risks for electricity distributors:

> **Regulatory Risk:** Among the largest risks of regulated electric distribution are unfavorable regulatory policy and unpredictable regulatory outcomes (lack of "transparency" in the regulatory process). If the regulatory climate is confiscatory or capricious, an electric distributor cannot uproot its assets and move to a more attractive jurisdiction. In mature markets, if the goal of the regulatory authority is to lower end-user prices, distribution tariffs may be ratcheted downward to the point that no further economies can be wrung out of the expense base, and profit margins and financial protection measures are eroded.
>
> **Commodity Price/Market Risk:** Some distributors are exposed to significant market price risk for the electricity they distribute, while others have access to hedging mechanisms, such as the ability to pass through to consumers the actual cost of the electricity supply. This is a major variable in comparing the risk of electric distributors. Distributors insulated from market price exposure will be able to carry more debt leverage at a particular credit rating level than those exposed to market price risk.[27]

Standard & Poor's (*S*&P) has expressed the same reservation with associating electric utilities with low-risk:

> Electricity distributors have typically been viewed as the least-risky function on the utility/energy production chain. However, distributors that have been designated 'providers of last resort' and are subject to protracted rate freezes without assurance of energy cost recovery have faced, and may continue to face, significant financial exposure in the event prices rise and remain elevated on a sustained basis.[28]

Under standard U.S.-style utility regulation, the cost of equity capital is set based on a comparable group. If a utility has more business and financial risk than the "comparable" group, it will not be compensated for that extra risk. Thus, utilities traditionally strive to have ratemaking mechanisms that moderate their risk.

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[27] "Electric Distribution Credit Criteria," *Fitch IBCA*, October 7, 2000, p.2.

[28] "Industry Report Card: U.S. Electric/Gas/ Water," *Standard & Poor's*, January 13, 2003, p.1.

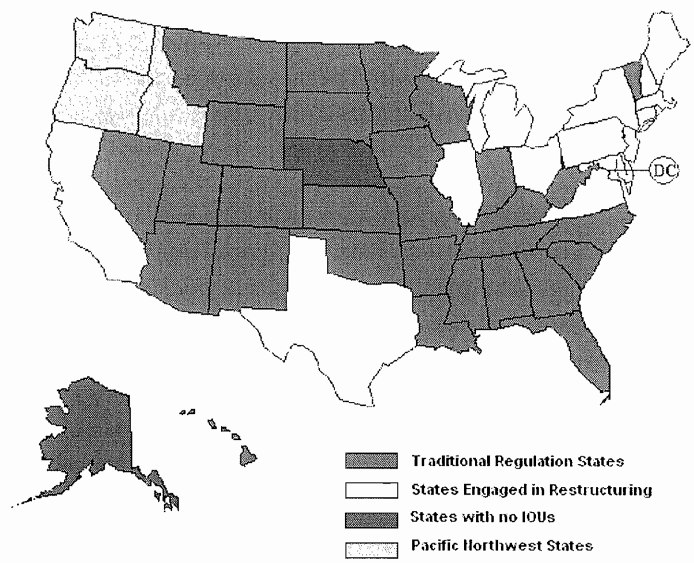
III. PCAs CONTINUE TO BE A STANDARD FEATURE OF UTILITY RATEMAKING IN TRADITIONAL STATES

PCAs continue to be used for vertically-integrated utilities in Traditional States. These PCAs provide the utility with timely recover of actual power acquisition costs, with a regulatory approval process that provides oversight with frequent PCA rate changes. The regulatory process generally provides opportunities for regulatory scrutiny of rate changes, including prudence reviews when needed.

A. Electric utilities in 30 US jurisdictions have the same basis for PCAs as in the pre-restructuring era

Of the total group of 50 states and DC, sixteen states and DC have engaged in meaningful electric restructuring starting the late 1990s.[29] Most electric utilities who have POLR obligations in states undergoing electric restructuring are able to pass through energy costs to ratepayers; those mechanisms are described in **Appendix 2**. The report excludes Nebraska and Alaska because they do not have investor-owned utilities (IOU) operating in the state (See **Figure 5**).

Figure 5: Status of Electric Restructuring: States Considered in Survey



*Oregon is engaged in restructuring.
Source: Regulatory Research Associates

Arizona, Kansas and Missouri are moving towards implementing PCAs for some or all utilities in their jurisdictions. The Arizona Corporation Commission (ACC) eliminated PCAs for

[29] Arizona has, to a large extent, gone back to traditional utility regulation, including re-introducing a PCA for Arizona Public Service Company. California still allows retail choice for some customers who switched prior to September 2001; however, the State has largely eliminated its electric restructuring efforts. Montana allows competitive choice for large industrial customers.

its two major IOUs in April 1989. However, as part of a rate case proceeding, the Commission approved a PCA for Arizona Public Service, recognizing the importance and necessity of allowing a utility to maintain or improve its credit rating in order for the utility to attract capital at decreased expense. The ACC stated that:

> The benefits of this [Power Supply Adjuster] PSA are that over time, the utility's earnings will be stabilized, thereby preserving its financial integrity and in the longer term, improve the likelihood that the company will attract capital on reasonable terms, to the benefit of ratepayers.[30]

In Kansas, Aquila Networks is allowed to use a PCA, but Westar Energy and Great Plains Energy are for the most part not permitted to recover fuel and purchased power expenses. Westar Energy is applying for a "Retail Energy Cost Adjustment Clause."[31]

In July 2005, Missouri passed Senate Bill 179, which permits the state's electric utilities to apply to the Missouri Public Service Commission approval, beginning in January 2006, to utilize fuel, purchased power, and environmental compliance cost recovery mechanisms.[32] The bill would allow the recovery of fuel, purchased power and other expenses within the context of a general rate case or complaint proceeding, and would require a utility that applies for any of these cost recovery mechanisms to file a general rate case within four years after implementing a mechanism. Each mechanism would be subject to an annual true-up for under- and over-collections, including interest. The recovered costs are also reviewed every 18 months for prudence issues.

Only New Mexico is currently moving away from a PCA as part of a merger agreement between Texas New Mexico Power and Public Service New Mexico.[33] **Figure 6** shows the movement of states toward and away from PCAs.

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[30] Before the Arizona Corporation Commission, *supra* note 22, p. 15.

[31] Before the State Corporation Commission of the State of Kansas, "In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in the Charges for Electric Service." Docket No: 05-WSEE-981-RTS, May 2, 2005.

[32] Missouri Senate Bill No. 179, "To amend chapter 386, RSMo, by adding thereto one new section relating to cost recovery for utility companies," Signed by the Governor July 14, 2005.

[33] Before the New Mexico Public Regulation Commission, "In The Matter of the Application Of PNM Resources Inc. and Texas-New Mexico Power Co. for Approval of PNM Resources' Acquisition of TNP Enterprises Inc." Case No. 04-00315-UT, Stipulation, February 28, 2005.

Figure 6: States Moving Toward and Away from PCAs

Moving Away From PCAs	Moving Towards PCAs
New Mexico (Merger agreement)	Arizona (Rate case decision)
	Kansas (Rate case decision)
	Missouri (Enacted Bill 179)

Commissions are realizing that uncollected fuel and purchased power costs can harm the utility's ability to provide service to its customers. Efforts in Arizona, Kansas and Missouri highlight the how regulators view electric rates reflecting costs.

B. Back to the Basics: PCAs in Traditional States

1. PCAs provide timely cost recovery of actual power costs

PCAs are designed to help electric utilities recover costs related to fuel and purchased power. Of the 28 states with PCAs, 25 states have PCAs with balancing accounts or true-up mechanism that allow the utility to recover their costs in a timely manner. However, sometimes the ***recovered*** amount is not commensurate with the ***recoverable*** amount.

True-up mechanisms (or balancing accounts) allow the utility to recover or refund the difference between actual and estimated costs. Out of the states that utilize PCAs, over twenty have balancing or true-up mechanisms. For example, Alabama uses an "Energy Correction Factor" to correct for past imbalances.[34]

Table 1 shows the time lag for the recovery of fuel and purchased power costs.

Table 1: Timeliness of Recovery of Fuel and Purchased Power Costs

	Cost Recovery Mechanisms		
State	**True-up Balancing Account** /	**Time-lag**	**Deadband and/or Sharing**
Alabama	√	3-months	

[34] ECRF = ETEC/ETS ± CF where ETEC is the estimated sum of various fuel costs, ETS represents the total energy sales for the company in a three month period, and the CF is the full reconciliation based on actual historical fuel costs and KWh sales. Source: Alabama Power's Rate ECR, by order of the Alabama Public Service Commission, Docket No. U-4373, November 5, 2001.

State	Cost Recovery Mechanisms True-up Balancing Account	/ Time-lag	Deadband and/or Sharing
Arizona	√	12-months	√
Arkansas	√	12-months	
California	√	Trigger mechanism: account balancing only occurs if the account reaches 4% of the prior year's revenue	
Colorado	√	12-months	√
Florida	√	12-months	
Georgia		3-months	√
Hawaii	√	1-month	
Indiana	√	3-months	
Iowa	√	1-month [EACs are modified monthly based on forecasted energy costs for two months]	
Kansas	√	1-month	√
Kentucky	√	2-months	
Louisiana	√	1-month	
Minnesota	√	1-month	
Mississippi	√	3-12 months	
Missouri		Bill just passed to allow PCAs	
Montana	√	12-months, each month adjusted for estimates of same period the year before	
Nevada	√	12-months	
New Mexico	√	Monthly, However, fuel clause will expire in December 2005.	
North Carolina	√	12-months	
North Dakota	√	1-month	
Oklahoma	√	12-months	
South Carolina		12-months	
South Dakota	√	2-months	√
Tennessee		1-month	
Utah		No Fuel Clause	
Vermont		No Fuel Clause	
West Virginia	√	12-months	
Wisconsin		1-month	
Wyoming		6 to 12 months	√

Source: Appendix 1, Utility and PUC websites.

2. Regulatory oversight in traditional states accommodates timely PCA rate adjustments

Table 2 shows how frequently utilities in each state can adjust their rates based on updated fuel and purchased power costs and how the utilities file for such an adjustment. Five states have "automatic" PCAs in which the utility can recover its costs with little or no lag-time.

Most of the states that have PCAs require public annual filings or hearings for increases on an established frequency. In Hawaii, the utility files its actual fuel and purchase power costs before the Commission, although no public review is normally required except when changes are made to the adjustment formula. Also, in Montana, after the specific fuel and purchase power tracker is approved in public hearings, the utility files a monthly interim report that estimate costs for the following month and an annual true-up report that reconciles actual charges from the previous year so no public hearings are necessarily required. Finally, in North Dakota, South Dakota, and Tennessee, adjustments are made in a similar fashion to Hawaii and Montana once the utility makes the proper filing.

Table 2: Frequency for Rate Adjustment and Process for Filing

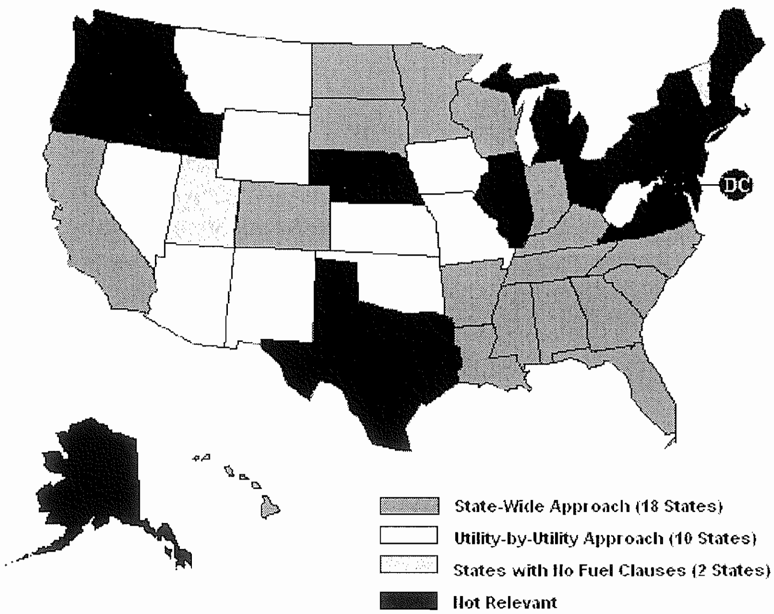
State	Often are Rates Adjusted	Public Process for Filing
Alabama	At most Quarterly	Routine filings are usually not suspended for hearings
Arizona	Annual	Annual Hearings.
Arkansas	Annual	Annual re-determination requires a report subject to review. Interim rate adjustments are possible.
California	Semi-Annually	The CPUC reviews the revenues and costs associated with a utility's electricity procurement plan at least semi-annually.
Colorado	Annual	More frequent review if deferred account reaches $40 million.
Florida	Annual	Any change to rates or rules requires a public hearing.
Georgia	Quarterly	Hearings required for rate increases.
Hawaii	Monthly	Automatic after filing.
Indiana	Quarterly	Hearings required.
Iowa	2-months	Filings every two months.
Kansas	Monthly	Monthly reports to Commission
Kentucky	Monthly	Semi-annual public hearings and bi-annual hearings for general evaluation of PCA.
Louisiana	Monthly	Monthly fuel reports. Bi-annual audits.
Minnesota	Annual	Annual report submitted to Commission.
Mississippi	Annual	Annual report submitted to Commission.
Missouri	Unspecified	Full base rate proceedings.
Montana	Monthly	Automatic after filing.
Nevada	Annual	Public “deferred energy rate case”
New Mexico	Fuel Clause will expire at the end of 2005 due to merger agreement.	
North Carolina	Annual	Annual hearing.
North Dakota	Monthly	Automatic after filing.
Oklahoma	Annual	Annual review by the Commission.
South Carolina	Annual	Annual submission of costs to Commission.
South Dakota	Monthly	Automatic after filing.
Tennessee	Monthly	Automatic after filing.
Utah	No Fuel Clause	
Vermont	No Fuel Clause	
West Virginia	Annual	Annual review of costs.
Wisconsin	Monthly and Annual	Reports and forecasts. Hearings upon request.
Wyoming	Semi-annual or Annual	Through filing.

Source: Appendix 1, Utility and PUC websites.

3. Most traditional states have a uniform approach that applies to all utilities

Of the thirty traditionally regulated states surveyed, eighteen have a state-wide approach to PACs. Of the remaining eleven, nine commissions approved PCAs on a utility-by-utility basis; only Utah and Vermont do not use PCAs. **Figure 7** shows the geographic distribution of the various approaches.

Figure 7: 30 Traditional States: State-wide Approach or Utility-by-Utility



Source: Results are derived from Questionnaire Matrix provided in **Appendix 1**.

a. Statewide PCAs

The Southeastern states as well as a few states in the Midwest and California have comprehensive and consistent state-wide policies for fuel and purchased power cost recovery. In an effort to standardize the recoupment mechanisms during the volatile period of the OPEC oil crisis, most state commissions or legislatures began to implement reports separate from the base rate cases that "permitted the utilities to recover their actual cost of fuel in a timely manner....This mechanism has been established due to the materiality and historical and potential volatility of these costs."[35]

These states have, in general, recognized the benefits for passing fuel costs onto the consumer:

[35] Before the Louisiana Public Service Commission, *supra* note 14, pp. 4-5.

> Fuel adjustment clauses are not designed to allow the utility to earn a profit; rather they are recoupment devices designed to permit a dollar-for-dollar recovery of fluctuations in fuel costs. Because only actual fuel costs should be recovered through the clause (with no return), neither the utility nor ratepayers should be harmed by the use of a fuel adjustment mechanism.[36]

Accordingly, these states have structured their fuel adjustment clauses to capture those costs that are beyond the control of and pose an unreasonable risk to the public utilities. However, it is just as important that utilities only pass through the costs the PCA rider was designed to recoup. When developing standards for fuel cost treatment and allocation, the Louisiana Public Service Commission "identified costs collected through the fuel adjustment clause that more properly should have been reflected in base rates. These items include capital expenditures, depreciation, lease expense, returns and operation and maintenance costs that are not generation-dependent [footnotes omitted]."[37]

Ten of the eleven Southeast regional states have some mechanism to provide more accurate price signals to the consumer: Arkansas, Florida, Georgia, Mississippi, North Carolina, and South Carolina project fuel costs based on a test period (usually 12 months, but shorter test periods and interim adjustments are possible if projections become significantly out of line) and use a true-up mechanism to adjust for the difference between actual and expected fuel costs; Kentucky and Louisiana employ automatic cost adjustments that result in a two month price lag; the lone exception, West Virginia, rolls fuel costs into base rate proceedings, but does allow for interim adjustments. In each case, the rules, rate adjustment process and reporting requirements instituted by the state regulatory commissions apply to all utilities in the state.

In addition, these states have acknowledged that, even with a PCA, the regulatory process can be burdensome. The Minnesota Public Utilities Commission states that:

> [t]hese automatic rate adjustments are intended to make rates more accurate and reasonable and to conserve regulatory and utility resources. Since fuel and purchased power costs can fluctuate significantly between rate cases, building these costs into non-adjustable rates can cause significant, recurring mismatches between expenses and rates. It can also strain utility and regulatory resources by forcing frequent rate cases and earnings investigations to address changes in the cost of fuel and purchased power.[38]

In response to price volatility, the commissions have occasionally changed the frequency of reports in order to reduce unnecessary regulatory costs in times of low volatility. Florida replaced monthly hearings with annual ones; Louisiana replaced monthly hearings with monthly

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[36] Before the Louisiana Supreme Court, *Daily Advertiser v. TransLa*, 612 So. 2d., 1993, p. 24.

[37] Before the Louisiana Public Service Commission, "Development of standards governing the treatment and allocation of fuel costs by electric utility companies." General Order, Docket No. U-21497, October 1, 1997, p. 1.

[38] Before the Minnesota Public Utilities Commission, "In the Matter of an Investigation into the Appropriateness of Continuing to Permit electric Energy Cost Adjustments," Docket No. E-999/CI-03-802, June 4, 2003, p. 2.

reports; and South Carolina has adjusted the filing requirements twice: from an automatic monthly adjustment mechanism to semi-annual hearing in 1979 to an annual hearing in 1995.[39] Mississippi moved in the opposite direction in 2000 by requiring Entergy Mississippi to file more frequently (quarterly vs. annually) in response to "instability in the cost of natural gas and purchased energy."[40] Despite these few changes, the regulatory process in the Southeast generally has been perceived as consistently allowing the utilities to focus on areas where they are capable of cutting costs rather than in new regulatory efforts.

Finally, some Southeastern states have also adopted unique innovations into the regulation of fuel costs and purchased power. For example, Florida employs a Generating Performance Incentive Factor, which provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the Florida PSC. The maximum reward or penalty is limited to a 25-basis-point ROE spread. The recent Florida order states that "[t]he purpose of GPIF is to provide an incentive for efficient performance. Goals and penalties are set based on historical performance, which changes from year to year."[41]

Wisconsin, Minnesota, Indiana, North and South Dakota have long-standing PCA, which receive the periodic scrutiny necessary to assure that they continue to operate in a manner consistent with the public interest. On April 6, 2005 the North Dakota Public Utilities Commission the applicants agreed to an informal hearing in which they would "work together to develop standardized appropriate FCA tariff language."[42] Similarly, the Minnesota PUC commissioned a study into the "appropriateness of continuing to implement an Energy Cost Adjustment Rider for the entire industry," but, to date, this docket has produced no reforms and remains dormant pending restructuring and Midwest Independent Transmission System Operator (MISO) related reforms.[43] The Wisconsin Public Service Commission recently released a report on "Electric Cost-of-Service and Rate Design" that stated:

> Fuel cost is also a significant portion of the operating expenses of a utility. As with production costs, small differences in the allocators used on fuel accounts can result in a transfer of millions of dollars in cost responsibility from one customer class to another. ...Unlike production costs, the allocation of fuel cost appears to be an area where a consensus of opinion is achievable. The current

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39 *See* Appendix 1.

40 Before the Public Service Commission of the State of Mississippi, "In re: Notice of Entergy Mississippi, Inc., of its Intention to Implement a Routine Change in Energy Cost Recovery Rider Schedule," Docket No 2000-UN-884, December 22, 2000, p. 6.

41 Before the Public Service Commission of Florida, "In re: Fuel and purchased power cost recovery clause with generating performance incentive factor." Docket No. 04001-EI, Order No: PSC-04-1276-FOF-EI, December 23, 2004, p. 21.

42 North Dakota Public Service Commission Docket Nos. PU-05-131, PU-05-135, PU-05-147, Interim Order, April 6, 2005.

43 Minnesota Public Utilities Commission, "In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments," Docket No: E-999/CI-03-802; Conversation with Janet Gonzalez, head of Minnesota PUC energy staff.

> difference of opinion involves the factoring in of time-of-day considerations in fuel cost. ...Since purchased power is a significant cost item and the allocation process has not been entirely consistent from case to case, it is important that special attention be given to this area to properly match the cost with the cost causers.[44]

After its failed attempt at deregulation, California recently re-instituted their PCA. In their proceeding renegotiating a PCA the California Public Utilities Commission noted:

> We agree...that we must balance the utilities' need for timely procurement cost recovery with the consequences of frequent rate adjustments on consumer behavior. We recognize [the] concern that [utilities] can no longer finance a large under-collection for a period of time longer than a month or two and recognize the importance of timely recovery of over-or-under collections of balancing accounts to their financial health and stability. We must, however, balance these concerns with customer interests.[45]

Accordingly, the CPUC reviews their PCA semi-annually and adopted a "trigger mechanism" that refunds the balance of a utilities true-up account only if it exceeds 4% of the utility's previous annual revenue.[46]

b. Utility-by-Utility PCAs

In the 1980s, most states had uniform FACs that applied to all of its regulated companies. However, in the 1990s, with the advent of electric restructuring, large mergers and acquisitions and, lower fuel and purchased power prices, FACs were eliminated in some specific instances and applied more frequently on a utility-by-utility basis. Recently, the trend is a reawakening of a movement towards uniformity that applies the recovery of fuel and purchased power costs to all utilities.

Most Midwestern and Rocky Mountain states generally implement their PCAs on a utility-by-utility basis (see **Figure 7**), creating inconsistencies in how fuel and purchased power costs are recovered. For example, in Iowa, while Interstate Power & Light (IP&L) utilizes an energy adjustment clause,[47] MidAmerican Energy does not. With regard to IP&L, the

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[44] Wisconsin Public Service Commission. Electric Cost-of-Service and Rate Design Report. Prepared by the Energy and Gas Division, July 2005, pp. 16-17.

[45] California PUC Final Decision No 02-10-062 in Rule Making Proceeding 01-10-024 "Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development," p. 5.

[46] *Id*, p. 6.

[47] Interstate Power Company, Electric Tariff, Thirty-Seventh Revised Sheet No. 23.2, Date Issued: June 27, 2005.

Commission has considered to cap or redesign the EAC, questioning IP&L's fuel and purchased power procurement practices.[48]

In Kansas, although adjustment clauses have been allowed since around 1977,[49] the extent to which adjustment clauses are used varies by the utility. Aquila Networks, for example, is permitted to utilize an energy cost adjustment clause, which is automatically calculated on a monthly basis based on projected fuel and purchased power costs for that month, with any under or over-recoveries reflected in the subsequent month. Great Plains Energy, on the other hand, operates under a system that allows it to only have one percent of its revenues reflect rates that include an automatic fuel adjustment provision. Its actual energy cost adjustment clause was eliminated in 1989 as part of a merger agreement.[50] On the low end of the spectrum is Westar Energy which has no fuel clause at all. However, Westar is in the process of applying for a Energy Cost Adjustment Clause to consist of a Fuel Adjustment Clause and an Off-System Sales Adjustment Clause and an Environmental Cost Recovery Rider.[51]

In Wyoming, both Cheyenne Light, Fuel & Power and Carbon Power & Light use an Energy Cost Adjustment clause. However, while Cheyenne has arranged to have a review whenever it wants, Carbon Power arranged for a twice a year review. Partly because Carbon Power feels the twice a year review gives them little flexibility, the utility is now attempting to eliminate its ECA. Recovery of fuel and purchased power costs has historically been addressed in rate cases for other utilities in Wyoming.[52]

While there are some states whose utilities have not been allowed to use PCAs, several states are in the process of introducing PCA legislation. For example, on May 27, 2005, the Missouri House of Representatives and Senate passed SB 179, a bill that was signed by the Governor in July 2005. This bill will allow the state's electric utilities to apply for Missouri Public Service Commission approval, beginning in January 2006, to utilize fuel, purchased power, and environmental compliance cost recovery mechanisms. Any utility that applies for any of these cost recovery mechanisms must file a general rate case within four years of implementation of the mechanism.[53]

Arizona, after eliminating its FAC in 1989, has instituted a Power Supply Adjuster (PSA) for Arizona Public Service in the context of a March 2005 rate case decision. This PSA is

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[48] State of Iowa Department of Commerce Utility Board, "In Re: Interstate Power Company and IES Utilities Inc.," Docket Nos. ARC-01-150, ARC-01-151, April 8, 2002.

[49] Before the Corporation Commission of the State of Kansas, "In the matter of a general investigation upon the Commission's own motion to establish general policies with regard to purchased natural gas, fuel for electric power generation, and purchased electric power," Docket No. 106, 850-U. April 19, 1977.

[50] Kansas City Light & Power "15-yr. Price history" http://www.kcpl.com/historytable.html. (Accessed 8/1/05). *See* also: Securities and Exchange Commission, Form 10-K for Great Plains Energy, Fiscal Year Ending December 31, 2004, p. 36.

[51] Kansas Corporation Commission, *supra* note 31

[52] Cheyenne Light, Fuel & Power, First Revised Sheet No. 42, Issued May 25, 2001 and conversation with Don Biedermann of Wyoming Public Service Commission, August 2005.

[53] Missouri Senate Bill No. 179, 93rd General Assembly 2005.

designed to reflect differences in fuel and purchased power costs versus those reflected in base rates beginning on the effective date of the rate case order. The Commission decided to limit the amount of net fuel and purchased power costs recoverable from ratepayers to $776.2 million.[54] Similarly, Kansas' Westar Energy, as mentioned earlier, is attempting to have its retail energy adjustment clause reinstated.[55]

c. States without PCAs

Two states, Utah and Vermont, have no PCA history, and there is also no clear indication that PCAs will be introduced in the foreseeable future. In Vermont, due to a 1984 Supreme Court ruling, fuel adjustment clauses are not permitted.[56] Although recent legislation now permits the Commission to adopt Alternative Rate Plans for energy companies, no such plans have been approved. In 2004, the PSB ruled that "exposure to fuel price or purchased power price fluctuations is far less for Central Vermont than for many companies; this is because Central Vermont currently procures most of its power through defined-price contracts that have been approved by regulators. Thus, based on the existing power-supply arrangements, Central Vermont would benefit little, if at all, from a fuel adjustment clause."[57]

Similarly, in Utah, no power cost adjustment mechanism is in place. However, PacificCorp has been allowed to implement a temporary rate increase to recover purchased power costs not included in base rates.[58] There has been some talk of implementing a power cost adjustment mechanism, but with no open docket, Utah is not formally pursuing it.[59]

4. Most traditional states treat fuel and purchased power costs on a level playing field

For those utilities that purchased power, both the demand of customers and the market prices are generally outside of their control. The basic principles for PCAs apply both to fuel and purchased power. **Table 3** demonstrates the extent that PCAs cover specific costs.[60]

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[54] Arizona Corporation Commission, *supra* note 22.

[55] Kansas Corporation Commission, *supra* note 31.

[56] Vermont Supreme Court, "In re Central Vermont Public Service Corporation." 144 Vt. 46, 56 Case Nos. 82-460, 83-240, January 13, 1984.

[57] Vermont Public Service Board, "Investigation into Memorandum of Understanding between Central Vermont Public Service Corporation and Vermont Department of Public Service," Docket No. 6866, January 27, 2004.

[58] Before the Public Service Commission of Utah, "In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," Docket No. 04-035-42, February 25, 2005.

[59] Conversation with Ted Boyer, Commissioner of Public Service Commission of Utah, July 29, 2005.

[60] Table 3 only discusses costs that were recoverable in each state's fuel adjustment or purchased power clauses. Some states also allow the recovery of environmental, security and uncollectible expense costs in separate clauses.

Table 3: PCA Coverage by Category

State	Recoverable Costs: Fuel Cost Energy	Purchased Power Energy	Purchased Power Capacity	Other: Financial Hedging
Alabama	√	√		√
Arizona	√	√		
Arkansas	√	√	√[6]	
California	√	√		
Colorado	√	√		
Florida	√[1]	√	√[6]	
Georgia	√	√	Base rate	√
Hawaii	√	√	√	
Indiana	√	√	No	
Iowa	√	√	Base rate	
Kansas	√[1]	√		
Kentucky	√[1]	√	No	
Louisiana	√	√		
Minnesota	√	√		
Mississippi	√	√		√[2]
Missouri[8]	√	√		
Montana	√	√	√	
Nevada[7]	√	√		√
New Mexico	√[5]	√[5]		
North Carolina	√	√		
North Dakota	√	√		√
Oklahoma	√	√	√	No
South Carolina	√	√	√	
South Dakota	√	√	√	√
Tennessee		√[3]		
Utah[4]				
Vermont[4]				
West Virginia	√	√		
Wisconsin	√	√	√[6]	
Wyoming	√	√		

Source: Appendix 1, Utility and PUC website

[1] These states specifically include the recovery of transportation costs as part of a utility's fuel cost.
[2] Mississippi Power has a separate Energy Cost Management clause to recover fuel hedging gains, losses and expenses.
[3] Tennessee primarily purchases power from the Tennessee Valley Authority.
[4] Utah and Vermont do not have PCAs.
[5] The PCA in New Mexico will expire at the end of 2005 due to a merger agreement.
[6] These states have separate capacity cost adjustment clauses.
[7] Nevada established a going forward rate for projected fuel and purchase power costs for Nevada Power Co.
[8] The Missouri legislature only recently approved the use of PCAs. Specific cost recovery is uncertain at this time.

The above table shows that most Commissions allow both fuel and purchased power showing that the regulators realize that both of these costs are outside the utility's control. The large majority of states with fuel clauses (26 of 28) treat fuel and purchased power costs similarly. These commissions realize that both fuel and purchased power expenditures are volatile depending on factors outside the utility's control. While some states allow the recovery of transportation and capacity costs within the PCA, other states allow their recovery in separate clauses independent of their PCA mechanism.

Further, at least six states allow the recovery of financial hedging costs. This provides an incentive for the utility to use all available tools to lower costs while providing adequate, safe and efficient service. For example, Georgia Power has a natural gas and oil procurement hedging program. The costs related to the program are recoverable through Georgia Power's fuel adjustment clause. In addition to its ability to recover costs related to the program, annual financial gains from the hedging program have to be shared, with retail customers receiving a 75% share and Georgia Power retaining 25%.[61] In South Dakota, Northern States Power is limited with respect to the losses from financial hedging it can recover. The cap is set at $875,000 a year.[62] In Oklahoma, utilities are prohibited from recovering losses associated with financial instruments.[63]

5. PCAs and prudence investigations go hand in hand.

In the absence of competitive forces, regulators must be charged with ensuring that costs imposed on consumers are reasonable, prudently incurred and approximate those that would occur in a competitive market. In most cases, states that allow for fuel cost adjustments also require some form of reporting to the public utility commission as well as a public hearing or audit (see **Table 2**). Most oversight of fuel adjustment costs and purchased power agreements has become routine; however, some Commissions report that, of late, rising fuel costs have placed added pressure upon the review process.

In addition, commissions frequently investigate the costs that are reflected in the fuel cost adjustment tariffs. **Table 4** is a list of current or recently settled investigations before public utility commissions that scrutinized fuel power costs:

Table 4: Selected Recent Fuel and Purchased Power Costs Scrutiny Investigations & Decisions

State	Company	Date	Description
IL	People's Gas, Light & Coke	8/18/2003	Review of Purchased Gas Adjustment and imprudent off-system sales contracts with an Enron subsidiary. Case is on-going.

[61] Before the Georgia Public Service Commission, "In re: Application of Savannah Electric and Power Company to increase the fuel cost recovery allowance pursuant to O.C.G.A. § 46-2-26," Docket No. 19042, October 25, 2004.

[62] Before the Public Utilities Commission of the State of South Dakota, "In the matter of the petition filed by Xcel Energy for approval of the inclusion of financial incentives in its fuel clause," Docket No. EL03-020, July 14, 2003.

[63] Oklahoma Energy Outlook 2005, Oklahoma Corporation Commission report, Summer 2005-Spring 2006, p.91.

State	Company	Date	Description
NJ	Elizabethtown Gas	5/14/2004	Settlement reached in an audit into company misconduct related to the company's power procurement practices: management failed to adequately consider the risks associated with its growth strategy, and had improperly utilized the financially healthy utility operations to support failing non-utility activities.
NV	Nevada Power Company	3/24/2004	The PUC authorized NPC recovery of $169 million of a requested $173 million of deferred energy costs as part of an application to recover fuel and purchased power costs as well as to adjust the prospective rate for fuel and purchased power.
OH	Vectren Delivery of Ohio	6/14/2005	Ohio PUC denied VDO recovery of gas-related costs following a management/performance audit of the company. The PUC indicated that the contract between Vectren and ProLiance was not at arms length, and that Vectren had no intention of awarding this asset management contract to an unaffiliated third-party. The Commission concluded improprieties occurred concerning the right to utilize unused gas transportation capacity, costs related to an unnecessarily high gas reserve margin and costs related to the treatment of interstate pipeline refunds. Pending Appeal.
TX	CenterPoint Energy Houston Electric	5/27/2004	Texas PUC precluded capacity costs from being recovered under fuel adjustment clauses, the CenterPoint contract had "an implicit capacity component because they had capacity attributes of reliability and firmness of supply and were used to meet Centerpoint's load obligations without increasing its generating capacity."
TX	El Paso Electric	5/5/2004	Reversed a decision allowing energy-only purchased power contracts to be recovered which had been previously disallowed as capacity costs. Did not reverse other findings that other contracts did not contain capacity costs.

Source: Author Construct, Regulatory Research Associates

In addition to scrutinizing costs, on rare occasions commissions will investigate and disallow the recovery of costs due to imprudent utility action, as summarized in **Table 5**. These typically occur when utilities are forced to purchase more expensive power on the wholesale market as a result of plant operation failure. For the utility to recover its costs "[t]he company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made."[64] **Table 5** is a list of selected prudence investigations from the past 15 years:

Table 5: Selected Prudence Investigations and Decisions (1990-2004)

State	Case	Date	Description

[64] Washington Utilities & Transportation Commission, RE: Puget Sound Power & Light Co., 156 PUR4th 297, 303(Wash UTC, 1994) as cited in Goodman, Leonard S. "The Process of Ratemaking" Vol. II, p.881-2.

State	Case	Date	Description
CT	Department of Public Utility Control	11/21/1994	Appeal against PSC's decision that electric utility had not acted imprudently in its efforts to control nuclear power plant's water supply (that lead to an outage).
FL	Florida Power & Light Co.[65]	1990	PSC held that training was a management responsibility (and thus associated costs were not recoverable), but it allowed costs. associated with needed repairs on the unit.
KS	Kansas Gas and Electric Co. v. State Corporation Commission of KS	6/29/1990	KCC ruled that fuel costs were imprudently incurred during outages at nuclear power plant.
LA	Entergy Gulf States, Inc. v. Louisiana Public Service Commission	1/20/1999	Disallowance of fuel adjustment clause; utility failed to demonstrate that it acted prudently in incurring replacement power costs.
LA	Alliance for Affordable Energy v. New Orleans Public Service	4/4/1991	Imprudently incurred costs could not be passed through to ratepayers, but had to be borne by utility shareholders.
MI	Consumers Power Co[1]	1992	Commission divided the cost of purchasing replacement power between shareholders and ratepayers when a nuclear electric plant experienced an electric outage.
NY	ConEd	2/11/2004	A settlement disallowed the recoupment of costs of replacement power associated with power plant outages that were, in the Staff's view "could have and should have been either avoided or reduced in duration; but it also notes that its position includes a significant degree of uncertainty.
PA	Pennsylvania Power Co. v. Pennsylvania Public Utility	5/6/1993	Unsuccessful petition against PUC's conclusion that nuclear plant operator's actions were imprudent and were also the proximate cause of plant shutdown.
TX	NucorSteel et al v. Public Utility Commission of Texas	8/31/2000	Utility did not act prudently concerning its cleanup of sludge mass (resulting in collapse of chimney) and could not recover replacement fuel costs.
TX	El Paso Electric Co. v. PUC of Texas	7/12/1995	Action against PUC order in electric utility rate that permanently disallowed certain costs for imprudence in construction delays and other costs.
WA	Puget Sound Energy	5/13/2004	WUTC established guidelines for recovery of costs associated with the company's long-term wholesale contract to purchased power from the Tenaska plant. The WUTC also found that the company did not, prior to the implementation of the PCA, adequately manage its fuel-cost risks and therefore ordered the company to adjust its power cost adjustment deferral account to reflect the

[65] Cited in Goodman, Leonard S. "The Process of Ratemaking" Vol. II, p. 881.

State	Case	Date	Description
			imprudent management.

Source: Author Construct, PUC websites

6. Dead-bands/sharing mechanisms are rarely used.

Six states have a dead-band and/or sharing mechanism as part of their PCA. **Table 6** lists the states that have dead-band and sharing requirements in their PCAs. As stated previously, PCAs and other fuel cost clauses are designed to lower the amount of risk born by utilities by reducing their exposure to volatility in fuel prices. However, some states, namely Arizona, Colorado, Kansas, Idaho, Washington and Wyoming, have limited the amount of the pass through. To do this, states use two different mechanisms, either separately or together: 1) a dead-band on fuel cost recovery passes a limited amount of volatility around pre-set base rate to the consumer; 2) a sharing mechanism attributes a percentage of the fuel costs to the utility. For example, in Kansas, Aquila Networks has only a dead-band on its fuel adjustment clause: if costs fall outside a set limit, the utility must submit an explanation and the Commission may insist the utility make the monthly computation at the limits, not the actual experienced cost.[66] Similarly, due to a 2001 settlement agreement, Wyoming's Cheyenne Light, Fuel & Power was limited to an $18 million increase in 2001 and a $28 million increase in both 2002 and 2003.[67]

Arizona and Colorado have both a dead-band and a sharing mechanism: Arizona's PCA caps recoverable fuel and purchased power costs at $776.2 million and includes a sharing mechanism where 90% of any costs or savings relative to the base level would be allocated to customers and 10% would be allocated to the company. In Colorado, the maximum profit or loss that PSCO can absorb in any one year is $11.25 million. Colorado's sharing mechanism is a tiered setup. The ECA allows for the first $15 million above or below a base level of purchased power costs to be allocated 50% to retail customers and 50% to shareholders. The next $15 million above or below the base is allocated 75% to retail customers and 25% to the shareholders. Any changes above $30 million are recovered from or flowed back entirely to the customers.[68]

Table 6: States with Dead-band and/or Risk Sharing Mechanisms

State	Clause	Mechanism
General Cost Clauses		

66 The State Corporation Commission of Kansas, Aquila Inc. Schedule: 04-ECA, Filed June 12, 2002.

67 Stipulated and Amended ECA Application and Settlement Agreement, Wyoming Public Service Commission Docket Nos. 20003-EP-01-59 and 20003-ES-01-58, May 11, 2001.

68 Before the Public Utilities Commission of the State of Colorado, re: the Investigation and Suspension of Tariff Sheets filed by Public Service Company of Colorado advice letter no. 1373-Electric, Advice Letter No. 593-Gas and Advice Letter No. 80-Steam, Docket No. 02S-315 EG. April 4, 2003.

State	Clause	Mechanism
Arizona	Dead-band & Sharing	There is a $776.2 million cap on recoverable fuel and purchased power costs. The PCA includes a sharing mechanism where 90% of any costs or savings relative to the base level would be allocated to customers and 10% would be allocated to the company.
Colorado	Dead-band & Sharing	The maximum profit or loss that PSCO will absorb is $11.25 million in any one year. The ECA allows for the first $15 million above or below a base level of purchased power costs to be allocated 50% to retail customers and 50% to shareholders. The next $15 million above or below the base is allocated 75% to retail customers and 25% to shareholders. Any changes above $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
Idaho	Sharing	The Power Cost Adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-ups.
Kansas	Dead-band	If costs fall outside a set limit, the utility must submit an explanation and the Commission may insist the utility make the monthly computation at the limits, not at the cost levels actually experienced.
Washington	Dead-band & Sharing	First Band (dead band): $20 million (+/-) annually, 100% of costs and benefits accrue to the Company. A graduated schedule exists beyond the dead band in which the company and the ratepayers share differing proportions of the costs/benefits according to their magnitude.
Wyoming	Dead-band	There are caps on what Cheyenne is able to recover through its ECA in a 2001 settlement agreement. 40% increases in rates as a whole or $18 million increase in 2001 and $28 million annually in 2002 and 2003. Amounts for 2004-05 were discussed in a later case.
Other Cost Specific Clauses		
Georgia	Sharing	Annual financial gains from the hedging program have to be shared with retail customers receiving a 75% share while Georgia Power retains 25%.
Kansas	Sharing	Aquillia Networks - WPK is authorized to retain 75% of off-system sales margins in excess of those imputed in base rates, through the company's ECA mechanism. The remaining 25% is to be credited to ratepayers.
South Dakota	Sharing	Cap on losses due to financial hedging

Source: Appendix 1, Utility and PUC websites

C. Other States

1. Pacific Northwest States

The Pacific Northwest region is divided on the treatment of fuel and purchased power costs for its utilities. The issue was at the forefront of attention during the Western-US energy crisis and drought that afflicted the region. Utilities in Idaho and Washington have PCAs that allow them to recover fuel and purchased power costs. Oregon, however, has not generally allowed its utilities to recover such costs through a PCA in recent years.

In the Northwest, Washington and Idaho allow their utilities to pass through fuel and purchased power costs. For Puget Energy in Washington, all significant variable power supply cost drivers are included in the PCA mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and wheeling cost variability). Idaho Power Company (subsidiary of Idacorp) has a PCA that provides for annual adjustments to the rates charged to its Idaho retail electric customers. In Oregon, the two major IOUs, Portland General Electric and Scottish Power (subsidiary of PacifiCorp) do not have a PCA in effect currently. The Commission did allow both utilities to recover power costs through an interim PCA in 2001-2002. However, this mechanism was discontinued for 2003 and forward.

2. Restructuring States

Some states that have engaged in meaningful restructuring have PCA like mechanisms to deal with the costs for POLR service customers. The 16 states and the District of Columbia have established some form of retail competition. In states that have retail competition, timely pass-through of POLR costs in rates is needed as the price of POLR service acts as a price-to-beat for competitors.

Six jurisdictions—District of Columbia, Illinois, Maine, Maryland, New Jersey and Pennsylvania—have competitive bidding in place or plans to establish it in the near term. Texas has a "price to beat" with semi-annual adjustments to reflect power cost increases that exceed certain benchmarks, thereby insulating the generation providers from market risk. Seven states, Connecticut, Massachusetts, Michigan, New Hampshire, New York, Rhode Island and Virginia have a PCA or other mechanism to recover fuel and purchased power costs for POLR customers for some or all of the utilities in their state. Among the states engaged in restructuring and that do not use (or plan to use) competitive bidding to procure POLR power, only Ohio does not allow PCAs or the equivalent for their POLR ratepayers and Delaware and Oregon have active dockets to address this question.

D. Description of "Questionnaire"

The survey initially examined financial statements, tariff sheets, rate case and merger orders and testimony by expert witnesses and public utility commission staff located on the websites of state public utility commissions, state legislatures, individual electric utilities and summaries provided by the Regulatory Research Associates. The focus of these inquires was to identify the mechanism through which energy costs where recovered, which costs were, in fact, recoverable and the history and evolution of each state's PCA. Also, the survey explored any general qualitative valuation performed prior to adopting or while amending state energy cost policy. Subsequent conversations with Commission staff were used to resolve and clarify any ambiguous, unique or dynamic aspects of each state's PCA. The results of this survey are presented in **Appendix 1**.

IV. CONCLUSION

Our survey and analysis of PCAs in the traditionally regulated states show the following results:

- PCAs continue to be ubiquitous, for the traditional reasons;
- PCAs are used to provide a "routine business expense true-up" not just to mitigate for extreme circumstances;
- More states are moving toward PCAs. For example, Arizona, Missouri and Kansas have each taken significant steps towards increasing the scope of their PCAs.

Appendix 1: Questionnaire Results

VI. Appendix 1: Survey of States with PCAs

Adjustment Clause Matrix

State:	ALABAMA
Major utility:	Southern Company (Alabama Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Yes, Alabama Power has a Energy Cost Recovery System ("Rate ECR"). Alabama Power is the only electric IOU in the state.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	The current PCA has been in place since at least 1981. Rate ECR has been in place since a May 29, 1981 order. (Docket No. 18148) The current form of the PCA (Rate ECR) replaced Rate FT.
Was the PCA discontinued for periods of time?	No.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes. The last time the ECR was examined was 11/5/2001 in Docket No. U-4373.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expense. The ECR (PCA) has been in place since at least 1981 with annual updates and quarterly consent orders.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The Commission uses rates set in the previous quarter, using the formula in 3.d.. Adds or subtracts estimated fuel costs/estimated KWh for the next quarter and adds or subtracts actual fuel costs/KWh for the previous quarter and uses a correction factor to reconcile actual vs. estimated EFC/KWh for the previous quarter.
b. How often are rates adjusted?	Once every three months, but proceedings are conducted semi-annually.
c. Is there a deadband around that starting point in the PCA?	No deadbands [See Rate ECR Rider]
d. Is there a sharing mechanism?	No sharing [See Rate ECR Rider]
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Routine filings each quarter, usually not suspended for hearings.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	No, the Commission issues consent orders quarterly adjusting the ECR rate.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, Reconciliations are used, called a Correction Factor (CF) to correct for past imbalances. [ECR Rider]. ETEC is the estimated sum of various fuel costs. ETS is the total energy sales for the company in a three month period. This factor is calculated by the commission every three months. the CF is a full reconciliation based on actual historical fuel costs and KWh sales.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	No.
Conact Info: Name	Alabama Commission
Phone Number:	334-242-2696

Adjustment Clause Matrix

State:	ALABAMA
Major utility:	Southern Company (Alabama Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	ECR is a rate rider that provides for the recovery by the Company of defined energy-related costs and establishes a procedure for the recovery of such costs through all base rate schedules to which it is applicable. In general terms, these costs presently include those related to fossil fuel and emission allowances, nuclear fuel, energy that is purchased for reasons of economics or reliability, and financial tools.
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	In this proceeding, the Commission allowed the ECR to "include not only physical commodity purchases and sales, but also the financial tools and strategies that have evolved in the marketplace for the purpose of hedging market price risk." (order in file) Before 2001, the ECR could only include physical commodity purchases and sales, but the 2001 order allows for these hedging tools to be included in the ECR.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The fuel adjustment clause covers the following: 1) Long-term coal-supply agreements; 2) Recovery of natural gas purchase costs for electric generating facilities; 3) Cost of financial tools used for hedging market price risk of up to 75% of the budgeted annual amount of natural gas purchases; and 4) Fixed costs of PSC-certified plant additions and long-term purchased power contracts.
b. How often are rates adjusted?	Rate ECR may not be changed more than once every three months and then only after hearings have been conducted. Rate ECR is established on the basis of estimates of sales, fuel, and net purchased energy costs for three future months, and reflects accumulated over- or under-recovered amounts.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	The ECR does say that it will disallow and make adjustments for any reported energy costs that is the result of illegal or imprudent Company conduct.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	$ECRF = \frac{ETEC}{ETS} + CF$ -
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	ARIZONA
Major utility:	Arizona Public Service (APS)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	No. In a March 2005 rate case decision, APS was allowed a Power Supply Adjustor (PSA) to reflect differences in fuel and purchased power costs versus those reflected in base rates beginning on the effective date of the rate case order and a mechanism to reflect changes in FERC-approved transmission rates. The Commission determined that fuel costs incurred in 2005 prior to the effective date of the decision would not be eligible for recovery.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1978 [NRRI, 1978, reproduced in Schmidt]
Was the PCA discontinued for periods of time?	Yes. The Commission eliminated the FAC for APS from April 1989 to April 2005. In 1989, the Commission stated that "the most significant factors that may cause volatility in fuel costs are the manner in which the system is operated and lengthy forced outages, not fuel price volatility. Without the PPFAC, APS management will be provided an incentive to minimize the forced outages at base load units."
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes. The FAC for APS was reinstated in a March 2005 rate case order.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	The Commission stated in the 2005 rate case decision that APS was experiencing "higher fuel and purchased power expenses." The fuel clause was discontinued for nearly 16 years. In addition, it is important to note that electric restructruing efforts failed in Arizona.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The amount of net fuel and purchased power costs that can be used to calculate the annual PSA will be limited to $776.2 million. Any fuel or purchased power costs in excess of $776.2 million is not recoverable from ratepayers.
b. How often are rates adjusted?	The PSA is to be adjusted annually each April, beginning in 2006, and is to include an incentive mechanism whereby 90% of any costs or savings relative to the base level would be allocated to customers and 10% would be allocated to the company. Changes in the PSA would be limited to $0.004 per kWh over the life of the PSA (versus $0.004 per kWh annually). Any additional recoverable or refundable amounts would be recorded in a balancing account. If the balancing account reaches plus or minus $50 million, APS could file for ACC approval of a surcharge (or credit) to amortize the balance over a period of time to be determined by the ACC, but in no event may the balance exceed $100 million.
c. Is there a deadband around that starting point in the PCA?	Yes. There is a $776.2 million cap on recoverable fuel and purchase power costs.
d. Is there a sharing mechanism?	Yes. The FAC includes a sharing mechanism where 90% of any costs or savings relative to the base level would be allocated to customers and 10% would be allocated to the company.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Adjusted annually each April.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	The 2003-2005 rate case was contentious. APS was forced to write off an estimated $184 million in generation assets.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes. Any additional recoverable or refundable amounts would be recorded in a balancing account. If the balancing account reaches plus or minus $50 million, APS could file for ACC approval of a surcharge (or credit) to amortize the balance over a period of time to be determined by the ACC, but in no event may the balance exceed $100 million.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Yes.
Conact Info: Name	Arizona Commission Utilities Division
Phone Number:	602.542.4251

Adjustment Clause Matrix

State: ARIZONA
Major utility: Tucson Electric Power

1. Basis of the PGA	
a. Does each utility in the state use a PCA?	As part of its 1999 electric industry restructuring order, the rates of Tucson Electric Power (TEP) are "frozen" through year-end 2008. Althuogh Tucson has currently filed a rate case to have a FAC. The utility is operating under a total rate cap and is not permitted to adjust rates for changes in power costs. TEP is operating under an agreement that provided for 1% price reductions for all customers to be implemented effective July 1, 1999 and July 1, 2000, followed by a price cap through 2008. The TEP rate case is still pending and hearings are scheduled for September 2005.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	Yes. The FAC is still discontinued for Tucson pending a rate case proceeding.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	No Fuel Clause
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	No Fuel Clause
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Fuel Clause
b. How often are rates adjusted?	No Fuel Clause
c. Is there a deadband around that starting point in the PCA?	No Fuel Clause
d. Is there a sharing mechanism?	No Fuel Clause
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Fuel Clause
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	No Fuel Clause
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	No Fuel Clause
d. Are balancing accounts (i.e., true-up or reconciliations) used?	No Fuel Clause ECR = (TUA + PEC) / PES
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	ARKANSAS
Major utility:	Entergy Arkansas
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Yes. Electric utlities can utilize an Energy Cost Recovery Rider (Rider ECR).
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1978 [NRRI, 1978 reproduced in Schmidt]
Was the PCA discontinued for periods of time?	No.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	[need to ask commission]
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	All fuel and purchased power costs.
b. How often are rates adjusted?	Rider ECR is calculated annually, reflecting the actual cost experience in the previous calendar year. Fuel cost changes are subject to a two-month lag. The energy cost rate includes a true-up adjustment reflecting the over-recovery or under-recovery, including carrying charges, of the energy cost for the prio calendar year. If costs exceed 10% of the proposed ECR, an interim adjustment may be made.
c. Is there a deadband around that starting point in the PCA?	No.
d. Is there a sharing mechanism?	No.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Calculated annually.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	No.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes. True-up mechanism is used. If a over or under recovery exceeds 10 percent of the energy cost determined for the period, then either the Commission or the Company can request an interim revision to the ECR. TUA is a true-up mechanism for the energy cost period. PEC is the projected energy cost for the projected energy period. PES is the projected sales in KWh for the projected period. Formula is explained in great detail in ECR Rider.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	No.
Conact Info: Name	Arkansas Commission
Phone Number:	501-682-2051

Adjustment Clause Matrix

State:	ARKANSAS
Major utility:	Southwestern Electric Power Company (part of American Electric Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	SWEPCO utilizes a fuel adjustment clause.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1978 [NRRI, 1978 reproduced in Schmidt]
Was the PCA discontinued for periods of time?	No.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	[need to ask commission]
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	All fuel and purchased power costs.
b. How often are rates adjusted?	Rider is calculated annually in March.
c. Is there a deadband around that starting point in the PCA?	No.
d. Is there a sharing mechanism?	No.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Calculated annually.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	No.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes. True-up mechanism is used. If a over or under recovery exceeds 10 percent of the energy cost determined for the period, then either the Commission or the Company can request an interim revision to the ECR. TUA, PEC, and PES explained in Entergy Arkansas section 1) JAF is a Jurisdictional Allocation Factor. The jurisdictional allocation factor will be derived in a two step process. First, for each jurisdiction the voltage level kWh at the meter will be divided by the most recent energy loss factors to determine the voltage level kWh at generation. Second, the Arkansas jurisdictional kWh at generation will be divided by the total kWh at generation for all jurisdictions to develop the Arkansas jurisdictional allocation factor. 2) LCG is the Loss Correction Factor 3) M is the amortization of mine closing and reclamation costs for mine adjacent to SWEPCO power plant.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	$ECR = \frac{TUA + (PEC * JAF)}{PES} * LCF + (M * LCF)$
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	CALIFORNIA
Major utility:	Pacific Gas & Electric, Sierra Pacific Power Company
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Yes, With the advent of electric industry restructuring, the utilities' Energy Cost Adjustment Clauses were eliminated in January 1998. However, effective January 1, 2003, the state's electric utilities, as required by statute, established a balancing account, the Energy Resource Recovery Account (ERRA) that is designed to track and allow recovery of the difference between the recorded procurement revenues and actual costs incurred under each utility's procurement plans, excluding the costs associated with the Dept. of Water Resources (DWR) allocated contracts and certain other items. The PUC must review the revenues and costs associated with each utility's electricity procurement plan at least semi-annually and adjust retail electricity rates or other refunds, as appropriate, when the aggregate over-collections or under-collections exceed 5% of the utility's prior year electricity procurement revenues, excluding amounts collected for the DWR. These adjustments are to continue until January 1, 2006
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1978 [NRRI, 1978 reproduced in Schmidt]
Was the PCA discontinued for periods of time?	Yes, with electric restructuring, the Energy Cost Adjsutments were eliminated in 1998. Due to the failure of the electric restructuring efforts in California, in 2003, the Commission established Energy Resource Recovery Accounts for electric utilities.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes,
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Costs associated with utility's electricity procurement plan.
b. How often are rates adjusted?	The CPUC reviews the revenues and costs associated with a utility's electricity procurement plan at least semi-annually and adjusts retail electricity rates or order refunds, as appropriate when the aggregate over-collections or under-collections exceed 5% of the utility's prior year electricty procurement revneues.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	California Commission
Phone Number:	415-703-2782

Adjustment Clause Matrix

State:	COLORADO
Major utility:	Xcel Energy (Public Service of Colorado)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Yes, Public Service of Colorado operates under an incentive-based electric commodity adjustment (ECA).
b. What was the reason for the implementation of a PCA?	In a 1976, the Commission established the FAC "to permit rapid recovery of increased costs over which the utility has no control. The Commission recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earn-ings. We observed that this erosion of earnings would, in turn, jeopardize the utility's ability to provide service."
When was the PCA first implemented?	Since at least 1976 [Case No. 5700, Decision No. 89225]. The current ECA was initiated as a result of the Public Service Colorado and Southwestern Public Service merger to form New Centuries Energy [Decision No. 95I-464E] that went into effect October 1996. This merger agreement eliminated the previous automatic FAC. This was continued as part of the merger between New Centuries Energy and Northern States Power [Decision No. 99A-377EG] that was continued through the end of 2002. Under a rate case adopted in June 2003, electric fuel and purchase power costs were recoverable through the end of 2003. In 2004, a new Electric Commodity Adjustment (ECA) went into effect through the end of 2006.
Was the PCA discontinued for periods of time?	No. FACs were not discontinued, but automatic FACs were discontinued in 1996 after the Commission concluded that "the historical reasons for imple-menting ECAs no longer exist that existing ECAs may inappropri-ately allocate the risk of fuel and energy price changes to rate-payers; and that existing ECAs may provide improper incentives."
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes, the FAC was established in 1976, re-examined in a merger agreement in 1996, adjusted in 1999, 2003, and 2004.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The current ECA covers fuel and purchased power costs. The ECA allows for the first $15 million above or below a base level of purchased power costs to be allocated 50% to retail customers and 50% to shareholders. The next $15 million above or below the base is allocated 75% to retail customers and 25% to shareholders. Any changes abover $30 million are to be recovered from or flowed back to ratepayers.
b. How often are rates adjusted?	The current ECA is until the end of 2006. The Energy Commodity Factor is calculated annually for calendar years 2004 to 2006. If the value in defered accounts exceed $40 million, then this can be calculated more frequently. PSCO is required to file an application by 4/1/2006 to address fuel and pruchase power costs after 12/31/2006.
c. Is there a deadband around that starting point in the PCA?	Yes, the maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
d. Is there a sharing mechanism?	Yes, The ECA allows for the first $15 million above or below a base level of purchased power costs to be allocated 50% to retail customers and 50% to shareholders. The next $15 million above or below the base is allocated 75% to retail customers and 25% to shareholders. Any changes abover $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Until 2006, the ECA is calculated through formulas described in 3.d. PSCO must file an application by April 2006 subject to hearings to establish a new ECA.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	No.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, ECA COS is the projected annual Electric Commodity Adjustment Cost of Service. PARS is the projected annual retail sales at transmission voltage. FEC is the Fixed Energy Cost. VEC is the Variable Energy Cost. AQIR is the Air Quality Improvement Rider. LWC is the Lamar Wind Cost. FPVM is the Forecasted Price Volatility Mitigation cost. **The ECA Recoverable Costs in each calendar year shall be the actual ECA COS plus or minus the Incentive Amount less the sharing of the real time pricing margins.** $\text{ECA COS Factor} = \frac{\text{ECA COS}}{\text{PARS}}$ $\text{ECA COS} = \text{FEC} + \text{VEC} - \text{AQIR} + \text{LWC} + \text{FPVM}$
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Yes.
Conact Info: Name	Colorado Commission
Phone Number:	303-894-2000

Adjustment Clause Matrix

State: FLORIDA
Major utility: Florida Power & Light

1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Florida Power & Light has a Fuel and Purchased Power Cost Recovery clause, which is designed to permit full recovery of certain costs and provide a return on certain assets used by these programs.
b. What was the reason for the implementation of a PCA?	"Until 1974, the PSC allowed utilities to recover fuel expenditures through a line item on customer bills known as the 'energy charge,' a charge that was included in customer "base rates." However, as a result of the severe price fluctuations in fuel costs experienced during the OPEC oil embargo, the PSC established a separate charge for fuel that can be adjusted in proceedings that do not involve base rates. These fuel proceedings were scheduled more frequently than base rate proceedings and a new line item on customer bills was established. As stated above, this new line item is known as the "fuel factor" and allows utilities to recover fuel costs." - PSC Consumer Bulletin
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	No, but the number of rate adjustment hearings was reduced from monthly to annually.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel costs (including transportation costs) in fuel clause; capacity payments, risk management costs, energy conservation, and costs of complying with federal, st Company uses a marginal production costing program to calculate As-Available Energy costs. Each hour, actual system data (dispatch fuel costs, system load, g replacement fuel purchased in excess of contract minimums" - FLP tariff sect.10, Appendix A
b. How often are rates adjusted?	Fuel costs are recovered from customers through levelized charges per kwh established under the fuel clause. These charges are calculated annually based on from the estimates used in setting the fuel adjustment charges for prior periods[04001]. An adjustment to the levelized charges may be approved during the cours
c. Is there a deadband around that starting point in the PCA?	Not annually, but mid year adjustments must be of a significant magnitude.
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Annual review. Based on 12-month projections of fuel costs and sales. Intermediate adjustments are permitted if a difference of plus or minus 10% develops betv power costs must be recovered on a demand basis, as opposed to a kWh-usage-basis, for each utility subsequent to its next base rate case. [04001]
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Annual review of whole sale market purchases can be reviewed in end of yr true up / ROE proceedings if PSC is petitioned. However, utilties are not required to submit request for proposals if extending a contract. [FL PSC: Docket 040001-EI, p.3] The ruling is subject to judical review on appeal. [FL SC decision]
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	Yes, a fuel recovery line loss multiplier specfic to time of use rates are used in calculating the fuel recovery factors. [04001, p.9-14]
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, True-ups are used to reconcile the difference between estimated and actual fuel costs.[04001]
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Yes, Included in the clause is a Generating Performance Incentive Factor, which provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the Florida Public Service Commission (PSC). The maximum reward or penalty is limited to a 25-basis-point ROE spread. [04001,p.21, need citation for 25pt.] "The purpose of GPIF is to provide an incentive for efficient performance. Goals and penalties are set based on historical performance, which changes from year to year." -[04001,p21]
Conact Info: Name	Bill McNulty
Phone Number:	850-413-6443,8/2/05, return call 8/4 from Todd Borman, general rule making or history, qualitiative considerations

Adjustment Clause Matrix

State:
Major utility: Progress Energy (Florida Progress Corp.)

1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Florida Progress Corp. is generally permitted to pass the cost of recoverable fuel and purchased power to its customers through a FAC.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	ate and local environmental and security regulations through separate adjustment clauses. [04 enerating unit status, interchange schedules, etc.) are automatically provided to the program. The
b. How often are rates adjusted?	estimated fuel costs and estimated customer usage for the following year, plus or minus a true-up se of a year to reflect a projected variance based on actual costs and usage. [PSC Docket No. 00
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	veen projected and actual costs. Interest is accrued on both over- and under-recovered balances.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	FLORIDA
Major utility:	Gulf Power (Part of Southern Company)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Gulf Power can utilize recovery clauses for fuel costs, the energy component of purchased power costs, energy conservation costs, and environmental compliance costs.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel costs, energy component of purchased power costs, energy conservation costs, and environmental compliance costs.
b. How often are rates adjusted?	Gulf Power's retail electric rates include provisions to annually adjust billings for fluctuations in those costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Adjustments are done on an annual basis.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	GEORGIA
Major utility:	Southern Company (Georgia Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Yes. Georgia Power (GP) uses a semi-automatic fuel adjustment mechanism.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1979 in accordance to Georgia Code 46-2-26.
Was the PCA discontinued for periods of time?	No.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes. In December 2002, the PSC authorized GP to implement a natural gas and oil procurement and hedging program. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery clause.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	As routine business expense generally, but increases in base rates are subject to hearings.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	In order to change its base rates, GP has to file an estimate of its fuel costs and retail sales for the next three consecutive calendar months and proposed base rates to recover those costs with the commission.
b. How often are rates adjusted?	The energy portion of purchased power transactions is permitted to be included in the mechanism, but the capacity component is recovered through base rates. Increases in base rates are subect to review with the possibility of retail customers intervening.
c. Is there a deadband around that starting point in the PCA?	No.
d. Is there a sharing mechanism?	Yes. Annual financial gains from the hedging program have to be shared with retail customers receiving a 75% share while GP retains 25%.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Yes, Hearings are required before increases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered fuel costs is considered in setting new rates.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Increases in base rates are subject to hearings. The commission will disallow for any reported fuel cost that is the result of illegal or clearly imprudent conduct on the part of the utility.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes. GP can increase base rates subject to hearings.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	Georgia Commission
	404.656.4501
Phone Number:	Ms. Boyer (404.656.0945)

Adjustment Clause Matrix

State:	HAWAII
Major utility:	Hawaii Electric Light Company, Hawaiian Electric Company, and Maui Electric Company
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Fuel adjustment clauses are in place for all electric utilities.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1928 [Hawaiian Electric Oil Clause Schedule].
Was the PCA discontinued for periods of time?	No.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	The fuel clause is written as state statutes.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expense for isolated islands that depend on imported fuel.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel, purchase power, capacity costs through surcharge, IRP costs and DSM program costs.
b. How often are rates adjusted?	The clauses are adjusted monthly for changes in fuel and the fuel component of purchased energy, and for variations from the forecasted generation mix. Purchased power capacity costs and the operation and maintenance expense component of energy costs are recoverable through base rates. The PUC may impose a surcharge on utility rates for recovery of capacity costs under purchased power contracts with non-fossil-fuel (i.e., geothermal, wind) producers. The PUC has approved recovery of Integrated Resource Plan (IRP) costs (to the extent that they are not recovered through base rates) and DSM program costs through an IRP Cost Recovery Provision, subject to review.
c. Is there a deadband around that starting point in the PCA?	No.
d. Is there a sharing mechanism?	No.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Automatic.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	No.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	The clauses are adjusted monthly.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	No.
Conact Info: Name	Janice Masuda
	Hawaii Commission Utility Analyst
Phone Number:	808.586.2036

Adjustment Clause Matrix

State:	INDIANA
Major utility:	PSI Energy
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Electric utilities in Indiana may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC).
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Unclear. The IURC's Order denied PSI's request for recovery of demand costs attributable to purchased power contracts entered into for the peak summer period of 1999. Court of Appeals affirmed. (Cause No. 41448) The IURC stressed that although the statutory law permits utilities to recover costs through fuel adjustment clauses or trackers, there has never been a guaranteed recovery.
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	According to Indiana Code, "The commission shall conduct a formal hearing solely on the fuel cost charge requested and shall grant the electric utility it if the commission makes the following determinations: (1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible; (2) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses; (3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the commission in the last proceeding in which the basic rates and charges of the electric utility were approved" (8-1)
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expense.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel and purchased power costs are covered under Indiana's fuel adjustment clause. PSI is also allowed to recover costs related to the installation of pollution control equipment, including clean-technology, that is necessary to comply with state and federal clean air regulations.
b. How often are rates adjusted?	It is based on estimated costs of fuel and purchased power for a future three-month period, with an additonal factor to provide for over- or under-recoveries caused by variances between estimated and actual costs in the previous three-month period. For pollution control expenses, PSI files semi-annually. By statute, the URC may not approve a revised FAC mechanism if it will result in a utility earning a return in excess of that authorized. The 'relevant period' for the earnings test is the longer of either the preceding five-year period or the time that has elapsed since the company's last base rate case. (RRA)
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	PSI is allowed to utilize a tracker to recover 100% of purchased-power capacity/demand charges as well as demand side management costs. (Cause No. 41448)
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	In the case of the tracker (see 3.a), "the IURC approved PSI's use of a purchased power tracker, on an interim basis, to recover demand costs attributable to purchased power contracts entered for the peak summer months of 2000, but denied PSI's request for use of the same tracker to recover its demand costs attributable to similar contracts entered for the 1999 peak period." (Cause No. 41448)
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	"The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill per kWh to recover and/or credit the cost for fuel in accordance with the following formula: Fuel Cost Adjustment Factor= F/S - \$0.014484 where 'F' is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs: fossil and nuclear fuel consumed by Company, the net energy cost purchased on an economic dispatch basis, and the cost of fossil and nuclear fuel reocevered through intersystem sales; "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F" (Standard Contract Rider No. 60)
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Fuel Cost Adjustment Factor = F/S — \$0.014484
Conact Info: Name	Indiana Commission
Phone Number:	317-233-1981

Adjustment Clause Matrix

State: INDIANA
Major utility: SIGECO

1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Electric utilities in Indiana may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC).
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Effective June 27, 1995, the energy charges for SIGECO "include a fuel cost adjustment clause" (Cause number 39871)
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	According to Indiana Code, "The commission shall conduct a formal hearing solely on the fuel cost charge requested and shall grant the electric utility it if the commission makes the following determinations: (1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible; (2) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses; (3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the commission in the last proceeding in which the basic rates and charges of the electric utility were approved" (8-1)
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expense.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel and purchased power costs are covered under Indiana's fuel adjustment clause.
b. How often are rates adjusted?	It is based on estimated costs of fuel and purchased power for a future three-month period, with an additonal factor to provide for over- or under-recoveries caused by variances between estimated and actual costs in the previous three-month period. By statute, the URC may not approve a revised FAC mechanism if it will result in a utility earning a return in excess of that authorized. The 'relevant period' for the earnings test is the longer of either the preceding five-year period or the time that has elapsed since the company's last base rate case. (RRA)
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	SIGECO files semi-annually for URC approval to recover carrying costs related to installation of pollution control equipment.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Effective June 27, 1995, the energy charges that "include a fuel cost adjustment clause shall be increased or decreased, to the nearest 0.001mill ($.000001) per kWh, in accordance with the following adjustment factor: Ajustment Factor= F/S - 15.267 Mills per kWh where "F" is the estimated expense of fuel based on a three month average cost beginning with the month immediately following the current billing cycle month and consisting of costs of fossil and nuclear fuel consumed by Company, the net energy cost purchased on an economic dispatch basis, and the cost of fossil and nuclear fuel reocevered through intersystem sales; "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the ent sum in kilowatt-hours of a) net generation; b) purchases; (c) net interchange, less; d) inter-system sales; e) energy losses and Company use." (General Terms and Conditions Applicable to Electric Service)
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	$$\text{Adjustment Factor} = \frac{F}{S} - 15.267 \text{ Mills per kWh}$$
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	INDIANA
Major utility:	Indiana Michigan Power (IMP), subsidiary of American Electric Power
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	IMP is allowed to utilize a fixed fuel adjustment charge.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	The commission "authorized to apply a fuel cost adjustment credit of $0.0000650 per kWh, applicable to I&M's Indiana retail tariffs for consumption occurring on and after August 28, 1996. This factor is to be billed by I&M commencing on September 27, 1996, and continuing through I&M's November and December 1996 billing months. The proposed factor will result in a increase of 1.16%, or $0.80 for a residential customer using 1,000 kWh." (Clause No. 38702)
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	According to Indiana Code, "The commission shall conduct a formal hearing solely on the fuel cost charge requested and shall grant the electric utility it if the commission makes the following determinations: (1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible; (2) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses; (3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the commission in the last proceeding in which the basic rates and charges of the electric utility were approved" (8-1)
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expense.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel costs.
b. How often are rates adjusted?	By statute, the URC may not approve a revised FAC mechanism if it will result in a utility earning a return in excess of that authorized. The 'relevant period' for the earnings test is the longer of either the preceding five-year period or the time that has elapsed since the company's last base rate case. (RRA) On September 22, 2004, the IURC issued an order re-extending the interim fuel factor from October 2004 through March 2005, subject to true-up following American Electric Power implementing corporate separation for its subsidiaries.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Fuel factor set in the context of a regulatory hearing.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	IOWA
Major utility:	Interstate Power & Light [part of Alliant Energy]
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	No, Iowa has energy adjustment clauses (EAC), but MidAmerican does not.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1978 [NRRI, 1978 reproduced in Schmidt]
Was the PCA discontinued for periods of time?	The Commission is considering amending the EAC in future rate case proceedings.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes. In 2002, the Commission investigated fuel and purchase power cost increases reflected in Interstate P&I's EAC in 2001. The Commission ruled that "Eliminating the EAC may be too harsh a remedy, especially when there is no clear evidence of undue manipulation or imprudence by Alliant." However, the Board strongly recommended that the Company look into its fuel and purchase power procurement practies and threatened "capping or otherwise redesigning the EAC in some manner."
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel and purchased power costs are covered under Iowa's energy adjustment clause. All demand side management, energy efficiency, and required renewable resource costs are permitted to be recovered through an adjustment mechanism. The capacity/demand portions of power purchased are recovered through base rates.
b. How often are rates adjusted?	EACs are modified monthly based on forecasted energy costs (fuel and purchased power) for two months.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	No.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Under- and over-recoveries are deferred and are charged/credited to customers in the succeeding month.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes. The formula in 3.e. is the formula used to calculate the energy supply cost adjustment. [see Rider 1E] EC is the estimated cost fo fuel and purchase power. EQ is the estimated total Company electric energy delivery in KWh. A is the beginning balance in the EAC from the previous month. EQ1 is the total electric energy consumption for the month in question and the previous month. AEP is the Alternative Energy Production Cost Recovery factor.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	$C = \frac{EC}{EQ} + \frac{A}{EQ_1} - \$0.01590 + AEP$
Conact Info: Name	Iowa Utilities Board
Phone Number:	515-281-3839

Adjustment Clause Matrix

State:	IOWA
Major utility:	MidAmerican Energy
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	MidAmerican is operating under an Alternative Regulation Plan since 1997. In 2001, the IUB adopted a modified ARP that is to be in place through year-end 2005. ME is also not permitted to seek a general electric rate increase that would take effect before January 1, 2011, unless the company's ROE remains below 10% for 12 consecutive months.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	
b. How often are rates adjusted?	
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	KANSAS
Major utility:	Aquila Networks-WPK
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Aquila Networks is permitted to utilize an energy cost adjustment (ECA) clause.
b. What was the reason for the implementation of a PCA?	Reduce regulatory lag. Reduce administrative costs due to frequent rate adjustment hearings. (77, p.8)
When was the PCA first implemented?	Prior to 1977, there were many case-by-case FAC throughout the state. In 1977, a report was commissioned to study/standardize them.
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes, see 1977 report, excellent discussion of pros/cons of each type of FAC
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	When used, business expense
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The ECA accounts the recovery of fuel and purchased power costs.
b. How often are rates adjusted?	The ECA is calculated monthly based on projected fuel and purchased power costs for that month, with any under-/over-recoveries reflected in the subsequent month. Penalties may be imposed if actual costs exceed projections for three consecutive months.
c. Is there a deadband around that starting point in the PCA?	If costs fall outside a set limit, the utility must submit an explanation and the Commission may insist the utility make the monthly computation at the limits, not the actual experienced cost.
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	The ECA is automatically calculated on a monthly basis. (see Aquilla rider)
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Monthly reports to the Commission.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Annual true-up in December for off-system sales. Monthly (2-mo. Lag) fuel cost true-up of estimated vs actual usage/cost.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Yes, see 1977 discussion, p.13. Efficiency costs "can be countered through the use of an appropriately designed variable energy adjustment clause and with appropriate reporting by the utilities, coupled with effective monitoring by the Commission and its Staff."
Conact Info: Name	
	Phil Sanchez, KCC,785-271-3213, 8/2/05, 2:30, confirm current state of affairs regarding ECAs and past elimination of ECAs: voluntary in early 90s, KCC would not eliminate an ECA.
Phone Number:	

Adjustment Clause Matrix

State:	KANSAS
Major utility:	Westar Energy (Kansas Gas & Electric)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	No Effective Fuel Clause, but the Company is applying for a "Retail Energy Cost Adjustment Clause," to consist of a Fuel Adjustment Clause and an Off-System Sales Adjustment Clause; and, an Environmental Cost Recovery Rider. According to the company, its proposed FAC is similar to fuel clauses approved by the KCC for other utilities. KCC Docket No: 05-WSEE-981-RTS
b. What was the reason for the implementation of a PCA?	Part of a debt reconstruction plan, an attempt to make Westar more financially sound. Provide proper price signals to consumers. http://www.wstnres.com/corp_com/contentmgt.nsf/publishedpages/energyadjustment
When was the PCA first implemented?	Currently in the application process.
Was the PCA discontinued for periods of time?	Yes, suspended for 12 years. (Avera testimony p. 17)
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Effective Fuel Clause. Fuel costs(FAC), wholesale power purchases (OSSA) and environmental costs (ECR) are proposed to be recoverable.
b. How often are rates adjusted?	No Effective Fuel Clause
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Effective Fuel Clause
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	In the proposed ECA, the FAC will have a monthly (with a 2-month lag) true-up and the Off-System Sales Adjustment will have an annual true-up.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	KANSAS
Major utility:	Great Plains Energy (Kansas City Power & Light)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Less than 1 percent of revenues reflect rates that include an automatic fuel adjustment provision. Consequently, KCP&L is at risk to bear flutuations in prices of coal, coal transportation, nuclear fuel, nuclear fuel processing, natural gas or purchased power and cannot recover the cost of fuel until rates are adjusted.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	ECA eliminated 1989 (http://www.kcpl.com/historytable.html) as part of a merger agreement.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Effective Fuel Clause
b. How often are rates adjusted?	No Effective Fuel Clause
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Effective Fuel Clause
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	KENTUCKY
Major utility:	Kentucky Power Company (part of American Electric Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Kentucky electric utility companies can utilize fuel cost adjustment clauses and an environmental cost clause.
b. What was the reason for the implementation of a PCA?	"Every utility may demand, collect and receive fair, just and reasonable rates for the services rendered or to be rendered by it to any person." (278.03)
When was the PCA first implemented?	Since 1976 the governing statute for FAC in KY has been in effect and not amended (KY Statute 278.03)
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense. "In general, changes in fuel costs in Kentucky are reflected in rates in a timely manner through the fuel cost adjustment clauses. All or a portion of profits from off-system sales are shared with ratepayers through fuel clauses in Kentucky." - KPC 3Q, 2004Q4,p.123.7
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel (including transportation costs), purchased power costs and environmental costs are recoverable. (see AEP tariff)
b. How often are rates adjusted?	Adjustments are automatically implemented monthly based on actual costs for the second preceding month (producing a two-month lag), with an under- or over-recovery mechanism included in the clause. (KY FAC)
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Public hearings are held every six months to examine procurement and other practices related to fuel and purchased power cost recovery, with adjustments to correct for any costs that the PSC determines are unjustified. Additional proceedings are conducted every two years to evaluate the operating of the clause and to set the level of such charges to be included in base rates. (KY FAC)
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Each Utility must provide detail calculations at its biannual review for determining its FAC. (see AEP example)
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, over or under recovery of fuel costs are amoritized and collected/refunded. (AED 3Q)
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
	Andrew Melnykovich, PSC spokesperson, 502-564-3940, 8/4/05,10, very pro FAC, long standing, no efficiency/incentive concerns.
Phone Number:	

Adjustment Clause Matrix

State:	LOUISIANA
Major utility:	Entergy Louisiana, Entergy New Orleans, SWEPCO (part of American Electric Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	These utilities' rate schedules include a fuel adjustment clause designed to recover the cost of fuel and purchased power costs.
b. What was the reason for the implementation of a PCA?	Standardization of practices across the state's various utilities and to prevent non-fuel related costs from being passed on in the less scrutinized fuel adjustment clause. [U-21497, p. 1]. FACs also "permitted the utilities to recover their actual cost of fiel in a timely manner" by avoiding to file base rate cases [p.4]. "The mechanism was established due the materiality and historical and potemial volatility of these costs" [p.5] "The purpose of the Louisiana Fuel Adjustment Clause mechanism is to provide an opportunity for the timely recovery of actual fuel and generation dependent costs incurred by electric utilities on a monthly basis." - [97 p.5]
When was the PCA first implemented?	The first effort to standardize by the LPSC was in 1975 after numerous base rate adjustments due to the rising cost of fuel on a case-by-case basis. [p.4]
Was the PCA discontinued for periods of time?	No, but monthly public hearings were discontinued and replaced with monthly fuel adjustment reports in writing. [p.4]
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes, LPSC Docket U-21497 from 10/1/97 was instituted to "develop standards goveming the treatment of fuel costs..."
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	These utilities can recover electric fuel and purchased power costs.
b. How often are rates adjusted?	The fuel adjustment contains a surcharge or credit for deferred fuel expense and related carrying charges arising from the monthly reconciliation of actual fuel costs incurred with fuel cost revenues billed to customers. The mechanism allows for monthly adjustments.[p.4]
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Where the fuel component of revenues is billed based on a pre-determined fuel cost (fixed fuel factor), the fuel factor remains in effect until changed as part of a general rate case, fuel reconciliation, or fixed fuel factor filing. If the FAC changes by more than 10%, utility must supply explanation and documentation in an affidavit. (12) Additionally, every month, utilites must provide documentation substantiating their fuel adjustment factor. Each utility is audited every two years. [14-15]
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	If a utility's fuel adjustment factor changes by more than 10% from the previous month, the utility must document and explain the change to the LPSC.[12] Additionally, every month, utilites must provide documentation substantiating their fuel adjustment factor. Each utility is audited every two years. [14-15]
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	These considerations are excluded for the purposes of the true-up accounts, but differentiation amoung customers according to the voltage level of the customers is required. [10-11]
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, a true-up account is to be maintained by the utilities which are required to earn the prime rate. [p10]
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	None mentioned in the exhaustive review. No incentive clauses. " 'Fuel adjustment clauses are not designed to allow the utility to earn a profit; rather they are recoupment devices designed to permit a dollar-for-dollar recovery of fluctuations in fuel costs.' Because only actual fuel costs should be recovered through the clause (with no return), neither the utility nor ratepayers should be harmed by the use of a fuel adjusment mechanism" p.3
Conact Info: Name	
	Donny Marks, 225-342-4404, , confirmed current status (97 order), no ECC, financial hedging costs are included, no efficiency concerns.
Phone Number:	

Adjustment Clause Matrix

State:	MINNESOTA
Major utility:	Northern States Power (Xcel Energy)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Automatic fuel and purchased gas adjustment (PGA) clauses are permitted, that provide for monthly rate revisions to reflect changes in the current unit cost of purchased gas compared with the cost last included in rates.
b. What was the reason for the implementation of a PCA?	"intended to make rates more accurate and reasonable and to conserve regulatory and utility resources." (E-999/CI-03-802.)
When was the PCA first implemented?	The Fuel clause adjustment became a separate line item on customers bills this year (see doc: 05-002) but had in place as part of a "resource adjustment" rider prior to that since 1976.
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	The MN Dept. of Commerce issues a Quadrennial Report in which the MPSC has an opportunity to comment on general trends. As a response to an increase in fuel price volatility, in 2000, "more real-time pricing in the fuel cost adjustments on customer bills, a demand-side management tool that allows large customers to benefit financially from reducing loads during peak hours" was recommended. In 2004, little was mentioned of FAC's. Docket No: E-999/CI-03-802. examined the appropriateness of continuing to implement a Energy Cost Adjustment Rider for Xcel, and the entire industry.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	business expense
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Through its PGA clause, NSP can recover costs associated with changes in the current unit cost of purchased gas. Through their electric fuel clauses, electric utilities can, on an interim basis, recover "Day 2 Market" costs as a result of their membership in the Midwest Independent System Operator (MISO). Day 2 Market costs are costs related to the MISO's implementation of a competitive wholesale electricity market, including locational marginal pricing and financial transmission rights.
b. How often are rates adjusted?	The fuel clause projects monthly costs and provides for a true-up to actual costs.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	By September of each year, the utilities are required to submit to the PUC an annual report of the PGA factors used to bill each customer class for the previous year beginning July 1 and ending June 30. (see 7825.2810)
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	The monthly adjustments for electric utilities are automatic, at the end of each month a report to the PUC is required. Any changes in its automatic adjustment of charges, the utility shall file an explanation. Annual review for accuracy and prudence (E-999/CI-03-802.) All purchased power agreements are subject to review.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, on a monthly basis. (see Xcel tariffs - p.90)
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	As a condition of its most recent merger, Xcel cannot file a base rate case until 2006.
Conact Info: Name	
	Janet Gonzalez, head of energy staff, (651) 201-2231, 8/2/05,2pm, inquired about current state of Docket: 03-802, which is dormant (first round of hearings produced no action, currently waiting for restructuring and MISO concerns). Also confirmed history of FAC.
Phone Number:	

Adjustment Clause Matrix

State:	MISSISSIPPI
Major utility:	Entergy Mississippi (EM)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Electric utilities can utilize electric fuel adjustment clauses called "Energy Cost Factors."
b. What was the reason for the implementation of a PCA?	Direct recovery of fuel costs. [rule 17]
When was the PCA first implemented?	Section 77-3-1,et seq., of the Mississippi Code of 1972 established the Rider Schedule Energy Cost Recovery. In 1983, the MPSC was commissioned with "monitor[ing] fuel adjustment clauses with great detail." - 2004 MPSC annual report. Fuel Adjustment Cost Riders were officially established in 1994 [MPSC rules & procedures - Rule 17]
Was the PCA discontinued for periods of time?	No
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	The annual report given by PSC does not appear to have sparked a debate in the legislature or within the PSC.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business Expense
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The fuel adjustment is based upon projected fuel use and costs, with a provision for the reconcilation of over- and under- recoveries. Both utilities can also recover emission allowance expenses. MPSC stipulated that when purchasing fuel from a company owned by the utility's parent company many cost normally included in the price of fuel (inventory, storage, fuel handling expenses, administrative, etc) are excluded. (Rule 17D)
b. How often are rates adjusted?	EM's fuel adjustment clause is adjusted on a quarterly basis. [2000-UN-884]
c. Is there a deadband around that starting point in the PCA?	No, but when considering ROE, the PSC does consider "a range of no change."
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	The PSC conducts an annual audit of all fuel purchases and interchange contracts and submits an annual report to the Legislature. They also examine the ROE
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	The Mississippi Public Utility Staff audits all IO utilities fuel expenditures to "ensure that they are properly chargable to ratepayers and are prudently incurred." [04report]
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	none
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, see Entergy's ECR-2 form. Balances are updated on a quarterly basis.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
	Virden Jones - Director, Electric, Gas & Communications, (601) 961-5800, 8/2
Phone Number:	

Adjustment Clause Matrix

State:	MISSISSIPPI
Major utility:	Mississippi Power (MP)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Electric utilities can utilize electric fuel adjustment clauses. MP also utilizes an Environmental Compliance Overview (ECO) Plan to recovery costs associated with environmental regulations.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The ECO Plan (MP only) provides for recovery of costs (including cost of capital) through base rates associated with environmental projects approved by the PSC. Under the ECO Plan any increase in the annual revenue requirement is limited to 2% of retail revenues. The plan also provides for carryover of any amount over the 2% limit into next year's revenue requirement.
b. How often are rates adjusted?	MP's fuel adjustment is set for a 12-month period.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	to determine if a base rate adjustment is required on an annual basis[04 annual report]
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, see MP's FCR-1 forms. Balances are updated on an annual basis.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	MISSOURI
Major utility:	Aquila Networks-MPS, Aquila Networks-L&P
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	On May 27, 2005, the Missouri House of Representatives and Senate passed SB 179, which, if enacted, would permit the state's electric utilities to apply for Missouri Public Service Commission (PSC) approval, beginning in January 2006, to utilize fuel, purchased power, and environmental compliance cost recovery mechanisms. The bill would allow such applications within the context of a general rate case or complaint proceeding, and would require a utility that applies for any of these cost recovery mechanisms to file a general rate case within four years of implementation of the mechanism. In addition, the annual recovery of environmental-related costs would be capped at 2.5% of the utility's Missouri gross jurisdictional revenues, less certain taxes. Each mechanism would be subject to an annual true-up for under- and over-collections, including interest. The costs to be recovered through any mechanism will be subject to prudence reviews every 18 months. This bill was signed by the Governor in July 2005.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The recovery is for those energy costs in excess of those in base rate revenue.
b. How often are rates adjusted?	The PSC is allowing these utilities to implement the surcharge for 2 years. The surcharge revenue is subject to refund, pending a prudence review.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Addressed in the context of full base rate proceedings.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	MISSOURI
Major utility:	Ameren
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	The Ameren Companies do not have in either Missouri or Illinois a fuel adjustment clause for their electric operations that would allow them to recover from customers costs for purchased power or increased fuel used for generation.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Fuel Clause
b. How often are rates adjusted?	No Fuel Clause
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Fuel Clause
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	MONTANA
Major utility:	Montana Power (Northwestern Energy), Montana-Dakota Utilities (Spoke with Will Rosquist at the Commission)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	It is done through a monthly electricity cost tracking process under which rates are based on estimated loads and electricity costs for the upcoming tracking period and are reviewed and adjusted by the PSC for differences in the previous year's estimates It appears that a tracking mechanism is allowed for all the investor-owned utilities in Montana.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	WIth respect to the electric side of its business, House Bill 474 was passed in 2001 by the Montana legislature, which, among other things, reaffirmed full cost recovery for the default supplier by mandating that the MPSC use an electric cost recovery mechanism providing for full recovery of prudently incurred electric energy supply costs and extended the transition period through June 30, 2027. In November 2002, Referendum 117 was passed, repealing HB 474 and reinstating a transition period ending on June 30, 2007. Two new electric energy bills, HB 509 and SB 247, were passed by the 2003 Montana Legislature. Collectively, these two 2003 bills established Montana Power Company as the permanent default supplier, extend the transition period to June 30, 2027, required smaller customers to remain default supply customers through the transition period, and established a specific set of requirements and procedures that guide power supply procurements and their cost recovery.
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Default customer supply costs.
b. How often are rates adjusted?	It is done through a monthly electricity cost tracking process under which rates are based on estimated loads and electricity costs for the upcoming tracking period and are reviewed and adjusted by the PSC for differences in the previous year's estimates to actual information.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	The electricity cost tracking process is done on a monthly basis.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	The utilities are expected to prudently administer their supply contracts and the energy procured pursuant to those contracts for the benefit of ratepayers. [Northwestern Energy 2004 10-K]
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	Rates are based on estimated loads.
d. Are balancing accounts (i.e., true-up or reconciliations) used?	The rates are reviewed and adjusted by the PSC for differences in the previous year's estimates
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	Will Rosquist
Phone Number:	406-444-6199

Adjustment Clause Matrix

State:	NEVADA
Major utility:	Sierra Pacific Power Company (SPP)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Currently, SPP is subject to a deferred energy cost recognition procedure, under which changes in fuel and purchased power costs are accrued for consecutive 12-month periods. (see FAQ) In Nevada, purchased power and fuel costs are separated from general rate related costs into a Defered Rate Case. However, as a part of the NPC/SPP merger settlement, neither company has a FAC.
b. What was the reason for the implementation of a PCA?	"Deferred energy accounting helps "even out" the bills Sierra Pacific and Nevada Power pay throughout the year for their fuel and purchased power. The companies determine load requirements and usage levels on an annual basis and payments for that period are "leveled out" based on current wholesale power rates. If wholesale fuel and power costs remain high, deferred energy accounting allows for the rates to be spread out over several years." - http://www.sierrapacific.com/energy_issues/faqs/
When was the PCA first implemented?	Late 70's, early 80's
Was the PCA discontinued for periods of time?	Yes, 2000-01 temporarily as a result of merger.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	No
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense to be handled on an annual basis.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Costs eligible for recovery include all expenses incurred to purchase fuel, capacity, and energy, as well as the carrying charges on the deferred balances. (financial hedging costs as well)
b. How often are rates adjusted?	The electric utilities are subject to a deferred energy cost recognition procedure, under which changes in fuel and purchased power costs are accrued for consecutive 12-month periods. After the 12-month period, the utility initiates a deferred energy rate case, designed to recover approved fuel and purchased power costs over a 12 to 36 month period.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Utility must initiate a deferred energy cost recognition procedure after 12 months.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Any imprudent expenses will not be refunded to the utility.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, refunded with interest on a annual basis.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	Large cost adjustments are often amoritized over multiple years.
	Fred Buck, Financial Analyst, Tariffs&Compliance, 775-684-6190, 8/4, confirmed current status of each utility, rule adjusment for interim hearings, financial hedging costs
Phone Number:	

Adjustment Clause Matrix

State: NEVADA
Major utility: Nevada Power Company (NPC)

1. Basis of the PGA	
a. Does each utility in the state use a PCA?	The settlement called for, and the PUC order established, a new going-forward rate for projected fuel and purchased power costs beginning April 1, 2005. The new rate is intended to be more in line with forecasted costs. Previously established energy rates have generally resulted in sizable deferred balances to be recovered over a number of months.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	Yes, 2000-01 temporarily as a result of merger.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	New rates for purchase power after April 1, 2005.
b. How often are rates adjusted?	New going-forward rate for projected fuel and purchased power costs beginning April 1, 2005.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Recovery of past purchase power costs and going forward rate for purchase power costs.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	NEW MEXICO
Major utility:	Texas New Mexico Power (TNMP)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	TNMP is allowed to utilize a fuel and purchased power cost adjustment clause. However, on May 27, 2005, the New Mexico Public Regulation Commission voted to approve PSNM's proposed acquisition of TNP (parent company of TNMP). The approved settlement specifies that TNMP's fuel and purchased power adjustment clause would be eliminated no later than year-end 2005. See [Case No. 04-00315-UT].
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel and purchased power costs. Fuel clause will conclude at the end of 2005 due to merger agreement.
b. How often are rates adjusted?	It is calcuated monthly and includes a balancing account in which there is approximately a two-month collection lag. Fuel clause will conclude at the end of 2005 due to merger agreement.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	TNNP is required to reapply for continuation of the clause every two years, at which time a comprehensive review of the clause is undertaken. Fuel clause will conclude at the end of 2005 due to merger agreement.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	NEW MEXICO
Major utility:	Public Service New Mexico (PSNM)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	No Fuel Clause. Rates are frozen through year-end 2007. PSNM does not have a fuel cost pass-through mechanism. On May 27, 2005, the New Mexico Public Regulation Commission voted to approve PSNM's proposed acquisition of TNP (parent company of TNMP).
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Fuel Clause
b. How often are rates adjusted?	No Fuel Clause
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Fuel Clause
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	NORTH CAROLINA
Major utility:	Carolina Power & Light (Carolina Progress Energy)
1. Basis of the PCA	
a. Does each utility in the state use a PCA?	Carolina Power & Light has a fuel-cost recovery mechanism. [Progress Energy Data Book, p.5]
b. What was the reason for the implementation of a PCA?	"The primary reason for adopting a fuel adjustment clause or procedure is the apportionment of risk between stockholders and ratepayers of the utility with respect to fuel prices and plant performance. Such a procedure, in his view, entails the use of pro forma or normalized generation, especially for base load facilities." [Source: DocketE-100, Sub 47, 5/1/84, p. 7]
When was the PCA first implemented?	Fuel adjustment cases here handled individually through the 70's. After a court challenge, GS 62-134 was amended in '76 to provide the statutory basis for fuel adjustment procedings. NCUC Docket No. 100, Sub 47, Appendix A, p 15 from 5/1/84 outlines the "Annual hearings to review the changes in the cost of fuel" In '87, again after a court challenge, a basis for true-ups was provided. In '95, FAC's were made permanent. [05]
Was the PCA discontinued for periods of time?	No, the above Docket remains in NCUC Rules and Regulations, Ch.8, Article 10, Rule R8-55. [http://www.ncuc.commerce.state.nc.us/ncrules/chap8.htm]
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Starting in July 1993, the Utilities Commission shall provide a report to the Joint Legislative Utility Review Committing summarizing the procedures conducted pursuant to GS 133.2 in the predeecing two years. [Source: NC GS 133.2 (g)] Most recent report: July 2005, see 2005fuelreport.pdf
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expense. Fuel cost adjustments will appear as a line item in the companies' rate schedules. [Source: Duke, NCFuelCostAdjRdr.PDF]
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel costs incurred by the utility. Annual meetings for rate adjustments that are pro forma, using a historical test period, looking forward. However, if these estim
b. How often are rates adjusted?	It provides for electric fuel costs to incrementally affect the electric rates estabilished in a company's last general rate case. The fuel cost is then further modified and the fuel-related revenues that were realized during the test year under the fuel cost component of rates then in effect.[05report]
c. Is there a deadband around that starting point in the PCA?	No, fuel cost adjustments are determined in annual hearings, no restrictions are placed on the size of increment or decrement, so long as they are uniform. [G.S. 62-13.3.2]
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Each utility has an annual hearing to review fuel costs, with a uniform test period determined by the NCUC for each company. [05 report] and the NCUC provides
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	"The burden of proof as to the correctness and reasonableness of the charge and as to whether the fuel charges were reasonably and prudently incurred shall be on the utility. The Commission shall allow only that portion, if any, of a requested fuel adjustment that is based on adjusted and reasonable fuel expense prudently incurred under efficient management and economic operations." [G.S. 62-133.2, d1]
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, the monthly billing factor is based on current estimates of fuel costs associated with the kw-hrs billed and a "true-up" factor for the second preceding month. The "true-up" is to collect or refund the difference between estimated and actual fuel cost for the applicable month. [Source: Progress Energy Data Book, p.5], [see also, 2005 fuel report.pdf]
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	"Commission uses nuclear capacity factors as indications of management efficiency and prudency" [05, p3] However, the Commission notes that this is no longer an accurate instrument, since nuclear efficiency has stablized and NC now relies more heavily on fossil fuels.
Conact Info: Name	
	Kenny Elks, 919-733-2267, 8/2/05, 4:15, general rate making, efficiency concerns, recently contentous nature due to rising fuel costs
Phone Number:	

Adjustment Clause Matrix

State:	NORTH CAROLINA
Major utility:	Duke Power (Duke Energy)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Duke Power has a fuel adjustment clause. [NCFuelCostAdjRdr.PDF]
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	ates are incorrect, the utility will true-up costs (see 3d)
b. How often are rates adjusted?	hrough an Experience Modification Factor (EMF), aka a "true-up", which reflects th
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	a report every two years to the legislature.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	NORTH DAKOTA
Major utility:	Northern States Power, Montana-Dakota Utilities (MDU), Otter Tail Power Company (spoke with Mike Diller at the Public Service Commission)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Automatic fuel and purchased power adjustments are permitted for all investor-owned utilities in North Dakota.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Fuel adjustment clauses have been around for at least 32 years. We spoke with someone at the Commission who says fuel adjustment clauses have been around for as long as he has been with the Commission.
Was the PCA discontinued for periods of time?	No, investor-owned utilities have had access to and have utilized a fuel adjustment clause mechanism ever since they were introduced.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes. The Commission ruled on April 6, 2005 that the utilities in North Dakota needed to work together to develop standardized appropriate FCA tariff language. (Docket Nos. PU-05-131, PU-05-135, PU-05-147)
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine Business. Fuel and purchased power cost adjustments are implemented monthly
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Fuel and purchased power costs based on a four month rolling average.
b. How often are rates adjusted?	Fuel and purchased power cost adjustments are implemented monthly, and there is generally a two-month lag for recovery.
c. Is there a deadband around that starting point in the PCA?	No deadband.
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Automatic adjusted monthly.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, true-ups are used as a means of adjusting for any over or under collections that took place over the previous month.
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	Mike Diller
Phone Number:	701-328-2400

Adjustment Clause Matrix

State:	OKLAHOMA
Major utility:	OGE Electric Service, Public Service Company of Oklahoma (subsidiary of American Electric Power)
1. Basis of the PCA	
a. Does each utility in the state use a PCA?	OGE and PSC have the opportunity to utilize a fuel adjustment clause and a purchased power clause. (see riders)
b. What was the reason for the implementation of a PCA?	"Obviously, the issue of fuel cost management by utilities is of ever-increasing importance. In the wake of the natural gas crisis in the winter of 2000-01, the commission formulated new rules for regulated natural gas companies in regards to this issue, and is currently examining potential new rules to more closely scrutinize the fuel purchases of electric utilities." [05Report, p4]
When was the PCA first implemented?	Fuel Adjustment clauses were first codified in 1991 and most recently amended in 2005.
Was the PCA discontinued for periods of time?	No
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	The Commission has the right to examine whether a FAC should be renewed after every monthly submission of fuel cost data [165-50-5-2-d2]
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense, except recently there has been a shift towards excessive committee scrutiny and ensuring that non-fuel related expenses or imprudent expenses are not passed along.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Certain cogeneration energy and capacity payment differentials are collected through the fuel adjustment clause. It also provides for deferred accounting with a balancing account, and allows for current recovery of line losses above or below the amount recognized in PSO's base rates.
b. How often are rates adjusted?	Fully automatic fuel adjustment clauses are prohibited in Oklahoma. The OCC must review companies' fuel clauses at least every 12 months. [165-50-5-3] OG&E's fuel clause charges can be calculated quarterly based on the average cost of fuel, with any difference from the monthly fuel costs reflected in base rates, debited (or credited) to customers on an annualized kWh basis. (see OGE rider). If the "in the event that the annual cost of fuel begins to differ significantly from the cost used in the annual fuel cost adjustment factor or the over/under-recovered balance" then an interim adjustment can be made, subject to approval. (AEP rider, but true to both utilities). Rates were adjusted quarterly for PCO, but as part of a settlement, are now adjusted annually (05 report, p49)
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Not Automatic. Through Commission review. Monthly filings and/or hearings are open to the public. FAC charges appear as a line item on bills.(165-50-5-3)
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Monthly reports to commission. Annual review of fuel clause.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, see riders (OGE refers to it as a OUF, PCO calls it a DEF)
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	OCC is charged with ensuring "The prudent and efficient use of resources, including making the most economical and efficient choice between utility self-generation and purchases through competitive bidding or otherwise from nonutility sources of energy, capacity, or both; and That electric utilities make every reasonable effort to efficiently and economically acquire fuel and generate or purchase power, or both, so as to provide electricity to their retail customers at the lowest costs reasonably possible. " [05 amendments, sect. 252]
Conact Info: Name	Note: OGE does not engage in financial hedging, since these costs are not recoverable under OK statutes. Instead they use physical inventories to manage risk. (05 report)
	Joyce Davidson, 405-522-1155, 8/02/05
Phone Number:	

Adjustment Clause Matrix

State:	SOUTH CAROLINA
Major utility:	South Carolina Electric & GAS (SCE&G) [Part of SCANA Corp.]
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	SCE&G utilizes a fuel cost recovery procedure which determines the fuel component in SCE&G's retail electric base rates. [SCE&G: Rider # 39: Adjustment for Fuel Costs]
b. What was the reason for the implementation of a PCA?	Combat rising fuel costs in the 70s.
When was the PCA first implemented?	Early to mid 70's
Was the PCA discontinued for periods of time?	No, but after fuel prices stablized in 1979, went from an automatic adjustment to semi-annual hearings/rate reviews and then in 1995 to an annual review.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Only in company specific annual reviews of base rates for fuel costs.
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The procedure is designed to help SCE&G recover fuel costs. Costs of "firm generation purchases" and "economy purchases" (wholesale market purchases) of fuel are included. [58-27-865,A]
b. How often are rates adjusted?	It is based on projected fuel costs for the ensuing 12-month period, adjusted for any overcollection or undercollection from the preceding 12-month period. [58-27 865,B]
c. Is there a deadband around that starting point in the PCA?	No
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Each electric utility is required to furnish the PSC an estimate of its fuel costs, including the cost of purchased power, for a prospective 12-month period. SCE&G has the right to request a formal proceeding at any time should circumstances dictate such a review. [58-27-865, B,D]
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Utilities must submit monthly accounts for the differences between the recovery of fuel costs through base rates and the actual fuel costs experienced [58-27-865, C]
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	The balance of (base rate - actual fuel costs) is included in the base rates for the succeeding 12-month period. [C]
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	"The Commission shall disallow recovery of any fuel costs that it finds without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs..." [58-27-865, F] However, "for the purpose of encouraging economy, efficiency and improvements in methods or service any electrical utility may, subject to the approval of the Commission, participate to such extent as may be permitted by the Commission in additional profits arising from any economy, efficiency or improvement in methods or service instituted by such electrical utility." [58-27-970]
Conact Info: Name	
	Randy Watts (refered by David Butler), SC Office of Regulatory Staff, formerly of the PSC, 803-737-1145, primarily historical information
Phone Number:	

Adjustment Clause Matrix

State:	SOUTH DAKOTA
Major utility:	Northern States Power (Xcel Power Systems)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Electric utilities are permitted to utilize automatic fuel and purchased power clauses.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	In 1975, statute no. 49-34A-25
Was the PCA discontinued for periods of time?	no, but commission says it needs to be revised (see contact)
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	The clauses cover changes in prudently incurred cost of fuel, fuel related items, and purchased energy.
b. How often are rates adjusted?	It provides for monthly adjustments to billings and revenues.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	Losses associated with financial hedging are capped at $875,000 per year.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Automatic. Annual Reports on financial hedging losses are required
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	All fuel clauses must be approved by the PUC.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	"A carrying charge or credit will be included in the determination of monthly fuel adjustment factors. Said charge or credit will be determined by applying one-twelfth of the overall rate of return granted by the South Dakota Public Utilities Commission in the most recent rate decision to the recorded balance of deferred fuel cost as of the end of the month immediately preceding the fuel adjustment factor determination." - NSP tariff
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
	Dave Jacobson, SDPSC, 605-773-3201, long standing fuel clause, in need of revision (MISO costs/revenue, sales for resale, stronger prudence mechanism), currently dealing with these issues in rate cases, despite the independent mechanism allowed in statute 49-34A-25
Phone Number:	

Adjustment Clause Matrix

State:	TENNESSEE
Major utility:	Kingsport Power dba American Electric Power Tennessee
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Much of Tennessee is served by the Tennessee Valley Authority, a public provider of electricity, which does not allow specific fuel cost related rate increases. Kingsport Power has a purchased power adjustment rider (PPAR).
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Business expense
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Any changes in wholesale, non-fuel related costs
b. How often are rates adjusted?	Rates are based on a 12-month test period. Automatic, adjusted monthly. (see AEP regulatory matrix)
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Automatic, but if the change in the company's expense recovered through the application of this rider exceed the level of change in the PPAR ultimately apporved by FERC, the difference shall be refunded. (Kingsport PPAR 2-9)
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Any rate adjustment must be documented 30 days prior with the PSC Staff.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	No, see (3a)
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
	Kierra Kimberlay, 615-741-2904 ext. 151, 8/4
Phone Number:	

Adjustment Clause Matrix

State:	UTAH
Major utility:	PacifiCorp
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	No power cost adjustment mechanism is currently in place, but PacifiCorp has been allowed to implement a temporary rate increase to recover purchased power costs not included in base rates. As part of PacifiCorp's general rate case proceeding concluded on February 25, 2005, the parties agreed to discuss power cost adjustment mechanisms. The meeting was informal with no recorder present, the utilities presented in favor of adopting an FAC, but was not warmly received. Currently, with no open docket, Utah is not formally pursuing it, but it is "likely" that it will be seen again in the future. Currently, there are statutes in place guarenteeing ROE and "just and reasonable" charges [54-3-1].
b. What was the reason for the implementation of a PCA?	Seasonal energy rates were designed to "give proper price signals to customers" regarding the increased cost of summer usage.
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Fuel Clause
b. How often are rates adjusted?	No Fuel Clause. PacifiCorp's rate agreement stipulated that PacifiCorp could not file for a rate change for at least 12 months.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Fuel Clause.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
	Ted Boyer, Commissioner, 7/29/05, 11:00, confirmed current status (1a), expressed efficiency concerns and that the lower utility risk due to FAC should result in lower ROE
Phone Number:	

Adjustment Clause Matrix

State:	VERMONT
Major utility:	Central Vermont Public Service, Green Mountain Power
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Due to a 1984 Vermont Supreme Court ruling, fuel adjustment clauses are not permitted. *Legislation enacted during the 2003 legislative session permits the Commission to adopt Alternative Rate Plans for energy companies, but no such plans have been approved.???? I think Maine adopted the ARP, not VT...?* In 2004, the PSB ruled that "Exposure to fuel price or purchased power price fluctuations is far less for Central Vermont than for many companies; this is because Central Vermont currently procures most of its power through defined-price contracts that have been approved by regulators. Thus, based on the existing power-supply arrangements, Central Vermont would benefit little, if at all, from a fuel adjustment clause." -[6866,p.13]
b. What was the reason for the implementation of a PCA?	OPEC fuel crisis.
When was the PCA first implemented?	early 70's
Was the PCA discontinued for periods of time?	"The Vermont Supreme Court has held that 'a rate that requires consumers to pay for past deficits of a utility or that requires a utility to refund to consumers a portion of its previously earned profits constitutes illegal retroactive rate-making.'"-[6495,p.37, see footnote for VT SC decision]
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	"Interestingly the Department has begun to show a disinclination to investigate utility rate cases in any detail. The DPS has supported rate increases for GMP, a sizeable rate increase for Vermont Gas, (and for the first time in Vermont regulatory history a Purchased Fuel Adjustment Clause), and is proposing to support without investigation numerous rate increases by Vermont's Municipal utilities." -2004 Energy Report
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	"However, in Vermont there have been situations where the extraordinary exception has been allowed. It has been applied to recovery of expenses associated with an unanticipated utility plant shutdown and with expenses related to a natural catastrophe. Market events have also been considered as extraordinary events, in the case of the oil shortage crisis of the early 1970s."-[6495,38] which 6495 was distinct from current rising fuel costs.
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	No Fuel Clause. "Today in Vermont, rates are set for an agreed-upon future period referred to as a "rate year," on the basis of information drawn from an historical period known as a "test year." Test year information is based upon a company's actual costs, load and available resources. Certain adjustments to these items are allowed, but the adjustments must be "known and measurable," i.e., "reasonably estimable and highly likely to occur in the rate year." -[6495,p.37]
b. How often are rates adjusted?	No Fuel Clause
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	No Fuel Clause
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Yes, "Under current practice, a regulated company has an opportunity to recover its costs and to earn a return on the investments it makes for public service purposes, if the company manages its business prudently." -[6495,p.37]
Conact Info: Name	
	Nellie Gillander, Utility Rate Accountant, 802-828-4076, confirmed no FAC, referred to Riley Allen, Director Planning Division x4053 for questions about future
Phone Number:	

Adjustment Clause Matrix

State:	WEST VIRGINIA
Major utility:	Allegheny Power, Wheeling Power Company (subsidiary of American Electric Power)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	These utilities cannot utilize fuel clause mechanisms, but can use an Expanded Net Energy Cost factor, which is based on a fixed level of fuel costs. No utility has utilized the ENEC since 1999. (Wheeling has applied to reinstate their ENEC -see AEP regulatory matrix)
b. What was the reason for the implementation of a PCA?	"removes the recovery of revenues and costs associated with system sales from a traditional rate case to a fuel review (NEC) proceeding." "It was anticipated that the application of deferred cost accounting principles would help to alleviate APCO's historical record of net income fluctuations associated with the unpredictablility of system sales." (86, p.3)
When was the PCA first implemented?	ENEC first appears to be an older term used in initial discussions in the mid 1980s, as an experiment. In 1983, the PSC recommended using the ENEC on an experimental basis and continues to be considered as part of the "rates and charges for electricity service." Currently, however, it does not appear on the utilities rate schedule and is governeed by Rule 30D - FERC approved whole sale power increases - that "sets forth a procedure for changing the rates per kWh charged to retail customers by non-generating electric utilities based exclusively on fuel cost allowances." There is also an Accerlerated Rate Procedure for... Electric Utilities that allows utilties to "amend tariff sheets on an interim basis, subject to refund" for "qualified costs" (defined as "changes in the cost of... electricity, purchased and/or transported for resale"). "Rates and charges for electric service are basically comprised of two parts - the base rates, which cover the utility's reasonable and prudent operating costs such as office expense and salaries, and the expanded net energy cost (ENEC) rates, which pass through the utility's reasonable and prudent costs to obtain fuel for the generation of electricity."
Was the PCA discontinued for periods of time?	No, see above for changes.
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes, see 1986 discussion
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine business expensing as part of the base rate determination and adjustments
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Wholesale energy costs
b. How often are rates adjusted?	They operate under an agreement that calls for the Expanded Net Energy Cost factor to be rolled into base rates at a fixed level.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Appears to be integrated into the base rate (see last quote in 1a); for any tariff changes the PSC may hold a hearing.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	"The Commission's investigation of the reasonableness of the rate increase shall be limited to the increased qualified costs, and the level of rates necessary to recover such costs." 13.1e Utilities must also present evidence of costs at rate hearings in order to set ENEC rates in the future as well as settle the previous period's energy costs.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, monthly reporting, quarterly account balancing [13.2.f , 13.3d of WV Code]
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	Considered and rejected: "No evidence was presented to show a disincentive by APCO to efficiently mange the Company" (86, p.10). There was still some concern of "risk sharing" between management/shareholders and ratepayers. (86, p. 19)
Conact Info: Name	Diane Davis
Phone Number:	304-340-0369

Adjustment Clause Matrix

State: Wisconsin
Major utility: Madison

1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Yes. Electric utilities can recover purchased power and electric fuel costs.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	It was first implemented in the 1980s
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes, the WPSC release a report in July 2005 reviewing all electric rate design and cost-of-service. (see pp. 16-17)
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	Routine for the most part. However, under PSC 116.06, "an electric public utility experiencing an emergency may apply for deferral accounting treatment for all costs caused by that emergency."
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Electric fuel and purchase power costs. The monthly and annual fuel cost ranges set by the commission are determined by a few factors including: "(a): the extent to which fuel costs are controllable by the utility", (b) the ratio of fuel costs to total utility costs, and the probable effect of changes in fuel costs on authorized earnings, (c) the types, quantities and delivered costs of fuel expected to be used by the utility, (d) the number, type, efficiency and amount of use of the utlity's generating units, and (e) the cost effect of known or projected opportunity purchases or opportunity sales.
b. How often are rates adjusted?	Under the fuel rules, each utility has established monthly and annual forecasts of fuel and purchased power costs on a prospective basis. If electric fuel costs exceed or fall below a 3.0% bandwidth set by the Commission, MGE can apply for a fuel surcharge or may have a fuel credit to its customers.
c. Is there a deadband around that starting point in the PCA?	Yes. In each rate proceeding considering fuel costs, "the commission shall establish tolerances within which the average cost of fuel may vary from monthly estimates either on a monthly or a cumulative basis or both, and a tolerance within which the average cost of fuel may vary from an annual estimate on a calendar year basis." (PSC 116.04, pg. 1)
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Through application to the Commission once fuel prices reach certain approved targets.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	Yes, in the sense that if the electric utility "experiences an extraordinary decrease in the cost of fuel the utility or any interested person may seek authority to decrease rates by requesting a proceeding limited in scope to the question of the average cost of fuel."
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	In 2002 a change to the fuel cost adjustment was made with respect to extraordinary Increases and Decreases. After a utility requests an increase/decrease in the rates due to an extraordinary change in the cost of fuel, and the commission agrees with it, it must grant on an interim basis, a rate increase/decrease to the applicant no later than 21 days after the applicant has provided notice to all its customers of its requests. [...] The interim order will set rates at the requested level, subject to refund plus carrying costs pending a full review, hearing and final determination by the commission. [116.07,116.08]
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	Candice Spanjar
Phone Number:	608-266-5481

Adjustment Clause Matrix

State:	Wisconsin
Major utility:	Wisconsin Power and Light
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Wisconsin Power and Light can recover electric fuel costs. However, on their tariff sheet, both the 2004 FAC and 2005 interm FAC have been cancelled.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Electric fuel and purchase power costs.
b. How often are rates adjusted?	Under the fuel rules, each utility has established monthly and annual forecasts of fuel and purchased power costs on a prospective basis. If electric fuel costs exceed or fall below a 3.0% bandwidth set by the Commission, MGE can apply for a fuel surcharge or may have a fuel credit to its customers.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Through application to the Commission once fuel prices reach certain approved targets.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	Wisconsin
Major utility:	Wisconsin Electric Power
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	Wisconsin Electric Power can recover electric fuel costs.
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Electric fuel and purchase power costs.
b. How often are rates adjusted?	Under the fuel rules, each utility has established monthly and annual forecasts of fuel and purchased power costs on a prospective basis. If electric fuel costs exceed or fall below a 3.0% bandwidth set by the Commission, MGE can apply for a fuel surcharge or may have a fuel credit to its customers.
c. Is there a deadband around that starting point in the PCA?	
d. Is there a sharing mechanism?	
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Through application to the Commission once fuel prices reach certain approved targets.
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	
d. Are balancing accounts (i.e., true-up or reconciliations) used?	
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	
Phone Number:	

Adjustment Clause Matrix

State:	WYOMING
Major utility:	Cheyenne Light, Fuel & Power; Carbon Power & Light (spoke with Don Biedermann of the Wyoming Public Service Commission)
1. Basis of the PGA	
a. Does each utility in the state use a PCA?	It appears these are the only two companies that utilize an Energy Cost Adjustment. Carbon Power & Light is seeking to remove it as a separate item and just have it rolled into base rates which generally take place every few years. Cheyenne has an Electric Cost Adjustment "to reflect the costs of purchased energy utilized to supply electric service." [see Cheyenne tariff sheet]
b. What was the reason for the implementation of a PCA?	
When was the PCA first implemented?	Since at least 1977. "Electric, Gas and Water Wholesale Utility Commodity Purchase Pass on Procedure. Pursuant to W.S. 37-3-106 (1977) as may be amended and the rate filing requirements of this Chapter, a utility may file an application to pass on to its utility customers in their rates, known or prospective cost increases or decreases in the utility's wholesale utility commodity; and the same may be authorized, subject to public notice, opportunity for hearing, and refund." See [Order, Docket No. 20003-EP-01-59] In February 2000, Cheyenne Light, Fuel & Power successfully changed the ECA methodology to "establish separate demand and energy components and to remove all wholesale electric energy and transmission costs from its base rates and include them in the ECA." [Docket 20003-ER-99-54]
Was the PCA discontinued for periods of time?	
c. Has the Commission in your state ever examined PCEs in a generic or rulemaking proceeding?	Yes, The last time Cheyenne's ECA was examined in a contested hearing was 2001. See [Docket No. 20003-EP-01-59]. In this proceeding, the Commission granted Cheyenne a siginificant increase to rates due to
d. How generally are PCA's viewed--as mitigation for extreme circumstances or as a routine business expense true-up?	
2. Mechanics of the PCA	
a. How are the starting fuel costs determined?	Increased purchased power costs.
b. How often are rates adjusted?	Cheyenne Light has arranged to have a review whenever they want. Carbon Power & Light arranged for a twice a year review. CP&L is currently trying to get rid of its ECA, because the required two times a year review gives them little flexibility. In 2001, the PSC adopted a settlement that provides for CLF&P to recover increased purchased power costs through an ECA mechanism through December 31, 2005.
c. Is there a deadband around that starting point in the PCA?	There are caps on what Cheyenne is able to recover through its ECA in a 2001 settlement agreement. 40% increases in rates as a whole or $18 million increase in 2001 and $28 million annually in 2002 and 2003. Amounts for 2004-05 were discusse in later case.
d. Is there a sharing mechanism?	No.
3. Other regulatory issues surrounding the PCA.	
a. Is there a public process or a routine filing?	Historically, for other Wyoming utilities, recovery of fuel and purchased power costs has been addressed in rate cases. For Cheyenne, filings for increases or decreases in the ECA is "subject to public notice, opportunity for hearing."
b. Are the costs subject to excessive scrutiny and/or prudence disallowances?	An increase in the ECA was the subject of a contested case in 2001, which capped increases to rates at 40% as a whole.
c. Are Load variations vis-à-vis base rate billing determinants considered in the PCA?	Yes. "If a customer's load supplied by Cheyenne Light decreases by 5 MW or more because the customer obtains electric supply from an alternate slource, such as cogeneration, Cheyenne Light will absorb the pro rata share of the remaining deferred balance based on the percentage of load decrease resulting from such alternate electric supply." [Docket Nos. 20003-EP-01-59]
d. Are balancing accounts (i.e., true-up or reconciliations) used?	Yes, Cheyenne is able to recover its fuel costs as described in the formula in 3.e. Electric Cost Adjustment = A + B + C + D A = Projected Demand Cost B = Projected Energy Cost C = Deferred Electric Cost D = Franchise Fee B = Projected Energy Cost C = Deferred Electric Cost D = Franchise Fee
e. Does your State view PCA's as having effects on efficiency incentives for your company (an effect postulated, but never measured, in the regulatory literature on the subject)?	
Conact Info: Name	Don Biedermann
Phone Number:	307-777-7427

Appendix 2: "Electric Restructuring" States are moving to mechanisms that pass through the full range of POLR costs to customers.

State	Recovery of Fuel and Purchased Power Costs for Provider of Last Resort (POLR) or Standard Offer Service (SOS)
Connecticut	Following electric restructuring enacted in 2003, CT permits the use of an energy adjustment clause to reflect changes in the transitional standard offer rate, which was extended by three years until December 31, 2006. This compensates utilities for having to provide standard offer service at a rate 10% below December 31, 1996 base rate levels.
Delaware	In October 2004, the Commission opened an investigation into the provision of SOS following the May 1, 2006 conclusion of the transition period. In March 2005, the Commission issued a Phase 1 order in which it determined that Delmarva Power & Light (DP&L) should continue as the POLR, with the power to meet POLR demand to procured on a competitive wholesale bidding process. A Phase 2 process is pending to determine: the specific design of the wholesale auction process; the definition and calculation of the "retail adder" to be included in SOS prices; and, social benefits issues. The Phase 2 decision is expected by year-end-2005.
District of Columbia	In determining the capped rates, Pepco's fuel adjustment clause was eliminated and fuel costs were rolled into base rates at the average level in effect for the 12 months preceding the asset sale. Doesn't have PCA from 1997 to 2007 due to merger stipulations for Pepco and Conectiv in 2002.
Illinois	Retail competition legislation was enacted in 1997, allowed the utilities to discontinue their PCAs, with a specific amount of fuel/purchased power costs (determined by the ICC) to be rolled into base rates. If that amount was unacceptable to the company, the utility could opt to retain the PCA. As of July 26, 2004, while most of the utilities decided to drop their PCAs, MidAmerican Energy has retained its PCA. The PCA is adjusted every month "based on fully-forecasted fuel and demand component of purchased power costs for the prospective month, and to correct for over-/under-recoveries the second prior month, with carrying charges on the unamortized amounts. The ICC annually investigates the prudence of the utility's fuel procurement practices. The Commission Staff supports the implementation of an auction process similar to that utilized in New Jersey to procure to meet the needs of customers who do not select an alternative generation supplier.
Massachusetts	As required by 1997 legislation, retail competition began in 1998. At the March 1, 2005 conclusion of the transition period, all customers who do not choose a competitive supplier will receive default service from third-party suppliers through competitive solicitations. The Legislature is informally reviewing what changes, if any, should be implemented at the end of the transition period. If no legislative changes are made, all customers would be eligible for default service. At present, about 25% of kWhs purchased by customers are supplied by competitive generators.
Maine	Adjustment clauses are used to recover costs of SOS on a fully-reconciling basis.
Maryland	The power to meet the extended SOS obligations is obtained through a competitive bidding process. To procure the power to meet residential SOS demand, each IOU is to solicit offers for contracts with one-, two-, and three-year terms, such that in any given year, one-year contracts will comprise at least 50% of the residential SOS power portfolio, two-year contracts will account for up to 25% of SOS power needs, and three-year contracts will be executed for the remaining SOS load. Pepco does not much exposure to fuel risk.

State	Recovery of Fuel and Purchased Power Costs for Provider of Last Resort (POLR) or Standard Offer Service (SOS)
Michigan	Michigan has re-instated the use of fuel adjustment clauses. State law had required customer rates (including fuel and purchased power charges) to be frozen until at least December 31, 2003. Residential rates was capped through January 1, 2006, after which the rates may not be increased until the earlier of December 31, 2013, or until the PSC determines that the utility meets a market power test and has completed certain transmission expansion requirements. POLR service is in place for both capped and uncapped customers, effective January 1, 2004, which is expected to reduce POLR revenues by $126 million annually. However, an interim order allowed Detroit Edison to increase base rates for customers still subject to the cap in an equal and offsetting amount with the change in the POLR factor to maintain the total capped rate levels in effect for these customers.
New Hampshire	Retail access was introduced in 2001. Public Service New Hampshire (PSNH) is required to offer transition service to residential customers until April 30, 2006. It also was required to provide transition service to commercial and industrial customers until February 1, 2005. Since May 1, 2001, fuel and purchased power costs in excess of those reflected in the transition and default service charges are being recovered through PSNH's stranded cost recovery charge.
New Jersey	In 2002, the BPU approved a multi-period wholesale auction process that is now conducted annually and was first utilized for service beginning August 1, 2003. Under the process, the IOUs procure capacity and supply energy at hourly prices for the state's largest industrial customers. For residential, commercial, and small industrial customers, the IOUs solicit fixed-price contracts, such that one-third of the fixed-price BGS load is served under one-year contracts, one-third under two-year contracts, and one-third under three-year contracts. Customer bills reflect a blend of the winning bids for the three contract periods.
New York	Consolidated Edison has a Monthly PCA. If the actual energy costs for a given month are more or less than amounts billed to customers for that month, the difference is recoverable from or refundable to customers. NYSEG satisfies the majority of its power requirements through purchases under long-term contracts from NUGs, the NYPA, and Constellation Nuclear and from generation from its several hydroelectric stations. RGE manages the fluctuations in the cost of electricity for its remaining power requirements through the use of electricity contracts, both physical and financial.
Ohio	No PCA during "market development period."
Oregon	Both Portland General Electric and PacifiCorp have had PCAs in the past. However PGE has not had one since the end of 2002 and PacifiCorp has not had one since May 31, 2002.
Pennsylvania	POLR service is competitively bid so DQE faces little fuel risk. DQE contracts with Orion Power Midwest (part of Reliant) to provide POLR service. Safeguards in POLR I and II designed to mitigate losses in the event that Orion defaults. If market prices for energy were higher than the POLR rate at the time of default, Duquesne Light could potentially be acquiring energy for sale to POLR customers at a loss.
Rhode Island	Legislation enacted in 2002, requires SOS to be available through 2009 at a discount from pre-restructuring bundled rates for those customers who do not select an alternative provider. As required by law, each electric distribution company has contracted with wholesale suppliers for power to provide SOS at a stipulated rate. The wholesale supply contracts provide for increases in the per-kWh-rate in the event fuel prices increase above certain levels. Each distribution company must provide "last resort" power for those customers who left SOS, but are no longer receiving electric service from a non-regulated power supplier. Such power is to be obtained from wholesale power suppliers.

State	Recovery of Fuel and Purchased Power Costs for Provider of Last Resort (POLR) or Standard Offer Service (SOS)
Texas	Texas has "price-to-beat" (standard offer) rates that are "capped" during the competition transition period (2002-2007). Semi-annual adjustments are permitted to reflect power cost increases that exceed certain benchmarks, thereby insulating the generation providers from market risk to some degree. In 2003, the Commission ruled that in order to increase the Price-to-Beat rate, the retail provider must demonstrate that gas prices have increased by at least 5%, or at least 10% if the increase request is filed after November 15 of any given calendar year.
Virginia	On April 14, 2004, Gov. Mark R. Warner signed into law SB 651, which extends the base rate freeze by 3 and 1/2 years, through December 31, 2010. The IOUs will be permitted to seek one base rate adjustment during the extended rate cap period, and the fuel factor is be fixed at January 1, 2004 levels until at least July 1, 2007.

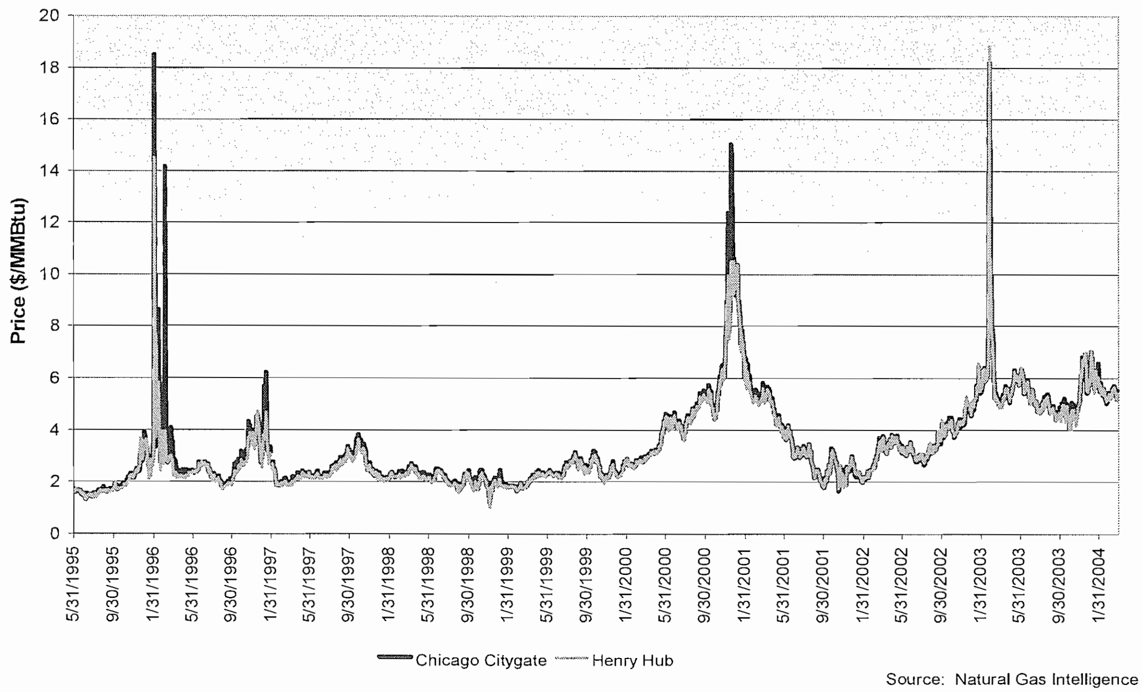
[1] For largest utilities within each state. There may be some utility specific variation on scheduled end or extensions.

Source: *Regulatory Research Associates* and the *Edison Electric Institute.*

Appendix 3: Volatility in Energy Fuel Sources

Prices for natural gas and crude oil, which accounted for about 20 percent of US net electricity generation in 2003, fluctuate on a daily or weekly basis.[69] **Figure 8** shows the volatility of natural gas from June 1995 to March 2004. During the past 10 years, natural gas prices have experienced extreme volatility, highlighting the need for PCAs.

Figure 8: Daily Natural Gas Prices at Major US Pricing Points (June 1995-March 2004)[70]



Monthly Mid-Continent electricity wholesale prices for June 1995 to March 2004, adjusted to constant 2003 dollars using the Consumer Price Index (CPI), shows high volatility as shown in **Figure 9**. Real power prices have been fluctuating at around $30/MWh except during the Western power crisis period (between June 2000 and May 2001), when prices increased to hundreds of dollars. During peak demand, utilities may turn to purchasing wholesale electric power. However, the price for purchase power can fluctuate to hundreds of dollars per kilowatt hour in a matter of for weeks or months. Utilities must be able to recover this high costs for meeting consumer demand for electricity.

[69] US Generation by Energy Source for 2003 was as follows: Natural Gas and Petroleum 20%, Coal 51%, Nuclear 20%, and Hydroelectric and other 9%. *See*: Energy Information Administration, "Electric Power Annual 2003," December 2004. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf (Accessed on August 4, 2005).

[70] Natural Gas Intelligence Press, Inc.'s Daily Gas Price Index, *See*: http://intelligencepress.com (Accessed August 3, 2005).

Figure 9: Mid-Continent Average Monthly Real Electric Wholesale Prices (June 1995 – March 2004)[71]

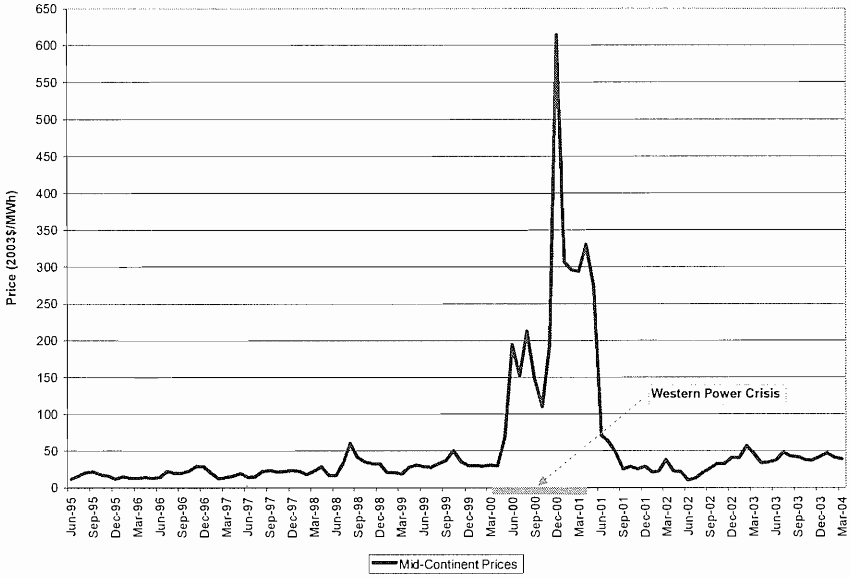
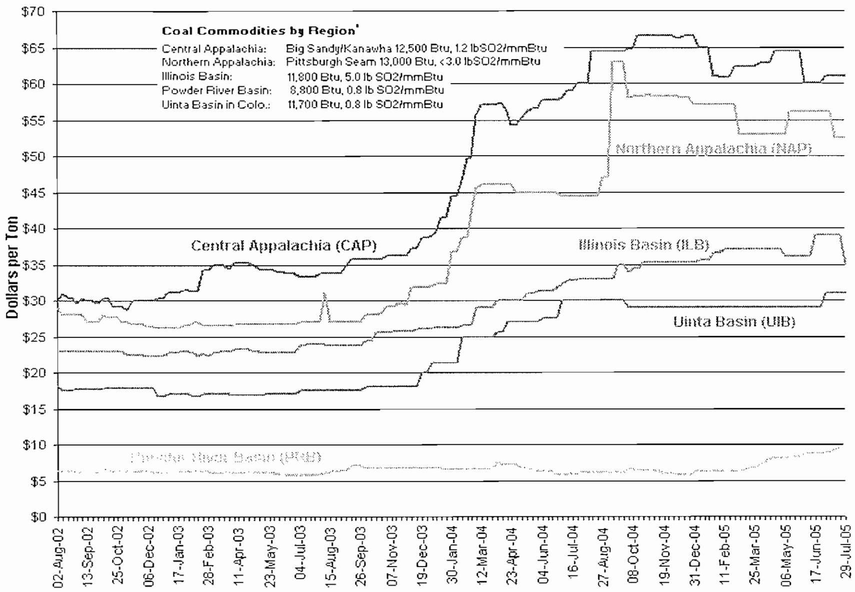


Figure 10 shows that major US coal prices have experienced sharp increases from August 2002 to July 2005. Some perceive coal as a cheap alternative to high natural gas and purchase power prices. However, the recent past has shown sharp increases in coal prices from all sources. Even a historically relatively stable fuel commodity like coal has experienced some volatility and prices increases in the past few years.

[71] Data derived from *Bloomberg* L.P. software.

Figure 10: Coal Prices by Region (August 2002-July 2005)[72]



Source: *EIA*

Despite fluctuating prices for fuel and purchase power, retail electric prices have generally decreased and not experienced similar volatility. **Figure 11** shows that real prices of electricity sold by the US electric power industry have steadily decreased since 1982 despite higher fuel and purchased power prices.

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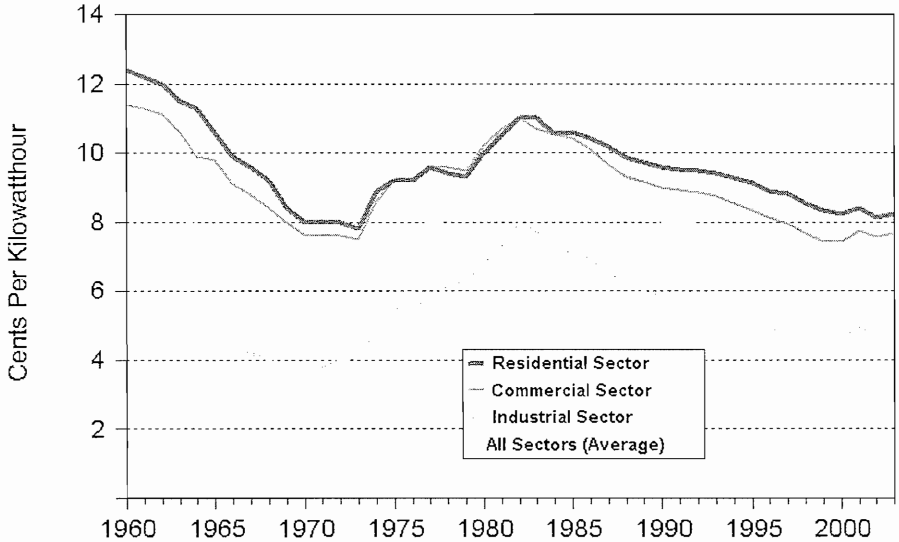
[72] Energy Information Administration, "Coal News and Markets," August 4, 2005, http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html (Accessed on 8/9/2005).

Figure 11: Average Real Retail Price of Electricity Sold by US Electric Power Industry (1960-2003)—Indexed to 2000 Dollars[73]



Source: *EIA*

[73] Energy Information Administration, "Electricity Infocard 2003," *See*: http://www.eia.doe.gov/neic/brochure/elecinfocard.html (Accessed on August 5, 2005)

Appendix 4: Rating Agency Perspective

This appendix provides discussion from three rating agencies about their view on PCAs with regard to how they affect their credit rating decision making.

While the presence of PCAs have always been noteworthy in ratings agency reports for the electric utility sector, the greater volatility of the merchant power markets has caused them generally to heighten their focus. This was especially true during and after the Western-US energy crisis. In terms of fuel adjustment clauses and utility credit quality, *S&P* states:

> Standard & Poor's is frequently asked what weight is given to FPPA. It is clear that continued gas price volatility and upward trends in historically stable coal prices underscore the importance of FPPAs....to the extent that an FPPA is transparent and well structured, regulators are likely to be less inclined to disallow a utility's fuel and purchased-power costs.[74]

Fitch Investor's Service (formerly *Duff & Phelps*) discusses the extreme adverse consequences of a state not enacting a PCA/FAC:

> California remains an extreme example of what can go wrong when FACs are eliminated, rates are frozen, and regulators are either unable or unwilling to extend support to local utilities.[75]

Three years after the Western-US energy crisis, *S&P* stated the following:

> It has been more than three years since the California energy crisis led to the rapid deterioration of credit quality for many Western electric utilities...The severe market distortions of the California crisis have faded, but FPPAs continue to play a significant role in the financial well-being of western electric utilities. Natural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development are daily reminders that **it is increasingly difficult for utilities to sustain their financial health solely through the use of hedging policies and regular general rate case filings** [emphasis added][76]

Fitch also discusses the effect of PCA of an IOUs bond rating:

> In today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in

[74] *Standard & Poor's* "Fuel and Power Adjusters Underpin Post-Crisis Quality of Western Utilities." October 14, 2004.

[75] *Fitch*, "Natural Gas Price Sensitivity of the U.S. Utility Sector." July 1, 2004, p. 7.

[76] *Standard & Poor's* "Fuel and Power Adjusters Underpin Post-Crisis Quality of Western Utilities." October 14, 2004.

> supportive regulatory environments which continue to feel the need for healthy reserve margins of generation.[77]

In terms of handling fuel volatility, Moody's states that:

> Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.... Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.[78]

In terms of natural gas price sensitivity of the U.S. Utility Sector, *Fitch* states that:

> The high price of natural gas and the increased price volatility witnessed during the past three years have presented challenges of varying degrees to issuers in U.S. electric and gas coverage. The ability of these companies to manage commodity price exposure varies considerably among firms within the sector and is an important rating factor.... However, integrated utilities with the obligation to serve and no adequate fuel cost recovery mechanism, as well as electric distributors operating under frozen rate tariffs that are required to defer power purchases, are generally more exposed to volatile commodity prices.[79]

In 1998, *S&P* noted that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."[80]

With respect to integrated utility companies, *Fitch* states,

> Although a majority of integrated utilities remain substantially protected from fluctuating commodity price levels due to the existence of fuel/purchased power adjustment clauses (FACs), a handful of companies possesses regulatory mechanisms that offer only partial protection while others lack such a clause altogether.... Unless a protective adjustment mechanism is in place, utilities purchasing power from the spot market to meet load requirements will be particularly exposed to high costs during periods of high demand, when gas is likely to be on the margin in all U.S. regions.[81]

Moody's mirrors *Fitch's* sentiments by stating:

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[77] *Fitch*, "Procuring Power in California: A Potential Stranded Cost." September 7, 2000, p. 4.

[78] *Moody's Investors Service*, "Credit Implications of Power Supply Risk." July 2000, p. 3.

[79] *Fitch*, "Natural gas Price Sensitivity of the U.S. Utility Sector." July 1, 2004, p. 1.

[80] *Standard & Poor's,* "Rating Methodology For Global Power Utilities," *Standard & Poor's Infrastructure Finance*, September 1998, p. 66.

[81] F*itch*, "Natural gas Price Sensitivity of the U.S. Utility Sector." July 1, 2004, p. 4.

> Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages…. Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.[82]

With regard to Provider of Last Resort service in restructured states, *Moody's* states that:

> In general, utilities have little incentive to accept the financial risk PLR service creates without being compensated by regulators with some form of pass-through. Each state will determine its own plan, and Moody's believes that elements of a purchased power adjustment clause will be retained for PLR service.[83]

These are typical passages from ratings agency reports in the era of competitive power markets. The ability of electric utility companies to charge compensatory rates in light of changing market power costs is of key importance in assessing the risk to which investors expose their capital.

[82] *Moody's Investors Service*, "Credit Implications of Power Supply Risk." July 2000, p. 3.

[83] *Moody's Investors Service*, *supra* note 83, p. 3.

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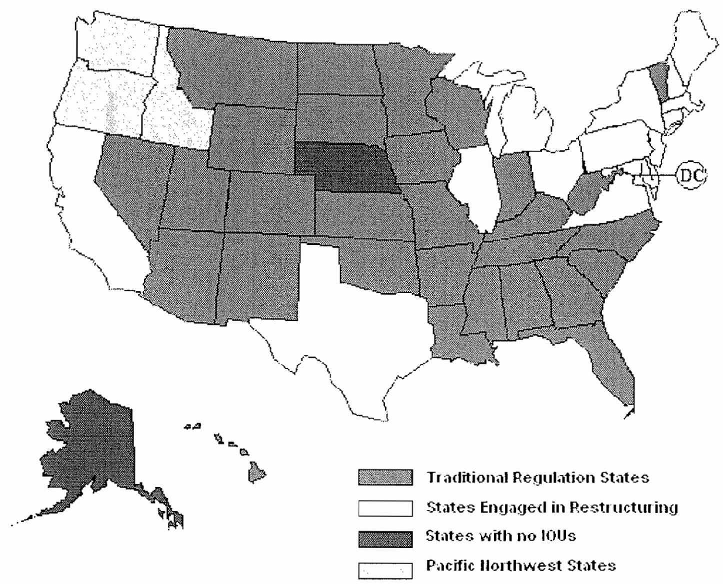
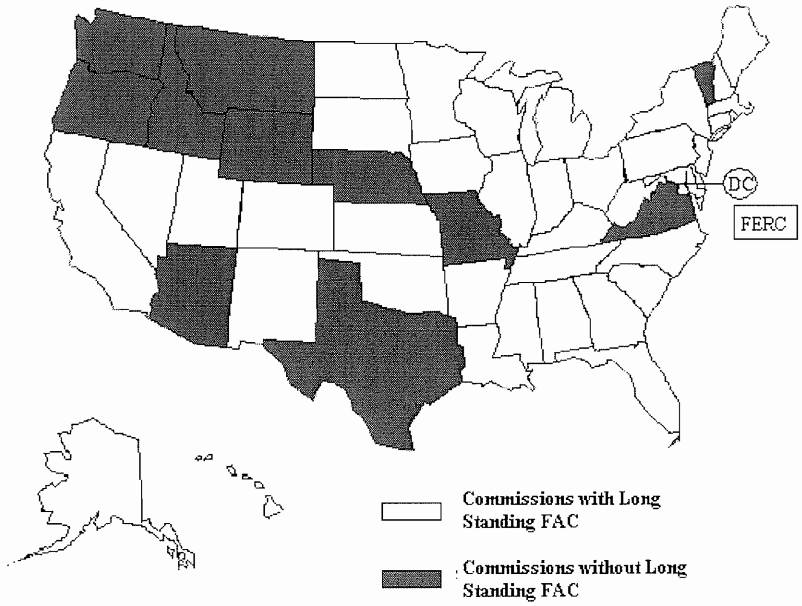
Exhibit 402
Status of Electric Restructuring: States Considered in Survey



*Oregon is engaged in restructuring.
Source: Regulatory Research Associates

Exhibit 402

Commissions with Long Standing PCAs



Source: NRRI Report, p. 18.

Exhibit 403

Cost Recovery Mechanisms in Current PCAs

State	True-up (Balancing Accounts)	Time-lag
Alabama	√	3-months
Arizona	√	12-months
Arkansas	√	12-months
California	√	Trigger mechanism (at 4% of yearly revenue)
Colorado	√	12-months
Florida	√	12-months
Georgia		3-months (Fuel costs are recovered in a base rate proceeding)
Hawaii	√	1-month
Indiana	√	3-months
Iowa	√	1-month (based on 2-month projections)
Kansas	√	1-month
Kentucky	√	2-months
Louisiana	√	1-month
Minnesota	√	1-month
Mississippi	√	3-12 months
Missouri		Bill just passed to allow PCAs
Montana	√	12-months (but with price signals for each month)
Nevada	√	12-months
New Mexico	√	Monthly
North Carolina	√	12-months
North Dakota	√	1-month
Oklahoma	√	12-months
S Carolina	√	12-months
South Dakota	√	2-months
Tennessee		1-month
Utah		No Fuel Clause
Vermont		No Fuel Clause
West Virginia	√	12-months
Wisconsin		1-month
Wyoming		6 to 12 months

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 180

General Rate Case Filing

PORTLAND GENERAL ELECTRIC COMPANY

Testimony and Exhibits

March 15, 2006

UE 180 / PGE / 500
PIRO – TOOMAN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Administrative and General

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

James J. Piro
L. Alex Tooman

March 15, 2006

Administrative and General

Table of Contents

I. Introduction

Q. Please state your name and position with Portland General Electric.

A. My name is James J. Piro. I am the Executive Vice President, Finance, Chief Financial Officer and Treasurer at Portland General Electric (PGE). My qualifications appear in PGE Exhibit 100, Section V.

My name is L. Alex Tooman. I am a Project Manager for Regulatory Affairs at PGE. My qualifications appear in PGE Exhibit 200, Section XI.

Q. What is the purpose of your testimony?

A. We present and explain PGE's request for $109.8 million in 2007 administrative and general (A&G) expenses. The 2007 forecast compares with the 2002 actual expenses of $95 million and represents an average annual increase of 2.9%. PGE incurs these costs because they are necessary to support PGE's operations, just as they are in other utility companies and in other industries.

Q. Why are these costs necessary to support operations?

A. They are necessary because on going operations require A&G support. One can consider the relationship of A&G to business operations as similar to the fuel and lubricant of an automobile engine. Direct O&M is the gasoline that makes the engine run, while A&G is the motor oil, which is required for the engine to run and keeps it running smoothly.

Q. What type of activities make up A&G?

A. A&G consists of a number of functions that support PGE's direct operations, including human resources, accounting and finance, insurance, purchasing, load research and forecasting, corporate security, regulatory affairs, legal services, and information technology. Exhibit 501 provides a list of A&G functions plus summary costs and full time equivalent (FTE) employees for 2002 (actuals) and 2007 (forecast). Table 1, below, identifies the major A&G categories that we address in this testimony. Compensation/Benefits are addressed in PGE Exhibit 900.

Table 1
A&G Summary Costs ($ Million)

Category	2002 Actuals	2007 Forecast
Section III, Major Functional Areas	53.4	57.4
Section IV, Other A&G/Enron Allocations	53.5	64.4
Section V, A&G Offsets	-11.9	-12.0
Total A&G	**95.0**	**109.8**

Q. What are the main reasons for the increase in A&G costs?

A. In general, inflation is the primary reason for the increase in costs. This has been especially true for some costs, such as benefits, (e.g., group health and dental plans), which continue to increase nationwide at a much higher rate than overall inflation. In addition, pension costs are increasing based on changes in returns on pension assets, mortality curves, and discount rates. Other cost increases, such as in the area of accounting and finance, are a result of new regulatory requirements (e.g., new FERC and Sarbanes-Oxley (SOX) compliance requirements) plus some new functions (e.g., investor relations, Board of Directors) that PGE will perform because we will become independent from PGE's former parent, Enron. These costs are offset by the elimination of cost allocations from Enron.

II. Cost Control

Q. Has PGE undertaken any efforts to control costs?

A. Yes. PGE engages in continuous efforts to control and minimize costs, as well as improve system reliability and enhance customer service and access, while making our business ever more efficient.

Q. Mr. Piro, can you give specific examples of how PGE controls its costs?

A. Yes. As Chief Financial Officer, one of my primary objectives is to provide a process to review PGE's costs and efforts to control those costs. I direct PGE's annual budgeting process, which establishes both capital and expense levels for upcoming years. These budgets are based on our on going requirements to deliver safe, reliable power and provide efficient customer service to our customers. The process factors in known and measurable changes for new programs, processes, or services. Each year, I then review the variance of actual results to budgeted amounts to ensure that PGE's costs are within expectations and that significant deviations are justified. I also provide oversight and governance for significant capital jobs that are submitted to PGE's Capital Review Group (CRG). The CRG reviews all capital jobs to determine which ones should be implemented based on their total cost and benefit to customers, relative to available capital funds (which is a target that I also establish). This process is designed to minimize costs and maximize benefits to customers within the context of our business requirements. Some examples of cost reductions we have pursued in recent years include:

- In 2003, PGE initiated a 10% management reduction program which resulted in the elimination of more than 30 management positions.

- Between 2002 and 2005, PGE invested approximately $5 million in communication infrastructure that reduced annual operating expenses by approximately $2 million (see Section IV, A, below).
- In 2004, PGE rewrote and consolidated its statistical load research models, which increased consistency and accuracy, and reduced labor costs by $200,000 annually.
- In 2005, PGE replaced its mainframe computer with newer hardware for an annual savings of approximately $1.0 million.
- Since 2002, PGE has reduced the number of officers by four.

Some non-A&G areas in which PGE has pursued cost savings include:

- In 2005, PGE implemented a "Peak Staffing" program at our customer service center that reduced overtime costs by approximately 55%.
- In the summers of 2004 and 2005, rather than replace highly expensive 500,000 volt capacity fuses on one of our transmission lines, PGE began painting them with ultraviolet resistant paint to protect them from sunlight for 15 years. Consequently, PGE incurred project costs of $44,000 versus replacement costs of $1,572,480.
- In 2005, PGE purchased five used "load tap changers" for use in the PGE system, avoiding purchase of new or remanufactured equipment for savings estimated between $200,000 and $300,000.
- PGE's FITNES program has increased the life of a typical wood pole from approximately 35 years to 55 years.

III. A&G Functions

Q. What are the major functional areas in A&G?

A. Sixteen functions fall into A&G. Table 2 lists each of the 16 major A&G functions, showing 2002 actual costs and 2007 forecasted costs. Table 3 shows the number of FTEs for each function, along with the change in staffing from 2002 to 2007. This section of the testimony describes each functional area and explains the reasons for any significant cost increase or decrease from 2002 to the 2007 test year.

Table 2
A&G Costs by Major Functional Area ($ Million)

Category	2002 Actuals	2007 Forecast	Change
Facilities/General Plant Maintenance	9.0	10.9	1.9
Accounting/Finance	6.4	10.9	4.5
HR/Employee Support/Ethics and Compliance	8.5	5.6	-2.9
Insurance, Injuries and Damages, etc.	6.1	10.4	4.2
Legal	6.1	5.6	-0.6
Federal and State Regulatory Affairs	1.8	2.9	1.2
Corporate Governance	1.3	2.1	0.8
Business Support Services	2.0	2.3	0.3
Environmental Programs	0.8	1.4	0.7
Corporate R&D	0.4	0.7	0.3
SB 1149 Project Management	6.6	0.0	-6.6
Contract Services/Purchasing	1.0	1.1	0.2
Security	0.6	0.8	0.2
Corp Communications/Public Affairs	1.6	1.6	0.0
Load Research	0.5	0.2	-0.3
Hydro Licensing	0.1	0.2	0.1
Governmental Affairs	0.6	0.7	0.1
Total for Major Functional Areas	**53.4**	**57.4**	**3.9**

Table 3
A&G FTEs

Category	2002 Actuals	2007 Forecast	Change
Facilities/General Plant Maintenance	14.6	14.6	0.0
Accounting/Finance	73.1	84.6	11.5
HR/Employee Support/Ethics and Compliance	82.3	87.0	4.7
Insurance	6.7	6.4	-0.3
Legal	24.7	28.1	3.4
Federal and State Regulatory Affairs	24.9	30.0	5.1
Corporate Governance	7.9	8.0	0.1
Business Support Services	8.2	8.5	0.3
Environmental Affairs	18.9	26.7	7.8
Corporate R&D	0.0	0.0	0.0
SB 1149 Project Management	2.6	0.0	-2.6
Contract Services/Purchasing	15.1	11.0	-4.1
Security	5.0	5.0	-0.1
Corp Communications/Public Affairs	30.1	19.8	-10.4
Load Research	0.0	0.0	0.0
Hydro Licensing	0.0	0.0	0.0
Governmental Affairs	10.1	7.7	-2.4
Total for Major Functional Areas	**324.3**	**337.4**	**13.1**
Information Technology (IT)	271.9	273.5	1.6
Total for A&G	**596.2**	**610.8**	**14.7**

Q. You also provide Full Time Equivalent (FTE) estimates. Are there any aspects to the calculation of FTE employees in your testimony of which we should be aware?

A. Yes. Although we assign each FTE to only one functional area, one FTE can charge costs to multiple areas. For example, all FTEs in Corporate Communications and Public Affairs are assigned to A&G but an employee working on the customer information newsletter "Update" may charge costs to several activities, most of which are not in A&G. In addition, FTEs in IT charge costs to all functional areas, including A&G, but all IT FTEs are included under A&G. In contrast, load research costs are charged to A&G ledgers but the employees that perform this function are assigned to Customer Services as part of the department that maintains the customer database.

A. Facilities and General Plant Maintenance

Q. Please describe this function and its associated costs.

A. This category includes the rent, operating, and maintenance costs associated with our corporate headquarters office space (i.e., World Trade Center), Tualatin Business Center, line crew centers, community offices, and other non-plant facilities. PGE's facilities and general plant maintenance expenses for 2007 are $10.9 million, which is an increase of $1.9 million over 2002. The annual cost increase of 3.9% is driven by increases in maintenance contracts, waste disposal services, energy costs,[1] lease costs for general facilities, and an updated allocation of utility floor space in the World Trade Center (i.e., calculation of space devoted to PGE utility versus non-utility and other tenants).

B. Finance and Accounting

Q. What are the 2007 forecasted costs for Finance and Accounting?

A. The finance and accounting cost for 2007 is $10.9 million, which is an increase of $4.5 million over the 2002 actual expense of $6.4 million. The department continues its standard functions in corporate finance and treasury, investment, and wholesale credit management. The department also remains responsible for standard accounting functions such as reporting financial statements, maintaining general ledgers and supporting records, FERC and OPUC reporting, and accounts payable and receivable.

Q. What caused 2007 forecast costs to increase from 2002 actuals?

A. The most significant cause is two new functions that did not exist in 2002, internal auditing and investor relations. While PGE previously had an internal audit department, we outsourced it to Arthur Andersen in 1998. In early 2002, however, PGE discontinued using Arthur Andersen's services and began transitioning back to an in-house internal audit group.

Consequently, 2002 is unique because PGE had minimal internal audit costs. This change accounts for an increase of $700,000 in cost and six FTEs from 2002 to 2007.

PGE's internal audit service (IAS) is designed to help the company achieve its objectives through an ongoing evaluation of the effectiveness of internal control and governance processes. In the course of its duties, IAS has unrestricted access to all operating areas, records, property, and personnel; it freely determines the scope of work, allocates resources, sets frequencies, and applies the techniques required to accomplish audit objectives. PGE performs financial, operational, information technology, compliance, and special audits in the following areas: Finance and Regulatory Affairs, Customer Service and Delivery, Administration, Power Supply and Operations, and Public Policy.

PGE has also re-established an investor relations group. In recent years, this function existed under PGE's parent corporation, Enron, and was included in the costs that Enron allocated annually to PGE. By 2007, PGE will be an independent, publicly-traded (i.e., not part of a holding company), investor-owned utility and will have to bear these costs. The investor relations group performs the following:

- Establishes and maintains a working relationship with key analysts, institutional investors, and investor relations consultants.
- Directs and coordinates all aspects of the company's annual report, quarterly reports, financial news releases, investor web site, and other special corporate communications publications used to disseminate financial information to investors and shareholders.
- Plans and coordinates all aspects of PGE's annual meeting of shareholders.

[1] All electric expenses are reversed in the duplicate charge offset discussed in Section V below.

- Directs the planning and preparation of PGE presentations for equity analysts and investors.

The establishment of the investor relations function adds $1.8 million to PGE's accounting and finance area. Approximately $1.5 million of this is for non-labor expenses related to annual and quarterly reports, the annual meeting, stock exchange fees, and transfer agent and registrar fees (i.e., costs for the record keeping of PGE shareholders). Most of the labor increase is for two additional employees.

Q. What factors contributed to the increase in PGE's Finance costs?

A. Costs for Finance increased by approximately $800,000 because of additional costs related to the return of PGE's 401k plan from Enron (including trust expenses and managing relations with investment consultants), additional credit work regarding ESS credit and transmission credit, additional requirements to manage PGE's health retirement accounts and health spending accounts, and increasing costs to be "rated" by financial rating agencies. These additional responsibilities increase non-labor costs by approximately $700,000 for professional and other outside service and require one incremental FTE.

Q. Please describe the drivers of cost increases for PGE's Accounting Department.

A. Costs for Accounting are up by approximately $1.3 million. Non-labor costs increase by approximately $500,000 primarily due to increases in outside auditor fees. The addition of (SOX) requirements on audit procedures, including SOX 404 attestation, plus PGE's change of outside auditors to Deloitte & Touche, account for the increasing audit costs. The Accounting department, however, has managed these additional requirements with only two additional FTEs. Because labor accounts for the majority of accounting department costs, the remaining cost increase relates to the rising cost for labor as described in PGE Exhibit 900.

C. Human Resources / Employee Support / Ethics and Compliance

Q. How are costs expected to change from 2002 to 2007 for Human Resources, Employee Support, and Ethics and Compliance?

A. We forecast that administrative costs for these functions (HR) will decline from $8.5 million in 2002 to $5.6 million in 2007. This net decline is due to several changes, some of which are increases and some decreases.

First, in 2004, two new work groups were created within HR and increased costs as follows:

- $370,000 for the Ethics and Compliance group, which focuses on documentation and program enhancements regarding FERC Standards of Conduct, Oregon Administrative Rule Division 38 requirements, and other matters of corporate regulatory compliance. The addition of this group has resulted in four new employees to HR.
- $250,000 for the Labor Relations group to support union negotiations and relationships, to interpret and document developments regarding the new union contract that became effective in 2004, and to provide support for other bargaining unit matters. The addition of this group has resulted in two new employees to HR.

Second, $430,000 in directors fees are forecasted for PGE's new Board of Directors.[2] These costs were included in allocations from Enron that have been eliminated.

[2] $430,000 of the forecasted directors' fees for 2007 are charged to HR and $670,000 are charged to Corporate Governance.

Third, costs for training and employee development have increased by approximately $300,000 because of the following programs:

- In 2003, PGE began a new management development program to increase the productivity and effectiveness of management employees.
- In 2004, PGE implemented a new employee development program to enhance productivity, motivation, and greater employee interaction.
- In 2005, PGE reemphasized its commitment to the Guiding Behaviors, which support PGE's culture of ethics and excellence.

Fourth, costs increased at least $500,000 in HR due to general inflation because the department's costs consist primarily of labor.

Fifth, two programs that existed in 2002 are not included in the 2007 test year forecast. These consisted of a retention program for $1.1 million and a severance program for $4.1 million. This offsetting reduction in costs produces the net decrease from 2002 actual costs to the 2007 forecast.

Q. What are the major challenges facing PGE's HR department?

A. The HR department is pursuing a number of initiatives to address the increasingly complex work environment, including:

- The implementation of PeopleSoft software to upgrade PGE's timekeeping and employee information system.
- Initiatives by HR Operations to address the need for entry level tradespersons and the increasing scarcity of certain skills as many of PGE's employees approach retirement.

- The implementation of new Wellness programs to reduce current and future health care costs.

D. Insurance, Injuries and Damages, etc.

Q. How have insurance and associated costs changed from 2002 to 2007?

A. PGE's insurance and associated costs (such as insurance premiums, safety-related costs, injuries and damages, liability claims, administration, and property damages) are projected to increase from $6.1 million in 2002 to $10.4 million in 2007. Table 4 below compares insurance policy costs between the 2007 forecast and actual costs in 2002. The main drivers for the overall cost increase from 2002 to 2007 are:

- $1.8 million increase in property and excess liability insurance premiums.
- $1.2 million increase in director and officer insurance premium costs. Most of this coverage was included in Enron allocations, but not separated and charged to insurance expense in 2002.
- $1.0 million increase in associated costs. This is primarily due to labor for safety training that was previously charged to distribution O&M but will be charged to A&G beginning in 2006. Additional components of this increase include higher brokers' fees and wage increases for labor to administer PGE's insurance programs, safety and injury prevention programs, liability claims, and property damage issues.

Q. How would you characterize your insurance program?

A. Our insurance program is designed to balance the adverse effects of accidental losses on PGE and provide appropriate sources of funding for recovery when accidents occur. We self-insure a portion of our risk and purchase external insurance to cover losses that exceed PGE's retained risk.

Table 4
PGE Insurance Costs by Policy ($000)

	Actual 2002	Forecast 2007
PGE Property Program:		
All-Risk Property	1,350	1,911
Trans & Dist Property	1,984	2,355
Enron Corp Allocated Insurance Premiums:		
Excess Liability	748	0
Director and Officer*	0	0
Fiduciary Liability, Fidelity & Crime	65	0
PGE/Enron Replacement Coverage:		
Excess Liability	0	1,617
Director and Officer	382	1,575
Fiduciary Liability, Fidelity & Crime	765	282
Workers' Compensation	112	401
Total Core Policy Costs	**5,406**	**8,141**
Nuclear Insurance Program	61	261
Other Coverage	366	171
Grand Total	**5,833**	**8,573**

*In 2002, the D&O liability coverage was part of the overall Enron allocation (now eliminated). That is, it was not separated and applied to insurance expense. By 2007, all PGE coverage will be separated from Enron.

E. Legal Services

Q. What are PGE's forecasted costs for legal services in 2007?

A. We forecast 2007 legal expenses to be $5.6 million, which is a decrease of $600,000 from the 2002 cost of $6.1 million. The Legal Department represents PGE in all areas requiring legal support including employment and benefit issues, state and federal regulatory matters, corporate financing, litigation, commercial transactions, such as power contracts and fuel purchases, and environmental matters. Although many issues are handled in-house, we retain outside counsel for workload peaks and to obtain expertise that we cannot cost-effectively maintain in-house. The level of legal costs can vary from year to year based on the level of work, plus the number and complexity of proceedings in which the department is involved.

F. Federal and State Regulatory Affairs

Q. What is the 2007 forecasted cost for Regulatory Affairs?

A. We forecast that the 2007 Regulatory Affairs cost will be $2.9 million, which is a $1.1 million increase over the 2002 actuals of $1.8 million. Regulatory Affairs is responsible for, contributes significantly to, or processes the following:

- Issues and proceedings related to the OPUC, FERC, BPA and other federal agencies
- Calculation and analysis of revenue requirements
- Pricing and tariff development
- Integrated resource planning
- Affiliated interests
- Property sales
- Various OPUC and FERC rule makings

Q. What are the drivers of the cost increase?

A. The cost increase is primarily driven by an increasingly complex regulatory environment. There are more dockets at all levels. PGE has added approximately five net FTEs to regulatory affairs (while reducing two managerial positions) in addition to hiring specialized consultants for transmission issues as well as the BPA power rate case. Additional contract labor is also needed to assist with administrative duties.

The increase in costs from 2002 to 2007 can be split as follows: state regulation, approximately $670,000, and federal regulation, approximately $430,000. At the state level, regulation has placed increasing emphasis on power cost issues, leading to more proceedings and analyses regarding power cost adjustments, direct access mechanisms, power cost modeling, power cost updates, plus power resource and hydro issues. In addition, PGE is involved in more proceedings, audits, rule makings and reporting requirements on numerous other issues including: OPUC investigations, code of conduct, income taxes, and affiliate interests. At the federal level, we created a department for federal regulation in 2002. Consequently, most of the increase in regulatory employees is due to the creation and growth of this group. In addition to the BPA issues and FERC filings addressed at that time, this group is facing an increasing number of topics including:

- BPA rate cases
- Negotiating the post-2011 BPA environment (all current BPA contracts expire by 2011)
- Regional transmission issues
- Increasing volume of FERC enforcement issues
- Increasing volume of FERC notices of proposed rule makings
- Implications of the 2005 Energy Policy Act, including increasing Department of Energy oversight based thereon

G. Corporate Governance

Q. What is Corporate Governance and what cost do you forecast for 2007?

A. Corporate Governance comprises the portion of expenses for senior management and their staff that we charge to A&G ledgers for executive oversight. We forecast a 2007 cost of $2.1 million, which is $0.8 million higher than 2002 actual costs of $1.3 million. The major cost driver behind this increase relates to changes in PGE's Board of Directors. Under PGE's former owner, Enron, PGE had three to six directors who were primarily from inside PGE and incurred minimal Board costs. In contrast, PGE has recently appointed eleven directors, all but one of whom will be from outside PGE, to serve on the Board as we become an independent, publicly-traded company. Approximately 60% of the costs associated with the new Board are included in Corporate Governance with the remainder in HR, as described in Footnote 2, above. This increase, however, is offset by declines in cost from the elimination of Enron allocations, which included costs for corporate governance.

H. Business Support Services

Q. What is your 2007 forecast cost for Business Support Services?

A. Business Support Services will cost $2.3 million for 2007, which is an increase of $300,000 over 2002 actual expenses of $2.0 million. This department provides general services to PGE that include purchasing office and paper products, arranging travel, maintaining office equipment, coordinating conference room schedules, managing mail, and maintaining WTC vehicles. The annual cost increase of 2.6% is approximately equivalent to inflation.

I. Environmental Programs

Q. What are the 2007 forecasted costs and FTEs for Environmental Programs?

A. Environmental Programs include operations support and policy issues. Costs for 2007 are forecast to be $1.4 million, which is an increase of $650,000 over 2002 actual costs. FTEs for these activities are expected to increase from 22 in 2002 to 27 in 2007.[3]

Q. What activities do these costs and FTEs support?

A. The Environmental Programs group fulfills environmental and other regulatory requirements, with responsibilities for production, distribution, transmission, fleet, and all other PGE operational areas and sites. Their activities include development, oversight and implementation of projects that ensure PGE's compliance with laws, regulations, and articles under FERC agreements, and providing information to management about environmental concerns, solutions, and emerging issues. Environmental requirements for PGE are performed by biologists, other science specialists, and technicians, and include:

- Monitoring air quality, water quality, and hazardous waste
- Controlling emission
- Supporting audits
- Restoring fisheries, wildlife, and habitat

Thus, the environmental group's costs are included in A&G because a principal component of its work is corporate regulatory compliance and because it provide environmental support throughout the company.

[3] As noted above, some departments have all their employees identified with A&G but some or much of their costs will be charged to other areas.

Q. Why are costs and FTEs projected to increase from 2002 to 2007?

A. The increases largely relate to the relicensing (both pre- and post relicensing requirements) of PGE's hydroelectric projects: Pelton/Round Butte and the Willamette Falls hydro project, which FERC issued in mid-2005 and December 2005, respectively, and the Clackamas project, which we expect will be re-licensed in 2008. Specifically, these requirements involve: 1) designing and monitoring facility modifications, 2) conducting pre- and post-dam removal monitoring, 3) conducting fish facility and mitigation studies with multiple agencies, 4) studying and monitoring wildlife and terrestrial resources, and 5) monitoring temperature and controlling water quality. Further, implementation and compliance with the new FERC licenses involve higher levels of agency and public participation, increase regulation, and use of newer scientific technology. In total, non-labor costs increase by approximately $380,000, primarily for outside services related to grants to environmental agencies (approximately $100,000), for environmental contingency funds for large and unexpected cleanup costs (approximately $200,000), and funds for the Clackamas River Fisheries Working Group (CRFWG – approximately $100,000). The CRFWG funds will be used to monitor juvenile salmonid production in six tributary streams, evaluate the effects of using salmon carcasses for stream nutrient enrichment, conduct stream habitat surveys on Deep Creek, determine summer distribution of juvenile salmonid in Deep and Clear Creek, and perform genetic sampling of unmarked summer steelhead returning to North Fork in September and October. Labor costs increase by approximately $275,000 related to the above requirements.

J. Corporate Research and Development

Q. What is your 2007 forecasted cost for Corporate Research and Development (R&D) activities?

A. For 2007, we forecast $700,000 in R&D costs. This is an increase of $300,000 from 2002 actual costs. Until 2006, PGE limited R&D funding with the result that we have not maintained contact with some of the critical research organizations and projects that enable us to make certain Integrated Resource Plan and O&M decisions. Our proposed 2007 research will be heightened extensively to include projects such as:

- Wave Energy
- Distributed Generation
- Water and Energy Technical Services
- Health and Safety
- Power Quality
- Advanced Instruments and Controls
- Multi-pollutant Emission Controls
- Critical Peak Pricing

Q. What process does PGE use to determine the projects in which to actively participate?

A. PGE has an established process for the evaluation and selection of the most critical annual R&D projects. A diverse management committee reviews the projects and allocates funds to optimize this resource for the benefit of PGE customers.

Q. How is Research and Development integral to PGE's success?

A. As customer loads grow, adding resources to the system becomes necessary. Continued research allows PGE to make knowledgeable and cost-effective choices on environmentally benign energy resources early in the decision-making process. Adding funds to PGE's Research and Development programs allows us to actively participate in demonstration projects and engage with research groups that are challenged with similar issues. Examples of R&D generation alternatives include: Wave Energy Research and Demonstration, Distributed Generation Research, Wind Energy, and Gasification-Based Power Plant Development and Deployment.

Further, R&D funds should not be limited to new resource options. PGE plans to continually improve O&M for existing generation and delivery systems. Examples of R&D opportunities for O&M are: Advanced Diagnostics for Generators and Transformers, Boiler Feed Pumps in Fossil Fired Plants, Coal Transfer System Design and Repairs, and Creep in Boiler Tubes and Remaining Life Analysis.

Finally, PGE should continue R&D for customers and the services that we provide. By understanding the needs of our customers, we are better able to serve and meet those needs. Examples of R&D projects for customer services are: Critical Peak Pricing Pilot, Smart Chip Appliance Technology Trial, and Evaluation of Web-Based Power Quality Monitoring Service.

Q. Do the R&D projects provide benefits to customers?

A. Yes, however, these projects typically involve long-term effort and benefits may not be realized for some years. Examples of benefits from prior R&D projects include:

- The "Oil Spill Containment" or "Oil Absorbing Mat" project was to design, test and evaluate a "Containment Mat" that could be used to absorb oil and otherwise contain small spills from leaky transformers, radiators and other oil filled electrical equipment found in substations and other areas of distribution systems. As a result, PGE is better equipped to address oil spills through an oil spill control system that PGE is installing in our substations and in several customer-owned substations.
- The Plant Information software project modified a program used by oil companies and a few utilities for system monitoring by converting it to a Web-based platform. This system, along with a real-time, gas-in-oil transformer monitor project, subsequently identified a 28 MVa transformer that was overheating, which avoided over $1.0 million in repairs.
- Selective Catalytic Reduction addresses emissions from dispatchable standby generators (see PGE Exhibit 700, Section VIII) so they can meet air permitting requirements.
- Ultra-Low Sulfur Diesel and Catalytic Device testing on PGE trucks has a goal of reduced emissions from PGE's fleet.

K. SB 1149 Project Management

Q. What is SB 1149 Project Management and what are its costs?

A. SB 1149 project management was a new function in the A&G area for PGE's last rate case, UE 115. In 2002, costs were $6.6 million. PGE established this department to integrate existing and new components of PGE's operations to accommodate the requirements of

SB 1149. As PGE no longer allocates project-specific costs to SB 1149 project management, this function has been eliminated and the 2007 cost forecast is zero.

L. Contract Services/Purchasing

Q. What is PGE's 2007 forecasted cost for Purchasing?

A. Purchasing costs are forecasted to be $1.1 million in 2007, which is an increase of $100,000 over 2002 actual costs of $1.0 million. The Purchasing Department is responsible for all of PGE's purchases and sales of surplus assets. The department also manages and provides quality assurance on construction contracts, and PGE's minority supplier program, Women and Minority Business Enterprises. The relatively small increase in costs is due to a general increase in wages for the labor-intensive purchasing function being offset by the reclassification of two employees to the Inventory Planning function, which removed those costs from purchasing.

M. Security

Q. What does PGE forecast to spend on security in 2007?

A. We forecast spending approximately $800,000 for security in 2007, which is about $200,000 higher than actual expenses in 2002. PGE contracts for security for the three WTC buildings and grounds, PGE assets, and employees, as well as the administration of the WTC Conference Center. Forecasted costs are higher by approximately $70,000 due to increases in costs for private security firms, whose prices increased after 9/11. In addition, PGE has expanded its security systems to include additional access controls, security cameras, digital collectors/recorders, and security doors for the World Trade Center and line crew centers. Further, PGE has added new substations, which have all required alarm monitoring systems. These systems require additional licenses, permits and O&M costs of approximately $50,000. Of the remaining increase, $55,000 is for wage increases at the general rate experienced by PGE from 2002 to 2007.

N. Corporate Communications and Public Affairs

Q. What is PGE's 2007 forecasted cost for Corporate Communications and Public Affairs?

A. The 2007 forecasted A&G costs for Public Policy and Corporate Communications are $1.6 million, which is equivalent to the 2002 actual expenses. Costs have remained flat because PGE has reduced employees from 30 to 20 resulting from attrition and workforce reductions since 2002.[4] This group provides communication support for many corporate efforts, including regulatory issues and Customer Services (see PGE Exhibit 700).

Q. What activities does this department charge to A&G?

A. The primary A&G activities consist of internal corporate communications and corporate memberships. Internal communications include activities associated with PGE's monthly employee newsletter, intranet communications, and other means of informing PGE's employees about corporate objectives, news, events, and new products and services. Corporate memberships are increasing by approximately $400,000 because PGE is planning to rejoin the Edison Electric Institute (EEI) in 2006 to regain access to many sources of information, which we have not been able to access since 1998. This industry association assembles useful information for members regarding reliability, energy infrastructure, consumer resources, environmental developments, utility practices (e.g., finance, accounting, and business related issues), and other industry topics and statistics. This

[4] As noted above, some departments have all their employees identified with A&G but some or much of their costs will be charged to other areas.

information will support PGE in developing innovations and efficiencies on behalf of customers and the company.

Q. Do these costs include any adjustments to reflect the degree to which some organizations engage in lobbying as part of their membership services?

A. Yes. We have reduced our membership costs by approximately $100,000 to reflect our estimate that 25% of the following organizations' efforts are devoted to lobbying:

- EEI
- Labor/Management Public Affairs Committee
- National Hydropower Association
- Northwest Energy Coalition
- Oregon Joint Use Association

O. Load Research

Q. What is PGE's 2007 forecasted cost for Load Research?

A. We expect to spend $200,000 for load research activities in 2007, which is a $300,000 decrease over 2002 actual costs. The decrease will be achieved by automating many of the load research processes by rewriting and consolidating PGE's statistical load research models. This would increase control and accuracy of the process and greatly reduce labor time. A major factor that contributed to this automation is the meter data consolidator (MDC), which is a component of PGE's network meter reading system and will also be a component of the proposed Automated Meter Infrastructure (AMI) system (see PGE Exhibit 800). Benefits of the MDC for load research include:

- More complete data so additional research is not required to calculate weather effects and load shape for the data gaps.

- Automated validation and editing.
- Greater efficiency of downloading files.

Q. What primary benefit does Load Research provide?

A. Load Research allows utilities to study the ways their customers use electricity. It provides hourly interval profiles for peak winter and summer days. Load Research also supports load factor analysis (cost of service studies), economic analysis, distribution load estimating, backcasts (reconciliation of profiles to actual usage), and demand-response program evaluation. Data are available for the following profiles:

- Residential: Residential Class, Dwelling Type, Electric Space Heat, and a combination of Dwelling Type and Heat.
- Commercial and Industrial: Sector Profiles, SIC Code Types, Revenue Class, Rate, Rate and Demand Level, and Rate and Revenue Class.

Q. How is this information used?

A. PGE uses this information in planning to meet the electricity demands of our customers in the most cost-effective way and to ensure that each customer segment pays for its own costs rather than subsidize the costs of other classes. In addition, we use it to enhance planning for delivery infrastructure. For example, the information helps with sizing transformers for new neighborhoods, so that we do not undersize or oversize. Ultimately, PGE uses load research data to be more efficient and to ensure that costs are allocated fairly.

P. Hydro Licensing

Q. What is Hydro Licensing, and what cost do you forecast for 2007?

A. Hydro Licensing costs charged to A&G represent PGE's compliance with certain FERC requirements for PGE's hydroelectric resources. Specifically, these requirements relate primarily to dam safety compliance and involve issues such as emergency action plans, project inspections, project security, and historic preservation. We plan to spend $200,000 in A&G for hydro licensing activities. The primary reasons for the $70,000 cost increase from 2002 to 2007 are:

- Additional travel for hydro compliance engineers as requested by FERC and to coordinate with the Dam Safety Division of FERC.
- Testing the functionality of Emergency Action Plan (EAP) procedures and associated response and communications among federal, state, and local entities, and PGE.
- Membership in the National Hydropower Association. In 2002 and 2003, these costs were charged to production O&M. As discussed in Section IV, below, membership costs are all charged to A&G by 2006. Consequently, this reflects a movement of costs within PGE rather than an overall increase.

Q. Governmental Affairs

Q. Please describe PGE's Governmental Affairs Department and its associated costs.

A. Governmental Affairs will cost $700,000 in 2007, which is $100,000 greater than 2002 actual costs of $600,000. Approximately 75% of the costs are for working with municipalities and counties in our service territory to maintain franchise agreements and contracts with local governments. These governments are not only customers, but they significantly influence how we operate within their jurisdictions.

Q. Do the costs for Government Affairs include expenses for lobbying?

A. No. PGE charges lobbying costs below the line.

IV. Other A&G Costs

Q. What are the Other A&G costs?

A. Other A&G costs do not directly correspond to specific A&G functions, but are nevertheless part of the A&G budget. For example, the Information Technology (IT) group does not perform an A&G function; rather, it is a service provider that charges and allocates its expenses to A&G, as well as to other functions in PGE. Table 5 provides a summary of other A&G costs and also identifies the components of this cost category covered by other PGE Exhibits.

Table 5
Other A&G Costs ($ Million – incurred unless specified)

Category	Covered in Exhibit	2002 Actuals	2007 Forecast	Change
IT: Direct & Allocated	500	11.3	8.2	-3.1
Other Service Providers to A&G	500	0.2	0.3	0.1
Enron allocations	500	12.4	0.0	-12.4
Total Comp/Benefits (net of capital allocs.)	900	17.1	34.3	17.2
PTO Loadings to A&G	900	3.7	4.3	0.6
Corporate Incentive Plan (net of capital allocs.)	900	3.3	4.8	1.6
Management Incentive Plans	900	2.5	6.8	4.3
Variable Pay - Coyote & Trojan	900	0.6	0.2	-0.4
Regulatory Fees	500	3.6	5.1	1.4
Other Membership Costs	500	0.1	0.4	0.3
Miscellaneous	500	-1.4	-0.1	1.3
Total Other A&G Costs		53.5	64.4	10.9

A. Information Technology

Q. What do the IT costs represent?

A. They represent the amount of IT directly charged and allocated to the A&G function. In 2007, these costs are $8.2 million, which is a $3.1 million decrease from 2002.

Q. Does this represent all IT costs for PGE?

A. No. This represents only a portion of the IT costs that are incurred for PGE as a whole.

Q. How have PGE's total IT costs changed from 2002 to 2007?

A. PGE's IT department has been diligent in controlling costs so that on an incurred basis, IT expenses have increased from $27.6 million in 2002 to $30.5 million in 2007. This represents a 2.0% annual increase. In addition, PGE's IT employees have increased by only 1.6 over this period. On a fully allocated basis, the costs have risen as listed in Table 6 below.

Q. Why have incurred costs increased at this level?

A. The principal driver is wage and salary increases because IT's costs are primarily labor based. The reason the overall increase is below the rate of inflation is that PGE's IT department has implemented programs to enhance efficiency and reduce costs. Examples of these include:

- Between 2002 and 2005, PGE invested approximately $5.0 million in communication infrastructure that reduced annual operating expenses by approximately $2 million. These systems included:
    - o A new telephone system at the World Trade Center that eliminated a leased system.
    - o A redesigned, integrated microwave system that was needed to replace many 20- to 30-year old analog systems.
    - o A high bandwidth, SONET fiber ring designed to best serve a variety of connectivity requirements including: PGE's voice and data networks, substation protection and relaying circuits, SCADA systems, mobile radio, remote metering, remote operation of new distributed generation locations, and all PGE offices, centers and power plants.

- In 2005, PGE retired its mainframe computer and replaced it with a modern hardware system, which produced net annual savings of approximately $1.0 million.

Table 6
IT O&M Costs ($000 – fully allocated)

IT O&M Costs ($000 – fully allocated)	2002 Actuals	2007 Forecast	Change
Application Systems Support (direct charged costs)			
• Generation and Transmission	1,847	1,723	(124)
• Power Operations	0	835	835
• Distribution	1,619	1,600	(19)
• Customer Service	4,584	7,550	2,965
• Corporate Systems	3,129	2,743	(386)
Voice, Data, Network, Communications and Office Systems (fully loaded, allocated costs)	21,024	27,474	6,450
IT O&M	32,203	41,924	9,721

Table 7
IT FTE's

	2002 Actuals	2007 Forecast	Change
Total IT FTEs	271.9	273.5	1.6

Q. If incurred costs only increased by $2.9 million, why is the increase on a fully allocated basis larger?

A. The difference can be explained on the basis of accounting impacts as listed below:

- $1.0 million for the customer information system (CIS) maintenance agreement that changed from a capital cost to O&M expense.
- $2.6 million for increased labor loadings (for allocated IT) based on:

  - o Increasing labor costs, including the transfer of IT employees from capital jobs to O&M, which is offset by decreases in non-labor costs.
  - o Increasing employee benefits costs.
- $2.5 million for updated IT allocation rates.
- $600,000 for "non-IT" charges to IT ledgers.
- $150,000 for allocated facility costs.

Q. Please explain the increase resulting from the CIS maintenance agreement.

A. IT O&M costs appear to increase $1.0 million because, in 2002, the CIS maintenance agreement was charged to capital and in 2007 it is charged to O&M. PGE's capitalization policy specifies that if maintenance agreements apply to a capital job prior to its being closed to plant, these contracts are capitalized to construction work in progress (CWIP) along with all other capital-related costs. Once the project is placed in service, costs associated with the maintenance agreements are then charged to O&M expense. PGE installed a new CIS in 2002. As part of that three-year capital project, PGE had purchased annual maintenance contracts, which were charged to CWIP in 2000 through 2002. In 2003 and thereafter, PGE continued to purchase CIS maintenance agreements but now the costs are charged to O&M expense.

Q. Which IT activities would result in loadings for PGE labor?

A. Work that is performed on voice, data, network, communications, and office systems. Because these costs apply broadly to all PGE activities and departments, they are not assigned to specific functional areas or charged directly to O&M. Instead, these costs are first charged to an asset account and are subsequently allocated to O&M. In accordance with PGE's accounting policies, such labor costs are fully loaded[5] when they are allocated to O&M. In contrast, non-labor costs (e.g., contract labor) would not have loadings applied for these same activities. This process can be summarized as follows:

- IT labor costs associated with voice, data, network, communications, and office systems increased as a result of wage inflation and because some employees were moved from completed capital jobs to O&M.
- This incurred labor was charged to a "D" ledger, which then had labor loadings applied.
- The incurred labor plus loadings were then allocated to "N" expense ledgers.
- IT non-labor costs associated with voice, data, network, communications, and office systems are charged to the same "D" ledger, but have only minimal material loadings applied when they are allocated to "N" expense ledgers.
- Non-labor costs were reduced by costs savings and by contract labor that was displaced by PGE labor that moved from capital to O&M.
- While incurred O&M costs remained approximately the same for voice, data, network, communications, and office systems (i.e., higher labor costs were offset by reduced non-labor costs), the addition of labor loadings increased total costs that were allocated to expense.

Q. Please describe the effect on IT O&M costs by increasing employee benefit loadings on allocated IT.

A. PGE's labor loading rates, not including employee benefits, have remained fairly flat. As discussed in PGE Exhibit 900, however, employee benefits costs have increased

[5] Labor loadings include paid time off, benefits, employee support, payroll taxes, and incentives. Labor loadings applied to balance sheet ledgers will reduce associated expense ledgers by an equal amount.

significantly from 2002 to 2007. The impact on the labor loading rate for employee benefits has been an increase from 22.99% in 2002 (final actual rate) to a forecasted rate of 30.44% in 2007. Consequently, loadings for employee benefits have increased on all IT labor that is charged to voice, data, network, communications, and office systems and allocated to O&M (as described above).

Q. How does the update to IT allocation percentages affect O&M costs?

A. PGE's IT costs for voice, data, network, communications, and office systems are allocated to O&M because they apply to PGE as a whole rather than being directly applicable to specific functional areas (the latter costs are directly assigned). As PGE's operations changed from 2002 to 2007, we reduced non-utility or "below-the-line" activities and increased utility operations. Consequently, allocations to non-utility activities decline by $1.7 million and are charged to utility operations. Further, in 2002, $600,000 of IT costs were allocated to utility ledgers that were not specifically identified with IT. Since 2002, we have been simplifying the allocations and almost all IT costs are now charged to only IT ledgers. This change has no effect on PGE's total utility costs.

Q. Does the change pertaining to non-utility activities reflect an increase in total IT costs?

A. No. This change does not reflect an increase in total IT costs but simply a change in the base of the allocation. PGE's voice, data, network, communications, and office systems are designed to accommodate all of PGE's utility needs plus additional capacity for growth. In 2002, some of this capacity exceeded PGE's current needs, and non-utility operations were interested in using some of this capacity. By 2007, however, non-utility activity has been greatly reduced and has been replaced by growth in PGE's utility operations. Consequently, the system costs are applied on the base to which they relate.

Q. How are allocation percentages determined?

A. The allocations are determined by a detailed review of the components of each system that is used by each functional area as assigned to PGE's vice presidents. If more than one major function reports to a given vice president, the allocations are separated further on the basis of labor hours. The specific allocation percentages to PGE's functional areas are listed in Table 8, which shows several categories have changed significantly based on updating our analysis of their usage of the various systems. Allocation rates for A&G have dropped along with those for non-utility, while rates for Customer Services and Distribution in particular have increased.

Table 8
IT Allocation Percents by Functional Area

	2002	2003	2004	2005	2006	2007
Generation & Transmission	14.55	13.92	11.91	15.88	15.88	15.88
Power Operations	-	-	4.84	3.64	3.64	3.64
Distribution	18.34	20.91	24.00	31.21	31.21	31.21
Customer Services	22.76	34.31	34.91	28.51	28.52	28.52
A&G	35.24	24.18	18.55	18.82	18.81	18.81
Retail / Non-utility	9.11	6.68	5.79	1.94	1.94	1.94
Total	100.00	100.00	100.00	100.00	100.00	100.00

Q. What was the effect of "Non-IT" charges to IT ledgers?

A. PGE defines IT costs as those resulting from IT responsibility centers (RCs). Virtually all IT costs are assigned or allocated to IT-related ledgers that apply to all of PGE's functional areas. When warranted, RCs that are not defined as IT will charge the IT ledgers and appear as IT-related costs. From 2002 to 2007, such costs increased approximately $600,000 and relate primarily to the automated meter infrastructure project. These costs are incurred for:

- Annual vendor maintenance cost associated with software and communication devices for systems completed and placed in service in 2002 and 2003.

- Line lease costs for "substation and collector" communications associated with various electronic metering devices.
- Increased labor in conjunction with the expanded network meter reading program.

Q. Why was there an increase to allocated facility costs?

A. As stated in Section III. A, PGE updated the allocation of utility floor space in the World Trade Center. The IT floor-space costs represent only a 2.09% annual increase and reflect the amount allocated to the IT departments associated with voice, data, network, communications, and office systems.

B. Other Service Providers

Q. Please describe Other Service Providers and their associated costs to A&G.

A. Other Service Providers consists mainly of allocations for printing services. The 2007 cost allocation forecast for these activities is $340,000, which is $100,000 higher than the 2002 allocation of $240,000. This increase is primarily due to higher costs for equipment maintenance and lease payments.

C. Enron Allocations

Q. Will there continue to be Enron allocations in 2007?

A. No. Enron stopped allocating costs to PGE in 2004 as we began to disengage ourselves from our parent company. When PGE is once again an independent company, there can be no further charges from Enron. Consequently, these costs will be zero in 2007, as opposed to $12.4 million in 2002. This reduction, however, will be partly offset by the costs summarized below:

- $1.8 million for investor relations.
- $1.1 million for directors fees.

- $630,000 for administration of the group health plan.
- $210,000 for administration of the 401K plan.
- $310,000 for finance costs related to the 401K plan.
- $1.2 million for D&O liability insurance.
- $530,000 for IT costs related to internet connectivity, electronic intrusion detection, and the loss of additional discounts on IT purchases based on Enron quantity purchases.
- Costs for other governance functions that have returned to PGE but whose amounts are not specifically identified, including:
  - Oversight of financing transactions
  - Design of all benefits programs
  - Legal support regarding benefits, the 401-K plan, Sarbanes-Oxley, and environmental requirements
  - Risk analysis and review of large company projects
  - Accounting expertise on FAS 133 implementation plus oversight and review of PGE's SEC Form 8Q, 10Q, and 10K
  - Review of PGE's income tax returns and support for tax audits and research for tax issues.

D. Regulatory Fees

Q. What do you forecast for Regulatory Fees in 2007?

A. In total, we forecast regulatory fees of $5.1 million, which are $1.4 million greater than 2002 actual costs of $3.6 million. Most of this increase occurs in FERC fees as described below. These costs consist of four different types of regulatory fees as follows:

- Trojan regulatory licenses and fees allocated to A&G will decline by approximately $100,000 and be zero in 2007. Prior to construction and licensing of the Trojan independent spent fuel storage installation (ISFSI), all Trojan Nuclear Plant Part 50 License, related NRC Fees, were considered to be Plant Operations and/or Spent Fuel Management O&M expenses. PGE paid these expenses with funds from the Trojan Operating Trust. All remaining fuel was removed from the pool in 2003, and it is now in ISFSI. The costs for licensing related to the ISFSI are paid through the Trojan Nuclear Decommissioning Fund under the ISFSI Part 72 license.
- The 2007 cost for FERC fees is $1.3 million. The FERC fees relate to PGE's hydro plants. The fees have two components: 1) an administrative charge based on an energy and average capacity charge factor times a specified unit charge factor, and 2) a U.S. lands charge based on the number of applicable acres times a per acre rate. In 2002, PGE incurred approximately zero costs for FERC fees because of an accounting adjustment that credited expense in order to adjust the prepaid fee balance. This entry proved to be in error and was corrected in 2004, which expensed $2.6 million in FERC fees. The 2007 forecast reflects the correct amount of fees.
- The OPUC fee for 2007 is $3.3 million. PGE uses a volumetric based method to calculate the OPUC fee. The product of the OPUC fee rate of $0.0001734/kWh and the forecast delivered test load in 2006 is the basis of the 2007 OPUC fee expense. Under the volumetric method, only changes in expected load affect the level of OPUC fees paid.

- FERC sales for resale fees are projected to be $440,000 in 2007. This fee is based on PGE's share of FERC program costs for long-term and short-term sales of energy. The 2007 budget is roughly $200,000 higher than 2002 actuals.

E. Other Membership Costs

Q. Please explain the increase in Other Membership costs from 2002 to 2007.

A. The reason for the $300,000 increase in Other Membership costs is that in 2002, departments that were not identified with A&G charged individual membership costs to their own functional area, i.e., O&M categories such as generation, distribution, customer accounting, etc. By 2006, individual membership costs for all PGE departments are charged to A&G, to coincide with the FERC definition of accounts (corporate memberships continue to be charged to A&G). This category reflects the change in accounting and represents membership costs for non-A&G departments that will be charged to A&G beginning in 2006. On a corporate basis, therefore, these costs have simply moved from a variety of O&M accounts to a single A&G account.

F. Miscellaneous A&G Costs

Q. What are your Miscellaneous Costs?

A. Miscellaneous A&G costs represent minor expenses that do not fit any of the categories previously described. In 2007, these are forecast to be approximately -$85,000 compared to -$1.4 million in 2002. The primary reasons for the negative costs in 2002 are:

- PGE corrected its miscellaneous payables balance to write off old balances and to match the account balance to the general ledger.
- PGE reversed a prior year accrual for costs, related to the restricted stock plan, that were not billed from Enron.

In 2007, the miscellaneous costs consist of several items including:

- Approximately $150,000 is the change in accrual for stub labor. This cost refers to labor that is accrued from the final hourly payroll of the year (which falls on a Tuesday), until the last day of the year. Because this accrual is made every year and reversed for the previous year, the net entry for a given year can be positive or negative.
- Approximately $100,000 represents regulatory costs from a non-A&G department that regularly works with the OPUC regarding customer complaints. This department is assigned to Customer Service Operations and charges most of its costs to that area.
- Approximately -$260,000 for a credit that reflects the transfer of certain depreciation and amortization costs to the co-owners of PGE's generating plants for systems and equipment that is applicable to those operations.
- The remainder consists primarily of miscellaneous costs charged to A&G in 2002 by various non-A&G departments for which there is no corresponding forecast in 2007.

V. A&G Offsets

Q. What are the A&G offsets?

A. A&G offsets are amounts deducted from the A&G expense budget as shown in Table 9. Capitalized A&G is that portion of A&G expense that is capitalized according to an administrative allocation. Through this allocation, certain A&G costs are distributed to PGE's capital, non-utility, and partnership accounts through a two-step process. The distributed A&G costs are for activities such as Human Resources, Accounting, and other corporate functions that support all PGE activities. Step one of the process is to pool the A&G support costs and allocate them to specific PGE capital, non-utility, and Boardman and Trojan Trust accounts. Step two is to charge the costs to specific capital jobs through the construction overhead loading. The offset for capitalized A&G is projected to be $10.2 million in 2007.

The Duplicate Charge Offset reverses PGE's costs for electric power. The 2007 offset forecast is $1.8 million.

Table 9.
A&G Offsets ($ Million)

Category	2002 Actuals	2007 Forecast	Change
Capitalized A&G	-9.9	-10.2	-0.2
Duplicate Charge Offset	-2.0	-1.8	-0.2

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibits	Description
501	Summary of A&G Costs and FTEs

Summary of A&G Costs and FTEs

	A&G Costs ($Million)				A&G FTEs (c)		
Category	2002 Authorized UE-115 (a)	2002 Actuals	2007 Forecast	Change (d) 2007-2002	2002 Actuals	2007 Budget	Change (d) 2007-2002
Major Functional Areas							
Facilities and General Plant Maintenance		9.0	10.9	1.9	14.6	14.6	0.0
Accounting/Finance		6.4	10.9	4.5	73.1	84.6	11.5
HR/Employee Support (net of capital allocs.)		8.5	5.6	-2.9	82.3	87.0	4.7
Insurance / I&D		6.1	10.4	4.2	6.7	6.4	-0.3
Legal		6.1	5.6	-0.6	24.7	28.1	3.4
Regulatory Affairs		1.8	2.9	1.2	24.9	30.0	5.1
Corporate Governance		1.3	2.1	0.8	7.9	8.0	0.1
Business Support Services		2.0	2.3	0.3	8.2	8.5	0.3
Environmental Programs		0.8	1.4	0.7	18.9	26.7	7.8
Corporate R&D		0.4	0.7	0.3	0.0	0.0	0.0
SB1149 Project Management		6.6	0.0	-6.6	2.6	0.0	-2.6
Contract Services/Purchasing		1.0	1.1	0.2	15.1	11.0	-4.1
Security		0.6	0.8	0.2	5.0	5.0	-0.1
Corp Communications/Public Affairs		1.6	1.6	0.0	30.1	19.8	-10.4
Load Research		0.5	0.2	-0.3	0.0	0.0	0.0
Hydro Licensing		0.1	0.2	0.1	0.0	0.0	0.0
Governmental Affairs		0.6	0.7	0.1	10.1	7.7	-2.4
Subtotal		53.4	57.4	3.9	324.3	337.4	13.1
Other A&G Costs							
IT: Direct & Allocated		11.3	8.2	-3.1	271.9	273.5	1.6
Other Service Providers to A&G		0.2	0.3	0.1			
Enron allocations/direct charges		12.4	0.0	-12.4			
Total Comp/Benefits (net of capital allocs.)		17.1	34.3	17.2			
PTO Loadings to A&G		3.7	4.3	0.6			
Corporate Incentive Plan (net of capital allocs.)		3.3	4.8	1.6			
Management Incentive Plan		2.5	6.8	4.3			
Variable Pay - Coyote & Trojan		0.6	0.2	-0.4			
Regulatory Fees		3.6	5.1	1.4			
Other Membership Costs		0.1	0.4	0.3			
Miscellaneous		-1.4	-0.1	1.3			
Subtotal		53.5	64.4	10.9	271.9	273.5	1.6
A&G Offsets							
Capitalized A&G		-9.9	-10.2	-0.2			
Duplicate Charge Offset (b)		-2.0	-1.8	0.2			
TOTAL A&G (d)	94.0	95.0	109.8	14.7	596.2	610.8	14.7
Annual Percent Increase 2002 to 2007			2.93%				

Notes:
(a) Authorized UE-115 detail by function is not available.
(b) The duplicate charge offset reverses PGE's charges to itself for electric power.
(c) These FTEs represent all the FTEs assigned to the department although a portion of their costs may be charged/allocated to capital, non-A&G, and/or non-regulated activities.
(d) Variances due to rounding

UE 180 / PGE / 600
HAWKE

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Transmission and Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Hawke

March 15, 2006

Transmission and Distribution Testimony

Table of Contents

I. Introduction and Overview

Q. Please state your name and position with Portland General Electric (PGE).

A. My name is Stephen Hawke. I am Vice President, Customer Service and Delivery. My qualifications appear at the end of my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present PGE's 2007 test year transmission and distribution expenditures and explain how they support PGE's goals of:

- Customer value
- Operational excellence
- Provision of infrastructure to support a growing service territory.

Q. Please summarize PGE's transmission and distribution O&M costs, full-time employees (FTE), and capital expenditures from 2002 through the 2007 test year.

A. Table 1 below provides this information.

Table 1
Summary T&D Statistics ($ Million)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
Dist. O&M Expenses	$43.6	$45.7	$50.6	$53.9	$56.8	$60.3
Trans. O&M Expenses	$6.0	$5.4	$7.6	$8.8	$10.3	$10.3
Distribution FTEs	951	922	921	974	971	977
Transmission FTEs	27	25	26	27	27	27
Distribution Capital	$102.8	$99.5	$111.8	$105.9	$120.9	$121.4
Transmission Capital	$9.4	$7.2	$6.1	$9.5	$7.8	$7.0

Q. Please describe PGE's transmission and distribution system.

A. PGE delivers electricity to more than 780,000 customers in an approximate 4,000 square mile service territory. We provide this service through 162 substations (137 distribution, 17 transmission, and 8 combined distribution and transmission), a system of 42,000 miles of overhead and underground distribution lines, and 1,400 miles of transmission lines.

Q. Has PGE's transmission and distribution system changed since 2002?

A. Yes. Our transmission and distribution system has grown significantly since 2002. Table 2 illustrates that we expect an increase of eight percent in our customer count between 2002 and the 2007 test year. Distribution line miles increased by approximately four percent between 2002 and 2005, and we project distribution substation capacity to increase by more than five percent between 2002 and 2007.

Table 2

Growth in PGE's Transmission and Distribution System

	2002 Actuals	**2003 Actuals**	**2004 Actuals**	**2005 Projected**	**2006 Forecast**	**2007 Forecast**
Distribution Line Miles	40,300	40,826	41,422	41,890	42,420	42,950
Average Connected Customers	740,593	750,495	762,336	775,533	787,229	800,019
Substation Capacity (MVa)						
Transmission	6,430	6,430	6,430	6,430	6,430	6,430
Distribution	5,231	5,272	5,362	5,431	5,467	5,506

PGE does not directly forecast new circuit line miles. The above line mile estimates for 2006 and 2007 are made by applying the average increase over the 2002-2005 period of 530 miles per year.

Q. What accounts for these changes in PGE's system?

A. The primary reasons for system expansion are people moving into our service territory, growth in the number of businesses to serve the increased population, and increased economic activity.

Q. What changes do you anticipate in the future?

A. The above factors will continue to influence our system. In addition, customers of all types demand increasingly higher levels of service quality. For example, businesses have increasingly sensitive manufacturing processes, and even momentary service interruptions have a significant impact on residential customers, who now have more sensitive computer and other equipment in their homes. I discuss increasing service quality demands in Section II.

Q. What are the major responsibilities of your transmission and distribution departments?

A. These departments perform five major activities. These are:

- Planning, analysis and design (PAD) of facilities to connect and serve new customers and reconductor existing lines and facilities. Transmission and distribution engineering ensures that PGE's system capacity and configuration meet customer needs.
- Construction of transmission and distribution systems. Our transmission and distribution departments build or contract for the construction of our transmission and distribution system.
- Performance of preventive maintenance. We inspect substations, overhead and underground lines, and equipment. We also perform ongoing vegetation management to meet regulatory and public safety requirements, reduce outages from tree damage, and minimize the risk of fires.

- Restoration of lines and substations. Our distribution department provides the personnel and materials necessary to return service to customers following outage events.
- Administration of PGE's Open Access Transmission and Gas Transportation Tariffs. Since FERC's adoption of Order 888 in 1999, we have provided personnel and systems to support wholesale transmission customers. In December 2003, we began operating the Kelso-Beaver pipeline under an open access gas transportation tariff.

2007 distribution O&M costs are mostly related to preventive maintenance (60%), PAD (20%), and restoration (20%). 2007 transmission O&M costs are mostly related to preventive maintenance (45%), PAD (15%), and tariff administration (40%). Capital additions for both transmission and distribution are for system construction.

Q. Do these activities result in good service quality for customers?

A. Yes. PGE's service quality measures are excellent, particularly when compared to other utilities.

Q. What are some measures of PGE's service quality?

A. Examples of PGE's service quality include the following:

- In 2005, J.D. Power and Associates rated PGE second out of the 53 largest American electric utilities in business customer satisfaction, and sixth out of 78 American electric utilities with more than 250,000 residential customers in overall customer satisfaction with power quality and reliability.
- A recent report from Environmental Consultants, Inc. states that "PGE is among best-in-class utilities in terms of tree-related interruptions."

- During a recent eight year period (1997-2004) we rejected only 0.52% of all distribution poles inspected through our Facility Inspection and Treatment to National Electric Safety Code (FITNES) program.
- PGE consistently meets OPUC-set goals of less than 1.0 outage of greater than five minutes per customer per year and less than 3.0 momentary outages per customer per year. Rates for outages greater than five minutes were only .65, .80, .77, and .84 for 2002, 2003, 2004, and 2005 respectively. Rates for momentary outages were only 2.20, 2.10, 1.97, and 1.60 for 2002, 2003, 2004, and 2005 respectively.

PGE's outage goals of less than 1.0 and 3.0 are the most stringent for investor-owned utilities in Oregon. PGE submits annual service quality measure (SQM) reports, which contain outage and other results. Commission Staff audits our SQM reports in detail and enforces the defined performance levels. Commission Order No. 05-1250 approved a Docket UF 4218 Stipulation concerning the upcoming distribution of PGE stock. This Stipulation extends current SQMs, which were adopted in Order No. 97-196 (Enron merger), through 2016.

II. Distribution Services

A. Distribution O&M Expenses

Q. Please restate how distribution O&M costs compare with recent years?

A. Table 3 below lists distribution O&M costs for the years 2002-2007. It also provides FTE figures for these same years.

Table 3

Distribution Employees and Expenses ($Million)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
O&M Expenses	43.6	45.7	50.6	53.9	56.8	60.3
FTEs	951	922	921	974	971	977

Q. Have you determined the major drivers of the O&M increases from 2002 to 2007?

A. Yes. Table 4 below summarizes these drivers and provides rough estimates for each to illustrate their relative impacts. I explain each of them below.

Table 4

Distribution O&M Cost Change Drivers 2002-2007 ($Million)

Cost Driver	**Impact Over 5-Year Period**
Transportation Allocation to Service Restoration	$2.0
IT Service Provider Allocation	$3.4
Customer Growth	$3.0
Labor and Material Cost Increases	$7.0
FITNES Program for Poles	$1.5
Porcelain Insulator Replacement	$0.5
Underground Facility Location Requests	$0.5
Tree Trimming	See Discussion
Total of Cost Drivers Over 5-Year Period	**$17.9**

These drivers explain the entire 2002-2007 increase of approximately $16.7 million.[1]

Q. Please explain the $2 million increase in service restoration costs.

A. This increase is due to an increase in transportation (vehicle) costs allocated to service restoration. Our latest depreciation study filed in Docket UM 1233 substantially reduced vehicle service lives, making vehicle services more expensive. In addition, fuel costs have increased. Greater transportation costs cause the approximately $2 million increase in service restoration.

Q. How has the IT service provider allocation increased?

A. PGE Exhibit 500 explains changes in the IT costs and related service provider allocations. The increased allocation to distribution of about $3.4 million is primarily due to a substantial increase in the percentage of IT costs allocated to distribution, total IT costs have also increased.

Q. How does customer growth contribute to the projected increase in distribution O&M costs over the 2002-2007 period?

A. We anticipate 8% customer growth over the period (see Table 2). More customers require more distribution infrastructure that we must then operate and maintain, resulting in a cost increase of approximately $3 million. Specifically, if we assume that distribution O&M directly increases with the rate of customer growth, then we would expect an increase of $3.5 million. If, on the other hand, the growth in distribution line miles over the period (6.5%) is more indicative of O&M cost increases, we would expect a $2.8 million increase. In reality, both are factors so we chose a mid-range estimate of $3 million for our analysis.

[1] The figures in Table 4 are rough estimates designed to provide a general understanding of our cost drivers. They do not consider details such as interactive effects.

Q. How much do labor escalation and inflation in materials costs contribute to the overall 2002-2007 increase in distribution O&M costs?

A. These factors account for approximately $7 million of the increase over the five-year period.

Q. Please explain how you calculated this $7 million figure.

A. First, *Global Insight* forecasts 2.6% as the rate of increase in consumer prices over the 2002-2007 period. Other things being equal, we would expect distribution O&M costs to increase at about that level. However, a tight labor market, particularly for journeyman linemen, puts pressure on labor costs. The wage rates in our union contracts will increase at a rate of approximately 2.8% over the 2002-2007 period. Labor is our primary cost element in this sector.

Although labor is our primary distribution O&M cost element, approximately 7% of test year distribution O&M costs are for materials. Metals are a substantial portion of materials costs and metal prices have increased and very likely will continue to increase faster than prices in the overall economy during the 2002-2007 period. *Global Insight's U.S. Economic Outlook* reports indicate a 6.4% forecasted (geometric) average annual rate of increase in the prices of metals and metal products over the 2002-2007 period. Although materials are a relatively small component of our distribution O&M costs, the rapid escalation of metal costs affects distribution O&M cost pressures by approximately 0.3% over the 2.8% labor cost increases. Based on these cost elements, we have used 3% as the estimated annual increase due to cost pressures, which yields our estimate of $7 million.

Q. What is PGE's FITNES Program and how does it increase distribution O&M costs, but decrease capital and overall expenditures?

A. Our FITNES program represents a cost-effective approach to maintaining poles for our distribution infrastructure. In 2007, we will begin our fourth cycle to inspect and treat poles and overhead facilities. We now focus on inspection and treatment, which costs only about $25 per pole, rather than replacement, which costs more than $2,000 per pole. This results in an increase in O&M costs, but a greater decrease in capital expenditures and overall costs. The focus on inspection and treatment increased O&M costs by approximately $1.5 million over the 2002-2007 period.

This focus on pole inspection and treatment rather than replacement is the result of practices dating back more than 40 years. In 1963, PGE pioneered a new pole treatment technique, and poles installed since then are far less likely to have decay problems than those installed earlier. Our pole rejection rate is now significantly less than one percent, one of the lowest rates in the country. In addition to the treatment technique, we have an ongoing testing program, which is supported by the research capabilities of Oregon State University.

Q. What are the advantages of PGE's porcelain insulator replacement program?

A. Our porcelain insulator replacement program is a least-cost approach to working with an aging system to provide safe, reliable power to customers. This program will increase distribution O&M costs by approximately $0.5 million by 2007. We have experienced a number of random failures of our porcelain insulators, many of which have been in place for almost 40 years. Replacing all porcelain insulators will maintain our current high reliability standards. Therefore, over a 16-year period beginning in 2006, we will replace all 57 kV and 115 kV porcelain horizontal post insulators with polymer insulators. We currently have approximately 25,000 insulators in our system, of which more than 19,000 are porcelain.

Q. Why is the increase of approximately $0.5 million in underground facility location costs appropriate?

A. In providing service to customers, PGE must follow Oregon laws and Commission standards. We are required to mark the location of underground lines and other facilities within 48 hours of a request. These requests decreased during the economic recession, but have recently increased significantly. Two sources – housing and other construction activity and Verizon's installation of an underground fiber optic network – account for most of the increase. Verizon anticipates that its higher request level will continue for at least six more years.

Q. Could changing tree trimming standards require a change in the distribution O&M revenue requirement?

A. Yes. Commission standards now require that PGE trim trees once every two years in urban areas, and once every three years in rural areas. Compliance with Oregon laws and Commission standards is necessary to provide service to customers. Therefore, reasonable compliance costs should be part of PGE's revenue requirement. At this time, the Commission is considering rule changes that could result in significant changes to tree trimming requirements. If rule changes lead to increases in expected 2007 test year costs, we will request a corresponding change in the revenue requirement, which could be several million dollars.

Q. Are premiums for storm insurance included in the distribution revenue requirement?

A. No. We treat them, as well as other insurance costs, as part of A&G expenses. PGE Exhibit 500 discusses insurance expenses.

Q. Does PGE have distribution system initiatives that improve reliability, but do not require large expenditures?

A. Yes. Recently started and upcoming initiatives are:

- Measures to increase power quality, particular for high-tech customers in Washington, Marion, and East Multnomah Counties.
- Replacement of underground cables that meet specific failure criteria on an ongoing basis.

Q. How do Customers benefit from these distribution system measures to improve power quality?

A. The sophisticated and sensitive technologies and production processes used by high technology and electronic component manufacturers make unique quality demands on the electric delivery system. At the same time, penetration of consumer electronic appliances and telecommunications, computer, and entertainment equipment is causing our residential customers to share some of the same power quality concerns as our commercial and industrial customers. The result is that decreases in even momentary outages are increasingly beneficial to all customer groups. We need to achieve high reliability and power quality levels, both to meet the needs of our current customers and to facilitate the location of new customers in our service territory. I also note that some distribution system measures that increase power quality are relatively inexpensive, thereby providing a very cost-effective increase in quality for customers.

A good example of these efforts is our Quality and Reliability Program (QRP), which targets large customers and includes various measures to reduce reliability risk. QRP measures include high reliability tree trimming associated with our Main substation in

Hillsboro, which serves Intel and other high technology customers. Although these measures significantly increase power quality, their costs for the 2007 test year are in the range of $200,000 - $300,000.

Q. How does replacing underground cables help customers?

A. Our underground cable replacement policies are a least-cost approach to dealing with an aging system. We installed underground cables with 220 mil[2] insulation, compared to the industry average of only 180 mil, with the result that our cables have lasted significantly longer than the industry average. However, they are near the end of their usable lives, and, like most utilities around the country, we are systematically replacing them according to very specific criteria. Replacing failed underground cables also contributes to the maintenance of high reliability standards.

Q. What are the specific criteria used to determine whether to replace an underground cable?

A. Our general replacement criteria are:

- The cable fails and tests indicate that it has deteriorated to less than 50% of its designed carrying capacity, or
- The cable fails and electrical readings indicate that additional failures are likely, or
- The cable fails three times.

We also replace underground cables under certain other very specific circumstances.

Q. Does the test year distribution O&M revenue requirement include the costs of recently initiated safety programs?

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[2] A mil is one 1000th of an inch. Hence, 220 mil is 220/1000 of an inch.

A. Yes.

Q. Please describe PGE's recent safety-related programs and initiatives.

A. PGE has initiated several safety and quality control programs in recent years. We have worked with Commission Staff on some of them; others relate to Homeland Security measures. They include:

- Safe Start Program: accident and injury reduction program for line crews and other field personnel.
- Public Safety Program: coordinated multi-channel advertising program designed around electrical safety; trends are monitored to provide effective focus.
- Quality Assurance Program: error reduction program concerned with the construction of new facilities and the operation of all facilities.
- Incident Command Structure: use of protocols and procedures common to state and county emergency organizations; used for all major storms, and would be used for terrorist incidents or natural disasters.
- Security Plan: corporate-wide plan begun in 2002 to meet Homeland Security requirements.

B. Distribution Capital Expenditures

Q. Please restate how PGE's distribution-related capital expenditures are expected to change over the 2002-2007 period.

A. Table 5 below shows these expenditures over the five-year period.

Table 5

Distribution Capital Expenditures ($Million)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
Dist. Capital	102.8	99.5	111.8	105.9	120.9	121.4

Q. What are the drivers of these changes?

A. The drivers are:

- Increased costs of both labor and materials – approximately $16.4 million over the 2002-2007 period
- Reclassification of 115 kV assets from transmission to distribution in 2003 – approximately $3 million

Q. What was the basis of the reclassification?

A. In accordance with the FERC seven-part test, we reclassified certain 115 kV and below facilities from transmission to distribution.

Q. Does the reclassification of assets from transmission to distribution change overall costs?

A. No. The reclassification from transmission to distribution does not change overall costs, i.e., there is an offsetting decrease in transmission capital expenditures.

Q. Are distribution capital-specific cost pressures approximately equal to the long-run rate of price increases in the general economy?

A. No. Our capital expenditures are subject to cost pressures greater than the rate of increase in consumer prices over the 2002-2007 period. *Global Insight* forecasts a 2.6% (geometric) average rate of increase in the consumer price index over the 2002-2007 period. However, we have assumed an overall increase of 3% per year to derive a rough estimate of $16.4

million as the impact of labor and material cost increases on distribution capital requirements.

Q. Please explain how you derived the 3% annual escalation rate.

A. Prices for copper, aluminum, and other materials are under severe pressure from outside factors, such as storms in the Southeast and rapid economic growth in China, and strongly affect our distribution capital expenditures. As I stated above, *Global Insight's U.S. Economic Outlook* reports indicate a 6.4% forecasted (geometric) average rate of increase in the prices of metals and metal products over the 2002-2007 period. On the labor side, as I have mentioned, our union labor costs will increase an average of 2.8% annually over the period. In addition, construction contractors have to factor in overtime to accomplish work on time because labor (particularly journeyman linemen) is currently in short supply. Based on this information, we assumed the 3% figure.

Q. Are there reasons to consider the $16.4 million figure implied by expected cost increases to be conservative?

A. Yes. Recent customer growth has required more from our distribution system than would be implied by simply considering the number of new customers because almost all new homes have air conditioning, which disproportionately increases our system summer-peaking requirements. Some of our substations are now, in fact, summer peaking. The capacity of a particular piece of equipment is often limited by its ability to shed heat, which is aided by colder air temperatures in the winter, but not in the summer. For example, we can safely run a substation transformer at 125% of its nameplate capacity in the winter, but only at 100% in the summer.

Q. Please discuss changes in year-to-year capital expenditures, particularly to connect new customers.

A. These costs vary from year to year depending on the number and type of expected new connects, which themselves depend on several factors. For example, in 2003, construction was still recovering from the post-9/11 economic slowdown. Housing construction then strongly increased in 2004, in part because of very low interest rates. These various factors result in the following actual (2004) and forecasted (2005-2007) new connection cost changes: $7 million increase in 2004, $3 million decrease in 2005, $9 million increase in 2006, and $3 million increase in 2007. Note that overall changes from year to year also depend on changes within more routine jobs, which account for more than half of overall distribution capital expenditures, and changes in recovery work in progress and reserves.

Q. Does PGE do anything that is unique in the nation to reduce distribution capital costs?

A. Yes. Our UNITY or composite crews install underground electric, gas, telephone, and cable service all at once. These crews are made up of both Northwest Natural Gas and PGE employees and have the necessary skills to jointly install all four services. This is unique in the country for separate gas and electric utilities; it is also very rare even for joint gas and electric utilities. In 2004, unity crews resulted in savings of more than $3 million.

Q. Are the capital expenditures you present in this section consistent with the goal of incurring reasonable costs to build, operate, maintain, and repair PGE's distribution system to provide safe reliable power to a growing number of customers?

A. Yes. People moving into our service territory and an increase in economic activity following the economic recession have both contributed to customer growth. Increases in capital expenditures to connect new customers to our system are the most important drivers of the figures in Table 5. These expenditures are necessary to provide safe, reliable power to our new customers.

III. Transmission Services

A. Transmission O&M Expenses

Q. Please restate how the transmission O&M component of the 2007 test year revenue requirement compares with recent years.

A. Table 6 below lists transmission O&M costs for the years 2002-2007. It also provides FTE figures for these same years.

Table 6

Transmission Employees and Expenses ($Million)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
O&M Expenses	6.0	5.4	7.6	8.8	10.3	10.3
FTEs	27	25	26	27	27	27

Q. What are the drivers of the O&M increase from 2002 to 2007?

A. The O&M cost increase relates to the following:

- Based on activity analysis and FERC accounting guidelines, in 2005, we began accounting for certain load dispatching and transmission and reliability services costs as part of transmission rather than other power costs – an increase of approximately $3 million.
- The IT service provider allocation to transmission has increased more than would be expected simply from inflation in the general economy and customer growth – mostly because of an increase in the percentage of IT costs allocated to transmission, IT costs have also increased – an increase of almost $1 million. PGE Exhibit 500 discusses IT allocations in detail.

Q. How much of the approximately $4 million increase in transmission O&M costs from 2002 to 2007 do these factors explain?

A. Absent these cost classification changes, the underlying transmission O&M costs in the 2007 test year revenue requirement are the same as 2002 actuals. In other words, our transmission O&M costs are not even rising as quickly as would be expected based on customer growth and cost pressures.

B. Transmission Capital Expenditures

Q. Please restate PGE's transmission-related capital expenditures over the 2002-2007 period.

A. Table 7 below shows these expenditures over the five-year period.

Table 7

Transmission Capital Expenditures ($Million)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
Trans. Capital	9.4	7.2	6.1	9.5	7.8	7.0

Q. What are the primary drivers of these changes after 2004?

A. These drivers are:

- Construction of a 230 kV line between Murray Hill and Sherwood – approximately $3.5 million and $3 million in 2005 and 2006 respectively.
- Willamette Valley Conversion Project – approximately $5 million in 2007.
- Installation of a step-up transformer at Sullivan – approximately $1.5 million in each of 2005 and 2006.
- Reclassification of 115 kV assets from transmission to distribution – approximately $3 million per year decrease for transmission, beginning in 2003.

Overall year-to-year changes also depend on more routine jobs, which account for all capital expenditures during the 2002-2004 period.

Q. Does PGE have programs which involve capital expenditures, but decrease overall costs?

A. Yes. PGE has a program to reduce reactive power charges from the Bonneville Power Administration (BPA), which involves installation of capacitors, both at the distribution and transmission voltage levels. BPA charges PGE when we draw too much reactive power (from BPA) at transmission interconnection points. The added capacitors, both at the distribution and transmission levels, have substantially reduced reactive power charges from BPA. Although the new capacitors result in capital and O&M costs, these costs are more than offset by the reduced BPA charges.

Q. Are the capital expenditures listed in Table 7 consistent with the goal of incurring reasonable costs to build, operate, maintain, and repair PGE's transmission system to provide safe reliable power to customers?

A. Yes. Without construction of the Murray Hill-Sherwood line, increased loadings would exceed acceptable limits, increasing the possibility of widespread outages. The Willamette Valley Conversion Project will maintain system reliability and provide the necessary infrastructure to support load growth in the northern Willamette Valley, particularly the rapidly developing area around Wilsonville. The new Sullivan step-up transformer will replace one that is more than 50 years old, having significantly passed the industry-average life span.

Q. Does the reclassification of costs from transmission to distribution represent an overall cost decrease?

A. No. The reclassification is not an overall cost decrease. There is an off-setting increase in distribution capital expenditures, which I described in Section II.

IV. Qualifications

Q. Mr. Hawke, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering and Mathematics from Oregon State University. I received a Master of Business Administration from Portland State University. I completed additional graduate work at Portland State University in Systems Science and graduated from the Public Utilities Executive Course at the University of Idaho. I am a registered professional engineer in the State of Oregon. I have been employed at PGE since 1973, starting as an Assistant Distribution Engineer. I have held positions such as Engineering Supervisor, Chief Underground Engineer, Chief Field Engineer, Sales Manager, Regional Manager in both the Salem and Western regions, Manager of Response and Restoration, General Manager of System Planning and Engineering, and Vice President of System Planning and Engineering. I began my current position, Vice President of Customer Service and Delivery, in August 2004.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Hawke

March 15, 2006

Customer Service

Table of Contents

I. Introduction

Q. Please state your name and position with Portland General Electric (PGE).

A. My name is Stephen Hawke. I am Vice President of Customer Service and Delivery. My qualifications appear in PGE Exhibit 600.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain PGE's 2007 test year expenses of $67.9 million for Customer Service.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section I is the introduction
- Section II provides an overview of Customer Service
- Section III details PGE's meter operations
- Section IV explains the billing function
- Section V describes the costs associated with PGE credit and collection activities
- Section VI discusses PGE's response functions
- Section VII describes information and technology costs
- Section VIII details other programs and service options within Customer Service
- Section IX explains customer communications

II. Overview of Customer Service

Q. What are the primary responsibilities of Customer Service?

A. PGE's Customer Service operations are responsible for most interactions with retail customers. These include numerous functions within that scope of responsibility, such as:

- Serving as the first point of contact for customers and providing customers with flexible options for contacting us and conducting transactions
- Reading and maintaining meters and evaluating and implementing meter technologies
- Producing monthly statements and complex billings, handling billing exceptions and processing remittances
- Helping customers with credit problems or special needs to establish and maintain service
- Minimizing write-offs and other costs associated with uncollectibles
- Maintaining customer information in our customer information system and ensuring our technologies are functional, efficient, effective, and secure
- Gathering and analyzing qualitative and quantitative feedback from customers and regulators in order to meet regulatory requirements and to provide better service to customers
- Communicating to our customers about safety, the wise and efficient use of energy, power options, billing and payment choices, and other information and alternatives available to them.

Q. What are PGE's estimated costs to perform Customer Service operations?

A. Table 1 summarizes major categories of cost by function and compares the difference between forecasted amounts for the 2007 test year and previous years. In total, Customer Service costs are projected to increase by an annual rate of approximately 5.95% from 2002 to 2007.

Table 1. Customer Service by Function ($000)

	2002 Actuals	2003 Actuals	2004 Actuals	2005 Projected	2006 Budget	2007 Forecast
Meter	5,678	6,331	6,646	6,908	7,006	7,493
Bill	7,198	7,130	7,572	7,838	8,229	8,691
Collect	12,166	12,959	12,953	13,132	12,710	13,922
Response	8,935	9,991	10,967	11,357	12,826	13,637
Information Technology (IT)	10,265	13,630	13,798	13,531	15,114	15,651
Other Programs and Service Options	4,410	3,542	4,551	5,401	6,934	6,689
Customer Communications	2,827	3,283	2,827	2,642	2,550	2,646
Total Customer Service	**51,479**	**56,867**	**59,314**	**60,808**	**65,370**	**68,731**

Q. What is the primary driver of the cost increases?

A. There are several major drivers of these increases. First and foremost is wage inflation. Labor accounts for the majority of costs associated with Customer Service. Although PGE continually updates its systems and technologies to be more efficient and limit labor costs as much as possible (as described in several sections below), we need employees to interact with customers and operate these systems. Labor comprises 51% of incurred Customer Service costs and 66% of allocated IT costs. In short, wage inflation will drive costs higher and increases associated with wages and salaries (as described in detail in PGE Exhibit 900, Compensation) are particularly relevant for Customer Service operations.

Q. What is the second driver of cost increases?

A. The second driver is that our customer base continues to grow. We project the number of customers to increase by more than 60,000 (well over 10,000 new customers per year), which is a 1.6% annual increase each year since 2002. More than any other operation within PGE, our Customer Service costs are a function of the number of customers we serve.

Q. What is the third driver of cost increases?

A. The third driver is that PGE's Customer Service operations perform more tasks, support more programs, and offer more service options than in 2002. These efforts are in response to customers' continued demand for higher levels of service, including efficient first-call resolution of requests or issues, more flexibility in contacting PGE via different methods (e.g., electronically, by phone, in writing, in person) and times of operation that are convenient to them. They also want more programs and options to meet their changing lifestyles and business requirements. Some examples of these improvements include:

- Enhancing the interactive voice response (IVR) phone system
- Implementing new customer programs and enhancing existing programs and service options such as Customer First (an extended-hours customer service group that assists customers with outage reporting and information), automated bill payment, One-Check payment (i.e. customers can pay multiple accounts with a single check), Dispatchable Standby Generation, Time of Use (TOU), renewable power, and key customer workshops; I will discuss these in more detail in later sections

- Expanding our web sites (i.e., portlandgeneral.com and portlandgeneral.biz) by adding several self-service options and providing more general and specific account information
- Increasing staffing and development to ensure customers experience quality service and information

PGE also increased staff to support its new Windows-based customer information system (CIS). At the time of our last general rate case, we estimated the resources required to support the new CIS but did not have tangible experience to accurately forecast that level. By working with the system, we gained this experience and increased staff in 2004 according to the system's actual requirements. I will provide more details in Sections IV and V below.

Q. How many employees does the Customer Service operation require?

A. Table 2, below, summarizes the number of full time employees (FTEs) for this function.

Table 2. Customer Service Employees

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Budget	2007 Forecast
Meter	148.1	150.4	153.7	160.1	164.7	167.7
Bill	81.7	88.1	93.3	94.4	95.4	96.4
Collect	46.1	53.3	55.7	58.6	58.8	58.8
Response	218.2	213.3	222.2	224.2	223.3	226.9
Other Programs and Service Options	52.4	41.4	42.6	33.7	39.4	36.8
Total Customer Service	**546.5**	**546.5**	**567.5**	**571.0**	**581.5**	**586.6**

Q. How does PGE compare to other investor-owned utilities for Customer Service?

A. We have been, and remain, efficient in providing quality service and adding value. Some examples include:

- In 2005, JD Power and Associates ranked PGE second in the country among the 53 largest American electric utilities for business customer satisfaction. In 2005, JD Power and Associates also ranked PGE sixth in the country among the 78 American electric utilities with at least 250,000 residential customers for overall customer satisfaction with power quality and reliability.
- PGE consistently has an at-fault complaint level well below our regulatory target of 0.07 per 1,000 customers. In 2005, the actual at-fault rate was 0.02.
- PGE is ranked second in the nation among all utilities (first among IOUs and first in the region) by the National Renewable Energy Laboratory for sales of renewable power.
- Market Strategies, Inc. ranked PGE's interactive voice response (IVR) system first overall in the nation in their 2005 Energy Utility IVR Bench Marking report. In other words, PGE efficiently balanced the areas of IVR functionality, usability and aesthetics (i.e. how customers feel after using the system), which are all important aspects of the customer experience.
- PGE's portlandgeneral.com web site is ranked first among 105 companies by E Source in its 2005 "Electric and Gas Company Web Site Review."
- Platt's "Business and Technology" magazine rated the portlandgeneral.com web site number one in the Northwest and number eight in the nation for ease of customer use and range of services when compared to other utility web sites.

Q. What are PGE's service quality measures and goals for Customer Service?

A. We have numerous goals and service quality measures for Customer Service. They include:

- We will increase the value customers receive from PGE and ensure that programs and service options are customer-driven. This is measured through customer satisfaction ratings across all of our customers and our goal is to be in the top quartile among our peer utilities and utilities nationally within the next four years.
- We will ensure operational excellence. This is measured, in part, by the number of at-fault complaints we receive. Our goal is to have fewer than 55 at-fault complaints in 2006. For operational excellence at the contact center, we want to achieve a 90% accessibility rating. Further, we want to answer calls within 126 seconds from the point where the IVR routes them into specific customer service call queues (e.g., residential, business, or outage).
- We will provide efficient and high-performance levels of communication and response to our customers.
- We will provide valuable programs and service options driven by customer needs. Examples include helping property managers more efficiently manage multiple accounts, implementing a consolidated bill for large customers, and developing programs for special-attention customers.
- We will partner with the Energy Trust of Oregon (ETO) to ensure our customers derive the maximum benefit from the available programs, to connect our customers with other sources of funding for energy efficiency investments, and to provide our customers with thorough energy efficiency information.

III. Metering

A. Meter Reading Operations

Q. What has changed in meter operations since 2002?

A. PGE hired 16 additional FTEs to perform meter reading. This increase was a result of two factors. One was the addition of more than 60,000 meters since 2002. The second is that these employees reduce overtime costs and help provide off-cycle reads (i.e. reads that occur outside of the monthly schedule). We anticipate needing to add a minimum of three full time employees over the next two calendar years to cover the addition of approximately 26,000 new electric meter installations (13,000 annually).

Q. Are these additional FTEs the primary driver of cost increases in the "Meter" category?

A. Yes, along with general wage inflation in this labor-intensive operation. The increase in employees is necessary to keep up with the increased volumes in meter installations. Most of our new meter installs are in urban areas that also include a gas meter installation (joint meter reading is discussed below). Labor costs associated with reading meters have increased approximately $1.1 million due to additional employees and increasing wages.

Q. Besides customer growth, are there other reasons you need additional meter readers?

A. We need enough staff to cover sick and vacation time, but most importantly, we needed additional personnel devoted to off-cycle reads (e.g. opening, closing and verification reads). On an average-annual basis, we conduct approximately 196,000 off-cycle reads that require additional scheduled time because they are not part of a normal route. In addition, PGE is required by tariff and Oregon Public Utility Commission (OPUC) rules to perform a meter reading within five days of a customer request. Without adequate staffing, our ability to complete these reads is seriously impeded.

Q. What other factors have increased costs for meter reading?

A. Besides meter reading labor, costs for vehicles have increased by approximately $280,000 because more vehicles are needed and because fuel costs have risen. In addition, as noted in PGE Exhibit 600, our latest depreciation study substantially reduced vehicle service lives, making vehicle allocations more costly.

Q. What benefits does the Joint Meter Reading partnership with Northwest Natural (NWN) provide?

A. In areas where PGE and NWN have overlapping services, the joint meter reading program increases meter reading efficiency for both utilities. Instead of each utility visiting a given site to read their meter, routes have been organized (and continue to be refined) so that only one utility reads both meters during each visit. Reducing the number of site visits to read meters also provides environmental benefits through decreased auto emissions, which benefits the entire service area and the state of Oregon.

Q. If NWN implements an automated meter reading (AMR) system, how will this impact the Joint Meter Reading partnership with PGE?

A. This largely depends on whether NWN deploys the system over its entire service territory. If it does so, it would terminate the joint meter reading program we have with NWN, which would affect PGE in one of the following ways:

- If PGE continues with its current system, we would need to hire 21 additional full-time employees to provide support functions and read 220,000 more meters that are currently on jointly-read routes. This would increase our annual meter reading expense by approximately $1.5 million.

- If PGE implemented its advanced metering infrastructure (AMI) and coordinates deployment with NWN, it could minimize the cost to both companies. For further discussion of PGE's proposed AMI system, see PGE Exhibit 800.

B. Meter Support

Q. What functions does Meter Support provide?

A. Traditionally, Meter Support is responsible for meter purchases, inventory, testing, installation, and repair. Although we assign the employees that perform these functions to Customer Service, they charge most of their costs to Distribution O&M. One change we implemented within this function was to install PowerTrack, a new system of records for meters and associated equipment.

Q. How does PowerTrack benefit customers?

A. PowerTrack is a new client-server application that is compatible with our CIS. It was implemented to comply with the OPUC-mandated standard (i.e., ANSI Z1.9) for sampling, testing and statistical analysis.

Q. What other changes have you experienced in the Meter Support area?

A. In 2002, we created the Network Data Operations (NDO) department to support PGE's existing network meter reading (NMR) system. The NDO department is responsible for managing the collection and distribution of electronic meter reading data and the systems that support these activities. Its activities include:

- Monitoring data flow from multiple communications servers that read the meters and ensuring the data is validated when accepted in the meter data consolidator (MDC).

- Maintaining and operating the MDC, which is the system of record for all PGE meter read data.
- Publishing meter data to multiple internal and external systems.

Because the NMR system was implemented between 2000 and 2003, the department was not fully staffed until 2004. Consequently, its costs have increased by approximately $410,000 between 2002 and 2007.

Q. Does Meter Support provide other benefits to customers?

A. Meter Support ensures timely installations for new service and prompt meter exchanges for customers who request enrollment in our Time of Use (TOU) service option. In 2005, we also performed 744 high-bill meter tests as requested by customers. Our accuracy rating was 99.95%. We also tested 4,067 meters for the OPUC Test Program to ensure meter accuracy. In total for 2005, PGE tested 15,467 meters with an average accuracy rating of 99.9%.

IV. Billing

A. Billing Department

Q. What cost increases has PGE experienced in meeting its billing requirements?

A. Costs to meet billing requirements have increased $1.5 million for a 3.8% average annual rate from 2002 to 2007. The primary drivers of this increase are the influence of general inflation and customer growth on labor and materials.

Q. What are the specific components of the cost increases?

A. Labor costs have increased by approximately $900,000 for additional employees and wage increases. Printing and mailing costs have increased by approximately $470,000, and non-labor costs associated with PGE's electronic pay options increased by approximately $120,000. I discuss this in more detail below. We increased our billing staff by approximately nine full-time employees because of the many manual processes and billing accuracy measures we perform primarily as a result of implementing our new Windows-based CIS, plus other new required programs.

Q. Why does the new CIS require more people to complete work than estimated in the 2002 rate case?

A. When we developed the forecast for UE 115, our new Windows-based CIS had not yet been installed and we estimated the number of employees needed to complete the tasks associated with that system. Subsequent experience with the system has allowed us to establish actual workforce requirements. Some reasons for the increase from estimates to actuals include:

- Billing adjustments, estimates, and open and close orders take more time to complete than estimated.
- Billing issues are more complex.

- To ensure continued accuracy, we have increased our preparation and monitoring of variance reports to ensure that PGE continues to deliver accurate bills.

We have also added manual processes to provide better customer service. For example, the billing group now ensures a seamless transfer for our customers enrolled in renewable power programs. When renewable customers move, they do not have to request re-enrollment. This process, while invisible to the customer, results in an additional report for PGE to manage and additional staff time to perform. Another example is the New Service Report, which is a quality assurance report designed to track new meter installations to ensure we have opened the accounts correctly.

Q. What are the regular functions of the Billing department?

A. The Billing department's primary role is to prepare all bills that the CIS does not routinely process or that our systems segregate for review because they fall outside certain parameters (e.g., the bill appears too high or the meter-read variance is outside guidelines). This work is commonly referred to as "exceptions," which are evaluated manually by Billing department staff with the goal of being timely and accurate.

Employees in this area also process adjustments, oversee billing issues related to city/county taxes, process all opening and closing bills, monitor variance reports, and process renewable transfers (i.e., transferring the renewable option with customers when they move).

Q. What other functions does this area perform?

A. They handle all complex billings in the Power Billing System (PBS). Complex billings are defined as the billing calculations for all metered rates and pricing options that neither our current nor prior CIS were designed to calculate. Examples of complex billing calculations are market-based hourly, daily, monthly, or quarterly pricing; frequent price option changes; bill calculations directly from interval data sources; and many other variable bill calculation requirements. The Specialized Billing personnel also process billings associated with customers on direct access (for PGE's portion of the customer's bill) and billings for unmetered services like streetlights, traffic signals, cable power amplifiers and area lights.

Q. What is the Power Billing System (PBS)?

A. PBS is the vendor product we use to calculate the complex billings described above. It is simply a low cost, highly reliable, flexible addition to a CIS, for specialized or unique billing calculation requirements. Generically it is called a complex billing engine as it only calculates utility billings (it does not maintain accounts receivables or delinquency financials). All charges and summary usage values calculated by the PBS are transferred to CIS, which still produces the actual customer statement.

Q. How many customers do you bill through the Power Billing System?

A. We bill approximately 590 commercial/industrial customers through this system. Even though this is a relatively small number, the generated billings amount to roughly 17% of our retail revenues.

B. Printing and Mail Services

Q. What cost increases have you experienced this area?

A. Printing and Mail Services added one full-time employee and increased its charges to Customer Service operations by approximately $470,000 since 2002. This represents a 2.9% average annual increase.

Q. To what is this increase related?

A. The increase is due to higher volumes of printing and mailing stemming from additional customers as well as a 5.4% increase in postage rates for 2006 and a forecasted increase of 4.5% in postage rates in 2007. In addition, we have assumed responsibility for PGE's engraving system from Distribution Services, which we use to identify poles and other equipment as required by the OPUC through the National Electric Safety Code (NESC). Further, we have added features to our billing statements such as highlight color. Recent customer focus groups overwhelmingly recommended this change for ease in identifying important information like the amount due and due date. Finally, we have purchased Jet Vision and IntellaCenter technology to help ensure 100% document integrity. Jet Vision is a camera system associated with mail inserters that ensures bills are accurately assembled and have correct postage. IntellaCenter is the computer server that works in conjunction with Jet Vision.

Q. What are PGE's accomplishments regarding mailing and remittances?

A. The primary accomplishment is that we provide printing and mailing services internally and at a lower cost than external providers. Through our printing and mailing services, we produce timely, accurate, and high quality billing statements and other communication documents for PGE customers. In 2005, we were named Greater Portland Area Mailer of the Year. In 2006, we were the first electric utility in the nation to earn Mail Processing Total Quality Management certification from the U.S. Post Office. This recognition demonstrates that PGE performs best-practice quality work on a cost-effective basis.

C. Community Offices

Q. Has PGE experienced overall cost changes related to its community offices?

A. No. These costs have remained flat at approximately $1.0 million because we have pursued efficiencies in locating our community offices. Based on our research, a declining number of walk-in customers, and the locations of other payment acceptance locations, we implemented the following changes to our community offices:

- We replaced our Sheridan office with a pay location operated inside the local hardware store.
- We combined our Tualatin and Tigard offices and relocated them to the growing community of Sherwood.
- We moved our Salem office to a more customer-accessible location.
- We strategically located other express pay locations (EPLs) and payment kiosks.

Q. Why does PGE have community offices?

A. Community offices provide a place for customers who prefer to transact their business in-person and they allow customers to pay in cash. Customers remitted approximately 6.8%, or 567,094 payments, at our community offices in 2005. We continue to provide this option in the most cost-effective and efficient manner possible.

Q. What are the current office locations?

A. We currently have seven community offices located in Salem, Woodburn, Sherwood, SE Portland, SW Portland, Gresham and Hillsboro.

Q. How has your support for this customer service changed over time?

A. A little more than a decade ago we had 17 community offices. Today, we have fewer offices in better locations and we have supplemented these with 24-hour a day options such as 80 kiosks, the web, and phone payments. We implemented this change because we have customers that are requesting new payment options that better meet their needs.

D. Electronic Payment Options

Q. Why does PGE offer electronic payment options?

A. Electronic payment options provide convenient ways for customers to pay their bills 24 hours a day, 365 days per year. In 2004, approximately 30% of our customers paid their bills electronically. We provide the options and services to make sure their customer experience is satisfactory. The number of electronic transactions and percent of growth of the electronic payment options is listed in Table 3 below.

Table 3. Electronic Pay Options

Year	Number of Transactions	Percent of all Transactions
2002	1,394,583	17.5%
2003	1,680,866	21.0%
2004	2,012,124	25.0%
2005	2,480,265	29.6%

Q. What are the current Electronic Pay Options available to customers?

A. Electronic Pay Options include:

- EPLs – located in retail outlets like drug stores
- Kiosks – ATM-like machines located in 7-Eleven food stores
- PortlandGeneral.com web site – provides a link to BillMatrix (see below) and allows customers to pay through their checking account
- Auto Pay – automatic withdrawal from checking or savings account
- CheckFree – bill consolidator, supporting automatic withdrawal from bank accounts

- RPPS – Remittance Payment Processing System, which is another bill consolidator that supports automatic withdrawal from bank accounts
- EDI – Electronic Data Interchange, which is used for data and payment exchanges, primarily by commercial customers
- BillMatrix – vendor-supported credit card acceptance
- Pay by Check option – available on PGE's Interactive Voice Response (IVR) telephone system

Q. Have you experienced cost increases in providing electronic payment options?

A. Yes. The costs of providing electronic payments have increased $170,000 since 2002 (approximately $50,000 in labor and $120,000 in non-labor). The main driver for the increase in costs is the additional number of electronic transactions we process compared to 2002, and the various electronic payment options we offer.

Q. Has the increase in electronic payment options resulted in cost changes elsewhere?

A. Yes. Due to the demand from customers to provide various electronic payment options and the relocation of some community offices, we have been able to reduce the number of community offices, as discussed above.

Q. What are EPLs?

A. EPLs are walk-up pay stations usually located inside drug, grocery or hardware stores, where our customers make payments directly to store employees who then process the transactions electronically. We currently have 25 EPLs.

Q. How many Kiosks are there?

A. Our customers have access to 80 ATM-like kiosks. All of them are located inside 7-Eleven stores and they allow customers to pay with cash, check or debit card (fees for debit card transactions are paid by customers).

V. Collections

Q. Have PGE's costs for collections increased?

A. Yes. The total increase in collection costs, however, has been limited to approximately 2.7% annually because our efforts to increase collections have resulted in significantly lower write-offs of delinquent accounts since 2002 and 2003. The collections function includes credit processing, field collections, customer resources, medical certificate processing, collections and fraud detection.

Q. How much does PGE write off and what percent of gross retail revenue is this?

A. We forecast that PGE will write-off approximately $8.7 million for uncollectible accounts in 2007, which represents 0.53% of gross retail revenue. This compares to the $9.5 million or 0.65% rate experienced in 2002.

Q. What changes has PGE implemented to increase collections and reduce write-offs?

A. We have added approximately 13 full-time employees in collections between 2002 and 2007 to reduce our write-offs as noted above and to adequately manage the dramatic increase in accounts with medical certificates. In total, labor costs have increased $1.7 million due to additional employees plus general wage and salary increases.

Q. In what specific areas did you add employees?

A. We added five additional inspectors for credit field work to address growing account balances and to ensure disconnect orders are being dispatched and performed in the field. Our write-off level dictated additional employee resources in fraud detection, where we added one employee. In addition, we added three employees to manage the increase in workload due to customer growth. Finally, we created a "finals call-out" team comprised of three more employees.[1]

Q. What is the finals call-out team?

A. PGE formed this team in January 2004 to be responsible for calling former customers who have not paid their closing bill. The team collects or makes short-term arrangements to prevent the bill from going to collections, which would negatively impact the customer's credit rating and would cost PGE a 19% commission if a collection agency subsequently collects the money. The team also finds that some of these former customers have actually re-established service with us or have other active accounts and are able to transfer the bill to the new or existing account.

Q. Has the team been successful?

A. Yes. Since its inception, the team has collected or avoided sending to our collection agency over $1 million, at a cost of approximately $120,000 annually.

Q. What changes have occurred with managing medical certificates?

A. PGE currently has four employees administering the medical certificate program and one program lead because it takes approximately one employee to adequately manage 500 medical certificates. In January 2002, we had 519 active medical certificates with an average balance of $405. In January 2006, we had 2,031 medical certificate customers with an average balance of $513.

[1] The total calculated increase in FTE's is 12.7, which was rounded to 13. The increases by function are rounded to the nearest employee and total 12.

Q. What other efforts is PGE pursuing to reduce the amount of uncollectibles and write-offs?

A. We have implemented a number of initiatives and redesigned business processes that are aimed at reducing write-offs. These include:

- Replacing our collection agency in June 2004. This has doubled our annual recoveries. Beginning in 2006, we plan to add a second collection agency to create a competitive environment and further increase recoveries. In total, collection agency fees and other non-labor collection costs have increased approximately $400,000 from 2002 to 2007.
- Applying additional parameters that prompt more field collection attempts. This resulted in approximately 2,000 additional service work orders annually.
- Refining our bill-payment extension policies in the field and in the office to reduce the number of extensions to roughly 5%. This reduces active arrears, and eventually, write-offs.
- Implementing a more efficient way of scheduling work orders in the field in 2006 that should result in increased field collections.

Q. Have you added any new programs to the collections process?

A. Yes. PGE has implemented an innovative new pilot project called "Par3." Par3 is an automated system that places calls to residential customers as a reminder to pay their bill within five days to avoid the possibility of having their service disconnected.

In 2006, we will expand the pilot to include calls to customers who receive 15-day notices as well. This will serve as an additional reminder to customers and give them several options for payment including the immediate opportunity to pay over the telephone.

Q. Have you experienced an increase in costs to provide Par3?

A. Yes. Par3 is a new program with an annual cost of approximately $260,000.

Q. What is the feedback you have received from customers regarding Par3?

A. We have received direct appreciative feedback from Par3 call recipients because the automated calls are perceived as nice reminders at a time when the customers did not remember to pay their bill. Par3 is an additional method to communicate with our customers and help them to avoid disconnections. In addition to notification, it provides customers with convenient options to pay their bill over the phone.

Q. Are there any other sources of cost increases from 2002 to 2007?

A. Yes, there is one item that does not represent an actual cost increase. In 2002, PGE posted a $250,000 credit to adjust PGE's light and power accounts receivables. This type of entry could be posted each year and could reflect both positive and negative costs. However, we do not budget or forecast such amounts because they are only known after the fact. Consequently, costs appear to increase from to 2002 to 2007 because the $250,000 credit in 2002 compares to zero in 2007.

VI. Responding to Customers

Q. How have costs for Responding to Customers changed and what are the primary drivers for the changes?

A. Costs for responding to customers are forecasted to increase by $4.6 million between 2002 and 2007. Because the response function is very labor intensive and because employees interact directly with customers, wage and salary increases plus growing customer counts are the primary drivers of higher costs.

Q. What functions does "Response to Customers" encompass?

A. "Response to Customers" is a category that encompasses the various ways we connect with customers and customers connect with PGE. It includes contact center operations, portions of our CIS, the interactive voice response system (IVR), key customer managers, and web sites PortlandGeneral.com and PortlandGeneral.biz. I discuss these below.

A. Contact Center Operations

Q. To what extent have costs increased at the Contact Center?

A. Contact Center costs have increased $3.5 million since 2002, comprising of $1.9 million for customer service representatives (CSRs), $680,000 for management, support, and supervision, and $970,000 to support the operation of PGE's customer information system. As described above, the main driver for this increase is additional labor costs for CSRs and support personnel to address the requirements created by:

- Growth in the annual number of written documents we process because of increased customer website correspondence and self-service options.

- An increase in call volumes. Calls to customer service representatives increased 23% between 2001 and 2005 and calls to the Interactive Voice Response system (IVR) increased by 26% for the same period
- An increase in the average handling time for calls, which is a combination of actual response time and post-call follow up
- An increase in the number of options available to customers due to the implementation of SB 1149
- The conversion to, and operation and support of, our new customer information system
- Additional support and supervision costs to manage the new programs, processes and services, and to propose and evaluate process improvements, to some extent, these management and support costs apply to all Customer Service functions but they are assigned to the Response function, (which is the largest by cost and number of employees) rather than allocated to other functions.

Q. Why are skilled CSRs so important?

A. As a result of many factors, including SB 1149 implementation, the utility industry has become much more complex than six years ago. We have more tariffs and more service options to explain to customers. To perform all necessary functions properly, we need intelligent, flexible, technically-capable people who can understand the diversity and complexities of the utility industry, navigate customer information systems, communicate well with people, solve problems, multi-task, and work quickly. They also need to be able to assess a large amount of information in a fairly short period of time, and they need to be committed to continual training as new procedures, new programs, and new technologies are introduced.

Q. What are the primary functions of the Contact Center?

A. The Contact Center supports PGE's core business and handles customer requests for service and information efficiently and cost-effectively. In addition to managing inquiries and communications received by mail and the web, the Contact Center staff manages approximately four million residential and small business customer calls annually (both directly and through the automated telephone system). They also play a large role in general and emergency outage response in terms of providing support to customers and in reporting valuable information to our distribution department for outage restoration. Additionally, the Contact Center has a special tactical group known as Customer Relations that:

- Acts as a central point of contact for unusual or escalated customer issues
- Manages OPUC referrals
- Provides customers with information that affects them directly (e.g., account information, planned outage notifications and/or service improvements)
- Manages unsolicited customer feedback to identify emerging trends and concerns, and to continually track processes and initiate improvements

Q. What other functions does the Contact Center serve?

A. Another primary responsibility of the Contact Center is to ensure that data in the CIS are current (e.g., processing change of address requests, returned mail, and requests for added services or programs). We accomplish this over the phone or through the management of written documents. Each year, the Contact Center receives and processes approximately 250,000 documents, including responses to customer letters, bill statement comments, change-of-address requests, program enrollments, return mail, and company-generated letters to notify customers about their accounts.

Q. Has the Contact Center implemented any initiatives or programs to enhance service to customers?

A. Yes. They have completed many initiatives to improve efficiency and provide customers with continued high levels of service. These include peak staffing and auto-indexing projects as well as our Customer First response team, enhanced training and development, and customer programs like PGE Connections.

Q. What is Peak Staffing and how has it improved Contact Center operations?

A. Peak staffing is a new and more efficient way to deploy our employee resources to better match our call-volume profile. Through creative and flexible scheduling, including various part-time options, we have systematically reallocated customer representatives so that we have more staff available to answer calls during peak call-volume times and fewer representatives available to answer phones during non-peak times. Consequently, we have increased our accessibility to customers and have helped meet customer needs faster, while reducing overtime expenses. Secondarily, we have supported a strong employee desire for alternate (more flexible) schedules.

Q. What is your auto-indexing program?

A. Auto-indexing was implemented in 2005 and creates an automatic electronic file of letters sent to, or received from, a customer. It also creates an automatic note on the customer's account. When done manually, this process takes more time and occupies employee resources that might directly assist customers in other ways. This is an important function for many reasons, but the principal advantage to customers is that any representative can locate records that have been electronically filed so the customer will not have to wait for follow up at a later time.

Q. What is Customer First and how does it benefit customers?

A. Customer First is a small tactical team of customer service representatives that primarily manage outage response during normal business hours as well as nights and weekends. Their primary responsibility is dealing with the surge of customer phone calls that occur during an outage, particularly outside of normal business hours. They can assess when it is appropriate to call additional employee resources in to assist with outage response, and they ensure that PGE has adequate staffing to manage outage response. Most importantly, they are available to provide information to customers regarding outages that normally would be addressed by Repair Dispatch, thereby freeing up our dispatchers to focus on outage restoration. During non-outage times, the Customer First team responds to regular customer calls and assists with document management and web response.

Q. Have you received positive feedback from customers regarding Customer First response?

A. Yes. Customers appreciate the fast and efficient way Customer First handles their outage calls. Before we created this team, customers calling after business hours sometimes had to wait for long periods while dispatchers managed multiple incoming calls and dispatched crews. By efficiently managing call volumes at the beginning of an outage, PGE can more quickly address customer concerns and questions regarding the outage.

Q. What other factors have produced cost changes for the Contact Center?

A. There have been two factors that net to approximately $110,000 increased costs. The first factor is approximately $480,000 for the stub labor accrual. As described in PGE Exhibit 500, this cost refers to labor that is accrued from the final hourly payroll of the year (which falls on a Tuesday), until the last day of the year. The $480,000 associated with Customer Service represents change from a negative $410,000 accrual in 2002 to a positive $60,000 accrual in 2007. Offsetting these costs is a $300,000 reduction in non-labor costs from efficiencies and savings.

B. Interactive Voice Response System (IVR)

Q. What cost changes are associated with the IVR?

A. Costs to maintain the IVR have increased approximately $33,000 since 2002. IVR costs relate to annual maintenance agreements plus efforts to add new features such as "Pay by Check," which I describe below.

Q. What is the primary function of your IVR system?

A. Our IVR provides an option for customers to complete transactions and obtain information by phone at any time. It is also a tool that routes customers to the correct call queue so that if they do wish to speak to a representative, they can do so without further transfers.

Q. What benefits does the IVR provide?

A. From a customer perspective, the IVR system allows them to quickly check basic account information as well as obtain information about office locations and hours, without waiting to talk to a representative. Customers can also report and receive automated outage updates. The IVR is essential for addressing simple transactions as it can process thousands of calls in a fairly short period of time, at any time. Consequently, when the IVR processes simple issues, it releases customer service representatives to address more complex calls.

Q. Why do some customers prefer the IVR?

A. Some customers will always prefer to interact with a person, but many now prefer transacting with an automated system, especially if it saves them time. Our IVR is particularly beneficial in managing large call volumes related to power outages. Not only can a customer quickly report their outage, they can call back to receive updates. The IVR populates our outage management system with updated customer information that improves our outage response. During outages, customers praise the system for its practicality, usefulness of information, and for the assurance it provides that we are aware of and responding to the outage.

Q. What other features does the IVR provide?

A. We recently enhanced our IVR system by adding a "Pay by Check" feature that allows customers to pay their bill by check over the phone in the same manner they currently can pay on the web. They can also make payments by credit or debit card through a third-party vendor. Further, in 2006, we plan to implement a program to allow customers to use the IVR or web to make automated payment arrangements with PGE.

Q. Do customers appreciate the new Pay by Check feature?

A. Yes. We implemented this feature on October 27, 2005, and after two months we had already received approximately 21,000 payments totaling more than $3 million. This was a clear indication that customers appreciated this convenient, simple, and no-cost option to pay their bills.

C. Key Customer Managers

Q. How have costs changed with regard to Key Customer Managers?

A. Costs for providing Key Customer Managers have increased by $1.0 million since 2002. The primary drivers for the increase are wage increases, the amortization of certain equipment costs associated with Dispatchable Standby Generation (DSG) and an accounting change to reflect that certain labor costs relate to Customer Service functions rather than Distribution and A&G.

Q. Please describe the labor cost increase since 2002.

A. Labor has increased by approximately $600,000 since 2002. Of this increase, $200,000 is due to labor costs shifting from Distribution and A&G to Customer Service to more accurately reflect the nature of the work performed. Approximately $260,000 of the increase since 2002 is associated with wage increases. These relate to general inflation plus the need to retain qualified employees that work closely with PGE's largest customers to maintain a high level of customer satisfaction. Approximately $120,000 of the increase relates to a change in focus from non-utility functions, which have been eliminated, to utility functions that are being reinforced.

Q. Has there been a reduction in costs in other areas of the company?

A. Yes. As stated above, the Distribution and A&G areas have experienced a combined reduction of approximately $200,000 because of the change in the Key Customer Managers' focus on customer service functions.

Q. What other factors have experienced cost increases?

A. PGE has purchased equipment that facilitates customers' efforts to implement DSG projects. We refer to these costs as "aid-in-construction." Because this equipment is ultimately owned by the customer, PGE amortizes these costs over the life of the contract, which is typically ten years. The amortization costs are charged to the Key Customer Manager function and have increased by approximately $200,000 as the number of DSG sites have increased. For more discussion of DSG, see Section VIII below.

Q. What functions do key customer managers perform?

A. Our Key Customer Group manages the service between PGE and approximately 900 large commercial, industrial, and governmental customers. This group of customers has 17,400 electric accounts and represents approximately 33% of PGE's total annual revenue. As with most utilities, key customer managers are assigned customers and their primary responsibility is to help those customers to make sound business decisions that account for their unique energy needs. The key customer manager is the single point of contact and helps facilitate the delivery of power and services to the customers they represent.

Q. What are the benefits for customers with assigned key customer managers?

A. Key customer managers are the first point of contact within PGE for these customers and are available 24 hours a day, seven days per week, primarily to address issues surrounding energy reliability and power quality. They expend considerable effort to educate their customers about regulation, energy markets, pricing, and PGE's role in the process. They assist customers in learning about and taking advantage of energy efficiency technologies related to industrial processes, lighting, refrigeration, motors and other equipment. Key customer managers provide information and support associated with the energy exchange, E-manager solutions, distribution services and renewable power. They ensure that PGE completes electrical distribution and transmission design requirements in a timely manner to provide safe, cost-effective service, and they address customers' concerns regarding electric service, power quality, and maintenance.

Key customer managers also assist customers by referring them to the ETO and its various incentives and programs designed to assist businesses. PGE has referred approximately 134 customers to the ETO in this regard, which is significant for customers as well as the ETO.

Q. What other activities do Key Customer managers offer their customers?

A. Other activities include resolving billing questions, coordinating line extensions, managing facility expansion or upgrade requests, solving energy delivery concerns, performing general customer maintenance activities, advising customers about applicable rules and regulations, resolving issues between the company and customer, supporting and assisting with customer service programs and power quality assessments, resolving damage claims as required, and verifying information about system reliability and performance. The key customer group also sponsors various educational workshops for commercial and industrial customers so they can learn more about efficient operations. These workshops, which we often co-sponsor with outside organizations such as the ETO and the Oregon Office of Energy, are very popular and focus on many topics including: power quality, power distribution, transformers, motors and controls, day-lighting, water purification, and refrigeration. Twice each year, we also sponsor executive forums that allow large customers to meet with PGE executives.

VII. Information Technology

Q. How have costs changed for Customer Service Technology?

A. Information Technology (IT) costs have increased by $5.4 million from 2002 to 2007 for Customer Service. These costs arise from IT applying direct charges ($3.0 million) and allocations ($2.4 million). Direct charges support specific applications and systems within Customer Service. IT costs that relate to voice, data, and office systems apply to all of PGE and are allocated across the functional areas.

Q. To what do you attribute the increase in direct charges from IT?

A. Direct charges from IT have increased because Customer Service has required additional IT support for the following new and/or upgraded systems:

- Customer Information System
- PowerTrack (meter inventory/testing database)
- Meter reading (Itron P+4)
- Power Billing System
- Bill Print
- Field work orders (ServiceLink)
- Remittance processing (Unisys)
- Electric bill payment and presentation on PGE's internet sites, PortlandGeneral.com (for residential and small commercial customers) and PortlandGeneral.biz (for large commercial and industrial customers)
- Updating approximately 20 systems interfaces to other PGE applications for each of the above.

Q. Why have allocated IT costs increased?

A. The changes to IT allocations are the result of accounting-related changes that are explained in detail in PGE Exhibit 500.

VIII. Other Programs and Service Options

Q. What does "Other Programs and Service Options" encompass and what factors are driving the additional costs?

A. Other Programs and Service Options include Customer Research and the management of approved utility products and services, such as our Renewable Power Program and E-Manager.

The costs to manage "Other Programs and Service Options" have increased by $2.3 million from 2002 to 2007. The primary programs responsible for cost increases include Customer Research, the Renewable Power Program, the ESS office, E-Manager, and DSG. I discuss these programs in further detail below.

A. Customer Research

Q. What has been the cost increase related to Customer Research?

A. There has been an increase of approximately $1.0 million since 2002 for third-party research, the customer database, and customer surveys. Over the last few years, we have consolidated most customer research expenditures within the Customer Service budget rather than the department sponsoring the research.

The primary driver to this increase is research using outside vendor services. In the last five years, we have pursued an increase in residential, general business and key customer satisfaction benchmarking research, call center and web transaction tracking research, and additional E-Source and Chartwell syndicated studies. I discuss these in more detail below.

Q. What kind of survey work does PGE regularly perform to learn about customer needs and satisfaction?

A. PGE performs or manages research studies to help understand customer trends and satisfaction that, in turn, help us to identify issues and opportunities from which to develop appropriate courses of action. Research studies include syndicated utility studies (e.g., Chartwell and E-Source), benchmarking studies (e.g., J.D. Power, Market Strategies Inc., and TQS Research), PGE-specific customer surveys and transaction tracking, purchased research, focus groups and "usability"[2] research. We also conduct comprehensive research to further understand the different service expectations and requirements of residential and business customers, including specific segments in each class.

We use both qualitative research such as focus groups and usability research through which we attempt to access ideas from customers so that we can provide better service or more useful information. In addition, we conduct quantitative research to assess where we rank among peer utilities and other companies. This is one way to judge customer satisfaction and set our goals to ensure we meet customer expectations.

Q. Do most utilities perform this type of research?

A. Yes. Most utilities are involved in customer satisfaction research, focus groups, syndicated research, benchmarking, and transaction-tracking research.

Q. How does Customer Research benefit customers?

A. The benefits of Customer Research include:

- Customer feedback from which to develop programs, service options, or other approaches to address concerns and issues that affect customer satisfaction.

[2] Usability research involves timing studies of various functions performed by customer service representatives as well as customers.

- Identification and evaluation of promising new programs and service options, such as Par3, enhancements to the renewable power options, and automated payment features.

Q. What is the purpose and benefit of the Customer Database?

A. PGE began developing a customer database (CDB) in 2000 to assemble transactional, behavioral, and demographic customer data so that we could more effectively apply customer information to improve program offerings and service options. This project consolidated information to improve services and ensure that the right customers receive the right information and to ensure that we are communicating efficiently to improve customer satisfaction. For example, we are currently analyzing bill payment practices so that we can better direct resources to customers who genuinely need assistance, versus those who appear to need assistance because they are slow- or non-paying customers.

Q. What other types of programs and service options does PGE provide?

A. PGE provides energy-related programs and services to augment our core programs. These include our Renewable Power Program, Dispatchable Standby Generation, E-Manager, and customer products. I discuss each of these services below.

B. Renewable Power Program

Q. What are the primary drivers of increased costs associated with the Renewable Power Program?

A. Renewable Power Program costs increased approximately $400,000 from 2002 to 2007 and primarily relate to the cost of consulting services to provide surveys and interviews, postage, printing, event costs, and incentives.

Q. How does the Renewable Power Program benefit residential customers?

A. Renewable power is a voluntary customer program that currently provides the additional environmental attributes associated with 25-30 average megawatts (aMW) of renewable resources. Introduced to customers as a requirement of SB 1149, the portfolio of renewable power options was created, and is overseen, by the Portfolio Options Committee (POC). This committee includes representatives from Renewable Northwest Projects, Fair and Clean Energy Coalition, Citizens Utility Board, the OPUC, Pacific Power, PGE and small business customers in Oregon. Currently, the program offers three residential renewable power options.

C. Dispatchable Standby Generation (DSG)

Q. What cost changes have you experienced in Customer Service related to PGE's DSG program?

A. The DSG program costs charged to Customer Service increased by approximately $300,000 from 2002 to 2007. As described in Section VI, above, $200,000 of this increase represents charges to Key Customer Manager costs for amortization of "aid-in-construction" costs. The remaining $100,000 of the increase relates to development costs for DSG projects, and is charged to Other Programs and Service Options.

Q. What is the DSG Program?

A. The DSG Program is designed to operate customer-owned generators up to 400 hours per year to provide operating reserve capacity generation, to significantly reduce wholesale purchased power costs for "needle" peak times, and enhance reliability for customers as a whole.

Q. How does DSG work?

A. The customer owns the electric generator but PGE pays for the switchgear that allows the generator to run synchronous with the grid. PGE also pays for the hardware, communication equipment and software to run the generator remotely. If it is cost-effective and the customer agrees, the costs for dual-fuel conversion and sound attenuation may also be included. PGE covers the cost of all maintenance on the generator, reimburses all fuel costs, and assumes responsibility for monthly testing. In return, the customer gives PGE the right to run their generator for up to 400 hours per year. The customer continues to pay for all electricity used at their facility. Ultimately, the electricity generated through DSG replaces more costly market power purchases, and the customer continues to receive their normal bill. DSG agreements with customers typically have a ten-year term.

Q. How is DSG advantageous to customers?

A. The additional power we receive from these generators is power we do not have to purchase at higher market rates. This keeps costs down for all customers and it allows customers who own generators to obtain added value from them, in addition to the 10-15 hours annually that the generators are typically operated in emergency situations.

Q. What environmental benefits does PGE's DSG program provide all customers?

A. PGE has installed oxidation catalysts on program generators. The oxidation catalysts convert 90% of the carbon monoxide to the less harmful carbon dioxide. When assisting the customer on generator selection, PGE recommends the installation of low nitrogen-oxide engines and requires low-sulfur diesel for all program generators.

In addition, PGE has installed two dual-fuel conversion packages to study the benefits of new, cleaner technology. Dual-fuel conversion allows program generators to be operated primarily on natural gas, which has lower emissions than diesel. This research has the potential to reduce up to 40% of the nitrogen-oxide, which is one of the major air pollutants from diesel engines. This may also eliminate the need to increase the stored fuel capacity for a facility. PGE continues to conduct additional emissions research.

D. E-Manager

Q. What cost increases are associated with providing E-Manager?

A. E-Manager[3] program costs have increased by approximately $180,000 since 2002. The increase occurred because in January 2004, the OPUC authorized PGE to charge E-Manager program costs to utility accounts if the service is provided within PGE's service territory. E-Manager program costs outside of PGE's service territory are considered non-utility and are not included in retail rates. The $180,000 E-Manager utility costs, however, are offset by $230,000 of Other Revenue that reduces PGE's overall revenue requirement.

Q. What is E-Manager and how does it benefit customers?

A. E-Manager provides consumers with interval-usage data depicted in charts and graphs for the purpose of comparing current and historic load data, identifying anomalies in usage, tracking savings from energy efficiency projects, and understanding energy usage. Two service options are available:

1) Standard Package – Data is updated on a weekly basis.
2) Enhanced Service – Data is updated on a daily basis.

An optional feature called Energy Worksite offers more automated tracking capability including the ability to track projects, work orders, and energy bills, as well as manage preventative maintenance.

[3] E-Manager refers here to Meter Information Services within PGE's service territory.

Q. Can you provide a specific example of E-Manager benefits?

A. Yes. Interval meter reports from E-Manager were instrumental in helping the Gresham-Barlow school district track and fine-tune energy usage, such that their schools now use 40 percent less energy than others nationwide. As a result, in 2005, the Gresham-Barlow school district was the first organization in the nation to be awarded the top levels of the U.S. Environmental Protection Agency's Energy Star Leader award.

E. ESS Business Office

Q. How have costs increased for the ESS Business Office?

A. Costs are forecasted to increase approximately $240,000 from 2002 to 2007. The increase is split almost equally between labor and non-labor factors. The increase in labor relates to wage increases. The increase in non-labor costs is to address the changing regulatory requirements associated with direct access (see Condition 15 to the Stipulation in UM-1206, approved by Commission Order No. 05-1250).

Q. What is the purpose of the ESS Business Office?

A. PGE developed the ESS Business Center in 2001 to address the requirements of SB 1149. The purpose of the center includes the following activities:

- ESS business application processing and set-up
- PUC coordination on ESS issues
- Direct access customer enrollment
- ESS account and relationship management
- ESS billing, including customer billing option, ancillary service reconciliation, and service fee billing
- ESS payment and remittance services

- ESS credit monitoring.

In addition, the ESS office assures quality of service to energy service suppliers and direct access customers by providing a single point-of-access for ESS services.

F. Other Products

Q. What other programs and/or service options does PGE offer or plan to offer customers and what are costs associated with these programs?

A. PGE has a number of other programs and/or service options that we currently offer or plan to offer. In total, costs for these programs are forecasted to increase approximately $340,000 from 2002 to 2007. Examples of these programs include:

- The "start service bundle" consists of several programs packaged together for customers to accept at the start of service (e.g., paperless bill, Equal Pay, Auto Pay). Currently, when customers request new service (i.e., a hook-up request), there is no "packet" explaining all of PGE's available options. Instead, customers learn via bill inserts and other sources over time, and have indicated they would like improvements. By offering available options at the inception of service, we enhance efficiency and minimize costs.
- PGE Connections enables customers to start service for electricity, telephone and cable TV in one call. This program benefits customers because the revenue we collect from PGE Connections exceeds the costs of the program. In 2007, we forecast this program to net approximately $44,000 on an incurred basis.
- Energy Efficency Education Services permits PGE's energy experts to receive additional training in energy efficiency and develops improved methods to introduce eligible PGE customers to ETO programs.

- Area lighting information provides detail to familiarize PGE's customers with our area lighting service.
- Billing and Payment Program evaluates communications regarding billing and payment options to facilitate customers choosing their optimal billing and payment plans.

IX. Customer Communications

Q. How have customer communication costs changed since 2002?

A. These costs are forecasted to decline by approximately $200,000 from 2002 to 2007. For 2007, we forecast that we will spend approximately $2.6 million for Customer Communications. Of this total, $2.0 million is for informational advertising regarding safety, customer communications and program communications; approximately $570,000 will cover communications regarding wise and efficient use of energy; and approximately $80,000 is for legally-mandated advertising that includes communications regarding power options.

Q. What role do PGE-initiated communications play in the effective delivery of services?

A. These communications provide essential information regarding safety, wise and efficient use of energy, power options, billing and payment options, and general customer service.

Q. What types of communication media does PGE use to communicate to customers?

A. As communication has become more fragmented and complex, PGE uses a wider variety of media to connect with customers and provide them with beneficial information. Communications channels we utilize include:

- Direct communications, such as hard-copy newsletters and bill inserts. Approximately $590,000 is for these materials in 2007.
- Brochures, flyers, fact sheets, and other printed materials. Approximately $240,000 is for these items in 2007.
- Advertising, such as television commercials, radio commercials, and newspaper advertising. These communication channels require approximately $1.5 million
- Event communications. Approximately $25,000 is for these activities in 2007.

- Educational materials and outreach. We forecast approximately $160,000 for these materials and school presentations.
- Point-of-sale materials, displayed in PGE community offices. Approximately $13,000 is needed for these materials in 2007.
- Spanish-language communications, such as radio, newspaper and magazine advertising, plus brochures and other materials printed in Spanish are expected to cost approximately $125,000 in 2007.

Q. How do your communications programs promote the safe use of electricity?

A. Electricity is an essential product for modern life, but it is potentially dangerous if misused. PGE has become an industry leader in the area of safety communications, as benchmarking research has shown. Some of the specific elements in our safety communications program include:

- Children's safety education, such as teaching materials provided to schools; public service announcements on children's television programs; brochures that include warnings about playing or climbing trees around overhead utility lines; and event communications such as the annual "Score One for Safety" information fair at PGE Park.
- Agricultural safety communications, such as our bilingual (English and Spanish) weatherproof safety posters and brochures mailed to PGE farm customers.
- Residential safety and outage preparedness communications, such as the safety reminders that appear in the "Update" customer newsletter, our summer safety brochure, and winter outage and safety brochure.

- Business safety and outage preparedness communications, such as the brochure that was mailed to PGE business customers, and the safety reminders that appear in the "Energize" (schedule 32) and "Power Report" (schedule 83) customer newsletters.

Q. Can you describe communications programs that promote wise and efficient use of energy?

A. Customer newsletters provide a consistent source of energy efficiency information, tips on managing energy use, and referrals to ETO incentives and Oregon Office of Energy tax credits. In 2005, the "Update" residential newsletter featured a new series entitled "Get Energy Fit in 2005." Each month an energy efficiency topic was addressed, from furnace maintenance to refrigerator seals.

Television, radio, and newspaper advertising has been used to generate referrals to ETO incentives, with considerable success. Co-branded and co-funded bill inserts, where costs are shared by PGE and the ETO, have promoted energy efficient lighting for businesses and heat pumps for residential applications. Brochures are also available that provide energy-efficiency information and contact information for efficiency incentives and tax credits.

Q. How do your communication programs promote power options?

A. A quarterly bill insert describes the power options available to PGE customers. Different versions of the insert are customized for different rate schedules. Individual brochures are available – both in hard copy and downloadable versions – regarding Time-of-Use and renewable power options. Other channels, such as television, radio, newspaper and magazine advertising, have also been used to communicate the power options available to PGE customers.

Q. How do your communication programs promote billing and payment options?

A. Because there are so many billing and payment options available to PGE customers, we have employed a wide range of communication methods to reach customers with this information. As the options are constantly evolving and changing, it is necessary for PGE to reach existing customers with new information that may save them time or money. These communications have included:

- Direct mail to customers whose profile resembles customers who have already enrolled in certain programs
- Point-of-sale materials at 7-Eleven stores to promote their new payment kiosks
- Newsletter articles announcing new billing and payment options, or providing occasional information about existing options
- Bill inserts and "bangtail" envelopes (i.e., envelopes with external tear-off forms) offering enrollment opportunities for specific options
- Brief radio commercials (ten to fifteen seconds) communicating the availability of specific billing or payment options.

Q. What communication programs provide general customer service information?

A. Some of the most important communications to our customers include how they can reach PGE in the event of questions or outages, where they can pay their bill, and our hours of operations. Various customer newsletters provide a variety of contact information on a monthly basis. PGE also places information advertisements in telephone directories. We post contact information, office locations, and business hours on PortlandGeneral.com. In addition, we have an automated system on the web so that customers can locate one of the new payment kiosks.

Q. Does this conclude your testimony?

A. Yes.

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HAWKE – CARPENTER – TOOMAN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Advanced Metering Infrastructure

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Hawke
Bruce Carpenter
L. Alex Tooman

March 15, 2006

Advanced Metering Infrastructure

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Stephen Hawke. I am Vice President, Customer Service and Delivery. My qualifications appear in Section IV of PGE Exhibit 600.

My name is Bruce Carpenter. I am General Manager of Revenue Operations. My qualifications appear at the end of this testimony.

My name is L. Alex Tooman. I am a project manager in Regulatory Affairs My qualifications appear in Section XI of PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the Advanced Metering Infrastructure (AMI) PGE proposes to install over the period 2006 through 2009, and to request that the Commission find that the decision to proceed with deployment of an AMI system is reasonable and prudent at this time. We are also asking for Commission approval of the ratemaking treatment we propose for AMI-related costs. This proposal includes a deferral of the revenue requirement for capital costs and O&M savings resulting from AMI installation.

Q. What will PGE do if the Commission does not find it is reasonable and prudent to proceed with AMI installation at this time?

A. PGE will not proceed with installation of an AMI system at this time.

II. AMI Proposal

Q. What is AMI?

A. AMI is a system that enables the automated collection of meter data via a fixed network. A complete AMI system consists of solid-state electronic meters; a communication system, or network, to transmit the data; and a communication server or computer system that receives and stores data from the meter, and as a two-way system, sends commands to the meter. This two-way capability enables the utility to send commands to the meter or control devices at the customers' premises.

Q. Have other Northwest utilities installed systems to automate the meter-reading function?

A. Yes. Puget Sound Energy completed the main deployment of its automated meter reading (AMR) project in 2001. Northwest Natural is installing a drive-by system in parts of its service territory. Clark County Public Utilities completed its system in 2002 and Columbia River PUD will complete its AMI system in 2006. San Diego Gas & Electric and Pacific Gas & Electric are both currently pursuing AMI, and the California PUC recently approved $49 million in "pre-deployment" costs for PG&E's proposed deployment of 9.3 million AMI devices.

Q. How has this recent activity influenced PGE's proposal to implement AMI?

A. This recent activity and the number of parties that have already implemented AMI tell us several things. First, this is a mature technology. PGE would not be a pioneer in the field of AMI; we would be following the lead of a host of other utilities, both large and small, that have seen the value of AMI. Second, we understand from the attention that has been paid to AMI in Oregon that this is a policy issue many parties would like to see addressed. For example, more than fifty parties, including CUB, recently participated in a process to identify opportunities for developing clean energy technologies. That process resulted in a report by Climate Solutions that specifically identified "smart meters" (automated meters) as a recommended part of an overall strategy to "take pressure off overloaded grid infrastructure and power costs, dramatically improve grid reliability and security, and accelerate the growth of cleaner power generation.[1]" In addition, the Energy Policy Act of 2005 states that federal policy is to encourage the deployment of technology to enable demand response programs, including automated metering, and encourages states to do the same. See Energy Policy Act of 2005 Section. No. 1252 (Smart Metering).

Q. Why does PGE propose to implement an AMI system?

A. PGE proposes to implement an AMI system to:

- Reduce operational costs in the long term
- Provide customers with better services such as customer-selected due date, outage detection, and reduced intrusions on their property
- Enable demand response programs
- Provide more accurate and timely billing.

Q. Why does PGE propose to proceed with AMI deployment now?

A. PGE believes now is the appropriate time to launch an AMI project because the technology is mature and a number of parties have signaled their interest in moving forward with future methods of grid management and demand response. We cannot begin to achieve these goals without AMI. While there are longer-term economic benefits to be gained from implementing AMI, the decision to proceed with this project is also a policy decision. For

[1] Patrick Mazza, Climate Solutions, Powering Up the Smart Grid: A Northwest Initiative for Job Creation, Energy Security and Clean, Affordable Electricity, at 2, 14 (July 2005)

that reason, we are asking the Commission to determine whether it is reasonable for PGE to pursue deployment of an AMI system at this time.

Q. What are the total costs of the AMI system?

A. Based on current estimates, we believe the initial system investment will cost approximately $141 million over a 2006 to 2009 deployment period. The projected capital costs of the components of the AMI system are summarized in Table 1, below. Although PGE did not issue a request for proposals (RFP) on the system until January 12, 2006, we based meter prices on confidential budgetary quotes provided by the vendors. These projections assume approximately 843,000 meters are installed by year end 2009. Our estimates assume our meters will be a mix of radio frequency (RF), power-line carrier (PLC), and phone meters. However, we have invited bidders to propose their best solution to meet our requirements.

Table 1
Projected AMI Capital Costs
2006-2009 ($000)

	2006	2007	2008	2009	Totals
RF Meters Including Installation	856.9	17,797.1	48,018.9	23,856.2	90,529.1
PLC & Phone Meters Including Installation	796.4	4,980.0	14,580.9	6,124.8	26,482.2
Meter Testing and Field Supervision	354.9	1,533.3	2,123.5	967.8	4,979.5
Systems Development	2,417.9	3,482.5	2,952.9	633.0	9,486.3
Servers & Storage	166.6	687.9	1,519.6	354.4	2,728.6
Network Equipment	146.3	1,346.8	3,471.0	1,000.4	5,964.5
Licenses, Handhelds & Misc.	140.7	284.8	240.0	175.0	840.5
Totals	4,879.8	30,112.4	72,906.8	33,111.6	141,010.6

Q. How does your joint meter reading program with NW Natural affect your estimates?

A. It does not affect the total investment because we plan to deploy the AMI system over PGE's entire service territory. Northwest Natural (NWN) is in the initial stages of deploying an AMR program. Based on our mutual discussions, we have determined that, by coordinating deployment, the joint meter-reading territory could be converted without either company having to hire temporary meter readers.

Q. What is the effect of deploying the AMI system on PGE's O&M expenses?

A. O&M expenses will decline primarily due to the reduction of meter readers and field collectors. The number of positions eliminated and magnitude of O&M savings, however, is dependent on the extent to which NWN deploys its AMR system. If NWN deploys an AMR system over its entire service territory, PGE (absent our AMI system) would have to hire an additional 21 meter readers to cover the area currently serviced by the joint-meter reading program. If NWN were to deploy an AMR system only in territory not jointly read with PGE, we would not have to hire the additional 21 meter readers. As filed, the revenue requirements in this case do not include these additional meter readers.

Q. Which outcome is more likely and what are the savings?

A. PGE is attempting to determine but is currently uncertain as to NWN's decision regarding AMR deployment. Consequently, we provide our AMI projections both with and without the 21 meter readers. As listed in Table 2 below, PGE projects that by 2010 the AMI system will achieve annual O&M savings of approximately \$17.1 million without and \$18.7 million with the addition of 21 meter readers. As stated above, these savings will be achieved primarily from the reduction of meter readers (114 without or 135 with the 21 meter readers by 2010) and field collectors (22 by 2010).

Table 2
Projected Annual O&M Savings - 2010

AMI Projected Savings	**Without 21 Meter Readers**	**With 21 Meter Readers**
Labor Cost	$ 11,190	$ 12,876
Non-labor Cost	890	890
Late Fees	1,732	1,732
Energy Unaccounted For	1,871	1,871
Power Cost Savings	1,248	1,248
Other Savings	125	125
Total Projected Savings	**$ 17,057**	**$ 18,743**

For the 20-year period beginning in 2007, we estimate the net present value of all AMI-related costs and savings will reflect approximately $4 million benefit (i.e., reduced revenue requirement) without the 21 meter readers and approximately $20 million with the 21 meter readers.

Q. Are the AMI investment and O&M savings included in your test year revenue requirement?

A. No. PGE has not included either of these items in the 2007 test year revenue requirement. Instead, we propose to mitigate the rate impact of deploying this system by deferring the revenue requirement associated with AMI capital expenditures. We also propose to include annual O&M savings in the deferral until December 31, 2009, when we anticipate the system will be fully deployed, in order to reduce the total amount deferred.

Q. How much is the projected deferral?

A. As this case is filed, the total deferral over the three years of deployment, net of operational savings, would be approximately $21.6 million.

Q. How will PGE track the deferral amounts and collect the deferral from customers?

A. We propose to file a deferral application and establish a balancing account that tracks the deferred AMI revenue requirements net of operating savings during the deployment period. PGE will record the following charges or credits to the deferral account as follows:

- Deferred AMI revenue requirement associated with deploying the AMI system. This will consist of the system's capital costs for meters and associated equipment, installation costs, and necessary support systems incurred during the primary deployment period of 2007 through 2009.
- Estimated operating cost savings resulting from the AMI deferral. These will accrue to the deferral account based on the percent of total meters deployed per month during the 2007 through 2009 primary deployment period.

PGE will collect or credit customers the estimated amount in the AMI balancing account in a manner approved by the OPUC.

Q. What impact would the AMI system have on the 2007 test year revenue requirement if it were included?

A. Because we propose to defer the revenue requirement of the new AMI investment and associated O&M savings, the potential impact of AMI on the 2007 test year would relate only to existing metering capital. Specifically, this would include accelerated depreciation of the existing system, so that the remaining net plant of the existing system is amortized as the new system is deployed. The effect of these changes would be to increase PGE's revenue requirement by approximately $3.7 million.

III. AMI System

Q. Please describe the AMI system PGE proposes to deploy.

A. PGE currently proposes to deploy a system with three parts:

1. A combination of radio frequency and power line communication networks that can most effectively and economically gather meter data from our entire service territory.
2. Hardware and software necessary to meet the data collection, storage, and processing requirements plus interfaces with all other necessary PGE systems.
3. Meters with two-way communications that enable accurate recording and transmitting of interval data for all customers.

PGE has issued a Request for Proposals (RFP) for all of the field equipment and all software necessary to manage the equipment that will be used to implement this system. The RFP also makes it clear we are open to other design suggestions that may better meet PGE's needs.

Q. Which classes of PGE's customers would be included in the AMI system?

A. All metered customers, including small non-residential and residential, would be included in the AMI system.

Q. When would the system become operational?

A. PGE has developed an illustrative project timeline that shows complete deployment of approximately 843,000 AMI meters throughout our service territory over the period of 2006-2009. Naturally, because we have just begun the RFP process, a variety of internal and external factors could affect that timeline. It is important to note that PGE already has one key aspect of the AMI system in place, a meter data consolidator (MDC), which we deployed as part of the UE 115 NMR Plan. PGE did not implement the entire NMR Plan contemplated in UE 115 because we found direct access did not proceed as rapidly as anticipated and the technology did not develop as expected. The MDC, however, is currently in use as the system of record for all PGE meter read data, and provides PGE's business systems (e.g., customer billing) with validated data. Because we already have the MDC in place, the AMI system becomes operational shortly after the satisfactory conclusion of the acceptance test on the AMI vendor system, and benefits from AMI start to accumulate as each meter is installed.

Q. What is PGE doing right now with regard to the AMI project?

A. Although PGE does not intend to proceed with full AMI deployment without Commission approval, we have taken a number of steps to evaluate the costs and benefits possible for our customers. We will spend up to $3 million to prepare for project implementation, which includes issuing a RFP, conducting a significant review by the Information Technology organization to estimate the cost of supporting the AMI project, and beginning the public process to support approval for this investment. This preparation also includes the early development work to enable our Customer Information System to automatically accept electronic records that result from meter exchange. Current efforts also include a detailed review and prioritization of all business processes that must be modified to support, or take advantage of, the greater availability of meter data.

IV. Benefits of AMI

Q. What are the primary benefits an AMI system can offer?

A. AMI offers a number of benefits, which we roughly categorize as follows:

- Demand benefits (demand response programs and direct load control)
- Transmission and distribution system benefits (outage reporting, detection, restoration, better distribution planning)
- Economic benefits (cost savings)
- Functional benefits for customers and employees (convenience, safety)

Q. What demand response benefits can an AMI system offer?

A. The system would provide the necessary infrastructure to allow PGE to provide sophisticated demand-side programs. An AMI system permits PGE to offer pricing options and load control options, and provides a mechanism for PGE to "get the most benefit from demand response.[2]" A report issued by the U.S. Department of Energy recently recommended adopting enabling technologies, including automated metering, as a means of encouraging the growth of demand response[3]. It is important to note that some of the demand response benefits will not be recognized immediately and some will require additional investment. For example, the AMI system will allow PGE to offer *smart appliance* services, but not until its customers have smart-appliances. On the other hand, we can offer customer-selected due dates right away. Due date selection ranks highest for PGE

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[2]*See Demand Response Programs for Oregon Utilities, page 35, prepared by Lisa Schwartz for the OPUC, dated May 2003; see also Powering Up the Smart Grid, at 13* (discussing demand response and automated grid technologies, including automated metering).

.[3]*See Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, page viii, xx, 58-59, U.S. Dept. of Energy (Feb. 2006)* customers when asked in surveys about billing and payment programs they would like to see implemented.

Q. How can AMI benefit PGE's transmission and distribution system as a whole?

A. AMI's potential for enhanced outage duration information and reporting, and improved outage detection and restoration potential can help PGE manage outages and improve system reliability. AMI also allows for better distribution planning and improved detection of energy losses.

Q. What economic benefits can result from AMI implementation?

A. PGE anticipates the following economic benefits can result from AMI implementation:

- Elimination of approximately 99% of manual meter reads
- Substantial reduction in the number of service disconnect orders requiring an off-cycle visit
- Remote, on-command meter reads
- Lower costs to open and close accounts in high-turnover dwelling units
- Lower marginal cost to obtain interval data on customer usage
- Reduced cost as a result of identifying sources of energy theft.

Q. Are there other economic benefits that may be realized?

A. PGE may be eligible for significant tax credits related to installation of the AMI system through Oregon's Business Energy Tax Credit (BETC) program. There are other environmental benefits we have not attempted to quantify, such as the many benefits that flow from taking vehicles used for meter reading off the road.

Q. What type of functional benefits can AMI offer PGE's customers?

A. These benefits fall into two primary areas: safety and service. In the area of safety, AMI allows for enhanced outage duration information and reporting and improved outage detection and restoration. It will also reduce the potential for vehicle accidents or physical injury. With regard to service, AMI can lead to fewer property damage and privacy issues, because PGE will not have to visit customer meter locations on a monthly basis, and it allows PGE to offer a customer-selected due date for bills. An AMI system also has the potential to allow customers access to daily usage data so they can respond to price signals and manage their energy usage. However, this latter benefit will require some additions to the AMI system currently proposed by PGE.

Q. Are there long term benefits that will accrue from the AMI project?

A. We believe the most significant long-term economic benefit of AMI is to improve PGE's asset utilization of generation and transmission resources. While the current costs of control technology at the end-use appliance level limits the capture of AMI's technical potential for load control, PGE is actively involved in a number of efforts to reduce costs and increase market acceptance of load control. In the future, we hope to participate in efforts to implement technology that aids in reducing daily peaks with residential appliance control, extended-outage restart assistance, and small-unit (<15KW) distributed generation command, control, and telemetry support. In addition, over the long term, PGE may be able to increase capacity utilization by providing customers with next day time-of-use rates that will allow them to respond to price changes as they do with other products.

Q. Has PGE attempted to quantify the impact of these long-term-benefits?

A. As noted above, PGE projects annual O&M savings of approximately $17.1 million as a result of deploying the AMI system (see Table 2 above). We have not developed an estimate of the long-term benefits.

Q. Will the projected $141 million cost provide all of the benefits described above?

A. No. PGE does believe, however, that it will deliver the $17.1 million of operational savings and provide the backbone for the remaining future benefits. The AMI system can be likened to the purchase of a complete computer operating system and some software. The computer has some functionality but also has great potential for additional benefits as the owner purchases or develops new software. Likewise, the AMI system as proposed will have a specified set of functions, including remote meter reading, remote connect/disconnect, daily collection of interval data, function to support automated "readings" for move in/out transactions, a system with basic functionality to identify unusual energy use, and customer-selected due date. Additional functions for other benefits such as demand response programs and automated use of outage-related data will need to be developed in the future. In other words, the proposed system is necessary for these additional applications, but it is not sufficient.

V. Qualifications

Q. Mr. Carpenter, please describe your educational background and experience.

A. I am general manager for revenue operations at Portland General Electric, and am responsible for PGE's metering services, including network metering, meter data acquisition services, and billing and collections functions. I have over 27 years of diverse management and operations experience in the electric utility industry, with special expertise in strategic planning, business processes design, implementation and operations of large, strategic systems. I was president of FirstPoint Utility Services, Inc., a firm providing meter data acquisition, meter services provider, and customer service functionality to energy services providers. I was also president of Si3, a joint-venture metering services company between Portland General Corp. and Itron. I hold a bachelors degree in business and an MBA from Oregon State University.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Arleen Barnett
Joyce Bell

March 15, 2006

Compensation

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Arleen Barnett. My position is Vice President, Administration. My responsibilities include establishing compensation policy and employee policies, improving the work environment, overseeing employee and labor relations, managing employee development, overseeing Environmental Services, as well as ensuring PGE's compliance regarding FERC Standards of Conduct, Oregon Public Utility Commission Code of Conduct rules, and other employee related standards. My responsibilities also include oversight for PGE's Information Technology Department, which is presented in Exhibit 500. My current qualifications are provided at the end of this testimony.

My name is Joyce Bell. My position is Director of Compensation and Benefits in the Human Resources Department. My qualifications are provided at the end of this testimony.

Q. What is PGE's goal for total compensation?

A. PGE strives to control total compensation costs on the one hand, while attracting and retaining enough skilled employees to provide safe, adequate and reliable service to our customers on the other hand. Total compensation costs include wages and salaries, benefits, and incentives.

Q. What are the challenges that PGE faces in meeting its goal for total compensation?

A. PGE faces several challenges in total compensation. One major challenge is PGE's employee and labor pool demographics. PGE has a larger proportion of workers ages 45 through 64 compared to other U.S. electric utilities and the U.S. general population. Twenty percent of PGE employees are currently eligible to retire. We expect total retirements to double from 52 (average annual retirements from 1996 through 2004) to 111 (expected annual average 2005 through 2017). By 2018, 55% of PGE's positions could be vacated through retirement. This is occurring in a tight labor market in which it is difficult to find employees that have the skills necessary for many utility functions. These demographics make attracting and retaining employees more difficult and costly.

Recent market forces also cause challenges for PGE. Since UE 115, financial market performance has lowered pension fund earnings to the point where net costs are again rising. The benefits market has continued to show significant increases in health and welfare costs to all companies in the past few years.

Additionally, PGE's existing employees face an increasing amount of new work. PGE is subject to a number of new, complex regulations (e.g., Sarbanes-Oxley, new FERC requirements, and others) that our employees must understand and comply with. Many work groups also have new or expanded activities, e.g., added work to maintain several new hydro licenses, a new generating plant, and approximately 60,000 more customers to serve. Finally, new program administrative duties, changes in our compensation programs, and changes in our workforce have also increased the complexity and amount of work for PGE's employees in Human Resources.

Q. What is PGE's strategy for meeting its total compensation goal?

A. PGE controls costs primarily by targeting each total compensation component to the 50th percentile of the labor market (the "market median"). In other words, half of the employers to which we compare ourselves pay more and half pay less. PGE strikes a balance between controlling costs and offering compensation that is competitive enough to attract and retain skilled employees. We monitor cost changes and implement program changes where appropriate in order to maintain that balance among compensation components, among our various employee groups, and between PGE employees and the labor market.

It is even more important for PGE to provide competitive compensation in a time during which over 20% of current employees are eligible to retire and there is a labor market shortage of skilled employees to replace them. PGE has made several changes to its benefit options to reflect the demographics and the tight job market. The benefits selections give greater flexibility for employees to choose from options that meet their needs and support PGE in controlling costs. Another way that PGE controls costs is by passing on 15% of the cost of health care premiums to employees so that both the company and the employee have incentives to minimize health care costs. Finally, PGE has sponsored new benefit programs to add to employees' choices and improve their health. Improved employee health increases productivity while reducing costs to PGE.

Q. What makes the design of PGE's total compensation complex?

A. PGE has four categories of employees, several incentive programs, and different benefits for each category of employee. The design of PGE's compensation program must consider multiple interests, including those of non-union and union employees, customers, the company, and the community. PGE must track and consider changes in the characteristics and preferences of our employees, practices in the compensation markets, and the rules that govern our options, while managing the impact to costs. Over time, this process must yield a set of reasonable choices for employees and applicants in order that PGE remain able to attract and retain the skilled employees needed to attain its corporate goals.

Q. What are the costs of total compensation?

A. Table 1 provides the costs of the compensation components, which have increased at 5.4% per year on average from 2002 through 2007.

Table 1 - Total Compensation Costs
($000)

	2002 Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Wages and /Salaries	156,739	156,484	160,027	172,135	180,673	189,856
Incentive	8,086	9,944	8,019	8,657	10,805	12,354
Benefits	32,694	36,319	43,586	47,941	50,717	54,349
Total Compensation	197,518	202,746	211,631	228,734	242,195	256,559

Q. What is the purpose of your testimony?

A. We support PGE's total compensation cost forecast for the 2007 test year. To this end, we describe compensation costs in detail, as well as our methods to set wage, salary, and incentive guidelines. We relate characteristics of PGE's employee population to these costs. We describe PGE's employee benefits costs and show how PGE develops employee benefit options that are reasonably designed and competitively priced. We also explain the effects of our 5-year union contract, agreed to in 2004.

Q. How is your testimony organized?

A. Our testimony has five sections. After this introduction, we discuss wages and salaries, in particular our strategy, process and costs. The following sections provide the same information for incentives and benefits. Our qualifications are the last section.

II. Wages and Salaries

Q. Why is wage and salary compensation important to PGE's total compensation?

A. Wage and salary compensation is among the primary factors that an employee or prospective employee will consider when deciding to start or remain working for any employer. Wage and salary compensation is also the foundation for incentive compensation. Controlling the cost of wages and salaries is important because it is the largest component of total compensation.

Q. What are the particular challenges that PGE faces regarding wage and salary compensation?

A. When PGE's wage and salary levels are too low, employees have a higher incentive to leave PGE for other companies. In addition, the applicant pool will not be as high in quality as applicants look towards better paying positions in other companies. Without an appropriate cash compensation strategy, PGE could quickly lose valuable skills and experience, which could result in reduced efficiency, increased turnover, and increased training needs.

Q. What is PGE's strategy in attaining its total compensation goal with regard to the wage and salary compensation component?

A. Our wages and salary expense is a function of both what we pay and how many people we pay. What we pay is determined by the labor market median. PGE monitors the labor market to gain information about compensation program design practices. Using recent market information, PGE can change the wage and salary structure to remain competitive in the labor market, to best meet human resource challenges as they arise, to achieve balance between PGE's employees, and to achieve balance between PGE and our labor market.

How many people we pay results from PGE's number of full time equivalents (FTEs). In our corporate budgeting process, PGE's managers first establish the number of labor hours at each pay grade they need to fulfill their assigned tasks and then convert that into FTEs. In other words, the work determines the number and deployment of people.

Q. Please describe the wage and salary compensation costs from 2002 to 2007.

A. Table 2 provides PGE's wage and salary compensation costs for 2002 through 2007. We project 2007 wage and salary compensation costs of $189.9 million, which is an increase of $33.1 million from 2002 costs, or an annual growth rate of 3.9% per year.

Table 2 - Annual Wage and Salary Cost
($000)

	2002* Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Wages and Salaries	156,739	156,484	160,027	172,135	180,673	189,856

* 2002 wages adjusted to remove an extra pay period for hourly and bargaining employees

Changes to the wage and salary structure (the market guide) cause some of the year-to-year fluctuation. Table 3 shows the target wage and salary structure year-to-year change for non-exempt, exempt, and bargaining employees.

Table 3 - Changes in Wage and Salary Structure

	2002	2003	2004	2005
Non-Exempt	3.5%	2.0%	3.0%	3.0%
Exempt	3.5%	1.5%	3.0%	3.0%
Bargaining	4.0%	4.0%	1.0%	3.0%

Other factors also influence the total cost fluctuations. For example, PGE reduced FTEs from 2002 through 2004, combined with an economy that slowed wage and salary increases in the market. This FTE reduction produced a slower cost growth rate. After 2005, the growth rate accelerates because of changes in the market structure, a new 5-year union agreement in 2004, and an increase in FTEs.

Q. What process does PGE follow to achieve the market median target?

A. In comparing our compensation levels with those of the labor market, we analyze several data sources because we define the relevant labor markets in terms of revenue, size, demographics, and recruitment areas. PGE's pay structure consists of seventeen salary categories for exempt, non-officer employees, fourteen categories for non-exempt employees, and one category for union employees. For 2007, PGE's base pay structure continues to closely correlate to the market for all of these categories, usually keeping PGE's overall target within 1% of the comparable market median.

In 2005, we compared PGE jobs to similar jobs in the market for clerical and administrative, middle and upper management, and executive positions. For clerical and administrative positions, we generally recruit from the local geographic area. As a result, we compare PGE's positions to levels of pay from the *Milliman Regional Industry Survey*, which includes information from Vancouver, Washington to Salem, Oregon. For hourly non-union positions, we compared nineteen of PGE's hourly non-union positions, which represent approximately 60% of our non-exempt position titles. For non-exempt positions, our regression analysis shows an 84% correlation between PGE's and the market's pay practices.

For salaried non-officer positions, PGE's salary structure review for 2005 included 56 of our middle and upper management positions, which represent approximately 60% of our exempt position titles. For this review, we relied upon the *Towers Perrin Energy Services Middle Management Survey*. For PGE's exempt positions, our regression analysis includes data from the *Towers Perrin Energy Services* surveys and indicates an 89% correlation between PGE's and the market's pay practices.

For executive positions, we relied on information from the *Towers Perrin Executive Energy Services Survey* and generally target this group's salaries to the median of the comparable market, although by 2005, PGE's executive salaries fell to 81% of median.

III. Incentive Compensation

Q. Why is incentive compensation important to PGE's total compensation?

A. PGE strives to attain incentive levels that attract, retain, and motivate skilled employees. As with wages and salaries, if PGE's incentive level is too low, more applicants may choose other employment and more employees may leave the company. Incentive programs also provide useful tools to match employee productivity and cost.

Q. What are the challenges to PGE's strategy in setting incentive levels?

A. The challenges to PGE's incentive compensation strategy are similar to those for wages and salaries. The labor market informs us about changes and emerging trends in incentive practice. We review these changes to maintain a balance between keeping incentive compensation competitive in terms of levels and features, while avoiding unreasonable or excessive cost.

Maintaining this balance is more difficult because the incentive component of compensation, while relatively small, appears to be growing faster than wages and salaries. Incentives are a valuable component of total compensation because they provide management more administrative flexibility and influence over employee behavior. But their rapid rise creates a challenge for our compensation program designers in meeting our total compensation goal.

Q. What is PGE's strategy for attaining its total compensation goal with regard to the incentive compensation component?

A. Our strategy for incentive pay includes several approaches. First, we align compensation incentive to market levels to ensure that employees who fulfill their performance targets can earn the market level of compensation.

Second, PGE can also employ individualized incentives to reward outstanding individual performance or effort by employees. For example, we provide a few, relatively small amounts through the Notable Achievement Award Program. PGE has at times also employed other types of incentives, such as signing bonuses and retention payments, in periods of critical skill competition or to ensure the completion of important tasks.

Third, in addition to setting incentive levels, PGE monitors the market to gain information about incentive compensation program design practices such as the growth in relative size of incentive within total compensation. Through such information, PGE can change the structure of our incentive programs to remain competitive.

Q. Please describe the incentive compensation costs from 2002 to 2007.

A. Table 4 provides PGE's incentive costs for 2002 through 2007, which have in total increased by an average of 8.8% per year. We discuss later the abnormally low level in 2002, which increases the annual rate.

Table 4 - Incentive Program Costs
($000)

	2002 Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Corporate Incentive Program (CIP)	3,916	3,946	3,212	4,436	4,796	5,354
Annual Cash Incentive Program (ACI)	1,065	2,437	3,212	2,823	3,539	3,646
Officer Incentives	1,740	1,215	1,426	1,258	2,304	3,188
Notable Achievement Awards	139	142	169	141	166	166
Retention/Signing Awards	1,225	2,204	-	-	-	-
Total Compensation Incentives	8,086	9,944	8,019	8,657	10,805	12,354

The Corporate Incentive Program (CIP) provides the opportunity for incentive pay at the median of market to all of PGE's hourly non-bargaining employees and most of the salaried employees. The Annual Cash Incentive Program (ACI) provides a similar opportunity to upper management employees and to those salaried employees who have critical roles or duties.

Due to declining loads and adverse effects of poor hydro conditions on net variable power costs, PGE's incentive cost in 2002, 2003, and 2004 was significantly lower than normal because less than targeted incentive was awarded under CIP and ACI. Thus, the apparent increase from 2002 to 2007 can be misleading because 2002 costs are lower than normal results, while the test year estimate is based on normal results. Table 5 provides the percent of targeted awards for ACI and CIP from 2000 to 2004 and shows that 2002 was significantly lower than normal.

Table 5 – Incentive Portions of Targeted Awards

Accrual Year	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual
CIP	100%	85%	60%	80%	93.20%
ACI	100%	70%	58%	70%	89.70%

Several other factors can also impact year-to-year totals, such as changes in base pay levels, changes in market levels of incentive pay, changes in FTEs and changes in the numbers of participants in the incentive programs. Decreases in the later years primarily relate to lower sign-on and retention costs. The 2005 costs reflect an increase in FTEs, decrease in upper management and officer costs, and the elimination of incentive for most bargaining unit employees. The 2006 and 2007 forecast incentive cost results from changes in the market and a few additional FTEs primarily to serve new customers, to comply with hydro relicensing terms, and to operate a new power station.

Q. What process does PGE follow to achieve the median market level of incentive compensation?

A. For most salaried and all hourly non-union employees, 2005 market data show that the incentive compared to base pay ranged from 4% to 14%. PGE's overall incentive target for this largest group was 6.25%, with targets for lower pay groups slightly higher than market and targets for higher pay groups slightly lower than market.

For the large majority of upper management, non-executive positions, the market range is generally 14% to 20% of base pay. PGE's target range is generally 13% to 20% of base pay, with some exceptions. For officer positions, we also usually set the incentive target level at the market median. For 2005, the market range was 20% to 75% of base pay for cash incentive pay. For PGE, officer incentives were set at about 37% of total incentive in the market because our cash incentive program did not include a long-term incentive component. In 2006, PGE plans to introduce a long-term incentive program for officers and key individuals to mirror market practice and to review total compensation. The long-term officer incentive plan is included in the 2007 test year.

IV. Benefits

Q. Why is benefit compensation important to PGE's total compensation?

A. Benefit compensation is another primary factor that people consider when choosing to join or to leave any employer. It was also an important part of the total package negotiated in the 2004 collective bargaining agreement, in which incentives were exchanged for more benefits. The pension and Retirement Savings Plan programs are particularly important for employee retention. Management of the benefits portfolio is important to the efforts to control the costs of total compensation because benefits comprise a large component of total compensation. The Health and Dental care program, the pension plan, and the Retirement Savings (401k) plan can account for over 80% of total benefit cost each year.

Q. What challenges related to employee benefit compensation does PGE face?

A. First, benefits are the second largest component of compensation cost and these costs have been quickly rising. Second, PGE's benefits package must be competitive with other employers. Third, we must design programs that consider employees' preferences for features and cost, at the same time that their characteristics and preferences are changing. Last, regulations in this area are changing, and we must respond to those changes; for example, the IRS has proposed new regulations regarding phased retirements.

In addition, benefit design is complex. PGE takes into account the many types of programs, the features of each program, the employee groups that are eligible or participate in each program, the cost and risk that the employer and employee share, and the features that interact between programs. This complexity challenges us in balancing programs and program features between groups of employees while trying to keep in line with market practice.

Finally, our responsibilities increased from earlier years because we regained control of our Retirement Savings Plan (401k) and Health & Welfare Programs from Enron in 2005 and because of the new union contract in 2004.

Q. What is PGE's strategy for attaining its total compensation goals with regard to the benefit compensation component?

A. As with wages, salaries and incentives, PGE uses market information to design employee benefits. As a result, our portfolio is competitive and, thus, sufficient to attract and retain employees. PGE also uses market information to create innovative program designs that provide greater employee choice and improve our ability to control costs. PGE strives to maintain a benefits portfolio that balances benefit features and costs between programs, between employee groups, and between PGE and market practice.

Q. Please briefly describe the employee benefits costs from 2002 to 2007.

A. We project 2007 employee benefit costs of $54.3 million, which represents an average annual increase of 10.7% and is primarily due to cost increases for Health and Dental benefits, the pension plan, and the Retirement Savings Plan (401k). A few new benefits were created by the 2004 negotiated union contract, which include a Short Term Disability Insurance program, and a Health Reimbursement Account. Table 6 shows the largest benefits costs, and the new accounts, in relation to the rest. Exhibit 901 provides a more complete list of PGE's benefit programs and costs.

Table 6 - Largest Sources of Benefit Cost
($000)

Benefit Description	2002 Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Health & Dental Plan	18,745	23,825	22,418	27,920	27,513	30,169
Retirement Savings Plan	9,411	9,605	14,109	14,519	12,933	13,306
Pension Plan	-	-	-	2	3,915	4,370
Health Reimbursement Account	-	-	568	1,055	1,446	1,400
Short Term Disability Insurance	-	-	149	326	416	521
Remaining benefit programs	4,538	2,889	6,342	4,119	4,494	4,583
Total Benefit Cost	32,694	36,319	43,586	47,941	50,717	54,349

Q. What process does PGE go through to make sure that the levels of employee benefits and costs are reasonable?

A. PGE routinely reviews its program portfolio and individual programs. We alter existing programs, and introduce new ones that help the company and employees control their various benefits and costs.

A. Health and Dental Program

Q. What are the particular challenges facing PGE with regard to Health and Dental benefits?

A. The Health and Dental program represents the largest portion of benefit costs, which have risen quickly, and for which market practice is changing. As we noted previously, PGE has a higher percent of workers ages 45-64, compared to the national average and other US based electric utilities. Given PGE's workforce demographics, health care costs are likely to increase more for PGE than other employers.

Q. What is PGE's strategy for attaining its total compensation goals particularly with regard to the Health and Dental benefits?

A. Due to the many complex attributes of health programs, PGE sponsors additional reviews by third-party experts to compare PGE to the market in terms of actual cost, average market cost, expected market cost, effects of demographics, and cost sharing to inform itself about the different attributes of health care and its cost drivers.

PGE also designs new programs that reduce total program, company, and/or employee costs. For example, in 2005, PGE introduced a new high deductible health plan option which can lower total program costs, and thus company costs, while allowing more healthcare choices for employees. Also, PGE has enhanced Health and Safety programs to promote healthy employee lifestyle practices that are designed to reduce long-term health care costs.

Q. Please describe the Health and Dental benefits costs from 2002 to 2007.

A. Health and Dental Plan cost increases are largely due to market and demographic influences and to the negotiated union contract. In 2003, for non-union employees, costs increased because the company adjusted its contribution to costs, for the first time since 2000, to better match the market practice for employer cost. In 2004, there was a small decrease for overall health care costs due to decreases in retiree medical costs and in the number of FTEs. In 2005, increases resulted from the new union contract, in higher premium costs, additional FTEs, and because PGE regained control of all of its health care programs (a cost increase of approximately $328,000 for new outsourced administrative services). In 2006, PGE expects total health care premiums to increase at lower rates than in recent years and the company's percentage contribution to cost remains unchanged. PGE forecasts health care costs in 2007 to increase by $1.5 million for non-union employees because of an expected rise in total program costs accompanied by an increase in the employer contribution percentage to mirror market practice; we also expect health care costs to increase by $1.1 million for union employees due to an increase in the company's contribution to the union medical trust as provided in the union contract.

Q. What process does PGE follow to make sure that these levels of Health and Dental benefits and cost are reasonable?

A. We use information from several market surveys that compare Health Care plans and attributes. These surveys compare PGE's employee benefit plans and/or costs to those of other companies. They inform us that:

- PGE's health care costs are very close to market average cost and lower than expected cost. (*Towers Perrin* "Performance Benchmarking" 2005)
- PGE's employer contribution to health care costs mirrors market practice. (*Hewitt and Associates* "SpecSummary" 2005)
- PGE's medical programs are competitive in benefit features when compared to similar companies. (*Towers Perrin* "BENVAL" 2005)

Table 7 shows Towers Perrin "Performance Benchmarking" findings that PGE's program cost is very close to the industry average (column c), and that PGE's program cost is significantly lower than the expected cost for PGE's programs and employees (column e).

Table 7 – Average Health Care Costs per Employee

	PGE (a)	Utility Industry (b)	PGE Similar to Industry (c)	Expected Cost (d)	PGE Lower than Expected (e)
Health Plan NonUnion	$8,217	$8,880	($663)	$9,403	($1,186)
Health Plan Union	$9,574	$8,880	$694	$10,545	($971)

Thus, PGE's design and management practice has yielded health plan costs that are similar to industry average cost and lower than the market would expect for the PGE group of employees and plans. This information implies that PGE's design and management of health care costs may be providing savings of about $2.9 million per year. Also, PGE's health care premiums may rise in the future to levels closer to expected market cost.

Additionally, Hewitt and Associates reviewed their "SpecSummary" data to provide PGE with market level information regarding employer and employee contributions to health care costs. Their results show that, for 2005, the employer contribution at market was 84% and the employee contribution was 16%.

For 2005, PGE targeted the company contribution amounts to 85% of the weighted average of program premiums with the knowledge that new, cost reducing health care programs would be initiated in 2005 to lower total health care costs, and that total premiums will likely rise, with the company contribution percentage likely to remain the same until 2007.

In the 2005 "BENVAL" Study, Towers Perrin shows that PGE's medical programs rank at or near the average of total value next to other comparable companies. For non-union employees, PGE medical programs for active employees rank 6th among 12 similar companies. For union employees, PGE ranks 7th for its medical programs among 13 similar companies.

In summary, PGE employs many approaches and varying sources of information to ensure that this program is reasonable in program attributes and cost.

B. Retirement Savings (RSP / 401(k)) Program

Q. What are the particular challenges facing PGE with regard to the RSP program?

A. PGE's challenges are to help its employees plan for retirement, to provide sufficient cash compensation and options to enable employees to be ready for their retirements, and to manage the RSP costs. RSP costs have increased because union employees can now switch to the RSP from the pension plan. The new union contract provides an enhanced 401(k) benefit until 2009; during this period, union members who participate in the defined benefit pension plan can switch from the defined benefit pension plan to the 401(k) plan. Any resulting overall increases in the cost of the RSP will be monitored and managed over time, but we expect overall future pension costs to be lower.

Q. What is PGE's strategy for attaining its total compensation goals with regard to the RSP?

A. In addition to reducing upward pressure on pension costs, the RSP aligns PGE with contemporary retirement savings plans. The RSP also provides employees with access to 401(k) modeling tools to help them better plan for retirement and enables employees to select from a variety of investment options.

Q. Please describe the RSP benefit costs from 2002 to 2007.

A. Changes in RSP costs result from fluctuations in employee participation and to provisions of the new union contract. For non-represented employees, PGE provides a dollar-for-dollar match up to 6% of base pay. Employees represented under the new main contract participate in PGE's pension program or PGE's RSP program. The new contract made several changes that affect this program and other programs that interact with it.

Most union employees (approximately 700) participate in the RSP. For these union member participants, PGE contributes from 5% for employees younger than 35 years old, and up to 10% for older employees, depending on age. (The company previously contributed 5% of base pay for each RSP participant.) For union members, PGE will also match employee contributions on a dollar for dollar basis up to 8%, depending on age and years of service. (The company previously matched on a dollar-for-dollar basis between 5% and 10% of base pay.)

Also, until the contract expires in 2009, union employees who participate in the defined benefit pension program may choose to permanently switch from the pension program to the RSP program. Thus, PGE has agreed to allow represented employees to opt out of the pension plan at a time when company contributions to employee 401(k) accounts are enhanced. While PGE's RSP costs may rise due to the current contract term, the liability to the pension program ceases to accrue service cost for each union member that chooses to switch to the RSP. Thus, while RSP costs may rise for a window of time, future pension plan cost is reduced for every employee that switches to the RSP.

Between 2002 and 2007, we forecast an increase of $3.9 million, or an annual growth rate of 7.2%. In 2002 and 2003, RSP costs were essentially flat because the program terms were stable. In 2004, an increase of $4.5 million resulted from one-time administration fees (which do not affect the 2007 forecast), a partial year of increases due to the new union contract, changes in other employee participation levels, and from fees to begin new record keeper activities.

In 2005, RSP forecast cost increased slightly due to an increase in matching funds, an increase in contributions to union accounts, offset by a decrease in administration fees. In 2006, costs are expected to fall because matching participation is expected to be lower, as are recording keeper fees. In 2007, we expect employee participation to remain stable and recording keeper fees to slightly increase for an overall program cost increase of 3%.

Q. Why is this level of RSP costs reasonable?

A. First, the RSP program helps PGE to remain competitive relative to post retirement benefits as a whole and should be viewed in the context of PGE's post retirement package that consists of the pension, the RSP, retiree medical and retiree life insurance. Second, the RSP offers PGE greater flexibility and control in post retirement cost, compared to the pension plan. Third, since RSP costs are incurred during the employee's active service time, RSP implementation better matches service activity to cost in time.

Fourth, this type of plan is now common among post retirement benefit options. Thus, it is one of the ways PGE remains competitive in benefit practice. Fifth, this type of program may appeal to a growing group of employees who prefer portability in their retirement options. Different employees prefer different retirement arrangements in terms of control and risk. Compared to traditional pension plans, the RSP provides employees with more control over the contributions to their retirement funds and with more control over the amount of risk that is taken with those funds.

The 2005 *Towers Perrin HR Services BENVAL* reports that PGE's RSP plan ranks 3rd in value among 12 comparable utilities that offer similar benefit to non-union employees. For the larger group of union employees, PGE program ranks 1st in value among 13 comparable utilities that offer similar benefit to union employees. For the relatively small group of union employees who may opt to participate in the RSP instead of the pension plan, PGE's post retirement package ranks 4th in value among the 13 comparable companies that offer similar benefit to union employees.

Q. PGE's RSP ranks high in value compared to other utilities. Is that appropriate?

A. Yes. In order to fully understand PGE's place in the market, we must also consider our total post retirement package. As we discuss below, PGE's pension program ranks low in value.

When analyzing the total post retirement package, the 2005 *Towers Perrin HR Services BENVAL* reports that PGE's total post retirement package ranks 9th in value among 12 comparable utilities that offer similar benefit to non-union employees. For the larger group of union employees, PGE's program ranks 2nd in value among 13 comparable utilities that offer similar benefit to union employees. For the relatively small group of union employees who may opt to participate in the RSP instead of the pension plan, the PGE's post retirement package ranks 7th in value among the 13 comparable companies that offer similar benefit to union employees.

C. Pension Program

Q. What are the particular challenges facing PGE with regard to the pension program?

A. PGE's current and future pension costs are rising. Current costs have increased with the growth of our retirement rate and the lengthening of retiree lives. Future costs rise with each year of active participant service, and with the lengthening of lifetimes. Also, due to change in the financial markets, the pension fund earnings are no longer off-setting the costs.

Other challenges to attain our goals include the need to account for differing preferences among various employee groups. In this case, age is important because younger employees may have different preferences than older employees regarding post retirement benefit choices.

Finally, while it continues to serve the preferences of some employees, the pension program creates a relatively large employee benefit cost that is less easily adjusted than other programs. Thus, the review process is complex for this particular program.

Q. What is PGE's strategy for attaining its total compensation goals with regard to the pension program?

A. PGE tries to thoroughly understand the interactions between market practice, cost, and the effects of the characteristics of our employees. While maintaining the pension as an important traditional employee benefit to attract and retain employees, PGE considers program designs and conditions that work among other post-retirement plans to serve various groups of employees. When approaching pension design, we also consider program features that can mitigate the growth in service cost/liability and therefore the future cost stream associated with retirees.

Q. Please describe the pension benefit costs in the test year.

A. In the test year forecast, net periodic pension cost is $4.4 million. Since UE 115, earnings on trust assets have declined, as has the discount rate. At the time of UE 115, the PGE pension plan held assets that provided earnings sufficient to offset service cost increase and growth in accumulated liability that resulted in no net cost in the calculation of net periodic pension cost (NPPC). Several conditions have changed the pension's position to a net cost.

First, financial returns have been sluggish for several years, resulting in a significant reduction of earnings on plan assets and future earnings expectations. Second, actuarial tables were updated with longer expected lifetimes of pensioners as required by federal guidelines, increasing the expected cost of the pension obligation. Third, the average age at retirement may be rising at PGE, which pressures pension costs upward. Because of these three factors, PGE's cost of service again includes an annual pension cost. However, the cost in the test year is less than it would otherwise be because, in 2005, PGE contributed approximately $10.0 million to the pension fund.

Q. What process does PGE use to make sure that this level of pension cost is reasonable?

A. We use several methods to make sure that pension costs are as reasonable as possible. First, PGE complies with IRS regulation, ERISA rules, and FASB guidance regarding the proper calculation and recording of pension costs. We make sure that PGE's definitions and practices are consistent with historical treatment of pension cost for OPUC filings and other purposes.

Additionally, we look at market surveys. *The Towers Perrin HR Services BENVAL Survey* reports that PGE provides a pension program that ranks 10th in value among 12 comparison utilities with programs for non-union employees, and that ranks 9th in value among 13 comparison utilities with programs for union employees.

D. Health Reimbursement Account

Q. What is the Health Reimbursement Account (HRA)?

A. The HRA was created in the new union contract to hold company contributions that are available to retired employees for qualified medical expenditures. The contract provides that, beginning July 1, 2007, PGE will contribute 25 cents per straight time hour into the HRA account, and that beginning July 1, 2008, that contribution will increase to 50 cents per straight time hour.

A second contribution to the HRA account is based on the "sick bank" of time that a union employee has accrued but not used prior to retirement from PGE. At the time of retirement, PGE will place 58% of the value of that bank into an HRA for the employee's use for qualified medical expenditures. Each sick bank was valued in May 2004, after which no further benefit accrued. After May, 2004, active union employees receive a Short Term Disability Insurance (STI, discussed below) payment at 60% of regular pay while they are sick, and can draw down their sick bank to make up their full pay amount.

The HRA also tracks benefit grants to non-union employees for qualified medical expenditures after they retire from PGE. These grants began shortly after the HRA was instituted for union employees and help to maintain the benefit balance between union and non-union employees. For non-union employees, PGE granted about $220 per employee in 2004; and in 2005 granted about $300 per employee with interest on the 2004 grant. In 2006 and 2007, PGE expects to continue these grants to maintain balance between employees.

Q. Please describe the HRA benefit costs from 2002 to 2007.

A. Expenditures for the HRA began in 2004 at approximately $568,000 for a partial year of obligation. The first full year of this benefit's cost is 2005, with expected costs of approximately $1.1 million that consist of approximately $759,000 for union employees and approximately $288,000 for non-union employees. PGE projects 2007 HRA costs of $1.4 million that reflects $971,000 in obligation to union members and approximately $415,000 to non-union employees.

Q. Why is this level of HRA cost reasonable?

A. The features of the HRA provide post-retirement benefits and costs that are relatively flexible and controllable. In practical terms, this program can be changed under normal circumstances with each new contract for union employees, and changed each year for non-union employees.

Another beneficial cost feature is that the company contribution to the HRA account based on residual "sick bank" time is made only for employees that retire from PGE. Thus, employees that leave the company before retirement are not eligible for this post-retirement benefit and for those that do not retire from the company, no added HRA expense is incurred, which tends to reduce total program cost.

A more general beneficial cost feature is that, for all of those eligible to withdraw from this account, the amount that each retiree can withdraw is finite. Thus, the HRA is a tool with flexibility in cost control that provides certain amounts for certain people who participate in this program.

E. Short Term Disability Insurance

Q. What is the Short Term Disability Insurance (STDI) plan?

A. The STDI program for union employees was created in the new union contract and provides that PGE will pay premiums for sick time insurance that provides 60% of regular pay to union employees on short term disability. If the union employee has an earned balance in his sick time bank, as of May 2004, he can draw the balance down in order to make up the difference from his regular pay.

Q. Please describe the STDI benefit costs from 2002 to 2007.

A. Expenditures for STDI began in 2004 at approximately $149,000 for a partial year of coverage. The first full year of coverage was 2005, with costs of approximately $326,000. PGE expects this cost to increase to approximately $416,000 in 2006 and $521,000 in 2007 primarily because the current contract expires in May 2006 and the other bids we received suggest that these projected costs are more likely to reflect market prices at that time.

Q. Why is the level of STDI costs in the test year reasonable?

A. These STDI costs are reasonable because this new benefit, taken together with the Health Reimbursement Account, eliminates growth in future cost for sick time pay. PGE does not need to accrue for an unknown future liability such as earned sick time for a large number of employees. This is particularly important considering that, in the years between 2000 and 2004, the number of participants in PGE's short term disability program doubled and the costs tripled, a trend that we expect is likely to continue, given PGE's workforce demographics.

F. Other Benefits

Q. What other benefits are included in the test year?

A. Table 8 shows the benefits and costs associated with activities that account for about 8% of total benefit cost in the test year. These activities are part of our basic benefits package and provide employees with choices that help PGE to attract, retain, motivate and support employees through life changes.

Table 8 - Other Benefit Costs
($000)

	2002 Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Group Life Insurance	992	360	1,231	1,284	1,276	1,301
Long-Term Disability	1,465	858	3,168	1,025	1,062	1,087
Benefits Administration	615	575	762	674	806	838
Employee Wellness Program	321	343	369	372	509	525
Education Plan	250	419	449	408	438	422
Misc. Employee Benefits	763	178	204	213	239	243
Employee Assistance Program	107	130	127	122	138	144
Recreation Program	24	25	30	20	25	25
Other benefit cost total	4,538	2,889	6,342	4,119	4,494	4,583

Q. Please describe the drivers of the other benefit costs.

A. Other benefit program costs have increased annually at less than one-half of one percent, despite increases in market costs for benefits as a whole and increases in participation. For Group Life Insurance, costs generally fluctuate with the age of the participants, with changes in actuarial expectations (e.g., actuarial adjustments in 2004 included amounts for 2003), and with changes in the proportions of employees who smoke. Long-Term Disability costs fluctuate primarily with changes in numbers and conditions of participating employees, and with change in actuarial expectation (e.g., actuarial updates reflected in 2002 and 2004 adjusted balances to year-end of 2001 and 2003).

For Benefits Administration, costs change with increased responsibility for administering the health and retirement savings programs, increases in design and research activity, and changes in regulation. The Employee Wellness program has grown to include more efforts to educate employees and involve them in adopting healthier habits to reduce future health care costs. The Employee Education program has grown because of an increase in the number of participants and an increase in the reimbursement to employees for completed college and post graduate courses that directly relate to work activities.

Miscellaneous Employee Benefit cost generally increases with the costs of employee service awards (in 2002 costs included an adjustment to balance payroll liabilities from prior years) and with the costs of PGE's Employee Commute Options (ECO) program to educate employees regarding alternate commuting options as required by OAR 340-242-0100 through 0290 and administered by Oregon Department of Environmental Quality. The Employee Assistance Program (EAP) cost has grown with the salary of the EAP professional, and with increases in the outsource fees for the services needed by employees. PGE's Recreation program cost is not expected to significantly change from the cost in 2002.

Q. Why is the level of other benefit cost in the test year reasonable?

A. These activities help PGE to attract, retain and motivate employees by providing basic benefit and employee services that are designed to support current and future employee productivity. In addition, activities of the smaller benefit programs like the Employee Assistance program and the Wellness program are designed to suppress growth in future health care costs, in other related costs, and in reductions to productivity.

Group Life, LTD and Benefits Administration costs rise largely due to changes in actuarial expectations, our environment, as well as in our employee characteristics and preferences. However, without these activities, we would likely fall behind the market in benefits compensation. Also, they are reasonable because a growing number of employees are working beyond midlife, and need support to remain productive while they:

- simultaneously experience child and elder care responsibilities, and/or grief, while coping with physical and other changes; as well as
- educate themselves about lifestyle choices that will enhance their health, and productivity.

With regard to the Education program, similar programs are commonplace among employers and PGE reimbursement levels are lower than IRS guidelines. In an industry heavily dependent on technological innovation, it is important for our employees to remain current in industrial innovation and to increase their transferability within the utility. The Education program motivates employees to innovate and improve work processes and supports PGE in meeting demographic change.

V. Qualifications

Q. Ms. Barnett, please summarize your qualifications.

A. I received a Bachelor of Arts degree from Abilene Christian University in 1972 and certification in Human Resources at Portland State University. I have completed coursework in Human Resources at the University of Portland. As Vice President of Administration, I oversee Ethics and Compliance, Environmental Services, Information Technology, and Human Resources areas.

I joined PGE in 1978 and have successfully bid and been selected for various positions at PGE. I guided the HR department through the merger with Enron in 1997 and became Vice President in 1998. My scope was broadened to include Information Technology and Environmental Services in 2002, and Ethics and Compliance in 2004.

Q. Ms. Bell, please summarize your qualifications.

A. I received a Bachelor of Arts degree from the University of Pittsburgh in 1975. I received a Masters in Business Administration (MBA) from the Joseph M. Katz Graduate School of Business, University of Pittsburgh, in 1976. Prior to joining PGE, I worked at Fireman's Fund Insurance, Co. and American Express in finance; and at Baltimore Gas & Electric Company in the areas of finance and human resources. In 1988, I joined Portland General Electric and I have been Director of Compensation and Benefits since 1998.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
901	Summary of Compensation Cost

SUMMARY OF COMPENSATION COST ($000)

Compensation category / program		2002 Actual	2003 Actual	2004 Actual	2005 Projected	2006 Budget	2007 Forecast
Benefit Compensation							
Short Term Disability Insurance		-	-	149	326	416	521
Group Life Insurance		992	360	1,231	1,284	1,276	1,301
Retirement Savings Plan		9,411	9,605	14,109	14,519	12,933	13,306
Recreation Program		24	25	30	20	25	25
Pension Plan	a	-	-	-	2	3,915	4,370
Health & Dental Plan		18,745	23,825	22,418	27,920	27,513	30,169
Education Plan		250	419	449	408	438	422
Misc. Employee Benefits		763	178	204	213	239	243
Long Term Disability		1,465	858	3,168	1,025	1,062	1,087
Employee Wellness Program		321	343	369	372	509	525
Employee Assistance Program		107	130	127	122	138	144
Health Reimbursement Account		-	-	568	1,055	1,446	1,400
Benefits Administration		615	575	762	674	806	838
Supp. Exec. Pension (SERP)	b	-	-	-	-	-	-
MDCP Pens/Savings Makeup	b	-	-	-	-	-	-
Benefit Compensation Total		32,694	36,319	43,586	47,941	50,717	54,349
Wages & Salaries (Utility ce11,12)		156,739	156,484	160,027	172,135	180,673	189,856
Incentive Compensation							
PGE CIP		3,106	3,304	2,883	4,037	4,503	4,738
Boardman Tmwrks (PGE share)		146	113	(2)	105	88	91
Wholesale Marketing		(200)	598	110	696	767	767
PGE ACI	c	1,251	1,797	3,037	2,068	2,719	2,824
Boardman ACI (PGE share)		14	42	65	59	53	55
Coyote Springs (PGE Share)		327	193	246	209	203	522
Trojan (PGE share of PGE O&M)		309	329	73	82	-	-
Pelton (PGE Share)		28	7	11	2	2	2
Officers		1,740	1,215	1,426	1,258	2,304	3,188
Notable Achievement Awards		139	142	169	141	166	166
Retention/Signing Awards		1,225	2,204	-	-	-	-
Incentive Total		8,086	9,944	8,019	8,657	10,805	12,354

a credits set to zero
b omitted
c removed out of period accounting adjustments 2002, 2003

UE 180 / PGE / 1000
QUENNOZ – NICHOLS

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Trojan Decommissioning

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz
Steven B. Nichols

March 15, 2006

Trojan Decommissioning

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric.

A. My name is Stephen Quennoz. I am Vice President, Power Supply. My qualifications are in PGE Exhibit 300, Section V.

My name is Steven B. Nichols. I am General Manager of Trojan and Hydro Operations. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. We present and explain PGE's proposal to reduce the annual contribution to the Nuclear Decommissioning Trust (NDT) from the current $14.04 million (through 2011) to $4.65 million (extended through 2024). Additionally, PGE proposes to return approximately $20 million from the NDT to customers.

Q. Please briefly explain the proposed contribution reduction and the return of $20 million.

A. PGE has consistently completed decommissioning projects both safely and under budget. This diligence has lowered costs and garnered international acclaim. As a result, a surplus has accumulated in the NDT even though PGE has updated its analysis with every general rate case filing. The $20 million represents accrued savings from the UE 115 revised decommissioning cost estimates. Rather than continue to hold these funds until decommissioning is completed, we propose to return the funds to customers in the near term. At this time, we are not recommending any particular ratemaking treatment to the accrued savings return.

In addition, because of our successful and cost-effective approach to decommissioning, we are able to lower annual cost estimates for future decommissioning activities.

Accordingly, we propose to lower the annual contribution to the NDT from the current $14.04 million to $4.65 million. The extension from 2011 to 2024 will allow a better match of contributions to costs. As we discuss later in this testimony, these savings and reduction in cost estimates for future decommissioning are a result of the following actions:

- Maintaining a highly competent, experienced workforce;
- Changing timelines where appropriate, such as accelerating building demolition; and
- Using innovative demolition procedures, as shown with the Reactor Vessel and Internals Removal Project (RVAIR).

Finally, if not for the delay in operation of the federal repository for long-term storage of spent nuclear fuel (Yucca Mountain), savings would be even higher.

II. Trojan Decommissioning Costs

Q. What is the NDT?

A. The NDT, established in 1990, is a financial fund that assures long-term financial coverage of PGE's portion of costs associated with decommissioning Trojan and the Independent Spent Fuel Storage Installation (ISFSI) as required by the Nuclear Regulatory Commission (NRC).

Q. What is the current level of the NDT?

A. As of December 31, 2005, the NDT balance was approximately $30 million.

Q. Is there a minimum required balance for the NDT?

A. Yes. The NRC requires that any money collected that is designated to cover PGE's ownership share of Trojan ISFSI radiological decommissioning costs must remain in the fund until used for radiological decommissioning.

Q. Will the NDT fall below the required minimum with the proposed $20 million return?

A. No. Assuming that the $20 million is returned to customers, the estimated NDT balance will slightly exceed $9.5 million in 2007. The portion of the NDT balance that is designated to cover PGE's portion of Trojan ISFSI radiological decommissioning costs will be approximately $3.1 million in 2007. Collections (combined with earnings) through 2024 are expected to offset costs and keep the fund at, or above, the estimated minimum for all years.

Q. How do you evaluate the annual contribution levels required to fund the NDT?

A. We use the same general model as in our last general rate case, with updates to the economic, financial, and cost information. We model the NDT fund to match total contributions with total expenses. Variables include the long-term inflation rate, the expected rate of return on the trust fund, tax rates, portfolio investment allocation, and fees to the trust managers.

Q. Why is PGE able to lower the annual NDT contribution level from $14.04 million to $4.65 million?

A. PGE is able to lower the annual contribution rate from $14.04 million (through 2011) to $4.65 million (through 2024) because current total cost estimates are significantly lower than previous estimates. The most significant cost savings are in two cost categories: NRC License Termination for Trojan Nuclear Plant (Trojan) and Non-Radiological decommissioning activities. Some cost increases will occur in both ISFSI Capital and Decommissioning and ISFSI Long-Term Management. Overall, however, the decommissioning cost decreases more than offset increases.

Table 1 below demonstrates the current cost estimates for Trojan decommissioning as compared to those presented in UE 115.

Table 1
Trojan Decommissioning Costs: Current vs. UE 115
(000's, 1997$)

	UE 115	Current Estimates	Difference	Percent Change from UE 115 Estimates
NRC License Termination	$240,919	$207,054	($33,865)	-14.06%
Non-Radiological	$42,250	$29,869	($12,381)	-29.30%
ISFSI Capital and Decommissioning	$80,034	$85,737	$5,703	7.13%
ISFSI Long-Term Management	$62,423	$86,042	$23,619	37.84%
Financing	$4,093	$16	($4,077)	-99.61%
Total:	$429,719	$408,718	($21,001)	-4.89%

Q. What are the major reasons for the decline in overall costs from UE 115 projections?

A. The decline is largely due to three projects:

- We completed the required Trojan Plant radiological decommissioning under budget (approximately $33 million);

- We avoided an expected shortfall in funding and associated bridge financing (approximately $4 million); and
- We accelerated building demolition and lowered Site Non-Radiological costs by successfully contracting for projects at less than initial cost projections (approximately $12 million).

Q. Are any decommissioning costs higher than expected?

A. Yes. Two cost categories show higher costs than expected in UE 115:

- Long-term ISFSI Fuel Management Costs are projected to increase by $23.6 million due to the delayed completion of the federal nuclear waste repository; and
- ISFSI Capital and Decommissioning costs increased approximately $5.7 million mainly due to new information regarding U.S. Department of Energy (USDOE) requirements for transferring spent fuel from the ISFSI to the federal nuclear waste repository.

Q. Please explain the increase in ISFSI Fuel Management Costs.

A. In UE 115, PGE assumed that the spent fuel stored in Trojan's ISFSI would be fully shipped by 2018. In July 2004, the USDOE issued a report that assumed the federal repository would open in 2010 and revised their projected commercial spent fuel acceptance schedule for the first-ten year period (2010 – 2019). PGE Exhibit 1001 is a copy of its report (we have excluded the voluminous appendices that do not provide useful information for our purpose here). For modeling purposes, PGE used information in this report to determine the earliest possible shipment date. Based on the report, PGE assumed the 2010 date for commencement of repository operation and the specified annual allocations for USDOE acceptance of spent fuel, with no priority afforded to Trojan spent fuel due to the shut-down status of the plant or other contractual mechanisms that PGE might seek to invoke. According to that schedule, PGE anticipated spent fuel remaining onsite until at least 2023 and completion of ISFSI decommissioning in 2024. However, the actual date when the Trojan spent fuel will be fully shipped to USDOE cannot be forecast with any certainty, and USDOE will almost surely not commence accepting spent fuel by 2010. This is because USDOE has not stated when it will submit the repository license application to the NRC or when the repository will be open. Further, on December 1, 2004, USDOE notified nuclear utilities, including PGE, that it had again suspended the Delivery Commitment Schedule (DCS) process by which utilities inform the USDOE of the type of fuel to be shipped and the schedule for those shipments, calling the resumption of the process "premature." Accordingly, PGE must assume that the spent fuel will continue to be stored in Trojan's ISFSI until at least 2023, and perhaps well beyond.

Q. Please explain the new information regarding USDOE requirements for transferring spent fuel.

A. There is considerable uncertainty regarding what the responsibilities of each party (USDOE and PGE) will be at the time of actual fuel shipment. Previous PGE cost estimates for transferring spent fuel to USDOE were based on an assumption that USDOE would cover some of the costs associated with loading the multi-purpose canisters (MPCs) into shipping casks and preparing them for transportation to the federal repository. PGE used an NRC approved MPC; by definition it is approved for both storage and transportation. While interpretation of Article IV of the Standard Contract (10 CFR 961.11) between PGE and USDOE is unclear, in updating our cost estimates for transferring spent fuel, we have used a conservative approach. Under this approach, we include the costs of removing the MPCs from the concrete casks, loading them into USDOE-provided shipping casks, placing the loaded shipping casks onto rail cars, and completing preparation of the shipping casks for transportation, at which point the USDOE will assume responsibility. USDOE will be responsible for all necessary transportation from the Trojan site to the USDOE repository. The additional work and costs for PGE are estimated to include the site preparation and all activities specified above for preparing the MPCs and their shipping casks for transportation. Additional equipment and labor will be required, as well as the construction of a railroad spur.

Q. Does PGE expect all of the spent fuel to be shipped offsite by 2023 to permit completing ISFSI decommissioning in 2024?

A. This is not clear. As noted above, the 2023 date was used for modeling purposes, in part because it represents the latest published information from USDOE. The 2023 date is based upon a 2010 start date for USDOE acceptance of spent nuclear fuel, which is unlikely. On the other hand, that 2023 date is also based upon allocations derived from simple oldest-fuel-first rankings, without potential priorities PGE might receive because of Trojan's shut-down status or exchanges of allocations, which would have the effect of accelerating removal of all spent fuel from the site. At present, and in light of all of the circumstances known today, PGE believes our modeling assumptions are reasonable.

Q. Do other agencies influence the long-term cost and duration of ISFSI fuel storage and final site decommissioning?

A. Yes. In addition to USDOE, the NRC, Oregon Department of Energy (ODOE), and Oregon Energy Facility Siting Council (EFSC) could affect final decommissioning costs.

Trojan operations must comply with NRC regulations to retain our 20-year license (SNM-2509) for operation of the Trojan ISFSI. NRC review and approval is also required for ISFSI decommissioning. Regulatory changes may affect the long-term costs and duration of ISFSI fuel storage and final site decommissioning. For example, security regulatory requirements related to plant operations have increased since the September 11, 2001, terrorist attack on the World Trade Center in New York City and the Pentagon in Washington D.C, resulting in increased ISFSI Fuel Management costs.

The NRC also oversees packaging and transportation of radioactive materials, such as spent fuel. Federal Regulation 10 CFR 71 contains the requirements for packaging spent fuel for shipment. Changes in this regulation may affect long-term costs and spent fuel storage duration. Updated security regulatory requirements for the ISFSI are also expected.

ODOE and EFSC oversee Trojan ISFSI operations and decommissioning to ensure compliance with Oregon Administrative Rules. Changes in these rules may also affect long-term costs and spent fuel storage duration.

Q. Your proposal to decrease annual contributions to the NDT includes extending the contribution period from 2011 to 2024. Why is this necessary and how will it benefit customers?

A. Costs associated with spent fuel storage (ISFSI Long Term Management) and ISFSI decommissioning are forecast to continue through at least 2024 – a minimum extension of five years from earlier estimates. Extension of the contribution term will allow PGE to match decommissioning costs to contributions, which will reduce the risk of over- or under-recovery. If contributions remained at the UE 88 and UE 115 historic levels through 2011, contributions could potentially exceed costs if ISFSI costs are less than originally projected. Similarly, future reinstatement of contributions might be needed if ISFSI costs are higher than projected. A lower rate over a longer period will be easier to adjust in the future should it be necessary.

Q. Did you incorporate the potential increased time of spent fuel storage in the model?

A. Not explicitly, although based on current estimates, annual NDT contributions at $4.65 million will cover the annual O&M costs associated with additional storage time, if continued beyond 2024.

Q. Will the NDT remain fully funded under your proposal?

A. Yes. We expect the NDT to remain fully funded (i.e., amounts for decommissioning activities will be available as needed) even if we lower the annual contribution to $4.65 million annually until 2024. This amount is about one-third of the current annual contribution of $14.04 million and includes returning $20 million to customers.

III. Decommissioning Activities

Q. Please summarize the decommissioning plan for Trojan.

A. The Trojan Nuclear Plant Decommissioning Plan (the Plan) contained five major operations:

- Large Component Removal Project
- Reactor Vessel and Internals Removal Project
- Spent Fuel Storage Project
- Area-by-Area Decommissioning and Dismantlement
- Site Final Radiation Survey

The NRC approved the Plan for decommissioning and termination of the Trojan operating license, NPF-1, on April 15, 1996.

Q. What has PGE accomplished under the Plan?

A. PGE has completed all five of the major operations required by the NRC in the approved Plan. This significant accomplishment was documented by an NRC letter, dated May 23, 2005, that terminated the Trojan operating license, NPF-1, and released the Trojan site for unrestricted use (PGE Exhibit 1002). PGE applied for a new license specifically for the ISFSI, which the NRC issued in March 1999.

PGE successfully completed the first major decommissioning project, the Large Component Removal Project, in 1995. This project encompassed the removal, packaging, transportation, and disposal of the four steam generators and the pressurizer. We completed this two-year, $17.8 million project on schedule and under budget, with no lost time accidents and a radiation dose to the workers under 50% of the "as low as is reasonably achievable" (ALARA) goal for the project.

PGE achieved another significant milestone in 1999 with the successful completion of the Reactor Vessel and Internals Removal Project (RVAIR). This first-of-a-kind project encompassed the removal, packaging, transportation, and disposal of Trojan's reactor vessel with its "internals" intact. We completed this $21.5 million project under budget and at a significantly lower cost than that of following the established approach of removing and segmenting the highly radioactive reactor internals. This approach effectively eliminated concerns over long-term storage of the most radioactive internal components. Because there is currently no definitive plan for a federal disposal facility for this type of waste, the single-piece disposal approach eliminated a significant risk to the cost of decommissioning Trojan. PGE received the International Project of the Year Award from the Project Management Institute for the innovative and successful RVAIR project.

Since UE 115, PGE has completed radiological decommissioning and license termination of Trojan and resolved the problems of the transfer of the fuel to PGE's ISFSI facility. We performed these activities safely and under budget. Major milestones include:

- January 2001: Completed Containment Building concrete removal
- October 2002: ISFSI license, SNM 2509, revised to permit use of new design and begin fuel transfer to the ISFSI
- September 2003: completed transferring spent fuel to the ISFSI
- September 2004: completed Trojan radiological remediation approximately 14% under budget
- December 2004: completed submittal of all final radiation survey reports to NRC
- April 2005: EFSC recognized that radiological decommissioning is complete

- May 23, 2005: NRC terminated Trojan Operating License, NPF 1, and released the Trojan site for unrestricted use; EFSC issued revised OARs reflecting license termination

PGE Exhibit 1003 contains a more detailed list of decommissioning milestones.

Q. Please summarize the remaining decommissioning activities for Trojan.

A. In the short term, non-radiological decommissioning work will continue. As we discussed above, remaining long-term activities concern the ISFSI and its final decommissioning.

Q. What activities are planned for the short term?

A. In the short term (through 2008), PGE plans to demolish the cooling tower and selected buildings. We are accelerating demolition, compared to the schedule in the UE 115 forecasts.

Q. Why is accelerating building demolition good for customers?

A. PGE presented its rationale for accelerating building demolition to the Oregon Public Utility Commission (OPUC) in March 2005. A copy of the presentation is included as PGE Exhibit 1004. The following are benefits of demolishing unused buildings in 2005, instead of waiting until 2018:

- Removes uncertainty for a significant portion of remaining costs.
- Uses Trojan Plant and decommissioning personnel experience base while still available.
- Allows for shared resources for demolition and remaining decommissioning.
- Avoids out-year costs of inspection and maintenance for demolished buildings.
- Helps to mitigate increases in out-year cost/risk from longer ISFSI storage.
- Expresses PGE's environmental stewardship.

- Provides jobs for near-term regional economic health.

Q. Will PGE maintain the diligence that lowered estimated costs by $20 million compared to UE 115?

A. Yes. There may be additional opportunities for savings, without sacrificing safety or quality. PGE will take advantage of those opportunities, if they arise, in order to benefit customers.

IV. Qualifications

Q. Mr. Nichols, what is your educational background, experience, and responsibilities?

A. I joined PGE in 1974, and since that time have held a number of positions related to the Trojan Nuclear Plant. These have included Licensed Reactor Operator; Training Specialist IV; Manager, Training; Manager, Outage Planning; Manager, Decommissioning Projects; and General Manager, Trojan. I entered my current position, General Manager, Trojan and Hydro Operations, in 2005. I am responsible for the overall organization, planning, and implementation of the tasks necessary for the safe, legal, and efficient decommissioning of Trojan, as well as the overall safe and efficient operation of the company hydroelectric facilities, and for the FERC relicensing activities associated with these facilities.

I completed three years of course work in Mechanical Engineering and Business. I attended the Public Utilities Executive Course at the University of Idaho. I have earned certificates in Management/Supervision at Portland Community College as well as Shift Technical Advisor Training/Certification. Finally, from 1976-1990, I was an NRC Licensed Reactor Operator/Senior Reactor Operator.

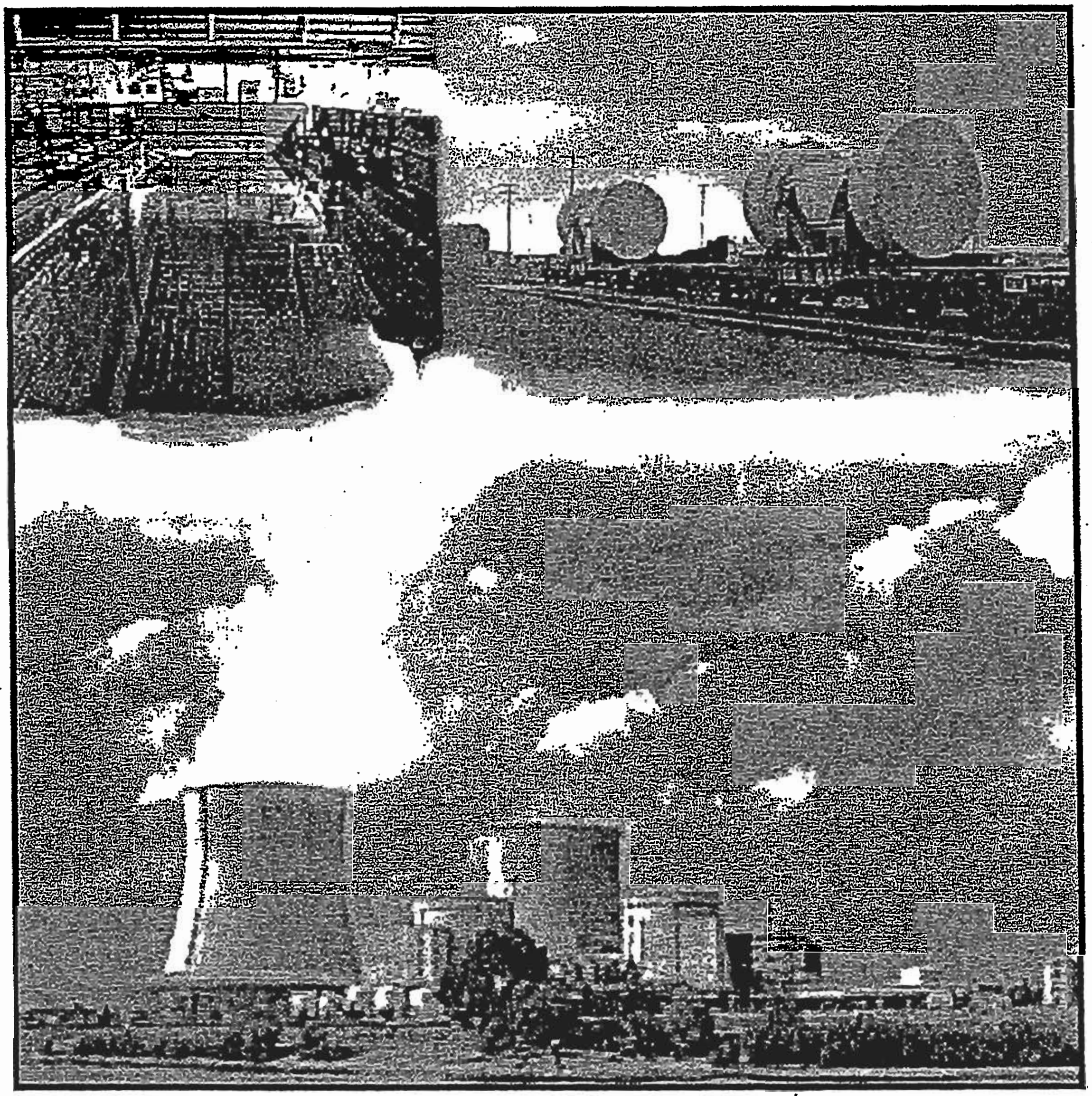
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1001	U.S. Department of Energy. Office of Civilian Radioactive Waste Management. *Acceptance Priority Ranking & Annual Capacity Report.* USDOE/RW-0567.
1002	NRC Letter. *Termination of Trojan Nuclear Facility Operating License No. NPF-1*, May 23, 2005.
1003	Major Trojan Decommissioning Milestones
1004	Portland General Electric. March 2005 Presentation to OPUC on Trojan Decommissioning.

Acceptance Priority Ranking & Annual Capacity Report



U.S. Department of Energy

Office of Civilian Radioactive Waste Management

July 2004

ACCEPTANCE PRIORITY RANKING

&

ANNUAL CAPACITY REPORT

U.S. DEPARTMENT OF ENERGY
OFFICE OF CIVILIAN RADIOACTIVE WASTE MANAGEMENT
WASHINGTON, DC 20585

JULY 2004

CONTENTS

ACCEPTANCE PRIORITY RANKING & ANNUAL CAPACITY REPORT

1.0 INTRODUCTION

The Nuclear Waste Policy Act of 1982, as amended (the Act)[1], assigns the Federal Government the responsibility for the disposal of spent nuclear fuel and high-level waste. Section 302(a) of the Act authorizes the Secretary to enter into contracts* with the owners and generators** of commercial spent nuclear fuel and/or high-level waste. *The Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste*[2] (Standard Contract) established the contractual mechanism for the Department's acceptance and disposal of spent nuclear fuel and high-level waste. It includes the requirements and operational responsibilities of the parties to the Standard Contract in the areas of administrative matters, fees, terms of payment, waste acceptance criteria, and waste acceptance procedures. The Standard Contract provides for the acquisition of title to the spent nuclear fuel and/or high-level waste by the Department, its transportation to Federal facilities, and its subsequent disposal.

The Standard Contract requires the Department to issue an annual Acceptance Priority Ranking (APR) report and an Annual Capacity Report (ACR). The APR establishes the order in which the Department allocates the projected acceptance capacity for commercial spent nuclear fuel. The ACR applies projected nominal acceptance rates for the system to the APR, resulting in individual allocations for the owners and generators expressed in metric tons of uranium (MTU). These capacity allocations form the basis for the Purchasers' submittal of Delivery Commitment Schedules (DCS). As specified in the Standard Contract, the ACR is for planning purposes only and, thus, is not contractually binding on either DOE or the Purchasers.

1.1 BASIS FOR THE ACCEPTANCE PRIORITY RANKING

As required by the Standard Contract, the APR is based on the date the spent nuclear fuel was permanently discharged, with the oldest spent nuclear fuel, on an industry-wide basis, given the highest priority. The phrase "date the spent nuclear fuel was permanently discharged" means the date the reactor went subcritical for the purpose of permanently discharging the spent nuclear fuel, as reported to the Department by the Purchasers on the Nuclear Fuel Data Survey Form, RW-859. The APR is the basis for allocating projected spent nuclear fuel (SNF) acceptance capacity in the ACR. The 2004 APR listing is based on SNF discharges through December 31, 2002. The APR listing has been included as Appendix A.

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* Individual contracts are based upon the Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (10 CFR Part 961).

** Owners and generators of spent nuclear fuel and high-level waste who have entered into contracts with the Department and/or have paid fees for purchase of disposal services are referred to as "Purchasers." In identifying the Purchasers listed in this report, the Department has relied upon written notices received pursuant to Article XII and XIV of the Purchasers' disposal contracts. In the event that any Purchaser believes that the listed designation is inappropriate, the Purchaser should contact the Department.

Future discharges will be added to the priority ranking based on their date of permanent discharge. If SNF currently designated as temporarily discharged is redesignated as permanently discharged (without subsequent irradiation), the date of redesignation will become the ranking date, instead of the date of actual discharge. Reinserted assemblies, previously designated as permanently discharged, will be removed from the priority ranking.

1.2 BASIS FOR THE ANNUAL CAPACITY REPORT

The ACR (see Appendix B) applies a 10-year projected nominal waste acceptance rate to the APR, resulting in individual capacity allocations. The projected nominal acceptance rate is based on the assumption of SNF acceptance beginning in 2010 at the Yucca Mountain Geologic Repository. These projected nominal waste acceptance rates are presented in Table 1.

Table 1. Projected Nominal Waste Acceptance Rates for Spent Nuclear Fuel

Year	SNF (MTU)
2010	400
2011	600
2012	1,200
2013	2,000
2014	3,000
2015	3,000
2016	3,000
2017	3,000
2018	3,000
2019	3,000

The Department will further define and specify the system operating and waste acceptance parameters as the Program progresses, and inform the Purchasers accordingly. Until the SNF is accepted by the Department, Section 111 (a)(5) of the Act assigns the waste owners and generators the primary responsibility to provide for, and pay the costs of, interim storage.

The Tables in Appendix B list the Purchasers' annual allocations for each of the first 10 years*** of projected CRWMS operation. Table 2 presents a summary of all Purchasers' annual allocations based on the nominal waste acceptance rates for the 10-year period covered by this report.

*** The term "year," when used in reference to capacity allocation in this report, means the calendar year, beginning nuary 1 and ending December 31.

TABLE 2. SUMMARY OF PURCHASERS' ANNUAL ALLOCATIONS (MTU)[a]

PURCHASER	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL
Aerotest Operations, Inc.	-	-	-	-	-	-	-	-	-	-	-
Alabama Power Company	-	-	-	-	45.6	119.3	73.4	77.8	60.2	89.9	466.2
Ameren UE	-	-	-	-	-	-	38.7	44.3	38.0	30.3	151.3
Ame... Energy Company, LLC	31.1	43.0	46.8	114.4	51.7	36.4	-	67.0	88.6	107.4	586.4
...blic Service Company	-	-	-	-	-	-	-	66.5	69.4	66.2	202.1
...nole Gas & Electric Co.	-	-	-	82.6	107.5	89.6	93.8	62.0	64.2	-	499.7
BWXT	-	-	0.1	0.1	-	0.1	0.1	-	0.1	-	0.1[b]
Carolina Power & Light Company	-	69.7	48.0	50.5	145.8	118.3	116.0	87.3	87.4	94.8	817.8
Cleveland Electric Illuminating Co.	-	-	-	-	-	-	-	-	22.6	76.7	99.4
Connecticut Yankee Atomic Power Co.	65.5	22.5	41.6	21.9	42.1	42.1	44.5	21.8	21.0	-	323.1
Consumers Power Co.	-	2.5	87.4	31.1	32.9	59.9	24.8	3.1	25.9	32.0	299.6
Dairyland Power Cooperative	0.8	6.0	3.0	3.9	4.9	5.7	6.1	7.8	-	-	38.1
Detroit Edison Company	-	-	-	-	-	-	-	-	19.1	-	19.1
Dominion Nuclear Connecticut, Inc.	5.5	40.7	52.5	41.9	113.8	93.3	103.6	123.7	103.9	71.2	750.1
Dow Chemical	-	-	-	-	-	-	-	-	-	-	-
Duke Power Company	-	24.9	48.2	176.4	124.2	162.3	200.0	318.5	234.6	246.3	1,535.5
Energy Northwest	-	-	-	-	-	-	10.8	29.4	52.5	37.9	130.7
Entergy Arkansas, Inc.	-	-	-	51.5	76.6	83.3	60.6	76.8	28.2	87.6	464.6
Entergy Gulf States, Inc.	-	-	-	-	-	-	-	30.5	41.1	32.9	104.5
Entergy Louisiana, Inc.	-	-	-	-	-	-	-	38.6	31.8	70.8	141.1
Entergy Nuclear FitzPatrick, LLC	-	-	-	51.4	30.0	71.8	34.4	35.8	33.6	27.3	284.2
Entergy Nuclear Generation Company	-	3.9	25.5	82.6	17.1	83.9	-	34.2	-	-	247.2
Entergy Nuclear Indian Point 2, LLC	3.0	27.7	32.8	27.1	52.8	33.8	63.5	31.1	33.0	25.8	330.6
Entergy Nuclear Indian Point 3, LLC	-	-	-	29.3	34.7	34.7	33.0	36.1	28.4	33.8	229.9
Entergy Nuclear Vermont Yankee, LLC	-	72.9	-	40.2	50.7	41.5	41.3	24.9	25.0	23.6	320.0
Exelon Generation Company, LLC	21.1	60.5	251.2	466.7	488.3	451.7	419.8	375.2	523.9	433.6	3,491.9
Florida Power & Light Co.	-	20.9	59.6	78.7	169.3	112.4	141.8	117.1	86.9	122.2	908.9
Florida Power Corporation	-	-	-	0.9	46.4	58.3	30.1	41.3	-	33.8	210.8
FPL Energy Seabrook, LLC	-	-	-	-	-	-	-	-	-	-	-
G.E. Uranium Management Corporation	145.2	-	-	-	-	-	-	-	-	-	145.2
General Atomics	0.1	0.1	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1[b]
Gene... Electric Company	0.3	-	-	-	-	-	-	-	-	-	0.3
G... ower Company	-	-	-	5.2	91.6	105.3	103.2	116.3	103.3	117.3	642.2
... Michigan Power Co.	-	-	-	57.8	132.6	120.2	119.3	35.7	65.7	71.5	602.9
Interstate Power & Light	-	-	15.4	36.4	32.0	23.6	22.0	23.4	21.9	19.1	193.9
Kansas Gas & Electric Company	-	-	-	-	-	-	-	27.7	33.7	35.3	96.7
Maine Yankee Atomic Power Company	-	26.4	57.9	78.0	52.5	30.0	54.8	24.5	20.8	27.4	372.3
Nebraska Public Power District	-	-	23.6	13.8	80.9	41.9	21.2	37.3	32.2	30.9	281.7
Nine Mile Point Nuclear Power Station, LLC	9.4	49.0	38.9	30.8	68.1	-	74.8	31.1	-	36.3	338.4
Northern States Power Co.	-	26.2	99.6	65.2	111.4	143.1	58.9	92.6	52.3	38.4	687.6
Omaha Public Power District	-	-	22.3	35.4	14.8	21.9	32.3	16.4	15.2	13.1	171.4
Pacific Gas & Electric Company	7.3	6.0	15.9	-	-	-	-	47.5	65.3	110.2	252.1
Pennsylvania Power & Light Co.	-	-	-	-	-	-	89.6	103.5	121.2	78.9	393.2
Pennsylvania Power Company	-	-	-	-	6.0	48.7	35.2	63.6	56.3	31.8	241.6
Portland General Electric Company	-	-	-	0.5	40.5	34.9	42.2	54.2	48.8	49.0	270.0
PSEG Nuclear LLC	-	-	-	-	46.9	72.6	64.6	133.0	96.0	133.8	547.0
Rochester Gas and Electric Company	32.0	4.6	24.4	32.3	35.8	12.7	35.1	23.5	12.8	23.6	236.9
Sacramento Municipal Utility District	-	-	-	35.3	49.2	32.0	30.1	-	82.0	-	228.6
South Carolina Electric & Gas Company	-	-	-	-	-	-	50.4	27.6	28.0	31.9	137.9
South Texas Project NOC	-	-	-	-	-	-	-	-	9.8	50.4	60.2
Southern California Edison Co.	35.6	20.5	38.6	19.2	19.3	-	73.9	118.7	112.7	60.5	498.9
Systems Energy Resources, Inc.	-	-	-	-	-	-	-	101.5	50.4	50.2	202.1
Tennessee Valley Authority	-	-	-	64.2	297.8	236.0	277.0	-	33.1	60.3	968.4
Texas Utilities Generating Company	-	-	-	-	-	-	-	-	-	-	-
Toledo Edison Co.	-	-	-	-	-	65.2	30.6	-	30.5	28.1	154.3
U.S. DOE	22.9	6.8	7.8	7.3	89.5	88.0	0.1	0.1	15.7	-	237.8[b]
Virginia Electric and Power Co.	-	8.2	113.3	54.7	105.5	133.0	151.3	86.0	108.6	85.9	846.4
Wisconsin Electric Power Company	16.3	43.1	32.6	64.2	50.2	57.0	29.9	53.7	37.8	37.7	422.5
Wisconsin Public Service Corporation	-	-	4.4	33.8	35.1	25.9	49.8	23.1	17.1	26.5	215.7
Yankee Atomic Electric Company	9.9	10.1	9.7	18.1	8.5	9.4	17.7	8.3	9.2	8.4	109.2
NOMINAL TOTAL	400	600	1,200	2,000	3,000	3,000	3,000	3,000	3,000	3,000	22,200

...erences in Purchaser allocations for individual years in Annual Capacity Report may differ from the Acceptance Priority Ranking due to rounding.
b These totals are not the sum of the annual allocations because the actual annual values are much less than .1 MTU.

1.3 SUBMITTAL OF COMMENTS ON THIS REPORT

Written comments are requested, especially from the Purchasers, on the content and format of this report. Comments received on previous reports were used to identify issues that needed to be addressed by the Department and the Purchasers in the implementation of the Standard Contract provisions. Comments on this report should be addressed to:

Mr. David K. Zabransky
Contracting Officer
Office of Civilian Radioactive Waste Management, RW-20E
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Or by e-mail at:

dave.zabransky@rw.doe.gov

REFERENCES

[1] "Nuclear Waste Policy Act of 1982," Public Law 97-425 (January 7, 1983) and the "Nuclear Waste Policy Amendments Act of 1987," Title V, Subtitle A, Public Law 100-203 (December 22, 1987).

[2] U.S. Department of Energy, "Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste," Code of Federal Regulations, Title 10, Part 961, 2004.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001
May 23, 2005

Mr. Stephen M. Quennoz, Vice President
Power Supply/Generation
Portland General Electric Company
Trojan Nuclear Plant
71760 Columbia River Highway
Rainier, Oregon 97048

SUBJECT: TERMINATION OF TROJAN NUCLEAR PLANT FACILITY OPERATING LICENSE NO. NPF-1

Dear Mr. Quennoz:

On December 20, 2004, Portland General Electric Company (PGE) submitted an application for termination of the Trojan Nuclear Plant (TNP) Facility Operating (Possession Only) License No. NPF-1. The application states that PGE has completed remaining radiological decommissioning and final status surveys (FSSs) of the TNP facility and site in accordance with the NRC-approved license termination plan (LTP), and the FSSs demonstrate that the facility and site meet the criteria for decommissioning and release of the site for unrestricted use that are stipulated in 10 CFR Part 20, Subpart E.

The U.S. Nuclear Regulatory Commission (NRC) staff has completed the review of the FSS Reports (FSSRs) and concludes in accordance with 10 CFR 50.82 that: (i) Dismantlement and decontamination activities were performed in accordance with the approved LTP, and (ii) The FSSRs and associated documentation, including an assessment of dose contributions associated with parts released for use before approval of the LTP, demonstrate that the facility and site have met the criteria for decommissioning in 10 CFR Part 20, subpart E. Therefore, License NPF-1 is terminated, effective May 23, 2005.

Under the 10 CFR Part 50 license, PGE maintains a quality assurance (QA) program that was previously approved by the NRC as satisfying the requirements of 10 CFR Part 50, Appendix B. Pursuant to 10 CFR 71.101(f) and 10 CFR 72.140(d), PGE applies this program to satisfy the QA requirements of 10 CFR Part 71, Subpart H, and 10 CFR Part 72, Subpart G. PGE letter VPN-001-2005, dated January 21, 2005, states that, upon receipt of NRC approval of PGE-8010, "Trojan Nuclear Quality Assurance Program," proposed Revision 28, and concurrent with Trojan Nuclear Plant license termination, PGE will issue the approved PGE-8010, Revision 28, to satisfy the quality assurance requirements of 10 CFR Part 71, Subpart H, and 10 CFR Part 72, Subpart G. The NRC has reviewed PGE-8010, proposed Revision 28, and issued Quality Assurance Program Approval for Radioactive Material Packages No. 0327, Revision No. 15, to be effective on the date of the 10 CFR Part 50 license termination. This approval will satisfy the requirements of 10 CFR 71.17(b) and 71.101(c) for a QA program approved by the NRC. In accordance with the provisions of 10 CFR 72.140(d), this previously approved QA program will be accepted as satisfying the requirements of 10 CFR 72.140 (b), except that the licensee shall also meet the recordkeeping requirements of 10 CFR 72.174. PGE-8010 describes how the recordkeeping requirements of 10 CFR 72.174 will be met. Therefore, upon issuance of PGE-8010, PGE will satisfy the QA requirements of 10 CFR Part 71, Subpart H, and 10 CFR Part 72, Subpart G.

As a condition of the termination of License NPF-1, PGE is required to maintain $100 million in nuclear liability insurance coverage, as described in Indemnity Agreement No. B-78, "until all the radioactive material has been removed from the location and transportation of the radioactive material from the location has ended as defined in subparagraph 5(b), Article I, or until the Commission authorizes the termination or modification of such financial protection." Termination of the TNP 10 CFR Part 50 license has no impact on the terms of the indemnity agreement. Further, it should be noted that the site location described in Item 4 of the attachment to the indemnity agreement means the "original" 10 CFR Part 50 license site boundaries. PGE shall incorporate its commitment to maintain $100 million in nuclear liability insurance coverage into the TNP ISFSI Safety Analysis Report to ensure that the liability insurance coverage level shall not be reduced below the minimum $100 million amount without prior NRC approval.

The staff's review of the FSSRs is documented in the enclosed Safety Evaluation Report. Enclosure 2 is the Notice of Termination which is being sent to the Federal Register for publication.

In accordance with 10 CFR 2.390 of the NRC's "Rules of General Applicability," a copy of this letter will be available electronically in the NRC Public Document Room or from the Publically Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

If you have any questions please contact John Buckley at (301) 415-6607.

Sincerely,

Andrew Persinko for.

Daniel M. Gillen, Deputy Director
Decommissioning Directorate
Division of Waste Management
and Environmental Protection
Office of Nuclear Material Safety
and Safeguards

Enclosures: 1. Safety Evaluation Report
2. Federal Register Notice

Docket No.: 50-344
License No.: NFP-1

cc: Trojan distribution list

3.0 DECOMMISSIONING ACTIVITIES AND TASKS

3.1 COMPLETED DECOMMISSIONING ACTIVITIES AND TASKS

Subsequent to the January 27, 1993, decision to permanently shutdown TNP, PGE selected the DECON alternative and proceeded to perform decommissioning activities and tasks. As of mid-2005, many decommissioning activities and tasks had been completed and a list of the more significant ones are provided below for historical purposes:

Year 1993

May 5, 1993, TNP Facility Operating License, NPF-1, changed to a Possession Only License.

July 31, 1993, PGE requested TNP Technical Specifications changes to reflect the permanently defueled status.

October 7, 1993, PGE issued updated Safety Analysis Report for the Defueled Condition (DSAR).

Year 1995

January 26, 1995, PGE submitted proposed TNP Decommissioning Plan to NRC and ODOE/EFSC.

March 31, 1995, NRC issued amendment to TNP (Possession Only) License, NPF-1, to reflect permanently defueled condition.

November 13, 1995, PGE submitted update to proposed TNP Decommissioning Plan to NRC and ODOE/EFSC.

November 1995, Completed removal and transport of Large Components (4 - Steam Generators and 1- Pressurizer) to US Ecology for disposal.

Year 1996

March 14, 1996, EFSC issued an Order approving the TNP Decommissioning Plan.

March 26, 1996, PGE submitted application for a Trojan ISFSI License to NRC.

April 15, 1996, NRC issued an Order approving the TNP Decommissioning Plan and authorizing decommissioning of Trojan.

October 30, 1996, PGE submitted final TNP site radiation survey report for the planned ISFSI area to NRC and ODOE.

November 26, 1996, NRC approved final TNP site radiation survey report for planned ISFSI area.

Year 1997

June 9, 1997, NRC approved amendment to the TNP License to allow processing Spent Fuel Debris in the Fuel Building.

Year 1998

February 11, 1998, Completed processing Spent Fuel Debris in the Fuel Building.

October 15, 1998, EFSC approved Reactor Vessel and Internals Removal (RVAIR) Project.

October 29, 1998, NRC issued authorization of the Trojan Reactor Vessel Package for Transport.

Year 1999

March 31, 1999, NRC issued new Trojan ISFSI License, SNM-2509.

August 16, 1999, completed removal and transport of TNP Reactor Vessel to US Ecology for disposal.

Year 2001

January 2001, completed Containment Building internal concrete removal.

February 12, 2001, NRC approved the TNP License Termination Plan, PGE-1078.

October 26, 2001, PGE submitted ISFSI License amendment to NRC to permit use of Holtec components.

Year 2002

October 23, 2002, NRC issued amendment to ISFSI License for use of Holtec components.

December 31, 2002, commenced spent fuel loading activities for transfer of fuel to the Trojan ISFSI.

Year 2003

September 3, 2003, completed transfer of spent nuclear fuel from the TNP Spent Fuel Pool to the Trojan ISFSI. Thirty four (34) Storage Casks are on the ISFSI Storage Pad.

Year 2004

July 2004, completed major radiological remediation of TNP site.

August 12, 2004, PGE submitted to NRC and ODOE final groundwater monitoring report information.

August 19, 2004, NRC approved TNP site groundwater monitoring reports.

October 7, 2004, completed all radiological remediation of TNP site.

October 15, 2004, ODOE approved TNP site groundwater monitoring reports.

November 22, 2004, completed collection of data for final TNP site radiation survey.

December 20, 2004, completed submittal of last final TNP site radiation survey reports to NRC and ODOE.

December 20, 2004, submitted application to NRC for termination of TNP License, NPF-1.

Year 2005

February 23, 2005, NRC completed approval of final TNP site radiation survey reports.

April 8, 2005, EFSC determined that TNP decommissioning was complete and the TNP site meets all criteria for unrestricted use.

May 23, 2005, NRC terminated TNP Operating License, NPF-1, and approved release of TNP site for unrestricted use.

May 23, 2005, Oregon issued revised OARs to reflect termination of the TNP License, NPF-1, and specific Rules for the Trojan ISFSI.

June 6, 2005, Revision 22 of PGE-1061, Trojan Nuclear Plant Decommissioning Plan, Defueled Safety Analysis Report, and License Termination Plan (PGE-1078) was converted into a historical licensing document.

TROJAN DECOMMISSIONING STATUS

OPUC Meeting

March 8, 2005

1

Meeting Agenda

- Trojan Decommissioning Overview
  - History
  - Major Projects
  - Overall Performance
- Remaining Major Activities
- Current Issues
  - USDOE Fuel Storage
  - Non-radiological Building Demolition
- Regulatory Preview

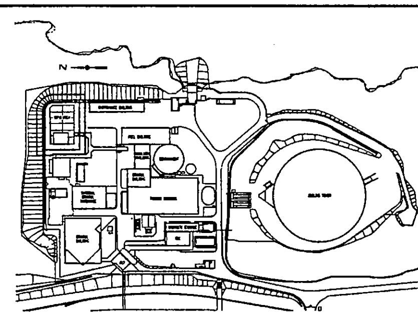
2

Decommissioning History

• Permanent Shutdown	Jan 1993
• Large Component Removal	Nov 1995
• Decommissioning Plan NRC Approval	Apr 1996
• Reactor Vessel Removal	Aug 1999
• Containment Building Concrete Removal	Jan 2001
• ISFSI Fully Loaded	Sep 2003
• Major Radiological Bldg Remediation Cp	Jul 2004
• All Radiological Remediation Complete	Sep 2004
• Final Survey Data Collection Complete	Nov 2004
• All Final Survey Reports Submitted to NRC	Dec 2004

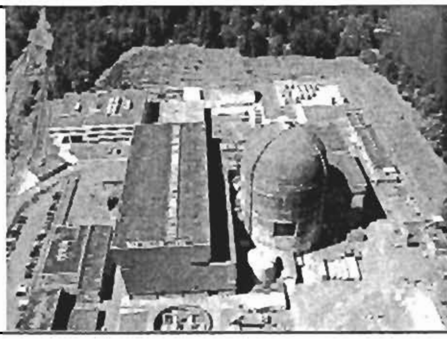
3

Trojan Site Layout



4

Trojan Structures



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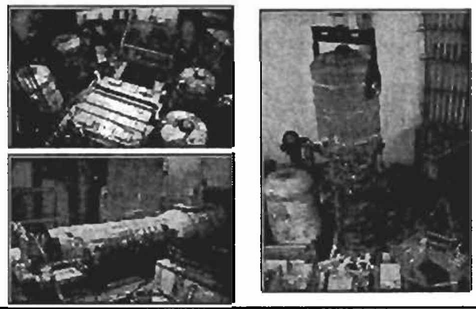
Large Component Removal



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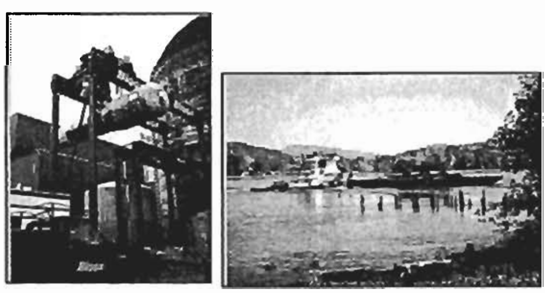
Large Component Removal



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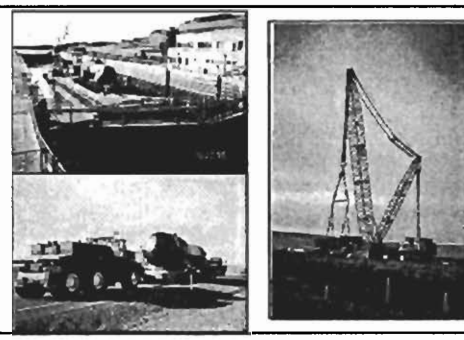
Large Component Removal



8

Reactor Vessel and Internals Removal Project (RVAIR)

9

RVAIR Project

10

RVAIR Project

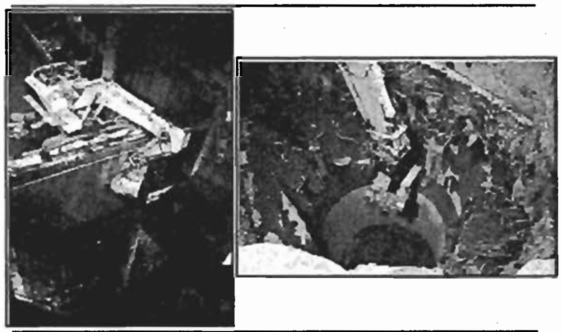
2000 Project Management Institute (PMI) International Project of the Year

11

Containment Concrete Removal

12

Containment Concrete Removal



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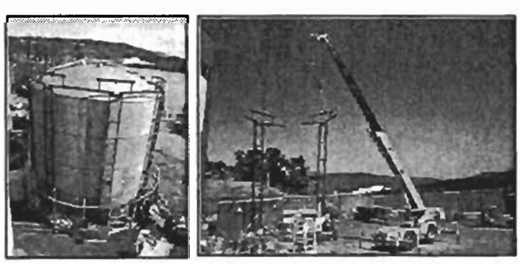
Containment Building – Pre/Post

1976

2001

14

Refueling Water Storage Tank



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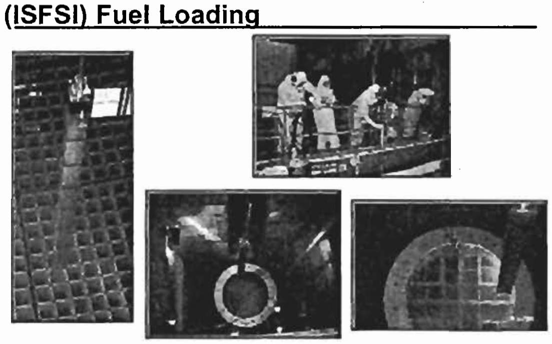
Independent Spent Fuel Storage Installation (ISFSI) Fuel Loading



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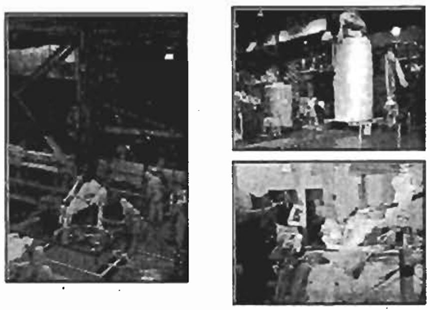
Multi-Purpose Canister (MPC) Operations



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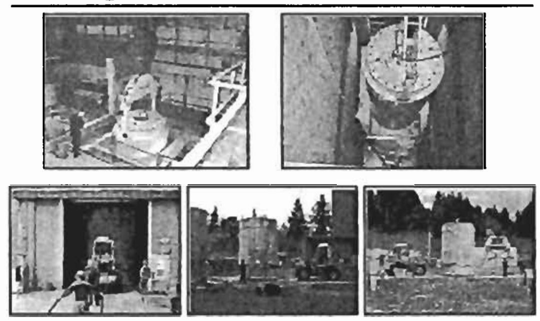
Moving the Multi-Purpose Canister



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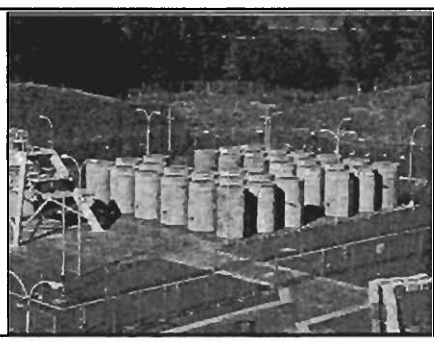
ISFSI Pad with Loaded Casks



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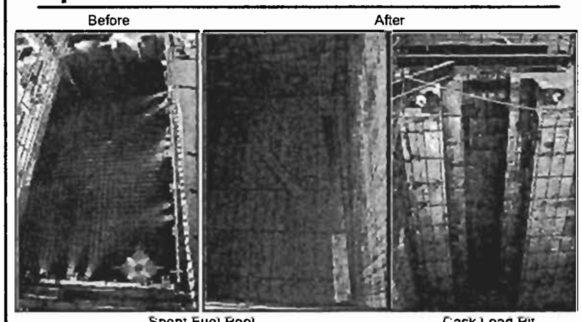
Spent Fuel Pool



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Radwaste Evaporator Room

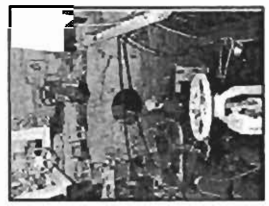
Before

After

21

Main Steam Support Structure

'A' Cubicle - 59' level



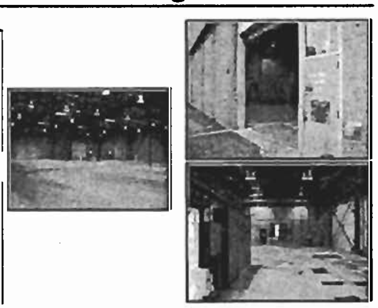
Before

After

22

Miscellaneous Buildings

Warehouse



Maintenance Building

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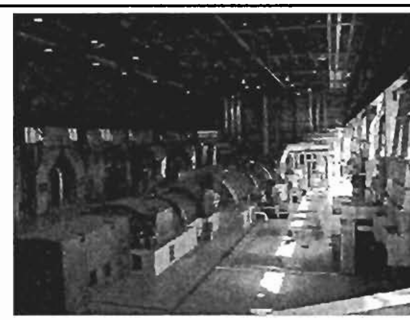
Turbine Building



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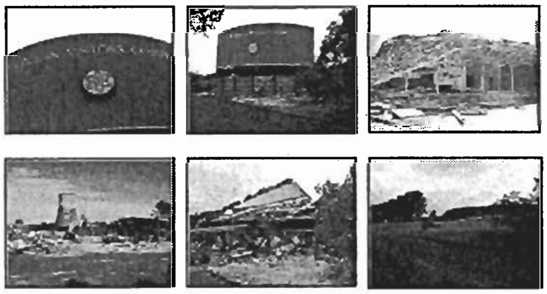
Trojan Visitors Center



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PGE

Final Radiological Survey

- Plant divided into 9 survey groups
  - Containment
  - MSSS/EPA/SGBD (between Containment, Turbine, and Control Bldgs.)
  - Turbine and Control Buildings
  - Embedded Pipe
  - Auxiliary Building
  - Fuel Building
  - Support Facilities and Site Grounds
  - Spent Fuel Pool Impacted Areas
  - Plant Systems
- Key Statistics
  - 250,000 Square meters of surface area surveyed
  - 26,000 Surveyor hours to collect data
  - 62,000 Survey measurements collected
- NRC Confirmation Surveys
- NRC Review and Evaluation of Final Reports

26

PGE

Decom. Cost Estimate Comparison
($1997)

Category	TDF Update UE-102	TDF Update Dec 99	TDF Update Dec 04
DECON	236.1	235.4	211.7
Non-Rad. Decom.	53.7	44.8	40.2
ISFSI Const./Fuel Load	62.9	66.7	82.0
ISFSI Long Term Ops	70.9	67.0	60.1
Financing	11.6	8.7	0.0
Subtotal	435.2	422.6	397.8
Project Reserve	0.0	7.1	35.7
Total	435.2	429.7	429.7

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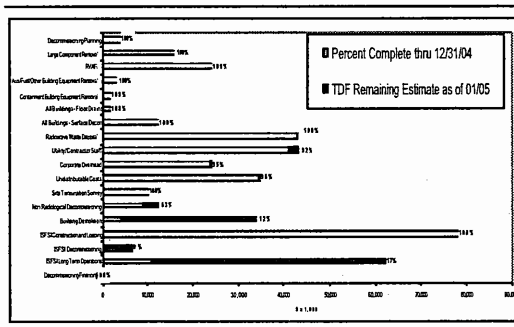
PGE

Project Completion Percentage



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PGE

Decommissioning Cost Estimate

as of December 2004 ($1997)

Category	Actual to Date	To Complete	TDF Update
DECON	205.3	6.4	211.7
Non-Rad Decom	3.8	36.4	40.2
ISFSI Const./Fuel Load	74.1	7.9	82.0
ISFSI Long Term Ops	7.0	53.1	60.1
Financing	0.0	0.0	0.0
Subtotal	290.2	103.8	394.0
Project Reserve	0.0	35.7	35.7
Total	290.2	139.5	429.7

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PGE

Decommissioning Cost Comparison

	Facility							
(all costs in millions '03 $'s)	Big Rock [1]	Yankee Rowe	San Onofre 1	Haddam Neck	Maine Yankee [2]	Rancho Seco	Trojan [3]	Average [3] (5 PWR's)
Thermal Rating (MWt)	240	600	1,347	1,825	2,700	2,772	3,411	
Total Cost NRC-Required Activities [4]	331.1	484.8	420.4	477.6	437.6	399.8	270.2	444.1
NRC Funding Level Requirement (waste processors)	386.0	302.0	301.9	321.4	348.6	345.5	279.0	323.9
Cost of NRC-Required Activities v. NRC Funding Level Requirements (%)	86%	161%	139%	149%	126%	116%	97%	137%
Cost Per Thermal Megawatt	1.38	0.81	0.31	0.26	0.16	0.14	0.08	0.45

Note 1: only BWR reactor in group
Note 2: only PWR located in Northwest Compact in group
Note 3: only PWR's not located in Northwest Compact
Note 4: does not reflect a $44 million credit received from performance and payment bond settlement

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PGE

Schedule, Staffing, Performance

- Overall Radiological Decommissioning Schedule Performance
  - ISFSI Project delayed approx. 3.5 years
  - Overall project delayed approx. 2.5 years
- Overall Radiological Decommissioning Cost Performance – Approx. 8% under budget
- Awarded - 2000 Project Management Institute Project of the Year
- Staffing – PGE and Contract Personnel
  - January 2003 171
  - December 2004 50
  - Additional layoffs thru 2005 30
- Staffing at the end of radiological decommissioning project
  - ISFSI Long-term staff

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PGE

Remaining Major Activities

- Complete Radiological Decom. June 2005
- NRC Terminate Part 50 License June 2005
- On-going Fuel Storage Operations thru 2018
- Fuel Shipment 2003-2018
  - Based on Original Decom. Plan
- Building/ISFSI Demo. and Site Restoration 2018-2019
  - Based on Original Decom. Plan

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PGE

Decom. Plan Changes

- ISFSI operations will continue until 2023 (current projection) due to delays with the High Level Waste Repository
  - USDOE scheduled to open repository in 2010
    - Significant uncertainty with this schedule
  - Based on fuel shipment allotment, first PGE fuel ships in 2013
  - Final shipment projected in 2023
  - ISFSI Decommissioning in 2024
- Accelerated Structure Demolition Proposal
  - Complete major building demolition in 2005-2008 versus end of project. (Cooling Tower, Turbine Building, Control Building, Auxiliary Building, Fuel Building, and Containment)
  - Co-owners concur with Accelerated Structure Demolition Proposal
  - Plan to proceed following management approval

33 PGE

Rationale for Accelerated Building Demolition

- **Advantages of Accelerated Building Demolition**
  - Resolves uncertainty for a significant portion of remaining costs
  - Uses Trojan experience-base while still available
  - Shares resources for demolition and remaining radiological decom.
  - Avoids out-year costs of inspections and maintenance
  - Mitigates increase in out-year cost/risk from longer ISFSI storage
  - Expresses PGE's environmental stewardship
  - Provides jobs for near term regional economic health
- **Risks of Stay-the-Course or Delayed Demolition: Increases in costs**
  - Demolition
  - Regulation
  - Inspection of remaining structures
  - Maintenance of remaining structures
- **Buildings in use or with potential future value will remain for later demolition.**

34 PGE

Regulatory Preview

- Continued Updates with OPUC Commission and Staff
- Audits
  - Staff
  - Internal
- Re-evaluate NDT contribution with next General Rate Case
  - Contribution continues through 2006
  - Update contribution with next general filing
    - Review work yet to be completed
    - Re-evaluate contribution for 2007 and beyond

35 PGE

UE 180 / PGE / 1100
HAGER – VALACH

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
William J. Valach

March 15, 2006

Cost of Capital

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital, including its Required Return on Equity. My qualifications appear at the end of this testimony.

My name is William J. Valach. Until the Fall of 2005, I was the Manager of Finance and Assistant Treasurer for PGE. I am now the Director of Investor Relations for PGE. I am responsible for managing the relationships and communications with PGE's shareholders and the investing public. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. We present and support PGE's requested cost of capital for the 2007 test year. Our requested cost of capital and capital structure give PGE the opportunity, in accordance with the *Hope* and *Bluefield* standards, to earn a fair return, help PGE reach its financial goals, and keep its financial costs reasonable. With a capital intensive business, PGE must be able to access the debt and equity markets and must be able to maintain its secured bond and credit ratings at investment grade levels to raise capital at a reasonable cost for the company and its customers.

Q. What are PGE's financial goals?

A. Our overall goal is to be viewed by the financial markets as a well-performing, vertically integrated utility. This would include:

- Maintaining investment grade bond ratings;
- Accessing capital markets to provide liquidity for operating and capital;
- Attracting capital on reasonable terms;

- Achieving a return on equity that is at or above that achieved by a group of utilities with similar characteristics, service territory, and business risks; and
- Setting prices at a sufficient level to recover prudently incurred costs, including an overall return on utility investment.

Q. What is your requested overall cost of capital for this filing?

A. We request and support an 8.97% cost of capital for the test year 2007, including a 10.75% Required Return on Equity. This point estimate is for revenue requirement purposes and is based on a recommended range of 8.13% to 9.27% for PGE's cost of capital and a recommended range of 9.25% to 11.30% for PGE's Required Return on Equity. Table 1 below shows the recommended cost of each of the three components of PGE's capital (common equity, preferred stock, debt), as well as PGE's 2007 forecasted capital structure.

We have examined PGE's risks and concluded that PGE operates in a risk environment that is more risky and uncertain than that of the electric utility industry on average. As discussed later in our testimony, we base our recommendations on the risks that PGE would bear assuming adoption of: (1) the power cost adjustment mechanism as proposed by Ms. Lesh and Mr. Niman (PGE Exhibit 400); and (2) PGE's expected capital structure in 2007, which includes 56% common equity. In addition, PGE faces other uncertainties that may affect its risk profile, as we discuss later in our testimony. Depending upon how these issues are resolved, we may have to reassess our cost of capital estimate.

Q. How did you derive the overall recommended cost of capital?

A. We first estimated the cost for each component by considering the range, PGE's risks, and financing needs. We then determined the "weighted" cost by multiplying the component's cost by its weight (*i.e.*, percent) in our recommended capital structure. Summing the weighted cost of each component produces a weighted or composite cost of capital. PGE Exhibit 1101 summarizes our conclusions and it is reproduced as Table 1 below.

Table 1
PGE's Weighted Cost Of Capital
(Test Year 2007)

Component	Average Outstanding ($000)	Percent of Capital	Cost	Weighted Cost
Long-term Debt	$997,280	43.75%	6.69%	2.93%
Preferred Stock	$6,633	0.29%	8.43%	0.02%
Common Equity	$1,275,487	55.96%	10.75%	6.02%
Total	$2,279,400	100.00%		8.97%

Q. How does the U.S. Constitution, as interpreted by the U.S. Supreme Court, guide cost of capital decisions?

A. Our understanding is that two fundamental U.S. Supreme Court decisions provide guidance: *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*[1] (*Bluefield*) and *Federal Power Commission v. Hope Natural Gas Co.*[2] (*Hope*).

Q. What guidance does the *Bluefield* decision provide?

A. The *Bluefield* decision established the principle that a utility is entitled to earn a return comparable to that earned by companies with similar risks and uncertainties, generally referred to as the "comparable earnings" requirement.

Q. What additional guidance is provided by the *Hope* decision?

A. In the *Hope* decision, the Supreme Court confirmed the principles established in *Bluefield*, and added "financial integrity" and "capital attraction" requirements.

These *Bluefield* and *Hope* requirements – the comparable earnings test, the financial integrity test, and the capital attraction test – continue to be the relevant standard today for

[1] 262 U.S. 679 (1923)
[2] 320 U.S. 591 (1944)

determining the adequacy of returns that a utility must be allowed to earn on the assets it devotes to public service.

Q. What do these decisions imply regarding regulation?

A. The regulatory principles from these decisions indicate that rates should be based on prudently incurred costs of service and those costs of service include a fair rate of return and recovery of investments made to provide regulated service. The regulatory bargain between utilities and commissions depends on investors having a reasonable opportunity to earn a fair rate of return.

Q. Has the State of Oregon provided any guidelines regarding cost of capital?

A. Yes. ORS 756.040 reflects the principles in the Hope and Bluefield decisions. It states, in part:

> The commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates. Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is:
>
> a. Commensurate with the return on investments in other enterprises having corresponding risks; and
> b. Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.

Q. What does this mean for the cost of capital you request?

A. Under the standards set forth in the Supreme Court decisions and the Oregon statute, PGE's return on equity must be commensurate with returns on investments in other enterprises with comparable risk, and must be high enough to maintain PGE's financial integrity and enable PGE to attract capital on reasonable terms.

Q. How is your testimony organized?

A. After this introduction, we discuss PGE's long-term debt, including new and redeemed issues. We also discuss the difficulty of financing during the volatile financial and energy markets between 2001 and 2005. In Section III, we discuss the additional risks faced by PGE and how they impact PGE's earnings and return on equity. We also estimate a range for PGE's Required Return on Equity (RROE) using various financial models. In the remaining sections, we describe PGE's Preferred Stock, our proposed capital structure, and the expected stock issuance and distribution in April 2006.

II. Cost of Long-term Debt

A. Calculating Long-Term Debt Costs

Q. How did you calculate the cost of long-term debt for 2007?

A. PGE Exhibit 1102 shows the amount and effective cost of PGE's long-term debt for the test year. This includes existing bond issues as of December 31, 2005, along with bond issuances and bond retirements that we expect in 2006 and 2007. We calculate the outstanding debt for each year by averaging the amount outstanding at the month end for each of the 12 months and estimate the cost of each issue by multiplying the amount outstanding in each period by the effective interest rate for each bond issue. The effective interest rate represents the internal rate of return for each of the cash flows associated with each debt issue, including call premiums and unamortized issuance expenses for debt issues replaced before maturity with less expensive financings. Table 2 below summarizes PGE's cost of long-term debt for 2007.

Table 2
Cost of Long-Term Debt
(Average $000)

	2007
Amount	997,280
Interest Cost	66,718
Effective Interest Rate	6.69%

Q. What future debt issuances did you include in your analysis?

A. We project three new long-term debt issuances for 2006 and 2007. First, PGE recently received OPUC authority to issue $275 million of new long-term (30-year) debt in 2006. We expect to redeem the 8.125% issue using part of this authority. The remaining $100 million will be used to pay down short-term debt and to fund various capital projects. Second, we plan to remarket $5.8 million of pollution control bonds associated with PGE's Coyote Springs I gas-fired generating plant. Third, we plan to issue an additional $100 million in long-term (30-year) debt in 2007, using the proceeds to pay down short-term debt and to fund capital projects. We expect to update our 2007 long-term debt projections and estimates in our rebuttal testimony as financial conditions change.

Q. How did you determine the coupon interest rate on the new long-term debt issues?

A. We contacted investment bankers, and using the information they provided, we expect to issue the $275 million at approximately 6.0% and the $100 million at 6.5%. We later performed an analysis using publicly available information. For the fixed rate debt, we began with the Global Insight *U.S. Economic Outlook December 2005* forecast for thirty-year Treasuries, which is 5.24% for 2006 and 5.43% for 2007. Based on our discussions with several investment banks, we added a premium to the Treasury rate to reflect increased risk to the bondholder for holding bonds. This premium amounts to 130 basis points for the appropriate spread for non-callable utility bonds rated "BBB+." Based on this analysis, the coupon interest rate on the $275 million long-term issue would be 6.54% and the coupon interest rate on the $100 million long-term issues would be 6.73%. This analysis confirms that our first estimate using information provided by the investment bankers is reasonable.

We intend to remarket the Coyote Pollution Control Bonds in 2006. We estimated the interest on this debt by considering the current two-year tax-exempt rate and adding 25 basis points for rising interest rates. The result is 3.5%.

Q. Why do you expect your estimates for the coupon rates to change?

A. We provided the coupon estimates last fall for our 2006 budget and 2007 financial projections and they have been incorporated into our 2007 test year. However, interest rates have changed since then and will likely change again. In addition, we expect to issue the

$275 million in two stages. The first $175 million would be issued in Spring 2006 and the remaining $100 million would be issued in the Fall. Given the time between the two issuances, we expect the coupon rates to be different. Again, we will provide the latest financial information and estimates in our rebuttal testimony as financial conditions and forecasts change.

Q. Is there any long-term debt maturing in 2006 or 2007?

A. Yes. PGE will have a $50 million issue maturing in June 2007.

Q. Has PGE issued or redeemed any long-term debt since PGE filed its last general rate case in 2001?

A. Yes. As interest rates declined, PGE refinanced higher cost debt when it was cost-effective, thus lowering the long-term cost of debt. In addition, PGE uses short-term revolvers for which the cost is usually lower than long-term debt. PGE also took advantage of the historically low long-term interest rates to redeem short-term debt and issue lower cost long-term debt. This results in a reduction of the cost of long-term debt from 7.8% requested in UE 115 to the 6.69% we request here. Table 3 shows that PGE will have redeemed twelve issues totaling $718 million and issued $981 million during the period 2001 through 2007.

Table 3
Amount Redeemed and Issued
(Test Year 2007)

Month/Year	Issue	Amount Issued	Amount Redeemed/Matured
December 2001	FMB 2.99%	$150,000	
January 2002	[1]MTN 7.66%		$ 15,000
October 2002	FMB 8.125%	$150,000	
October 2002	FMB 5.6675%	$100,000	
December 2002	FMB 2.99%		$150,000
April 2003	FMB 5.279%	$ 50,000	
August 2003	FMB 5.625%	$ 50,000	
August 2003	FMB 6.750%	$ 50,000	
August 2003	FMB 6.875%	$ 50,000	
August 2003	MTN 6.47%		$ 40,000
Sep. 2003	*MTN 9.46%		$ 25,000
Sept. 2003 - June 2004	*QUID 8.25%		$ 75,000
Dec. 2001 – Dec. 2003	*FMB 7.75%		$150,000
July 2004	MTN 7.61%		$ 11,000
July 2004	MTN 7.61%		$ 26,000
July 2004	MTN 7.60%		$ 8,000
August 2005	MTN 9.07%		$ 18,000
April 2006	FMB 6.00%	$ 275,000	
April 2006	*FMB 8.125%		$150,000
June 2006	PCB Variable	$ 5,800	
June 2007	FMB 6.5%	$100,000	
June 2007	MTN 7.15%		$ 50,000
	Total	$980,800	$718,000

[1] MTNs are FMB offerings except with a different structure

* Redeemed prior to maturity

B. Financial Markets between 2001 and 2005

Q. Please describe the environment in which PGE issued debt between 2001 and 2003.

A. The economic and financial markets began the decade with slow or negative growth. Beginning in early 2000, U.S. economic growth slowed for several quarters, picking up in 2003. During 2001, the U.S. economy suffered negative growth in the second and fourth quarters. As shown in PGE Exhibit 1103, in 2001, stock markets had already declined significantly from their historic highs in 2000, leading to financial distress for many companies. Also in 2001, the energy markets were in a state of flux which contributed to the deterioration of the financial markets as a whole, but particularly for energy companies (including electric utilities). By the end of 2002, financial institutions had tightened their lending requirements, limiting the ability of energy companies to borrow or raise equity.

Q. Did the deterioration of the financial markets affect energy companies more than in the past?

A. Yes. The deterioration of the financial markets impacted energy companies far more than in the past for several reasons. First, retail deregulation led many major utilities to divest most of their generation. These utilities then became more exposed to fluctuations in wholesale power prices, which resulted in increasing risk, although this may not have been apparent at the time. In some cases, this risk was worsened by legislatively imposed multi-year retail rate freezes. Buyers, including Independent Power Producers (IPPs), tended to be highly leveraged and either did not have long-term contracts in place or did not sufficiently cover their risk exposure for fluctuating energy prices.

Second, along with the wholesale markets that developed in the late 1990s came energy marketers that had few, if any, physical resources to "back up" their transactions. These marketers tended to be deliberately "long" or "short," exposing themselves to fluctuating wholesale prices, causing their earnings to be volatile, and creating additional financial stress.

Third, the integrity of some in the financial markets (such as financial analysts, financial rating agencies, banks, etc.) as a whole fell because of the many financial scandals including WorldCom, Qwest, Dynegy, Enron, HealthSouth, and others.

Q. Did electric utilities also suffer financially during this period?

A. Yes. Borrowing costs rose significantly because of credit downgrades, widening spreads, and the drop in utility common stock prices. Electric utilities in 2001 saw their stock prices fall while at the same time they faced increased exposure to margin calls for energy contracts. In addition, the West Coast was experiencing several years of an energy crisis, leading to rotating blackouts in California. As a result, the utility industry experienced sweeping credit downgrades, which increased borrowing costs and made financing more difficult. As shown in PGE Exhibit 1104, the three major rating agencies took downgrade actions on 150 utilities in 2001, 279 (2002), and 216 (2003), compared with total upgrades of 57 (2001), 19 (2002), and 35 (2003). During this period, the utility industry experienced a general shift from an "A-" rating by Standard and Poor's (S&P) to a "BBB" rating.[3]

Volatility existed in both the corporate bonds markets and Treasury bond markets. For example, the gap between "A" and "BBB" rated bond yields widened considerably in 002 as seen in PGE Exhibit 1105. In addition, the "BBB" rated utility industry was financing long-term debt at over 8% by late 2002.

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[3] All bond ratings used in this testimony refer to the utility's secured bond rating.

Finally, utility share prices dropped substantially and suddenly, increasing the cost of borrowing because the steep decline in the share price tends to magnify the risk profile of companies needing to refinance.

Q. Did the deteriorating financial markets affect utilities' ability to finance long-term debt?

A. Definitely. Energy companies (including electric utilities) found that, if they could borrow long-term, they faced higher costs, and had to provide more collateral and faced more stringent terms. The energy market was experiencing a "credit crunch" that began in 2001. As we noted above, this led to numerous credit downgrades, which greatly concerned financial institutions. The lending community took a pessimistic view regarding the financial status of most energy companies, including most electric utilities, and this became the predominant view. Financial institutions reduced the amount they were willing to lend to energy companies overall. This contagion among lending institutions increased the reticence among capital markets and the banking community to roll over existing unsecured lending.

Banks and lending institutions were concerned that the increased volatility in the financial and energy markets would increase defaults. They mitigated the potential defaults by adding security to their loans. That is, they required tighter covenants, shorter maturities, and additional collateral. S&P noted that the falloff in financing activity was partly attributable to "capital market jitters, especially for those firms that [were] most in need of capital market access." They also noted that financial guarantee insurance became more prevalent during this period.[4]

[4] "Bond Insurance Overview and Analytical Focus", Standard and Poor's Bond Insurance Book, 2001.

Q. Did PGE experience any of the consequences of the credit crunch?

A. Yes and no. Even though the market was experiencing an unprecedented credit crunch, PGE was able to secure a one-year First Mortgage Bond for $150 million at less than 3% in December 2001, indicating the company's strength in achieving competitive rates during a most difficult time in the energy industry. However, PGE was affected during the credit crunch because we, along with many other utilities, faced financing difficulties as we described above. PGE elected to purchase insurance on long-term bonds to significantly reduce the overall cost. PGE purchased insurance for the 5.6675% series and the 5.279% series. The insurance provided PGE with an opportunity to issue the new debt at a lower cost (approximately 100 basis points) than without the insurance. As seen in PGE Exhibit 1105, even including the issuance costs, PGE received competitive and reasonable rates for the size of its financing during this time period.

Q. Did PGE take any specific action to mitigate the effects of the credit crunch?

A. Yes. PGE took several actions that helped strengthen the ring fencing from Enron that was in place and increased its liquidity, including issuing the "Golden Share" and postponing dividend payments to Enron. These actions ensured sufficient cash flow and provided additional protection from the Enron bankruptcy.

Q. What is the Golden Share?

A. The Golden Share is one share of special preferred stock. It is held by an independent third party, not by PGE or by Enron. The owner of the Golden Share must submit an affirmative vote for PGE to be able to file for voluntary bankruptcy. Also, it provides additional protection to bondholders. This mechanism was beneficial in allowing PGE to more easily obtain financing. The Golden Share provided additional ring-fencing assurance to Standard and Poor's and other rating agencies, helping to insulate PGE from the effects of Enron's bankruptcy and to stabilize PGE's credit ratings. As a result of this and other factors, PGE was able to issue long-term debt at competitive rates.

Q. Was PGE downgraded during this period?

A. Yes. PGE was downgraded from "A" to "BBB+" by S&P in December 2001 and from "A2" to "A3" and then to "Baa2" by Moody's in November 2001 and May 2002. These downgrades were in line with electric utilities as a whole. As S&P stated, "The recent downgrade of Portland General Electric Company...directly addresses the refinancing challenges facing even robust subsidiaries of troubled parents." Moody's ratings also reflected concerns about PGE's ability to remain fully insulated from Enron.

Q. What happened to PGE's financials after the downgrade?

A. Although PGE's S&P credit ratings were downgraded to "BBB+" during this period, PGE continued to maintain solid investment grade ratings by S&P and Moody's despite the Enron bankruptcy due to PGE's strong cash flows, significant ring fencing provisions, and our ability to secure financing to meet debt obligations on time.

PGE's financial profile remained strong in 2002. S&P did not further lower PGE's rating in 2002 even though PGE experienced several adverse financial events, including $25 million in unrecovered power costs, a poor water year, several claims associated with the West Coast energy crisis, and continuing fallout from Enron's credit status.

Q. Are credit ratings the only factor lenders consider when pricing debt?

A. Credit ratings are one input lenders consider in pricing debt. Many other factors are pertinent in determining the pricing, such as the company's financial results and financial ratios.

Q. How do a utility's credit ratings affect the cost of a particular issuance?

A. A bond's interest rate is based on the sum of the corresponding treasury yield and the credit spread investors require as an incentive to purchase the bonds. Credit spreads reflect the accumulation of all public information in the market encompassing PGE's creditworthiness, an assessment of PGE's ability to generate cash sufficient to repay interest and principle on its debt obligations, and an assessment by investors of the overall risk in the energy/utility sector. Investors will refer to S&P and Moody's bond ratings, but will also perform their own due diligence on PGE. Finally, bond credit spreads can be affected by the overall environment in the capital markets: general market forces over time can, and do, increase or decrease credit spreads.

Q. Aren't utility credit ratings determined by the ratings of their corporate parent?

A. No. It is common in the utility sector to have a strong operating subsidiary borrow in its own name, while the parent holding company may or may not be able to borrow in its name. In many cases, the parent's lower rating will constrain the subsidiary's ability to borrow and adversely affect the cost of borrowing. In PGE's case, however, PGE undertook preventative measures to minimize any such impact.

Q. You noted that California was experiencing difficult times during this period. Did this affect the availability, pricing, and the terms of financing to PGE?

A. Indirectly, yes. The California energy crisis contributed to the credit crunch the entire utility industry experienced. As Moody's Investor Service noted in its Electric Utility Industry Outlook in 2001, the California energy crisis tended "to paint other parts of the U.S. power system with the same dark brush" and the "proximity and links to the California grid make the Northwest a recipient of much of this attention." However, Moody's added the belief that its bond ratings for Northwest utility should avoid any steep and rapid plunge. In continuing to separate the Northwest from California, Moody's noted that unlike California, all utilities in the Northwest Power Pool still owned generating assets and the utilities in the Northwest in many instances continued to benefit from low-cost, long-term supply contracts from hydroelectric power.

Moody's specifically stated that it was impressed by "management teams who continue to work tirelessly with regulators and legislatures to craft plans for the future in light of California. One recent example of this is Portland General Electric Company's success in obtaining regulatory approval for recovery of its higher power costs under more volatile wholesale market conditions."

Q. What happened to interest rates during the period from 2001 through 2005?

A. In response to overall issues in the financial markets the Federal Reserve Bank (Fed) lowered its Federal Funds target rate in several steps from 6.5% in early 2001 to 1.0% in mid 2003. The Fed has subsequently raised the Federal Funds target rate in several steps to 4.25% at the end of 2005, as shown in PGE Exhibit 1106. The ten-year Treasury rate declined beginning slightly in advance of the Federal Funds rate and stabilizing in mid-2002 around 4.0%. It has since trended upward and at the end of 2005 was approximately 4.5%.

Q. What has occurred in the period after the credit crunch?

A. The financial picture for electric utilities has improved. In fact, by 2004 credit upgrades nearly equaled credit downgrades, with the total number of credit actions decreasing significantly from the previous years. In addition, the major stock indices, such as the Dow Jones and S&P 500, have shown significantly positive returns. Utility stocks have also somewhat recovered, showing a gain of over 20% in 2004. Finally, balance sheets have strengthened and the industry's debt to capitalization ratio has fallen from 62.2% in 2002 to 58.2% in 2004.

Q. What are the financial issues facing utilities today?

A. The issue now is rising interest rates. Since the beginning of 2003, interest rates have consistently risen. The long-term rates have remained steady while short term rates, such as the one-year Treasury, have increased from 1.25% in 2003 to 3.63% in 2005 - more than 200 basis points. In addition, Global Insight forecasts that "Aa"-rated Public Utility Bonds will rise by 102 basis points to 6.48% by 2007. These higher rates can adversely affect utilities in two ways: increased borrowing costs in a capital-intensive industry and less attractiveness of dividend paying stocks.

The above conditions mean that PGE's prospective debt cost for the foreseeable future will likely be higher than they are today as we issue new long-term debt.

III. PGE's Required Return on Equity for 2007

A. PGE Risks

Q. What types of business and regulatory risks does PGE face?

A. PGE must contend with many business and regulatory risks, examples include:

Business Risks

- Higher than expected inflation
- Interest rate changes
- Unexpected changes in load growth or its composition

Regulatory Risks

- regulatory uncertainty (risks that regulation *may* assign to PGE)
- Regulatory lag
- Regulatory framework (regulatory risks that are assigned to PGE, such as SB 408 or the interpretation of Ballot Measure 9)

PGE can manage some of these risks. Others, we cannot. For example, PGE can partially manage unexpected changes in load by delaying some O&M work or hiring (if loads decline substantially) or by focusing investment on critical infrastructure (if loads increase beyond expected levels). Risks PGE cannot manage include those assigned by the government or regulatory framework, such as the enactment of SB 408 and Ballot Measure 9. For many risks, even though PGE can partially manage them, PGE remains significantly exposed.

We elaborate here on three risks that currently have significant impact on PGE: new wholesale power environment, hydro, and regulation.

Q. You stated that there is a "new wholesale power environment." What is new in this environment?

A. The wholesale environment has changed since the mid-1990s from one that was primarily buying and selling between electric utilities to one that is now between utilities and third-parties, such as energy brokers or marketers. Since we filed UE 115 in the Fall of 2000, the financial and energy markets have experienced a crisis, the WECC pricing is more dependent on natural gas rather than hydro availability, and natural gas has become a national and international market. In addition, many non-utility participants entered the wholesale market. Some utilities established wholesale trading operations expecting to profit from taking aggressive "long" or "short" positions and, as a result, caused more volatility in the energy markets. During UE 115, the effects of the new wholesale power markets were unclear. We now have a clearer picture of non-crisis markets as PGE has discussed in testimony in the RVM dockets (OPUC Docket Nos. UE 139, UE 149, UE 161, and UE 172).

Q. What effects do high, and often volatile, gas and electric markets have on electric utilities?

A. These types of markets have several effects. The volatility associated with the Western power crisis caused investors to dramatically increase their assessment of risk associated with the electric power industry. In particular, investors are focusing more on the regulatory framework. Investors are looking at whether utilities will be able to recover prudently incurred costs, such as increased power costs from volatile gas and electric markets.

Q. Why do you consider hydro to be a significant risk?

A. For many of the same reasons just discussed. The risk is similar to a forced outage of low-variable-cost thermal plants but worse because the generation output in the short-term is largely unaffected by investment or maintenance practices. Every year hydro will be different from what is expected, and therefore reliance on hydro makes planning more difficult than in other regions of the country. In addition, PGE does not have a fuel adjustment clause in an environment where most utilities have some form of a fuel adjustment or power adjustment clause. Finally, wholesale market prices are much higher than they were in the 1990s, increasing the cost of hydro variance and thus, the volatility of earnings.

Q. How have PGE's regulatory risks changed since 2001?

A. In the past, PGE faced risks of regulatory uncertainty regarding the completion and recovery of investment and the prudence of various expenditures while our retail load tended to be growing. Today, in addition to these risks, PGE faces the risk of higher earnings volatility because of cost and load variability and frequent opportunities to review the prudence of contracts purchased for retail customers. PGE also continues to face the risk of regulatory lag and regulatory uncertainty. More recently, PGE has experienced increased risk from the regulatory framework, such as the enactment of SB 408, the interpretation of Ballot Measure 9, both of which tend to increase the volatility of utility earnings, increasing the utility's risk. Another recent unfavorable change in the regulatory framework is the limitation on the usefulness of deferred accounting to protect a utility from unexpected short-term costs it cannot avoid.

Q. What do these risks mean for the cost of capital you request?

A. All else equal, risks have increased for electric utilities. Unless these risks are mitigated, the cost of long-term debt, as well as the cost of equity, will be higher than otherwise.

Q. Don't the financial models used for determining RROE account for these business and regulatory risks?

A. Not necessarily. If the risk is relatively new, or if the sample group does not have this risk at a comparable level, then the financial model will not appropriately account for the risk. The investor must use his expertise to determine whether the return on the investment is worth the risk. For example, PGE Exhibit 1107 shows PGE's higher risk - a higher standard deviation and lower average ROE than the sample groups. Parameters that the investor would consider for an electric utility are the required return, the expected return, and the authorized return. We discuss these in the next section.

B. Definition and Significance of Required Return on Equity

Q. What is the required return on a security investment?

A. The required return is the return that the investor must receive in order to hold an investment, such as PGE's common stock or long-term debt.

Conceptually, the required return to induce an investor to purchase any security investment is:

$$k = r + \pi + i + b + f + l \tag{1}$$

where:

k = *required return*
r = *real risk-free interest rate*
π = *inflation premium*
i = *interest rate risk*
b = *business risk*
f = *financial risk*
l = *liquidity risk*

The first two terms of the equation (r and π) equal the nominal interest rate. The remaining four terms are the "risk premium" above the nominal interest rate that the investor requires to purchase the common stock or investment. Interest rate risk is the risk for uncertainty about future real rates and inflation or the variability in the return that is caused by changes in the level of interest rates. Business risk includes all the operating factors that could affect expected future cash flows of the business. Financial risk refers to the additional variability of earning through the use of fixed-cost financing, such as debt and/or preferred stock. Liquidity risk is the possibility of a loss when converting the asset to cash. A rational risk-averse investor considers these factors when forming his or her expectations.

Q. What is the expected rate of return on equity (expected ROE)?

A. The expected ROE refers to an investor's anticipated return on an investment security as part of a purchase or sale decision. As part of the assessment process, the investor considers expected returns, such as dividends and/or capital gains due to appreciation.

Q. What is the authorized ROE?

A. The authorized rate of return is the rate of return allowed by a regulatory commission in a utility rate case.

Q. What is the relation between the authorized ROE and investors' expected ROE?

A. The authorized ROE effectively establishes investor expectations on the potential return on equity that the company can provide them on their investment in the security. If the authorized return on equity is set "low," or the regulatory regime does not provide a fair opportunity to reach the authorized return, then investors will expect to earn less on their purchase of the stock because of a lower return on equity. Conversely, if the authorized return on equity is set "high," then investors will expect to earn a higher return on equity.

Q. What do you mean by PGE's Required Return on Equity (RROE)?

A. When we speak of PGE's RROE we mean two things. First, PGE's RROE is the ROE that investors require in order to buy or hold PGE's common stock. Second, the ROE that we request the Commission adopt in this proceeding as PGE's authorized ROE should be sufficiently high and certain to support investors' expectations of RROE. This is the appropriate rate for PGE, using a 2007 test year and considering the pricing and operational risks proposed for PGE as discussed elsewhere in this filing.

Q. Why is it important that PGE's authorized ROE be set at or above PGE's RROE?

A. As a regulated utility, the rate setting process provides PGE the opportunity to set prices at a level sufficient to recover all of our prudently incurred costs, including an overall return on our utility investment sufficient to attract the capital necessary to finance the business. In other words, this is the level of return necessary to support dividends and/or capital appreciation that investors require to purchase or not sell the security. PGE is a capital-intensive business that requires access to capital markets to raise the funds necessary to finance ongoing operations and its capital construction program. In addition, as a capital intensive business, PGE must be able to maintain its bond ratings at an investment grade level to access the capital markets at a reasonable cost for the company and its customers. Further, it is more important than ever for PGE to maintain its bond ratings above investment grade because PGE must access the wholesale energy markets to fulfill PGE's obligation to meet customers' electricity requirements.

Q. How does an investor factor the authorized return into his analysis?

A. In making a purchase or sale decision, an investor derives his or her required return on equity for a security over an investment horizon based on a number of factors, including investment risk of the security and expected returns on other (alternative) investments. Most investors use or have used one or more financial models, such as the single- or multi-factor Capital Asset Pricing Model (CAPM), the Arbitrage Pricing Theory model, Risk Premium, Comparative Earnings, and variations of the Discounted Cash Flow (DCF) model. After calculating a required ROE for the selected stock, the investor then compares it to the expected ROE. As stated above, the expected return for a utility is dependent on the utility's authorized rate of return and regulatory regime. If the investor's required ROE is less than the expected ROE, the investor will purchase the company's stock, driving the price up. Conversely, if the investor's required ROE is greater than the expected ROE, the current investor will sell the stock, driving the price down.

To ensure its ability to attract common equity in the marketplace, PGE must provide current and prospective shareholders with a ROE that encompasses their range of required ROEs. The return we request in this case will accomplish this goal and, if authorized by the Commission, would allow PGE to attract capital on comparable terms in the marketplace to finance our capital expenditure program, and will keep costs lower than otherwise for customers.

C. Estimating PGE's Required Return on Equity for 2007

Q. How did you estimate PGE's Required Return on Equity (RROE)?

A. We relied upon the Discounted Cash Flow model and the Risk Positioning Method. Both models are based upon finance principles, use independent sources of data, and are often used in state and federal regulatory proceedings to estimate the cost of equity. Table 4 shows the results for the various methods that we used to estimate PGE's RROE.

Table 4
Summary Results for PGE's RROE

Method	Low	High
Multi-stage DCF - *br+vs*	8.10%	9.60%
Multi-stage DCF – GDP	8.90%	11.20%
Risk Positioning – 7-Year Treasuries	11.10%	11.30%
Risk Positioning – Corporate Bonds	10.50%	10.50%

Q. Did you use a Capital Asset Pricing Model to estimate PGE's RROE?

A. No. In UE 115, we presented evidence that CAPM was unreliable and did not provide realistic results for electric utilities. We updated our analysis and our conclusions remain unchanged.

Q. Why don't you use a single model to estimate PGE's RROE?

A. Determining ROE is a dynamic and complex process and one should consider several models. Each model uses different assumptions regarding the financial market, investors, expectations, etc. Thus, different methodologies can produce significantly different results. As a consequence, these models should be taken together in determining ROE, and expertise and judgment is required.

For example, in theory, the Discounted Cash Flow model is very simple. In practice, few analysts obtain the same estimates for the same company over the same period. The differences among DCF estimates are in general, due to different assumptions or estimates for the model parameters.

Q. Are these financial models accurate?

A. The models provide guidance. A standard financial text notes:

> In a practical world, it is often best to use all three methods – CAPM, bond yield plus risk premium, and the DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of capital. Unfortunately, this is not

possible. Finance is in large part a matter of judgment, and we simply must face this fact.

(Eugene F. Brigham, Financial Management, Theory and Practice, Fourth Edition, pg 256.)

Q. How should the Commission determine PGE's cost of equity?

A. The Commission should use the models' results as a guide to determine PGE's Required Return on Equity. In addition, the Commission should consider the relative returns of companies elsewhere in the economy that have similar risks. They should also consider PGE's financing requirements over the next several years.

1. The Discounted Cash Flow Method

Q. What was the first financial model that you used to estimate PGE's RROE?

A. We used a single- and a multi-stage Discounted Cash Flow model. The DCF model begins with the premise that the intrinsic value of any investment is the present value of the future cash flows that the owner will accrue. Most DCF models assume that these cash flows will be in the form of dividends. For example, an investor may use the DCF model to examine expected ROEs for a sample of companies, or for a single company which he or she is considering.

Q. What is the single-stage DCF model?

A. The single-stage DCF model assumes constant dividend growth. If constant dividend growth is assumed, then the stock's valuation is:

$$P_o = D_1 \div (k_e - g) \qquad \textbf{(2)}$$

where:

P_o = current stock price
D_1 = next period's dividend
g = dividend growth rate
k_e = cost of equity or expected rate of return

Solving this equation yields the expected return on equity, which, in equilibrium, also equals the RROE:

$$k_e = (D_1 \div P_0) + g \quad (3)$$

This form of the DCF model is known as a single-stage growth model because it assumes a constant dividend growth rate over time. For an electric utility, this means that the utility's earnings would continually grow, in spite of increased economic, regulatory, and other risks.

Q. What is the multi-stage DCF model?

A. In concept, the multi-stage DCF is very similar to the single-stage DCF. Because the multi-stage DCF does not assume a constant dividend growth rate, solving for the cost of equity is more complicated. Equations 2 and 3 above assume a single growth rate. If more than one dividend growth rate is assumed, then the equations become more complex:

$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n} \quad (4)$$

or

$$P_o = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \frac{P_n}{(1+k)^n} \quad (5)$$

where:

P_o	=	current stock price
P_n	=	stock price in period n
D_t	=	expected dividend in period t
k	=	cost of equity or expected rate of return

The RROE is then found by applying an internal rate of return calculation to solve for "k" in equation (5) above. The OPUC Staff and others have used a multi-stage DCF model to estimate the RROE.

Appendix A provides more detail on both the single and multi-stage DCF methodologies.

Q. Can you apply either the single- or multi-stage DCF to PGE's stock price?

A. No. PGE's common stock has not traded since 1985. In UE 115, we used a sample of comparable companies to compute estimates for the DCF model.

Q. Are there any issues with using a sample?

A. Yes. Sample selection is important for the analysis to approximate the expected risks and returns of PGE. The sample selection should represent companies with similar risk profiles. The sample selection process can also avoid the impact of extraordinary events such as plant cancellation or corporate restructuring. Exhibit 1108 lists the companies in our samples.

Q. How did you derive your company sample for the DCF analysis?

A. We analyzed several sample groups. First, we combined two samples of electric utilities: the utilities in Moody's Electric Utility Index and the utilities in S&P's Electric Utility Index. We also used a comparable sample prepared for PGE by our outside consultants. Finally, we used the sample group from PacifiCorp's last general rate case (UE 170 Rebuttal) that was found acceptable by Staff. These samples provide a basis for estimating PGE's RROE.

In all sample groups, we screened the utilities and eliminated those that: omitted or reduced the common dividend; merged within the last three years or are in merger discussions or proceedings; or have negative earnings or do not have sustainable growth in earnings. We removed these companies from the sample for a variety of reasons, including that the necessary historical data were not available or their stock prices were affected by temporary phenomena such as merger discussions or dividend omissions/cuts.

Q. Are you confident your samples are representative of PGE?

A. Yes and no. Each sample represents various characteristics, but no sample can fully represent PGE. Each sample is only an approximation. Here we use more than one sample. One sample represents the market as a whole, another represents utilities with similar characteristics of PGE, and the UE 170 Rebuttal sample is one that was found acceptable by Staff for use with respect to another Northwest utility.

Q. How did you calculate your DCF estimates?

A. We calculated our DCF estimates using the month-high closing price, month-low closing price, and the month-end price for each of the last three months in 2005 to reflect the volatility in the stock market. Historical and forecasted data available in the October through December 2005 period were used for the analysis. Because of the lead time necessary to prepare this filing, information subsequent to December 2005 is not incorporated into the filing. However, we expect to update our DCF estimates later in this proceeding. PGE Exhibit 1109 contains the estimates for the multi-stage DCF model for the months October through December using the combined S&P and Moody's utilities, PGE comparables, and the UE 170 Rebuttal sample. The different ranges for RROE are presented in Table 5 below.

Table 5
DCF Estimates

	Low	High
Multi-Stage (br + vs)	8.10%	9.60%
Multi-Stage (GDP)	8.90%	11.20%

Appendix A describes the details of our DCF calculations, including dividends and the growth rate.

2. The Risk Positioning Method

A. The Risk Positioning Method is a risk premium model that estimates the RROE by adding an explicit premium for risk to a current or expected interest rate. Usually, the interest rate is that of an intermediate- or long-term government bond or corporate bond. The equation is:

$$r_j = r_c + r_p \tag{6}$$

where:

r_j = cost of equity for firm j
r_c = yield on the long-term bonds
r_p = risk premium estimate

Q. How does the Risk Positioning Method differ from other risk premium models?

A. We use the phrase Risk Positioning Method to differentiate this form of the risk premium model. The most often used risk premium model is the CAPM, which estimates the risk premium between the risk-free rate and the stock market. The Risk Positioning Method estimates the risk premium as the difference between the yield on Treasuries (or corporate bonds) and the cost of equity found appropriate in non-stipulated, authorized ROE decisions for electric utilities. The Risk Positioning Method assumes that non-stipulated ROE decisions by regulatory bodies, on average since 1983, provide unbiased estimates of the cost of equity for electric utilities. In other words, these authorized ROEs produced expected ROEs that resulted in investor decisions to buy or hold stock and provided adequate expected returns.

We used two forms of the Risk Positioning Method. In the first model, we estimated the risk premium over the yields on electric utility corporate bonds. In the second model, we estimated the risk premium over the yields on Treasuries.

a. Risk Positioning with Corporate Bonds

Q. What steps did you take in estimating PGE's RROE using the Risk Positioning Method with Corporate Bonds?

A. First, we ascertained the authorized ROE from reported, non-stipulated ROE decisions for electric utilities. There were 486 such decisions since January 1983. This large sample provides data over various electric utilities, state regulatory environments, and business cycles. Next, we gathered the estimated yields on the appropriate long-term, non-callable bond for each utility. Finally, we estimated the equity risk premium using the reported authorized ROEs and the yields on the long-term bonds of those utilities.

Q. How did you estimate the equity risk premium over corporate bond yields?

A. We estimated the average risk premium over corporate bonds using an ordinary least squares regression, regressing the authorized ROE in each of the 486 decisions against the yield on the appropriate long-term corporate bond of each company, or, if necessary, the S&P bond index or Mergent Bond Record index, lagged one month.

Q. What is the yield to maturity for PGE's most recent non-callable long-term bond?

A. PGE issued its most recent non-callable secured long-term bond on August 4, 2003, (6.875% First Mortgage Bond, 30-year term). However, this bond has not traded since it was issued. In order to calculate a yield for this bond, we contacted a third party investment service and requested an estimate for the price of the bond as of December 30, 2005. We then used this indicative price to calculate the yield on the bond.

Q. What is PGE's estimated RROE using the Risk Positioning Method with Corporate Bonds?

A. Using corporate bonds, PGE's RROE for 2007 is approximately 10.5%.

Q. Did you calculate a high and low yield on the bonds?

A. Yes. However, as seen in Table 6, the high and low estimates are virtually the same, so the range is almost zero.

Table 6

PGE's RROE Using the Risk Positioning Method With Corporate Bonds

	Low	High
Yield on Bond	6.140%	6.150%
Risk Premium Estimate	4.346%	4.343%
PGE's RROE	10.486%	10.493%

Q. Does this method address differences in risk between PGE and these other utilities?

A. No. This method assesses the estimated average risk premium required by investors to buy or hold an electric utility stock. Because of the broad sample and time frame -- every non-stipulated decision since 1983 -- the risk premium is an *estimate* and will not, of course, fully explain the RROE for any particular utility. The analyst must use his or her expertise to assess the RROE for PGE as with any other utility.

Q. Is the risk premium constant over interest rates?

A. No. PGE Exhibit 1110 shows that the risk premium varies inversely with interest rates. That is, as interest rates decline, investors will expect a higher premium for risk. For example, at 6%, the risk premium is 440 basis points, but at 7%, the risk premium is only 405 basis points.

b. Risk Positioning with U.S. Treasury Bonds

Q. What steps did you take in estimating PGE's RROE using the Risk Positioning Method with U.S. Treasury Bonds?

A. We followed the same steps that we used with Corporate Bonds. We estimated the equity risk premium over 7-year Treasuries using the same set of 486 non-stipulated ROE decisions for electric utilities and the yields on Treasury bonds around the times of those decisions. Second, we estimated the yield on 7-year Treasury bonds in 2007.

Q. How did you estimate the equity risk premium over Treasuries?

A. We estimated the average equity risk premium over Treasury bonds by regressing the authorized ROE in the 486 non-stipulated regulatory decisions against the seven-year Treasury bond, lagged one month prior to the dates of the decisions. We lagged the yield on the government bond one month prior to the time of each regulatory order to reflect our belief that state regulators use financial information from the month(s) preceding their order. We also performed the same study with an eight-month lag and found only a slight difference in the results.

Q. How did you estimate the yield on Treasury bonds for test year 2007?

A. Global Insight does not forecast the yield on a 7-year Treasury. So, we used the average of Global Insight's December 2005 forecast for intermediate (5 and 10 year) Treasury bonds in 2007.

Q. What is PGE's RROE using the Risk Positioning method and Treasury Bonds?

A. As shown in Table 7, the range for PGE's RROE in 2007 using Treasury bonds is 11.13% to 11.34%.

Table 7
PGE's RROE Using the Risk Positioning Method with 7-Year Treasury Bonds

	Low (8-month lag)	High (1-month lag)
Yield on Bond (Global Insight Forecast)	5.22%	5.22%
Risk Premium Estimate	5.91%	6.12%
PGE's RROE	11.13%	11.34%

PGE Exhibit 1110 contains the results for the regression analysis as well as our estimate for PGE's RROE using Treasury bonds. As in our Corporate Bond analysis, we found that the spread between the RROE and interest rates is inversely related to the level of interest rates, as represented by the 7-year Treasuries.

Q. How did you calculate high and low risk premium estimates in this analysis?

A. We calculated the low value in three steps. First, we determined the 7-year Treasury rate for 2007 by averaging the 5- and 10-year Treasuries, using forecasts from Global Insight *U.S. Economic Outlook December 2005.* The 7-year Treasury rate is expected to be 5.22% in 2007. Second, we estimated the risk premium (when Treasuries are 5.22%) using the 8-month lag model. At this level of Treasuries, we found the risk premium to be 5.91%. Finally, we combined the expected Treasury rate and the risk premium estimate, yielding 11.13% in 2007.

We calculated the high value using the same estimate for 7-year Treasuries, 5.22%. Then, we estimated the risk premium (when Treasuries are 5.22%) using the 1-month lag model (rather than the 8-month lag model used for calculating the low value). We found the risk premium to be slightly higher at 6.12%. Finally, we calculated PGE's RROE for 2007 by combining the 5.22% Treasury rate and the 6.12% risk premium, yielding 11.34%.

Q. In the past, the Commission has used current interest rates. How would your estimate for PGE's RROE change if you used current interest rates?

A. Our estimates using the Risk Positioning Method would change slightly. For Treasuries, using the 4.42% rate for 7-year Treasuries from the January 15, 2006, Federal Reserve Statistical Release, the RROE would be approximately 45 basis points lower.

Q. Does this method address differences in risk between PGE and other utilities?

A. No. As we stated earlier, this method assesses the estimated average risk premium that investors expect. A financial analyst would adjust his estimate to reflect the differences between the individual utility and the sample.

3. Other Models

Q. Did you evaluate other models for calculating RROE?

A. Yes. We continually review various methods for estimating RROE in order to take into account any developments that may have improved the analytical process for estimating capital costs. In addition, we participate in conferences on regulated cost of capital as well as the Edison Electric Institute (EEI) Forum on Cost of Capital. EEI has sponsored research into several new models to estimate RROE over the past few years.

Q. What models have you evaluated?

A. We have evaluated three financial models: comparable earnings, arbitrage pricing theory, and the Fama-French methodology.

Q. How have these model performed?

A. These models are still in the developmental stage, although they have been presented in cost of capital proceedings in other states.

Q. Have any decisions been based on these models?

A. To the best of our knowledge, two of the three models have not yet been the primary basis for commission decisions. The comparative earnings model has been used in many proceedings for many years in many forms. We are unaware of any recent regulatory commission decisions based on the comparative earnings approach.

a. Comparable Earnings

Q. What is the comparable earnings method?

A. Comparable earnings is grounded in the theory of competition in the market for goods and services where the return earned by the average firm in a competitive industry is equal to the opportunity cost of capital. The comparable earnings method assumes that regulation is a proxy for competition. Investors consider the risks attached to their investments and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken.

Q. How do you estimate ROE using comparable earnings?

A. To estimate comparable earnings, we would need to find a long-run cost of equity equivalent to the average level of returns earned in the market. The steps would include selecting a cross-section of companies, removing firms that have monopoly power, and analyzing the differences in risk. The relevant time period should include at least one full business cycle that is representative of the prospective economic conditions. Finally, the sample should be large enough to cancel out major deviations.

Q. Why is the comparable earnings approach not used more often?

A. The comparable earnings approach is a data intensive process. It requires analyzing companies in all industries, not just the electric utility industry. The large sample of companies must then be screened for risk comparability, using such measures as similar betas, whether the company is publicly traded, whether the company is reported in Valueline and whether it has a rating similar to the subject company. The sample is often further screened using qualitative criteria. The sample must also be corrected for any time differential to encompass any deviations that result from business cycles.

Q. Did PGE perform a comparable earnings analysis?

A. No. We looked at the comparable earnings method and began gathering relevant data. However, we quickly realized that we did not have the time or resources to complete this analysis.

b. Arbitrage Pricing Theory

Q. What is the Arbitrage Pricing Theory?

A. The Arbitrage Pricing Theory (APT) is a model based on the CAPM. It is a multiple factor CAPM with multiple betas and multiple risk premiums. The APT rests on two presumptions: (1) that security returns are influenced by economy-wide systematic factors and (2) that assets that are close substitutes will sell for the same price.

The APT asserts that security returns are generated by a multifactor linear model where investors have an expected return plus a "surprise" factor that will take into account unexpected economic forces.

The APT also states that there must be a relationship between the cost of capital, or expected return, and the systematic risk measures for a given security if there are no riskless investments in the market.

The arbitrage occurs when returns deviate from what the APT equations predict and profit-seeking investors will buy undervalued securities and sell overvalued securities.

Q. Did you analyze the Arbitrage Pricing Theory?

A. No. This model is still in a developmental stage for regulatory purposes. It has been presented in regulatory proceedings, but not used in any decision yet. There are several issues that need to be resolved such as which factors to use, the method to choose the factors, if the factors change over time, etc. Given these considerations, we decided not to attempt to estimate and present an APT based RROE.

c. Fama-French Model

Q. What is the Fama-French model?

A. During the early 1990s, researchers identified two additional characteristics that help explain security returns. The first is a "size effect." Researchers found that over long periods of time small capitalized stocks (companies capitalized between $300 million and $2 billion) provide greater average returns than large capitalized stocks without significantly greater risk. The second is a "value effect." Value stocks (stocks with high book-to-market ratios), tend to out-perform growth stocks (stocks with low book-to market ratios) without significantly greater risk.

Eugene Fama and Kenneth French developed a three-factor model (the Fama-French model) that captured these effects. In addition to the market factor of the CAPM, they specified two new factors: the size premium small firms realize (captured by a factor they called SMB or "Small Minus Big"), and the value premium (captured by HML or "High book-to-market Minus Low book-to-market"). The model rationale is that in addition to bearing market risk (MKT), investors are rewarded for exposure to size risk (SMB) and value risk (HML).

Q. Did you analyze the Fama-French model?

A. Yes, we considered the Fama-French model. The model has been used in various forums for many years, but like the APT, this model is still in its early stages of development for utility use and is just beginning to be introduced into the regulatory arena. It has not yet been used by commissions in determining authorized ROEs.

4. Summary and Recommendation on RROE

Q. Please summarize your findings on PGE's Required Return on Equity.

A. We estimated ranges for PGE's RROE using two financial models – the DCF and the Risk Premium Method. We developed the DCF range in part by comparing our results with those results if we included all of the electric utilities. Our range for the DCF method is 8.10% to 11.2%. From our analysis using other commonly employed measures of risk, we determined that the return authorized for PGE should be towards the top of this range.

We also considered the estimates from the risk positioning method, recognizing that if current interest rates were used, the RROE would be about 11%. We found that using the appropriate range for the Risk Premium Method was 11.10% to 11.30%. Weighing the results from these two methods, we determined based on our judgment and experience, as well as the operation and price risks undertaken by PGE, that the appropriate range for PGE's RROE is 9.25% to 11.3%. We also determined that he appropriate point estimate for PGE's RROE is 10.75%. Table 8 below summarizes our results for each of the methods.

Table 8
Summary Results for PGE's RROE

Method	Low	High
Multi-stage DCF - *br+vs*	8.10%	9.60%
Multi-stage DCF – GDP	8.90%	11.20%
Risk Positioning – 7-Year Treasuries	11.10%	11.30%
Risk Positioning – Corporate Bonds	10.50%	10.50%
Recommendation	**9.25%**	**11.3%**

Q. What is your request for PGE's authorized Return on Equity?

A. Based on the Risk Positioning Method, the DCF Method, and the risk profile of PGE given the pricing and operational proposals in this filing, we conclude that for revenue requirement purposes PGE's RROE is 10.75% for a 2007 test year. As a point of reference, authorized ROEs within the past year averaged 10.5% as seen in PGE Exhibit 1111. In developing our point estimate for PGE's authorized ROE, we did not simply take the average of the highs and lows. Rather, we used our judgment and experience first to construct the range and then to determine the appropriate point estimate for revenue requirement purposes.

Q. In your RROE request, what did you assume about PGE's risk profile, given the pricing and operational proposals offered by PGE in this filing?

A. As discussed earlier in our testimony, we made our estimate assuming that PGE's power cost risk was mitigated by the net variable power cost regulatory framework described by Ms. Lesh and Mr. Niman (PGE Exhibit 400). We also assumed that PGE's capital structure would reflect PGE's 56% equity ratio in 2007, which would help mitigate several additional business and regulatory risks, including margin calls, bond ratings, and debt equivalence. In the event PGE does not receive authorization to implement the proposed NVPC framework or the Commission adopts a weaker capital structure than the one we propose, our recommended RROE would have to be adjusted upward to compensate investors for the higher risk.

Q. Are there other risks that may need to be reflected in your ROE analysis?

A. Yes. There is continuing uncertainly regarding the effect of SB 408 upon PGE's earnings. Depending upon how SB 408 is implemented, it could result in more downside volatility and increased risks for PGE, thereby requiring us to reassess our RROE recommendation. Similarly, the City of Portland is claiming authority to set PGE's retail rates, and the resolution of this issue is also uncertain. In the event the City of Portland attempts to regulate PGE's retail rates, a recent Oregonian article quoted an S&P analyst stating that such regulation would be a "credit negative." Depending upon how this matter is resolved, we may need to reassess our ROE recommendation to capture any additional exposure borne by PGE investors. A copy of the article and the most recent S&P release are in our work papers.

IV. Preferred Stock

Q. What is the amount and expected cost of PGE's outstanding preferred stock for 2007?

A. PGE Exhibit 1112, Cost of Preferred Stock, shows the amount and effective cost of PGE's outstanding preferred stock for 2007. This preferred stock issue has a sinking fund, which requires PGE to redeem a certain percentage of the preferred stock issue each year. The sinking fund began in June 2002 and, at December 31, 2006, the amount outstanding is expected to be $16 million. However, the issues mature in June 2007 so that the average outstanding amount of preferred stock is approximately $6.7 million. The average outstanding balance is calculated by averaging the amount outstanding at the month end for each of the 12 months. The effective interest rates represent the internal rate of return of the cash flows associated with the remaining preferred issue.

The total cost of the remaining preferred issue is shown in Table 9 below.

Table 9
Cost of Preferred Stock
(Average $000)

	2007
Amount	$6,680
Cost of Preferred	7.75%
Effective Preferred Cost	8.432%

Q. Will PGE be issuing any preferred stock in 2007?

A. No.

V. Capital Structure

Q. What is PGE's forecasted capital structure for 2007?

A. Table 10 below shows PGE's forecasted capital structure for 2007.

Table 10
PGE Capital Structure 2007
($000)

	Amount	% of Capital
Long-term Debt	$997,280	43.75%
Preferred Stock	$6,633	0.29%
Common Equity	$1,275,487	55.96%
Total	$2,279,400	100.00%

Q. How did you determine the appropriate level for common equity in 2007?

A. We calculated PGE's capital structure using the forecasted income statement and balance sheet for 2007, as well as our expected financings through 2007.

Q. Has PGE's regulated capital structure changed significantly since 2002?

A. Yes. Table 11 below shows that in 2002, PGE's regulated capital structure had 52.16% equity. In 2007, we expect common equity to comprise 55.96% of PGE's capital structure. In addition, PGE's last remaining issue of preferred stock matures in June 2007 and we do not expect to issue any preferred stock in 2007. PGE's capital structure by year is PGE Exhibit 1113.

Table 11
PGE's Regulated Capital Structure

	2002	2007
Long-Term Debt	46.32%	43.75%
Preferred Stock	1.53%	0.29%
Common Equity	52.16%	55.96%
Total	100.00%	100.00%

Q. What caused the increase in the equity component of the capital structure?

A. There are several reasons why PGE's equity ratio continued to increase over the last several years. First, Enron did not ask for cash dividend payments from PGE from Third-Quarter

2001 until Third-Quarter 2005, when PGE made a special cash dividend payment. Second, PGE did not finance any large capital projects beyond its annual $200 million of capital expenditures. Third, PGE must maintain a strong balance sheet in order to attract debt at the lowest possible cost during the transition to a publicly-traded company.

Q. Why does PGE intend to maintain its 56% equity ratio in 2007?

A. There are several business reasons for our requested 56% equity ratio. This capital structure will enable PGE to: (1) maintain its financial strength, flexibility, and adequate liquidity, (2) maintain reliable and economical access to the capital markets, (3) minimize the overall cost of capital to customers and shareholders and (4) offset debt equivalence of purchased power contracts.

In addition to these general reasons, and to the general business and regulatory risks described above, there are several specific circumstances supporting our requested capital structure. First, we must comply with Condition 5 of OPUC Order No. 05-1250, which requires PGE to maintain an equity capital ratio of at least 48%, and Condition 6(c) of the same Order, which requires PGE to maintain at least $40 million in additional equity beyond the 48% until 30 days after the tariffs for the next general rate case are approved. Second, PGE must be able to maintain liquidity for unexpected margin calls as wholesale prices fluctuate and for unresolved issues including litigation and SB 408. Third, PGE has high capital expenditures associated with hydro relicensing, beginning in 2007 and increasing in the following years. Fourth, PGE is exploring new wind ownership or purchase in the near future and has proposed an AMI (advanced metering infrastructure) system. Fifth, PGE must be able to offer assurance to its equity and bond investors of sufficient cash flow, including sufficient equity to offset debt equivalence imputed by financial rating agencies.

Finally, the regulated capital structure does not include our current short-term debt or revolvers, which we have reduced since 2001.

Q. Did PGE's equity ratio change as a result of the catch-up dividend and Port Westward expenditures?

A. Yes. PGE paid Enron Corporation a $150 million special cash dividend in the Third-Quarter of 2005. Port Westward expenditures are funded through internal cash flows and long-term debt. These actions lowered PGE's equity ratio from approximately 58.6% to 55.6%.

VI. Stock Issuance and Distribution

Q. You mentioned that PGE's common stock is held by Enron Corp. and does not publicly trade. Didn't the Oregon Public Utility Commission recently authorize an issuance of PGE common stock?

A. Yes. Last December the Commission issued an order allowing PGE to issue new common stock to Enron's creditors and Disputed Claims Reserve (OPUC Order No. 05-1250). PGE will issue its stock in April 2006; the DCR will distribute shares as Enron settles claims. There are 80 million shares authorized, with 62.5 million being issued.

Q. Will creditors receive all 62.5 million shares be distributed to creditors in April 2006?

A. No. Creditors will receive at least 30% of the stock, or approximately 19 million shares with allowed and settled claims.

Q. When do you expect the DCR to distribute the remaining shares?

A. There is no fixed schedule, but currently we expect at least 50% of the claims to be settled by April 2007 and 70% or more by April 2008.

Q. Will PGE's common stock or shares trade immediately upon issuance?

A. Yes. PGE has received clearance from the New York Stock Exchange's Listing and Compliance Committee and has been invited to submit an "Original Listing Application". We expect to complete this process in April 2006.

Q. Does PGE expect to pay a common stock dividend?

A. Yes. We expect to pay a dividend on our 62.5 million shares of common stock. However, PGE's Board has not set a dividend policy, so the exact timing and amount has not been determined. For modeling purposes, we used $16.25 million as a quarterly dividend for 2007.

VII. Qualifications

Q. Mr. Valach, please state your educational background and experience.

A. I received a Bachelor of Science degree in Business Administration from the University of Montana in 1979. I received a Masters in Business Administration from the University of Oregon in 1986 with an emphasis in Finance. I joined PGE in 1991 as a Business Analyst and was Manager of Corporate Finance and Assistant Treasurer from July 1997 to September 2005. I am now PGE's Director of Investor Relations.

Q. Mr. Hager, please state your educational background and experience.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Mr. Hager, what are your responsibilities within PGE?

A. My responsibilities include estimating PGE's Required Return on Equity (RROE).

Q Does this complete your testimony?

A Yes.

APPENDIX A

The Discounted Cash Flow Model

The Discounted Cash Flow (DCF) model estimates the cost of equity by determining the present value of all future income investors expect to receive from holding a share of common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation (i.e., capital gains). The cost of equity is calculated as the discount rate, which equates the stock's current market value with the present value of all future expected returns (i.e., dividends and capital gains). Both PGE and Staff have used the "periodic" DCF model in the past to calculate PGE's Required Return on Equity. The single-stage periodic model has the form:

$$P_0 = D_1 \div (1 + k) + g \qquad \textbf{(I)}$$

From which, we derive the formula for the cost of equity.

$$k_e = D_0 * [(1 + g) / P_0)] + g \qquad \textbf{(II)}$$

or

$$k_e = (D_1 / P_0) + g \qquad \textbf{(III)}$$

where:

D_0	=	previous dividends paid
P_0	=	stock price
D_1	=	$D_0 * (1+g)$
k_e	=	cost of equity
g	=	dividend growth rate

The single-stage periodic DCF model assumes a single growth rate, estimate using any number of proxies, including dividends and earnings per share. This simple DCF model works best in a stable environment, such as that experienced by utilities in the past, when their dividend growth rates were fairly stable.

The single-stage model is a simple form of a more general form of the DCF model depicted in equation IV below.

$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n} \quad \textbf{(IV)}$$

$$P_o = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \frac{P_n}{(1+k)^n} \quad \textbf{(V)}$$

The multi-stage DCF model assumes multiple growth rates for different periods. This form of the DCF is better suited to an environment where the near term growth rate is expected to be different from the long-term growth rate.

According to the DCF method, in order to calculate D_1, the next period dividend, both the previous dividend paid, D_0, and the first growth rate, g_1, must be determined. This can be derived from equation (III) above. For the multi-stage model, this growth rate was assumed to be given, and the indicated dividend for the next 12 months, as provided by Value Line, is accepted as D_1.

The second growth rate, g_2, is estimated as the growth occurring between D_1 in the year 2006 and the Value Line estimated dividend for 2009 (provided by Value Line as an average of estimated dividends for the years 2008-2010). This growth rate is applied to calculate dividends D_2, D_3, and D_4.

The final, or terminal growth rate, g_t, was estimated using an expanded growth rate formula. When stock is issued at prices in excess of book value, existing shareholders realize earnings growth. Shareholders also realize earnings growth when the company invests the retained earnings. The sustainable dividend growth rate becomes:

$$g = (B * R) + (S * V) \qquad \textbf{(VI)}$$

where:

B = the fraction of earnings expected to be retained
R = the expected return on average equity
S = the funds raised from the sale of stock as a fraction of existing common equity
V = the fraction of funds raised from the sale of stock that accrues to shareholders at the start of the period

Analysts also consider other growth rates, including the earnings growth rate. As a second method to estimate the underlying growth rate, we followed Staff's and others' method and used the growth in the Gross Domestic Product (GDP) as a long-term proxy for the earnings growth rate. The dividend growth rate is in part a function of the earnings growth rate. If the dividend growth rate is higher than the earnings growth rate, then the dividend growth rate must be reduced. Likewise, if the dividend growth rate is substantially below that for earnings, then retained earnings will increase in the short-run and the dividend growth rate should eventually increase.

Appendix B

FERC Accounts

This Appendix tracks PGE's cost of capital to its Federal Energy Regulatory Commission (FERC) book accounts. PGE has FERC book accounts for several components of its long-term debt, preferred stock, and common equity. For accounting purposes, PGE uses the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) in 18 CFR Part 101. These accounts form the basis for an Oregon utility's books of account.

Table II-A presents PGE's composite cost of capital. The rate of return allowed is the weighted average of the amounts and costs of the three separate components of capital, long-term debt, preferred stock, and common equity.

Table II-A
Cost of Capital, Projected 2007

	Amounts (1)	Percentage (2)	Cost % (3)	Weighted Cost (4) col (2) x col (3)
Long-term Debt	$997,280	43.75%	6.69%	2.93%
Preferred Stock	$6,633	0.29%	8.43%	0.02%
Common Equity	$1,275,487	55.96%	10.75%	6.02%
Total	$2,279,400	100.00%		8.97%

The amount in column (1) for Long-term Debt is the sum of several FERC accounts. The principal accounts are account Nos. 221 (Bonds) and 222 (Reacquired Bonds).[5] The amount of preferred stock is from FERC account Nos. 204 (Preferred Stock Issued) and 205 (Preferred Stock Subscribed). The total Common Equity in column (1) is the sum of several

[5] The accounts also include Nos. 224 (Other Long-term Debt); 225 (Unamortized Premium on Long-term Debt); 226 (Unamortized Discount on Long-term Debt - Debit).

accounts including Nos. 201 (Common Stock Issued) and 216 (Un-appropriated Retained Earnings).[6]

We show <u>the cost</u> of each form of capital in column (3) as a cost *rate*, a percentage. For the long-term bonds, it is the projected average interest rate of the bonds. This is found on the books of account by dividing the principal amount by the interest charges recorded on the books of account. For example if the principal is \$100 and the interest is \$5, the cost rate is 5 % (i.e., \$5 ÷ \$100 = 0.05 or 5%). PGE records debt interest principally in FERC account No. 427 (Interest on Long-term Debt).[7]

In the same manner, the cost of preferred stock is found by dividing the preferred stock dividends recorded in FERC account No. 437 (Dividends Declared - Preferred Stock) by the amount of Preferred Stock outstanding. The cost of equity is also found on the FERC books of account. Account No. 433 contains the Balance Transferred from Income into retained earnings. This is the net income from operations of the utility. After adjustment for preferred dividends (account No. 437) dividing account No. 433 by the principal amount of common equity produces the historic rate earned on common equity.

The return allowed on rate base (and on the undepreciated investment in retired plant) is computed as shown in column (4) in the above table. It is the weighted cost of each form of capital based on its percentage share in the total capital structure.

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[6] Common equity also includes account Nos. 202 (Common Stock Subscribed), 207 (Premium on Common Stock) and, 215 (Appropriated Retained Earnings), and account Nos. 208-211 (other Paid in Capital).

[7] As with the other accounts, interest on long-term debt is recorded in other FERC accounts including 428 (Amortization of Debt Discount and Expense) and 431 (Other Interest Expense) to name a few.

List of Exhibits

Exhibit No.	Description
1101	PGE 2007 Cost of Capital
1102	PGE 2007 Long-Term Debt
1103	Dow Jones Industrials and S&P 500
1104	Credit Actions and Ratings by Agency 2001-2004
1105	PGE Debt Issuances, Utility Indices, Yields
1106	Federal Funds Rate vs. 10-Year Treasuries
1107	Risk Return Tables
1108	Sample Companies
1109	DCF Estimates
1110	Risk Positioning Method Estimates
1111	Recent Authorized ROEs
1112	PGE Preferred Stock
1113	PGE Capital Structure 2002-2007

Portland General Electric

Composite Cost of Capital
Test Year Based on 12 Months Ending 12/31/07

	Average Outstanding *	Percent	Percent Cost	Weighted Average Cost
Long Term Debt	$997,280	43.75%	6.69%	2.93%
Preferred Stock	$6,633	0.29%	8.43%	0.02%
Common Equity	$1,275,487	55.96%	10.75%	6.02%
Composite Cost of Capital	$2,279,400	100.00%		8.97%

* Represents the Average of the Month End Balances

Cost of Long-Term Debt
December 31, 2007

(A)	Ledger (B)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)	Call Premium & Unamort. DD&E of Refunded Issue (K)		Net Proceeds (L) [I-J-K]	Embedded Cost (M)	Net to Gross Rate (N) [L/I]	Face Amount Outstanding (O)	Net Outstanding (P) [N*O]	Face Amount Weight (Q) [O/Total]	Weighted Rate (R) [Q*M]
1	G11514	FMB	5.6875% Series	28-Oct-02	25-Oct-12	10	5.668%	$100,000,000	$12,217,227	$0		$87,782,773	7.420%	87.783%	$100,000,000	$87,782,773	10.018%	0.743%
2	G11515	FMB	5.279% Series	08-Apr-03	01-Apr-13	10	5.279%	$50,000,000	$4,209,517	$0		$45,790,483	6.434%	91.581%	$50,000,000	$45,790,483	5.009%	0.322%
3	G11516	FMB	5.625% Series	04-Aug-03	01-Aug-13	10	5.625%	$50,000,000	$408,842	$0		$49,591,158	5.734%	99.182%	$50,000,000	$49,591,158	5.009%	0.287%
4	G11517	FMB	6.750% Series	04-Aug-03	01-Aug-23	20	6.750%	$50,000,000	$521,342	$0		$49,478,658	6.846%	98.957%	$50,000,000	$49,478,658	5.009%	0.343%
5	G11518	FMB	6.875% Series	04-Aug-03	01-Aug-33	30	6.875%	$50,000,000	$521,342	$0		$49,478,658	6.958%	98.957%	$50,000,000	$49,478,658	5.009%	0.349%
6	G11501	Series MTN	9.31% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	2.004%	0.188%
7		FMB	6.0% Series	01-Apr-06	01-Apr-36	30	6.000%	$275,000,000	$3,025,000	$0	20	$271,975,000	6.080%	98.900%	$275,000,000	$271,975,000	27.549%	1.675%
8		FMB	6.5% Series	15-Jun-07	15-Jun-37	30	6.500%	$54,166,667	$850,000	$0	19	$53,316,667	6.565%	98.431%	$54,166,667	$53,316,667	5.426%	0.356%
9	G40027	Notes	7.875% Series	13-Mar-00	15-Mar-10	10	7.875%	$149,250,000	$1,472,800	$1,266,000	17	$146,511,200	8.128%	98.165%	$149,250,000	$146,511,200	14.952%	1.215%
10	G21186	PCB	Brdmn 98A Fixed	28-May-98	01-May-33	35	5.200%	$23,600,000	$85,850	$1,267,030	5,16,18	$22,247,120	5.544%	94.267%	$23,600,000	$22,247,120	2.364%	0.131%
11	G21185	PCB	Clstrp 98A Fixed	28-May-98	30-Apr-33	35	5.200%	$97,800,000	$355,835	$1,617,373	6,16,18	$95,826,792	5.336%	97.982%	$97,800,000	$95,826,792	9.797%	0.523%
12	G21184	PCB	Colstrip 98B Fixed	28-May-98	30-Apr-33	35	5.450%	$21,000,000	$76,420	$438,143	16,18	$20,485,437	5.620%	97.550%	$21,000,000	$20,485,437	2.104%	0.118%
13	G21191	PCB	Trojan 85A Fixed	01-Jul-98	01-Apr-10	25	4.800%	$20,200,000	$218,352	$244,162	16	$19,737,486	5.058%	97.710%	$20,200,000	$19,737,486	2.024%	0.102%
14	G21193	PCB	Trojan 85B Fixed	01-Jul-98	01-Jun-10	25	4.800%	$16,700,000	$180,519	$184,473	16	$16,335,008	5.046%	97.814%	$16,700,000	$16,335,008	1.673%	0.084%
15	G21195	PCB	Trojan 90A Fixed	01-Jul-98	01-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	16	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.962%	0.053%
16	G21196	PCB	Troj Ser 1990B-Fix	15-Dec-90	15-Dec-14	24	7.125%	$5,100,000	$163,234	$0		$4,936,766	7.412%	96.799%	$5,100,000	$4,936,766	0.511%	0.038%
17	G21123	PCB	Coyote 96 Float	01-Dec-96	01-Dec-31	35	Variable	$5,800,000	$159,350	$0		$5,640,650	3.671%	97.253%	$5,800,000	$5,640,650	0.581%	0.021%
			Loss on Reacquired Debt							$1,380,749		($1,380,749)						
			Total Debt					$998,216,667	$24,745,977	$6,582,910		$966,887,779			$998,216,667	$968,268,529	100.00%	6.550%
			Cost of LT Debt (includes loss from reacquired)															6.689%

	Losses on Reacquired Debt	Reacquired	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense
Y61181	13.50% FMB Due 10/1/12	25-Apr-88	$75,000,000	$8,989,952	$374,581
G11502	9.46 Series Due 08/12/2021	01-Sep-03	$25,000,000	$1,946,809	$108,156
G11511	7.75% Series Due 8/15/2023	08-Dec-03	$115,100,000	$17,960,242	$898,012
					$1,380,749

FOOTNOTES

5 PCB Series Due 4/1/84-11 - PGE refunded its $25.45m Fixed Rate Port of Morrow PCB scheduled to expire serially from 1984-2011 with 26 year variable rate PCB due 6/1/13. Unamortized debt expense and call premium totaled $1,395,954, which is being recovered over the life of the replacement PCB.

16 On 5/28/98, PGE re-marketed and extended the Boardman 88A (now Boardman 98A), the Colstrip 83A-D, the Colstrip 84 (these issues combined to form Colstrip 98A), and the Colstrip 86 (now colstrip 98B). The previous issue costs and premiums were amortized to 5/28/98 and included in the call premium column. The remarketing costs are included in the Issue Costs column. All of the above issues' coupon costs were fixed. On 7/1/98, the Trojan variable rates were fixed, although not extended.

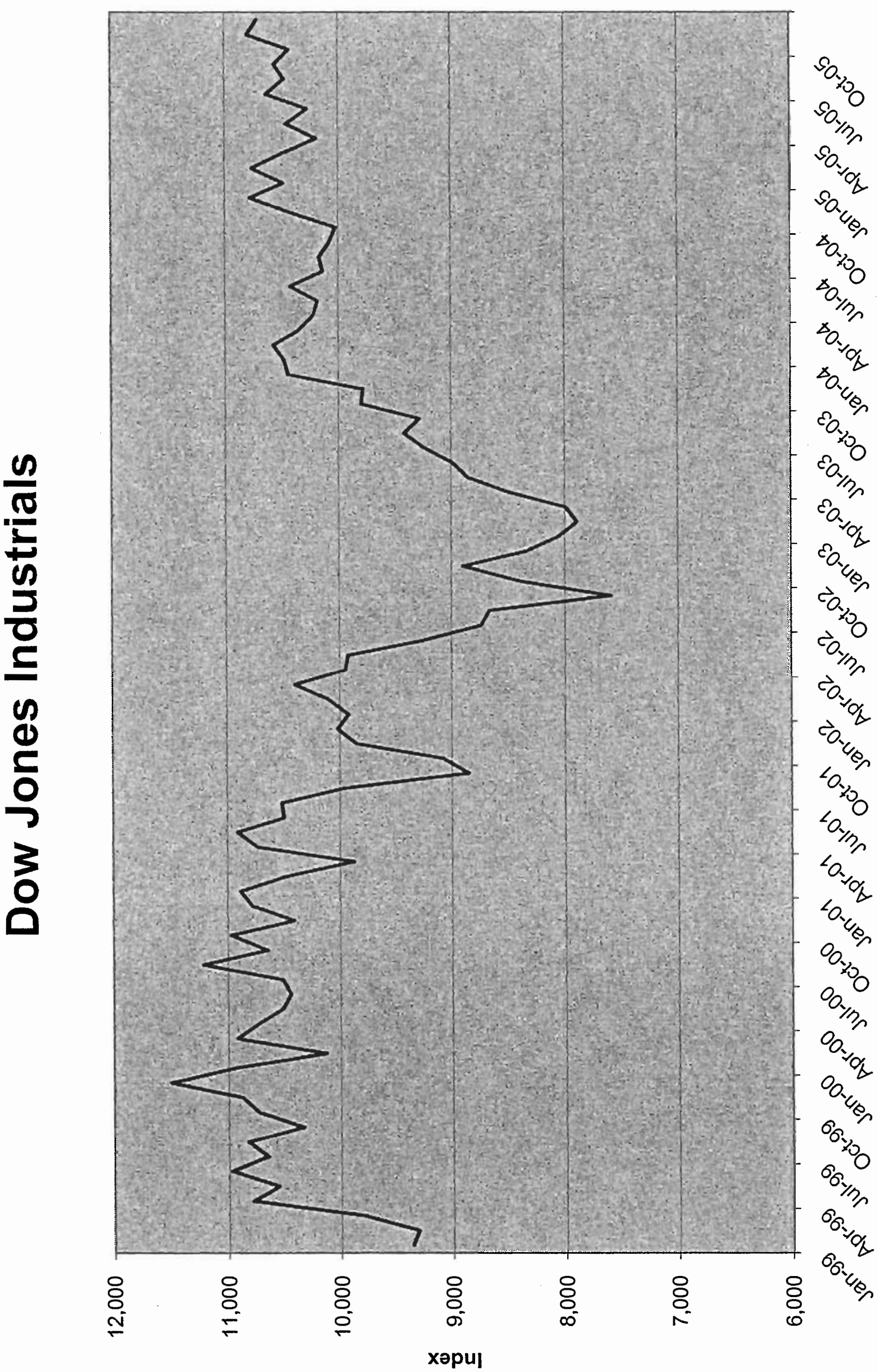
17 One time buydown event of $750,000 in July 2002.

18 Ledger # changed between 2000&2001 when interest rate swaped from floating to fixed.

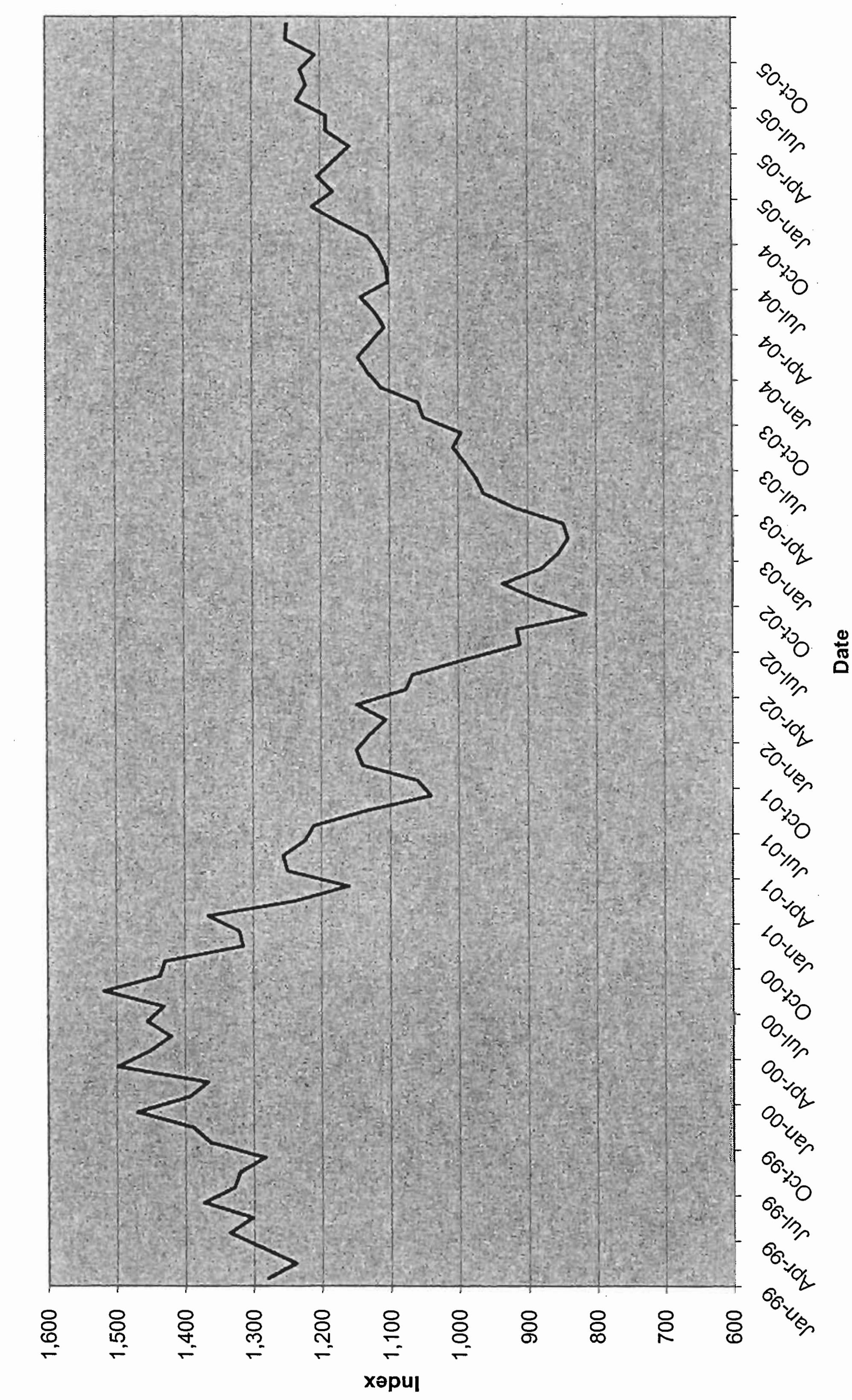
19 $100 million planned issuance in June 2007. The amount and weighted value is based on the average monthly balance over the 2007 calendar year.

Year End 2006	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Average of Averages
$0	$0	$0	$0	$0	$0	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	
Average Monthly Balance	$0	$0	$0	$0	$0	$50,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$54,166,667

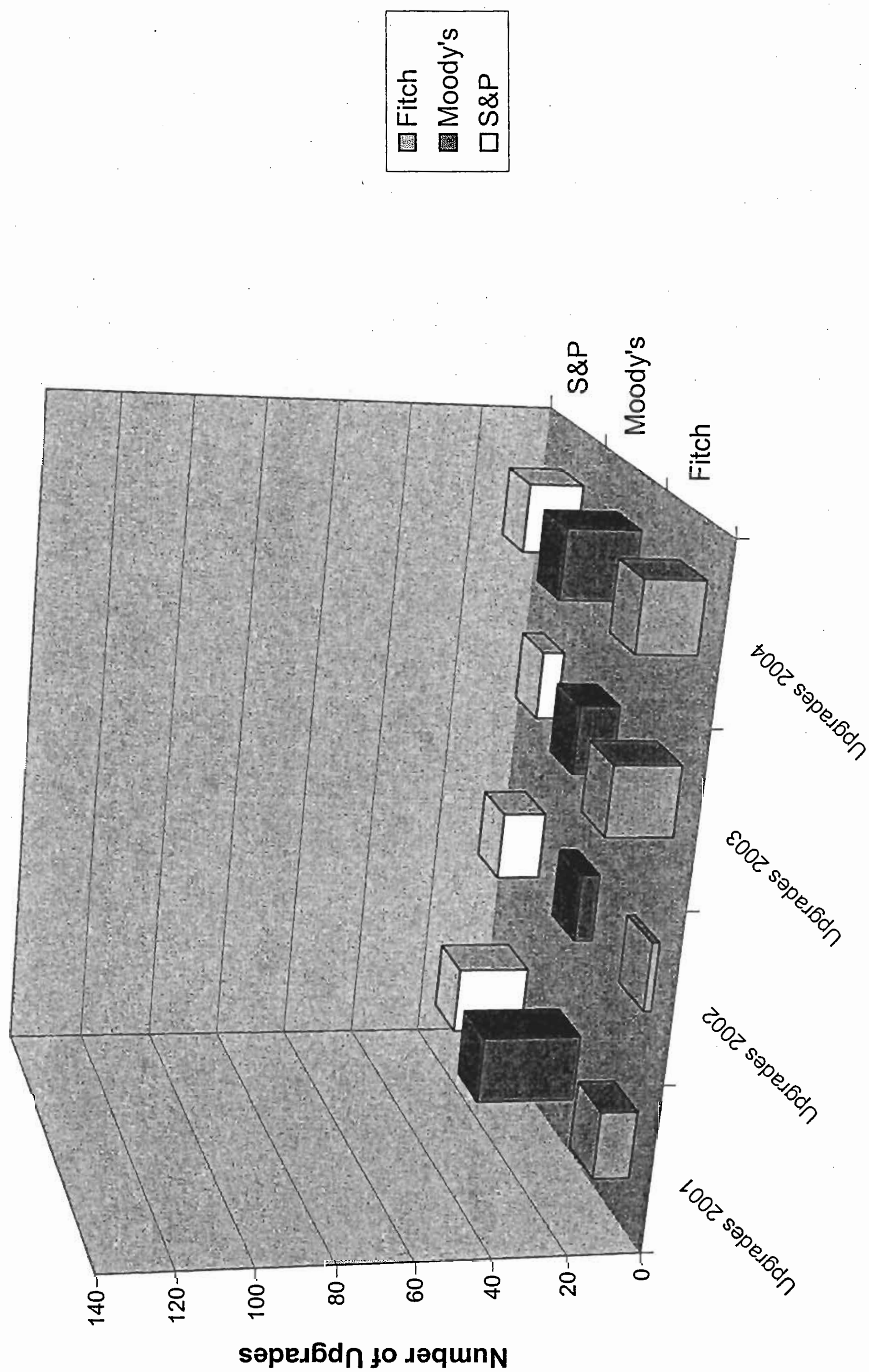
20 There was a $17 million call premium on the 8.125% redeemed issue. This premium is rolled into the new debt and will be paid over the period of the April 2006 issuance.

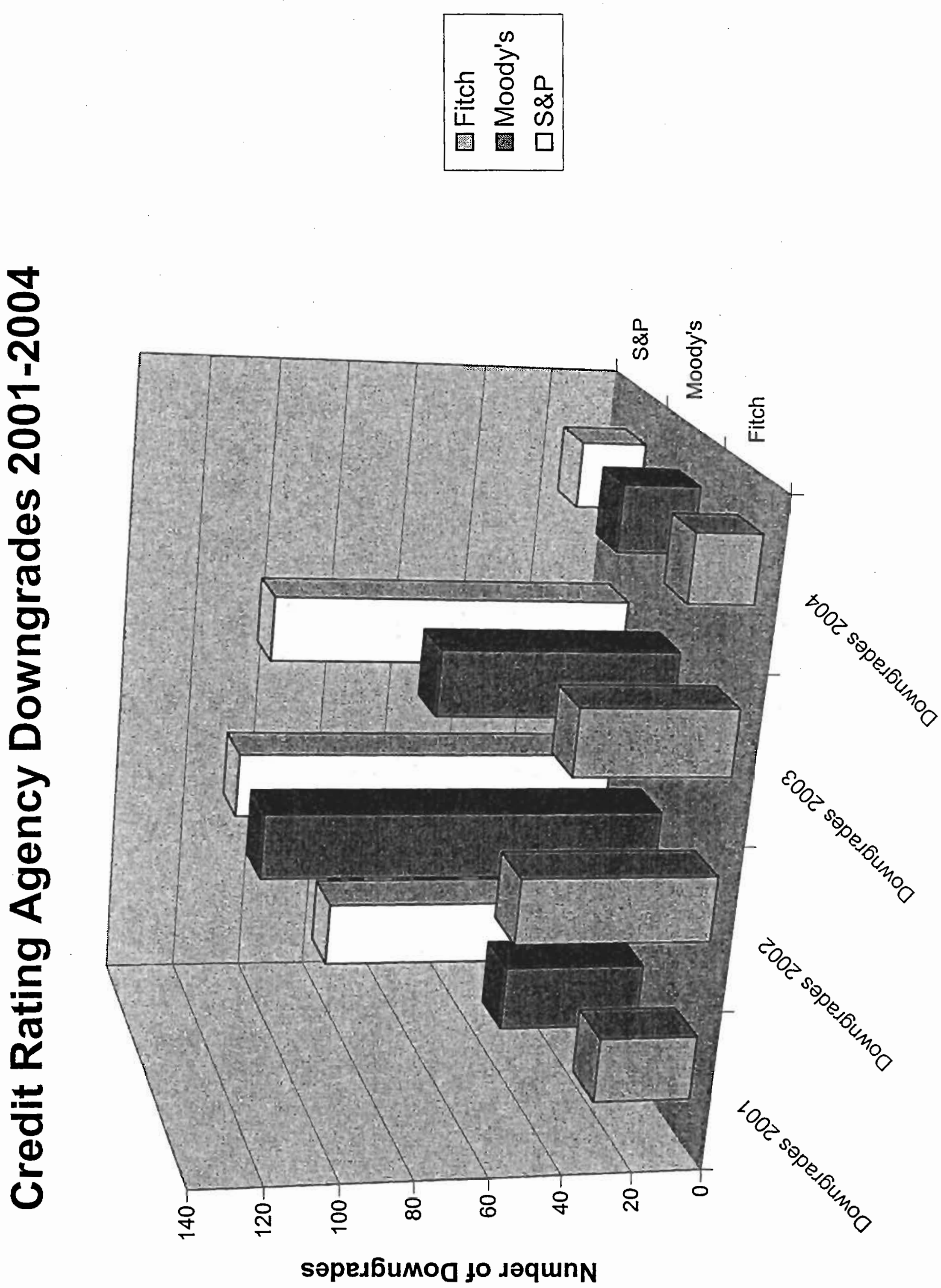

Dow Jones Industrials
Index
12,000
11,000
10,000
9,000
8,000
7,000
6,000
Date
Jan-99
Apr-99
Jul-99
Oct-99
Jan-00
Apr-00
Jul-00
Oct-00
Jan-01
Apr-01
Jul-01
Oct-01
Jan-02
Apr-02
Jul-02
Oct-02
Jan-03
Apr-03
Jul-03
Oct-03
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05
Jul-05
Oct-05

S&P 500

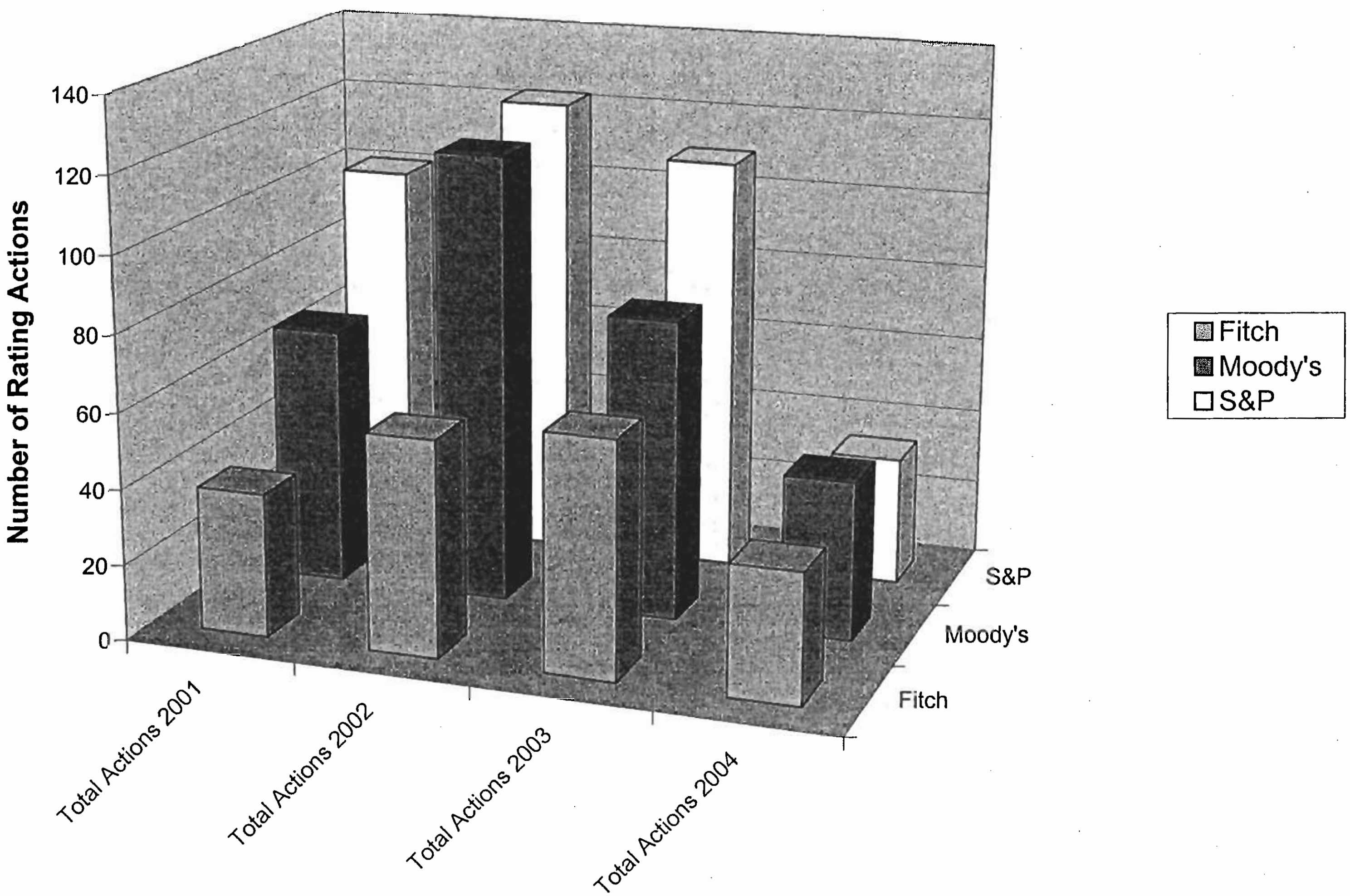

Index
1,600
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
Jan-99
Apr-99
Jul-99
Oct-99
Jan-00
Apr-00
Jul-00
Oct-00
Jan-01
Apr-01
Jul-01
Oct-01
Jan-02
Apr-02
Jul-02
Oct-02
Jan-03
Apr-03
Jul-03
Oct-03
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05
Jul-05
Oct-05
Date

Credit Rating Agency Upgrades 2001-2004




Credit Rating Agency Downgrades 2001-2004
Number of Downgrades
0
20
40
60
80
100
120
140
Downgrades 2001
Downgrades 2002
Downgrades 2003
Downgrades 2004
Fitch
Moody's
S&P
Fitch
Moody's
S&P

Credit Actions by Agency 2001-2004



Portland General Electric

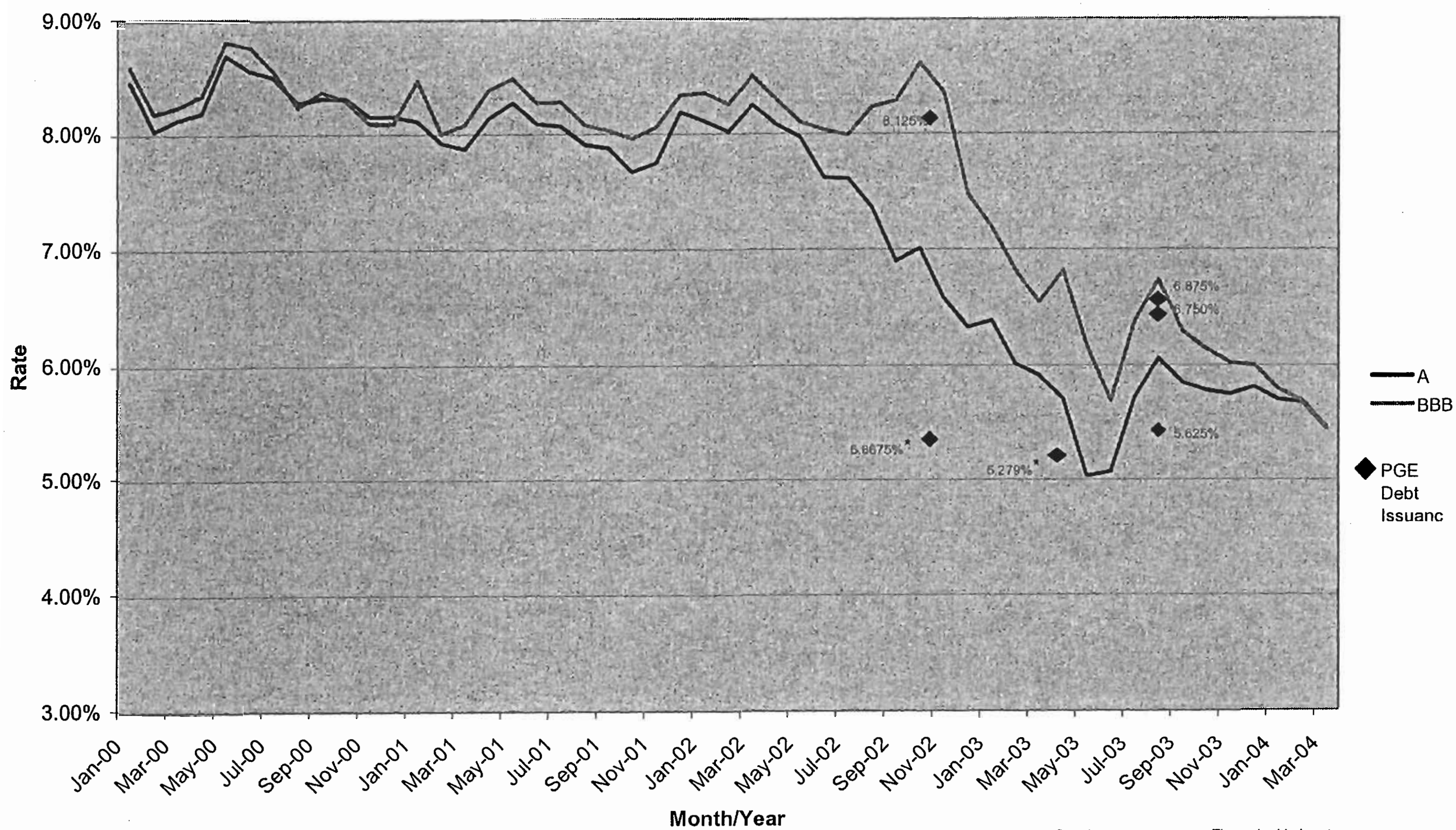
Bond Ratings

September 20, 2005

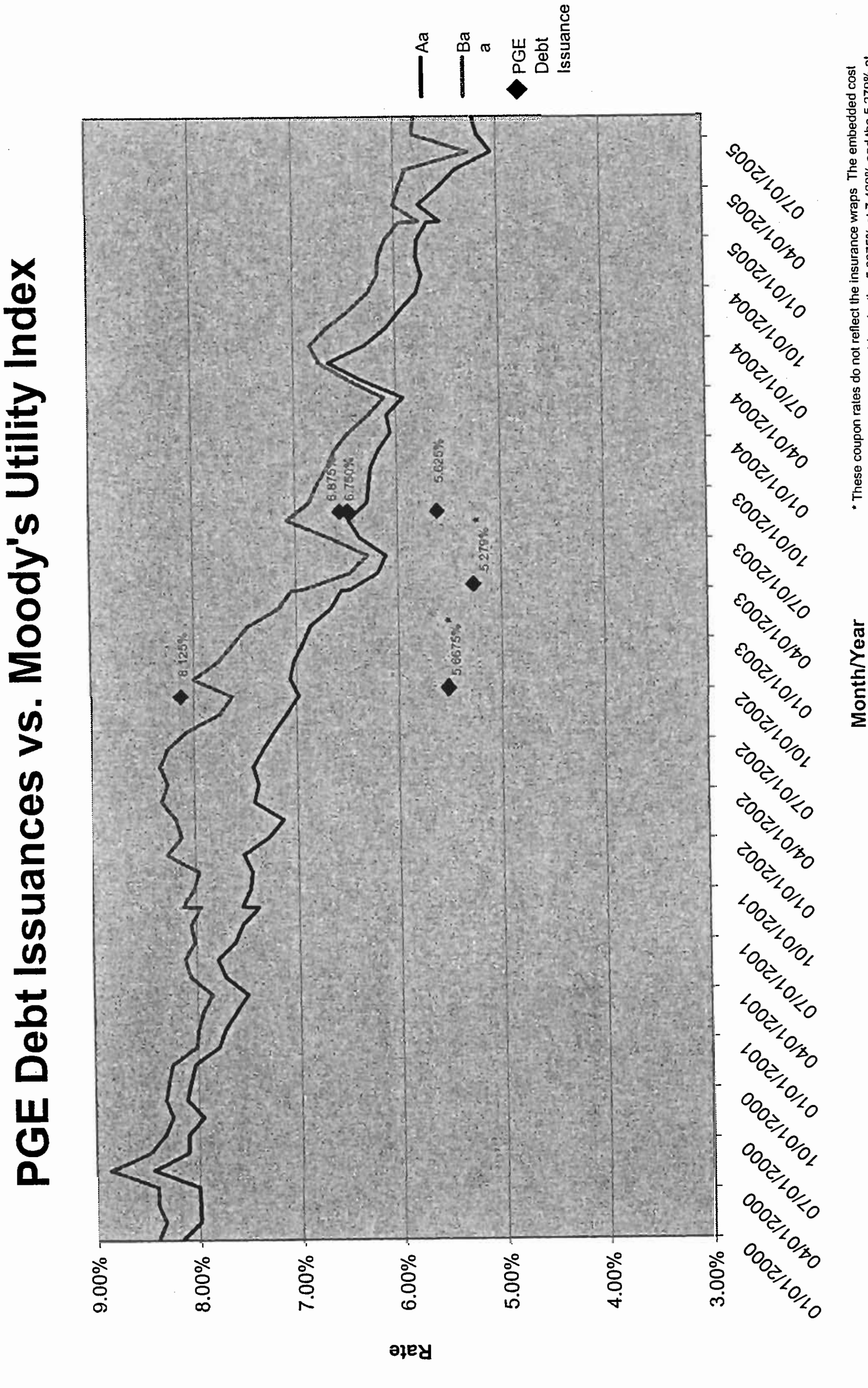
	Standard & Poors[1]	Moody's[2]	Fitch[3]
First Mortgage Bonds	BBB+	Baa1	A-
Senior Unsecured	BBB	Baa2	BBB+
Preferred Stock	BBB-	Ba1	--
Commercial Paper	A-2	P-2	F-2
Outlook	Stable	Stable	Stable

1. On September 20, 2005 the Outlook was changed from "Developing" to "Stable". This was the result of the S&P viewing the near certainty of stock distribution as settling PGE's ownership question. All other ratings were reaffirmed at current levels.
2. On June 9, 2005, all of PGE's ratings by Moody's increased one notch. The Outlook was revised from "On Review for Possible Upgrade" to "Stable".
3. On March 28, 2005 PGE's FMB and Senior Unsecured ratings where upgraded from BBB- and BB, respectively. PGE's preferred stock rating was upgraded from B+ to BBB- and then withdrawn due to the small amount of securities outstanding. PGE' Commercial Paper rating, which was previously withdrawn by Fitch, is rated F-2. Also, on March 28, 2005 the Outlook was changed from Positive to Stable.

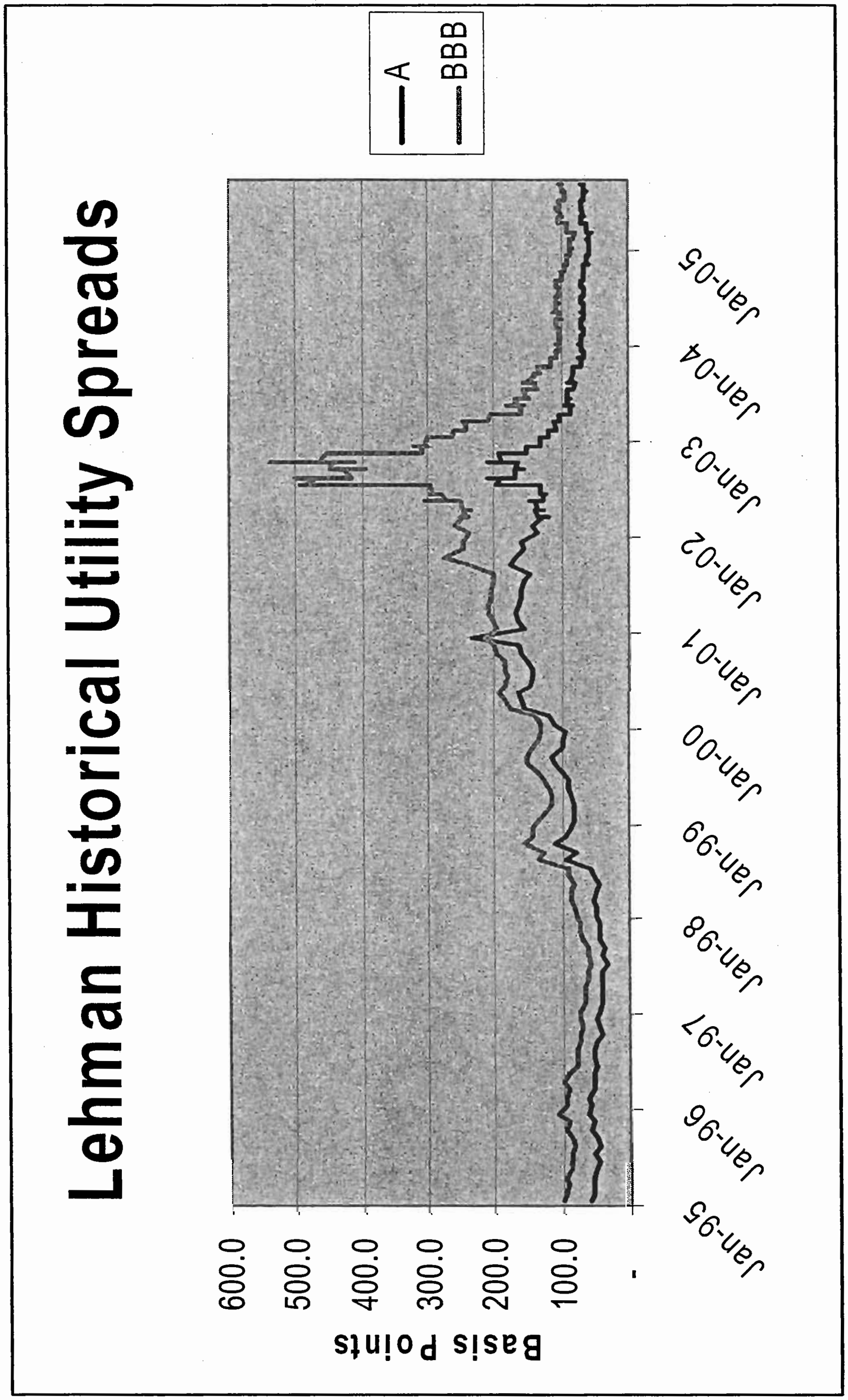
PGE Debt Issuances vs. S&P Utility Index



* These coupon rates do not reflect the insurance wraps The embedded cost including the insurance would make the 5.6675% at 7.420% and the 5.279% at 6.434%



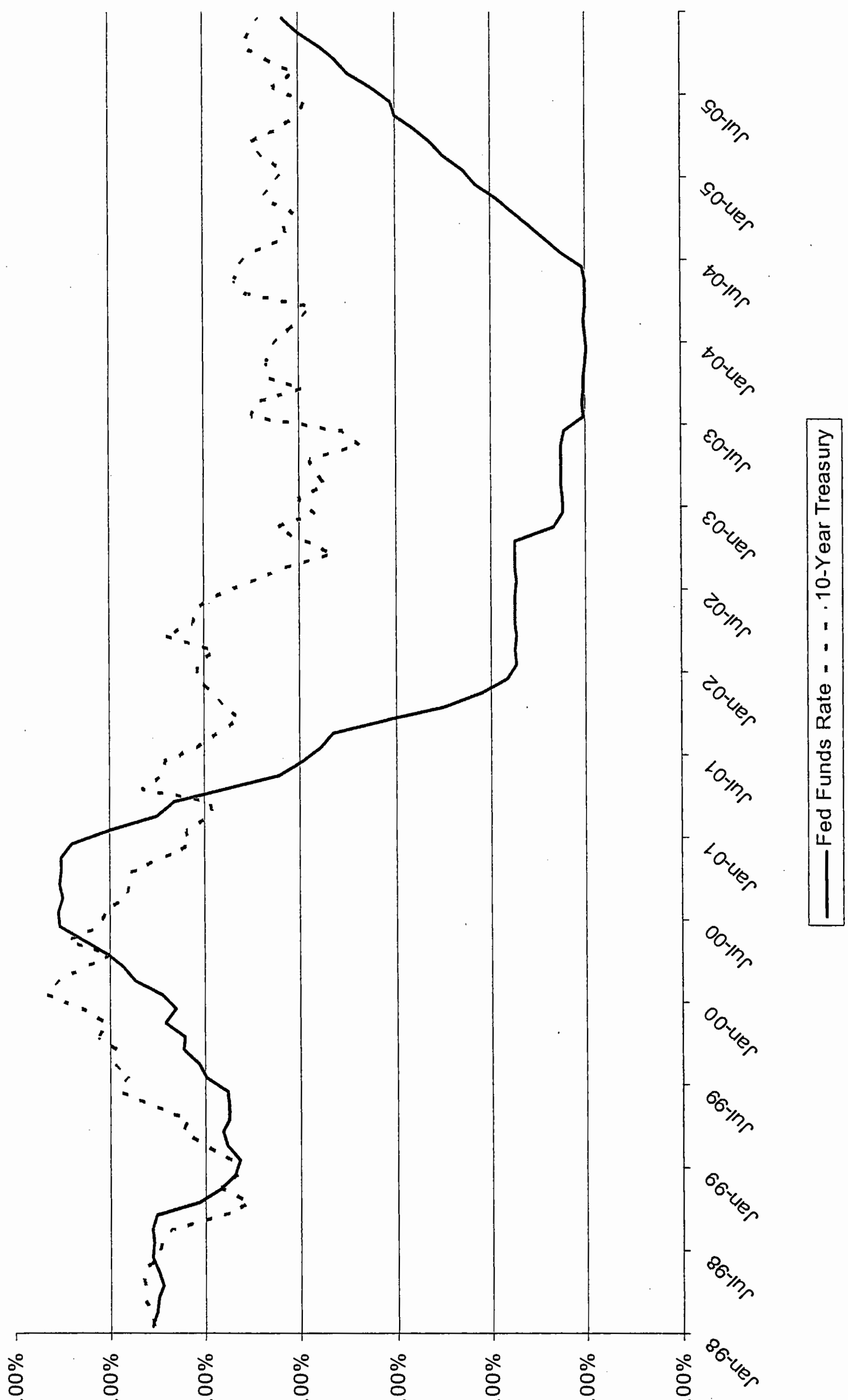
* These coupon rates do not reflect the insurance wraps The embedded cost including the insurance would make the 5.6675% at 7.420% and the 5.279% at 6.434%


Lehman Historical Utility Spreads
A
BBB
Basis Points
600.0
500.0
400.0
300.0
200.0
100.0
-
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05

Analysis of Public Utility Bond Yields

	Utility Yields by Ratings (All numbers are in percent)				Spreads (All numbers are in percent)		
	Aaa	Aa	A	Baa	Aaa-Aa	Aa-A	A-Baa
Dec-05	n/a	5.55	5.80	6.14	n/a	0.25	0.34
Nov-05	n/a	5.59	5.88	6.19	n/a	0.29	0.31
Oct-05	n/a	5.50	5.79	6.08	n/a	0.29	0.29
Sep-05	n/a	5.27	5.52	5.83	n/a	0.25	0.31
Aug-05	n/a	5.23	5.50	5.80	n/a	0.27	0.30
Jul-05	n/a	5.18	5.51	5.81	n/a	0.33	0.30
Jun-05	n/a	5.05	5.40	5.70	n/a	0.35	0.30
May-05	n/a	5.39	5.53	5.88	n/a	0.14	0.35
Apr-05	n/a	5.56	5.64	5.95	n/a	0.08	0.31
Mar-05	n/a	5.76	5.83	6.01	n/a	0.07	0.18
Feb-05	n/a	5.55	5.61	5.76	n/a	0.06	0.15
Jan-05	n/a	5.68	5.78	5.95	n/a	0.10	0.17
Dec-04	n/a	5.78	5.92	6.10	n/a	0.14	0.18
Nov-04	n/a	5.79	5.97	6.16	n/a	0.18	0.19
Oct-04	n/a	5.74	5.94	6.17	n/a	0.20	0.23
Sep-04	n/a	5.79	5.98	6.27	n/a	0.19	0.29
Aug-04	n/a	5.95	6.14	6.45	n/a	0.19	0.31
Jul-04	n/a	6.09	6.27	6.67	n/a	0.18	0.40
Jun-04	n/a	6.30	6.46	6.84	n/a	0.16	0.38
May-04	n/a	6.66	6.62	6.75	n/a	0.04	0.13
Apr-04	n/a	6.33	6.35	6.46	n/a	0.02	0.11
Mar-04	n/a	5.93	5.97	6.12	n/a	0.04	0.15
Feb-04	n/a	6.10	6.15	6.28	n/a	0.05	0.13
Jan-04	n/a	6.06	6.15	6.47	n/a	0.09	0.32
Dec-03	n/a	6.18	6.27	6.61	n/a	0.09	0.34
Nov-03	n/a	6.26	6.37	6.69	n/a	0.11	0.32
Oct-03	n/a	6.28	6.43	6.79	n/a	0.15	0.36
Sep-03	n/a	6.30	6.56	6.87	n/a	0.26	0.31
Aug-03	n/a	6.48	6.78	7.08	n/a	0.30	0.30
Jul-03	n/a	6.37	6.57	6.67	n/a	0.20	0.10
Jun-03	n/a	6.12	6.21	6.30	n/a	0.09	0.09
May-03	n/a	6.20	6.36	6.47	n/a	0.16	0.11
Apr-03	n/a	6.47	6.64	6.94	n/a	0.17	0.30
Mar-03	n/a	6.56	6.79	7.05	n/a	0.23	0.26
Feb-03	n/a	6.66	6.93	7.17	n/a	0.27	0.24
Jan-03	n/a	6.87	7.06	7.47	n/a	0.19	0.41
Dec-02	n/a	6.94	7.07	7.61	n/a	0.13	0.54
Nov-02	n/a	7.03	7.14	7.76	n/a	0.11	0.62
Oct-02	n/a	7.07	7.23	8.00	n/a	0.16	0.77
Sep-02	n/a	6.98	7.08	7.62	n/a	0.10	0.54
Aug-02	n/a	7.10	7.17	7.74	n/a	0.07	0.57
Jul-02	n/a	7.22	7.31	8.07	n/a	0.09	0.76
Jun-02	n/a	7.33	7.42	8.26	n/a	0.09	0.84
May-02	n/a	7.43	7.52	8.33	n/a	0.09	0.81
Apr-02	n/a	7.38	7.57	8.26	n/a	0.19	0.69
Mar-02	n/a	7.42	7.76	8.32	n/a	0.34	0.56
Feb-02	n/a	7.14	7.54	8.18	n/a	0.40	0.64
Jan-02	n/a	7.28	7.66	8.13	n/a	0.38	0.47
Dec-01	7.53	7.53	7.83	8.27	0.00	0.30	0.44
Nov-01	7.45	7.45	7.57	7.96	0.00	0.12	0.39
Oct-01	7.45	7.47	7.63	8.02	0.02	0.16	0.39
Sep-01	7.52	7.55	7.75	8.12	0.03	0.20	0.37
Aug-01	7.36	7.39	7.59	7.95	0.03	0.20	0.36
Jul-01	7.46	7.55	7.78	8.05	0.09	0.23	0.27
Jun-01	7.50	7.62	7.85	8.02	0.12	0.23	0.17
May-01	7.61	7.79	7.99	8.11	0.18	0.20	0.12
Apr-01	7.53	7.72	7.94	8.06	0.19	0.22	0.12
Mar-01	7.31	7.51	7.68	7.85	0.20	0.17	0.17
Feb-01	7.46	7.62	7.74	7.94	0.16	0.12	0.20
Jan-01	7.53	7.73	7.80	7.99	0.20	0.07	0.19
Dec-00	7.51	7.79	7.84	8.01	0.28	0.05	0.17
Nov-00	7.71	8.03	8.11	8.25	0.32	0.08	0.14
Oct-00	7.80	8.08	8.14	8.29	0.28	0.06	0.15
Sep-00	7.92	8.11	8.23	8.32	0.19	0.12	0.09
Aug-00	7.89	7.95	8.13	8.25	0.06	0.18	0.12
Jul-00	8.00	8.10	8.25	8.33	0.10	0.15	0.08
Jun-00	7.96	8.10	8.36	8.47	0.14	0.26	0.11
May-00	8.22	8.44	8.70	8.86	0.22	0.26	0.16
Apr-00	7.87	8.00	8.29	8.40	0.13	0.29	0.11
Mar-00	7.87	7.99	8.28	8.40	0.12	0.29	0.12
Feb-00	7.82	7.99	8.25	8.33	0.17	0.26	0.08
Jan-00	7.95	8.17	8.35	8.40	0.22	0.18	0.05

Federal Funds Rate vs. 10-Year Treasuries



S&P and Moody's

Company Name	Ticker	S&P Bond Rating [1]	Moody's Bond Rating [1]	5 yr Avg Debt/Capital [2]	5 yr Avg Primary Earn/Div [3]	5 yr Avg Fully Diluted Earn/Div [3]	--------5 yr: '00-'04-------- Avg. ROE [4]	STD	STD/Avg
Ameren Corporation	AEE	A-	A3	45.48%	1.21	1.21	11.78%	2.35%	0.20
Constellation Energy Group Inc.	CEG	BBB+	Baa1	49.06%	2.76	2.04	10.50%	1.19%	0.11
CH Energy Corp.	CHG	A	A2	34.68%	1.29	1.27	9.12%	1.39%	0.15
Consolidated Edison	ED	A	A2	48.94%	1.23	1.28	10.32%	1.62%	0.16
Dominion Resources	D	BBB+	Baa1	58.22%	1.44	1.45	10.88%	2.27%	0.21
DTE Energy Co	DTE	BBB	Baa2	58.72%	1.41	1.42	9.96%	2.74%	0.27
Energy East Corp	EAS	BBB+	Baa2	59.02%	1.55	1.81	10.40%	2.82%	0.27
Entergy Corp	ETR	BBB	Baa3	46.66%	1.13	2.39	10.14%	0.76%	0.08
FirstEnergy Corp	FE	BBB-	Baa3	55.70%	1.41	1.56	9.66%	2.78%	0.29
F P L Group Inc.	FPL	A	A2	47.64%	1.81	1.93	12.20%	0.81%	0.07
OGE Energy Corp.	OGE	BBB+	Baa1	57.54%	1.20	1.22	11.80%	1.48%	0.13
Pinnacle West Capital Corp.	PNW	BBB	Baa2	49.18%	1.62	1.83	9.70%	2.29%	0.24
PEPCO Holdings	POM	BBB+	Baa2	57.34%	1.99	2.36	9.40%	2.01%	0.21
PPL Corp	PPL	BBB	Baa3	66.28%	1.80	2.66	21.76%	4.47%	0.21
Progress Energy	PGN	BBB	Baa2	56.56%	1.35	1.47	10.22%	2.13%	0.21
Southern Company	SO	A	A2	44.68%	1.37	1.39	14.22%	1.15%	0.08
Xcel	XEL	BBB	Baa1	59.08%	1.39	1.23	9.16%	3.28%	0.36
Average - S&P/Moodys Comb.				**52.63%**	**1.53**	**1.68**	**11.25%**	**2.09%**	**0.19**
Portland General Electric*		BBB+	Baa1	42.92%			9.37%	3.01%	0.32

Bond Ratings as of 10/05.

Sources:
(1) *RRA,* Utility Focus, October 28, 2005
(2) *Valueline* Long-Term Debt Ratio; East: December 2005, West: November 2005, Central: October 2005
(3) *Valueline* EPS, *Factiva;* note some EPS are calculations from *Valueline* data
(4) *Valueline* Return on Common Equity; East: December 2005, West: November 2005, Central: October 2005

*PGE ROE: from Semi Annual Report, "Actual Financial Statements"
*PGE LTD/CAP: from Semi Annual, "Composite Cost of Capital, End of Period"

PGE Comparables

Company Name	Ticker	S&P Bond Rating [1]	Moody's Bond Rating [1]	5 yr Avg Debt/Capital [2]	5 yr Avg Primary Earn/Div [3]	5 yr Avg Fully Diluted Earn/Div [3]	--------5 yr: '00-'04-------- Avg. ROE [4]	STD	STD/Avg
Avista	AVA	BB+	Ba1	56.88%	1.61	2.21	6.96%	2.71%	0.39
Cleco	CNL	BBB	Baa3	56.40%	1.24	1.60	13.40%	1.31%	0.10
Northeast Utilities	NU	BBB	Baa2	60.80%	1.63	2.66	6.70%	1.41%	0.21
Oklahoma Gas & Electric	OGE	BBB+	Baa1	59.54%	1.11	1.22	11.80%	1.48%	0.13
Potomac Electric Power	POM	BBB+	Baa2	57.34%	1.98	2.36	9.40%	2.01%	0.21
Pinnacle West	PNW	BBB	Baa2	49.18%	1.77	1.83	9.70%	2.29%	0.24
Puget Sound Energy	PSD	BBB-	Ba1	59.98%	1.02	1.08	8.60%	2.50%	0.29
Unisource Energy	UNS	BB	Ba3	80.32%	3.01	2.92	9.06%	2.97%	0.33
Wisconsin Energy	WEC	BBB+	A3	59.40%	1.59	2.21	9.98%	2.39%	0.24
Average - PGE Comparables				**59.98%**	**1.66**	**2.01**	**9.51%**	**2.12%**	**0.24**
Portland General Electric*		BBB+	Baa1	42.92%			9.37%	3.01%	0.32

Sources:
(1) *RRA,* Utility Focus, October 28, 2005
(2) *Valueline* Long-Term Debt Ratio; East: December 2005, West: November 2005, Central: October 2005
(3) *Valueline* EPS, *Factiva;* note some EPS are calculations from *Valueline* data
(4) *Valueline* Return on Common Equity; East: December 2005, West: November 2005, Central: October 2005

*PGE ROE: from Semi Annual Report, "Actual Financial Statements"
*PGE LTD/CAP: from Semi Annual, "Composite Cost of Capital, End of Period"

UE 170 Rebuttal

Company Name	Ticker	S&P Bond Rating [1]	Moody's Bond Rating [1]	5 yr Avg Debt/Capital [2]	5 yr Avg Primary Earn/Div [3]	5 yr Avg Fully Diluted Earn/Div [3]	--------5 yr: '00-'04-------- Avg. ROE [4]	STD	STD/Avg
Ameren	AEE	A-	A3	45.48%	1.21	1.21	11.78%	2.35%	0.20
CH Energy	CHG	A	A2	34.68%	3.13	3.11	9.12%	1.39%	0.15
Cleco	CNL	BBB	Baa3	56.40%	0.50	0.65	13.40%	1.31%	0.10
Consolidated Edison	ED	A	A2	48.94%	1.32	1.28	10.32%	1.62%	0.16
Empire District Electric	EDE			54.72%	1.12	1.12	7.02%	2.25%	0.32
Energy East Corp	EAS	BBB+	Baa2	59.02%	0.61	0.67	10.40%	2.82%	0.27
FPL Group	FPL	A	A2	47.64%	1.13	1.12	12.20%	0.81%	0.07
Madison Gas & Electric	MGEE			43.34%	1.76	1.76	12.14%	1.41%	0.12
NSTAR	NST	A	A2	59.32%	0.91	1.17	13.46%	0.38%	0.03
Progress Energy	PGN	BBB	Baa2	56.56%	1.88	2.06	10.22%	2.13%	0.21
Scana Corp	SCG	A-	A3	55.90%	2.01	1.70	11.40%	0.85%	0.07
Southern Company	SO	A	A2	44.68%	1.43	1.43	14.22%	1.15%	0.08
Vectren	VVC	A-	Baa1	50.12%	0.83	0.85	10.32%	1.70%	0.17
Xcel	XEL	BBB	Baa1	59.08%	1.88	1.17	9.16%	3.28%	0.36
Average - UE 170 Rebuttal				**51.13%**	**1.41**	**1.38**	**11.08%**	**1.67%**	**0.16**
Portland General Electric*		BBB+	Baa1	42.92%			9.37%	3.01%	0.32

Sources:
(1) *RRA,* Utility Focus, December 16, 2005
(2) *Valueline* Long-Term Debt Ratio; East: December 2005, West: November 2005, Central: October 2005
(3) *Valueline* EPS, *Factiva;* note some EPS are calculations from *Valueline* data
(4) *Valueline* Return on Common Equity; East: December 2005, West: November 2005, Central: October 2005

*PGE ROE: from Semi Annual Report, "Actual Financial Statements"
*PGE LTD/CAP: from Semi Annual, "Composite Cost of Capital, End of Period"

S&P/Moody's Combined

	Company Name	Included / reason for exclusion (Old)
AYE	Allegheny Energy	No dividends paid since 12/31/2002
AEE	Ameren Corporation	Included
AEP	American Electric Power	Dividend reduction within last three years (6/30/03)
CEG	Constellation Energy Group	Included
CHG	CH Energy Group	Included
CNP	CenterPoint Energy	Dividend reduction within last three years (3/31/03)
CIN	CINergy Corp.	Merger in progress with Duke
ED	Consolidated Edison	Included
DPL	DPL Inc	Dividend reduction within last three years
D	Dominion Res Inc VA New	Included
DTE	DTE Energy Co.	Included
DUK	Duke Energy Corp	Merger in progress with Cinergy
EAS	Energy East Corp	Included
EIX	Edison Int'l	Dividends suspended and reinstated within last three years
ETR	Entergy Corp.	Included
EXC	Exelon Corp.	Merger in progress with PSEG
FE	FirstEnergy Corp.	Included
FPL	FPL Group	Included
IDA	Idacorp	Dividend reduction within last 3 years (12/31/03)
IPL	Ipalco Enterprises	Acquired by AES
NI	Nisource	Dividend reduction within last 3 years (12/31/03)
OGE	OGE Energy Corp	Included
PCG	PG&E Corp.	Dividends suspended since March 2001; filed for Chapter 11 bankruptcy
PEG	Public Service Enterprise Group	Merger in progress with Exelon
PNW	Pinnacle West Capital	Included
POM	Potomac Electric Power Co	Included
PPL	PPL Corp.	Included
PGN	Progress Energy, Inc.	Included
SO	Southern Co.	Included
TE	TECO Energy	Dividend reduction within last three years (6/30/03)
TXU	TXU Corp.	Dividend reduction within last three years (3/31/03)
XEL	Xcel Energy Inc	Included
	Total Companies: 32	Included: 17

PGE Comparables

LNT	Alliant	Dividend reduction within last three years (3/31/2003)
AVA	Avista	Included
CNL	CLECO	Included
DPL	D P L Inc.	Dividend reduction within last three years
IDA	Idaho Power Co.	Dividend reduction within last three years (12/31/2003)
NU	Northeast Utilities	Included
NOR	Northwestern Corp.	No longer followed by Valueline
OGE	Oklahoma Gas & Electric Co.	Included
POM	Potomac Electric Power Co.	Included
PNW	Pinnacle West Capital Corp.	Included
PSD	Puget Sound Energy	Included
UNS	UniSource Energy Corp.(Tucson Electric Power Co.)	Included
WR	Western Resources	Dividend reduction within last three years (6/30/2003)
WEC	Wisconsin Energy Corp.	Included
	Total Companies: 14	Included: 9

UE 170 Rebuttal Sample

LNT	Alliant	Dividend reduction within last three years (3/31/2003)
AEE	Ameren Corporation	Included
CHG	CH Energy	Included
CNL	CLECO	Included
ED	Consolidated Edison Co. NY Inc.	Included
EDE	Empire District Electric Co.	Included
EAS	Energy East Corp.	Included
ETR	Entergy Corp	no data for October through December 2005
EXC	Exelon Corp.	Merger in progress with PSEG
FPL	F P L Group Inc.	Included
MGEE	MGE Energy	Included
NST	NSTAR	Included
PGN	Progress Energy	Included
SCG	Scana Corp	Included
SO	Southern Company	Included
VVC	Vectren	Included
XEL	Xcel Energy Inc.	Included
	Total Companies: 17	Included: 14

PGE Multi-Stage DCF Estimates
Terminal Growth: BR+VS

Combined S&P, Moody's

	Stock Price		
2005	High	Low	Close
Oct	9.08%	9.63%	9.39%
Nov	9.12%	9.38%	9.21%
Dec	9.10%	9.33%	9.25%

PGE Comparables

	Stock Price		
2005	High	Low	Close
Oct	8.69%	9.18%	8.99%
Nov	8.44%	8.67%	8.50%
Dec	8.42%	8.53%	8.46%

UE 170 Rebuttal PacifiCorp

	Stock Price		
2005	High	Low	Close
Oct	8.14%	8.62%	8.38%
Nov	8.25%	8.48%	8.33%
Dec	8.29%	8.48%	8.43%

PGE Multi-Stage DCF Estimates
Terminal Growth: GDP Trend

Combined S&P, Moody's

2005	Stock Price		
	High	Low	Close
Oct	9.08%	9.69%	9.43%
Nov	9.18%	9.46%	9.28%
Dec	9.11%	9.36%	9.27%

PGE Comparables

2005	Stock Price		
	High	Low	Close
Oct	8.86%	9.49%	9.24%
Nov	8.92%	9.21%	9.00%
Dec	8.93%	9.12%	8.99%

UE 170 Rebuttal PacifiCorp

2005	Stock Price		
	High	Low	Close
Oct	8.94%	9.51%	9.24%
Nov	9.18%	9.45%	9.28%
Dec	9.14%	9.39%	9.31%

PGE Multi-Stage DCF Estimates
Terminal Growth: GDP Historical

Combined S&P, Moody's

2005	Stock Price		
	High	Low	Close
Oct	10.59%	11.17%	10.92%
Nov	10.68%	10.95%	10.78%
Dec	10.62%	10.86%	10.77%

PGE Comparables

2005	Stock Price		
	High	Low	Close
Oct	10.38%	10.98%	10.74%
Nov	10.43%	10.71%	10.51%
Dec	10.44%	10.62%	10.50%

UE 170 Rebuttal PacifiCorp

2005	Stock Price		
	High	Low	Close
Oct	10.45%	10.99%	10.74%
Nov	10.68%	10.94%	10.77%
Dec	10.64%	10.88%	10.81%

Risk Positioning Method (Data through 12/05)

Using *Global Insight* Forecast

7yr Treasury Yields 1983-2005.11 (1 month lag) | R-squared 0.61

Variable	Coefficient	t-statistic	p-value
Constant	8.45808	63.50	0.0001
yr71	-0.44772	(27.59)	0.0001

			Implied ROE 2007
Dec-06 GI est 2007	5.22	+8.45808 - (0.44772 * 5.215) =	11.34

---

yr Treasury Yields 1983-2005.11 (8 month lag) | R-squared 0.63

Variable	Coefficient	t-statistic	p-value
Constant	8.13733	64.95	0.0001
yr78	-0.42622	(28.78)	0.0001

			Implied ROE 2007
Dec-06 GI est 2007	5.22	+8.13733 - (0.42622 * 5.215) =	11.13

Risk Positioning Method (Data through 12/05)

Using January 2006 Interest Rates

7yr Treasury Yields 1983-2005.11 (1 month lag) R-squared 0.61

Variable	Coefficient	t-statistic	p-value
Constant	8.4581	63.50	0.0001
yr71	-0.44772	(27.50)	0.0001

			Implied ROE 2007
7-yr Treasuries 02/15/2006	4.60	+8.45808 - (0.44772 * 4.6) =	11.00

---

yr Treasury Yields 1983-2005.11 (8 month lag) R-squared 0.63

Variable	Coefficient	t-statistic	p-value
Constant	8.13733	64.95	0.0001
yr78	-0.42622	(28.78)	0.0001

			Implied ROE 2007
7-yr Treasuries 02/15/2006	4.60	+8.13733 - (0.42622 * 4.6) =	10.78

Risk Positioning Method (Data through12/05)

Corporate Bonds 1983-2005.11) R-squared 0.47

Variable	Coefficient	t-statistic	p-value
Constant	6.47434	38.37	<.0001
DebtCost	-0.34659	-20.48	<.0001

			Implied ROE 2007
PGE Estimated FMB Bond	6.15	+6.47434 - (0.34659 * 6.15) =	10.493
Moodys Baa Utilities Nov	6.14	+6.47434 - (0.34659 * 6.14) =	10.486

Recent Authorized ROEs

Date Decision	State	Company Name	Authorized ROE	State Auth PCA?
01/06/2005	South Carolina	South Carolina Electric & Gas	10.70%	Y
01/28/2005	Kansas	Aquila Networks-WPK	10.50%	Y
02/18/2005	Washington	Puget Sound Energy	10.30%	Y
02/25/2005	Utah	PacifiCorp	10.50%	N
03/10/2005	Missouri	Empire District Electric	11.00%	Y
03/24/2005	New York	Consolidated Edison New York	10.30%	N
03/29/2005	Vermont	Central Vermont Public Service	10.00%	N
03/31/2005	Texas	Texas-New Mexico Power	10.25%	Y
04/07/2005	Arizona	Arizona Public Service	10.25%	Y
05/18/2005	Louisiana	Entergy Louisiana	10.25%	Y
05/19/2005	Oregon	Idaho Power	10.00%	N
05/25/2005	New Jersey	Jersey Central Power & Light*	9.75%	N
05/25/2005	Georgia	Savannah Electric & Power	10.75%	Y
05/26/2005	New Jersey	Atlantic City Electric*	9.75%	N
06/08/2005	New Hampshire	Public Service New Hampshire	9.62%	N
07/19/2005	Wisconsin	Wisconsin Power and Light	11.50%	Y
08/05/2005	Texas	Cap Rock Energy	11.75%	Y
08/15/2005	Texas	AEP Texas Central	10.13%	Y
09/28/2005	Oregon	PacifiCorp	10.00%	N
12/12/2005	Wisconsin	Madison Gas & Electric	11.00%	Y
12/13/2005	Oklahoma	OGE Energy	10.75%	Y
12/16/2005	California	San Diego Gas & Electric	10.70%	Y
12/16/2005	California	Pacific Gas & Electric	11.35%	Y
12/16/2005	California	Southern California Edison	11.60%	Y
12/21/2005	Ohio	Cincinnati Gas & Electric	10.29%	
12/21/2005	Washington	Avista	10.40%	Y
12/22/2005	Wisconsin	Wisconsin Public Service	11.00%	Y
12/22/2005	Michigan	Consumers Energy	11.15%	Y
12/28/2005	Kansas	Kansas Gas & Electric	10.00%	Y
12/28/2005	Kansas	Westar Energy	10.00%	Y
		Average	**10.52%**	

* Transmission and Distribution only utilities

Data comes from Regulatory Research Associates

Portland General Electric

Cost of Preferred Stock

Test Year Based on 12 Months Ending 12/31/07

Preferred Stock	Effective Rate	Issued	Average Outstanding	Interest Cost
7.75% Series	8.432%	16-Jun-92	$6,633	$559
			Cost of Preferred	8.432%

Note: Beginning 6/15/2002 must redeem 15,000 shares for each of the next five years.
at a price of $100 per share. Can optionally redeem an additional 15,000 each year.
Mandatory redemption on 6/15/2007 of all remaining shares.

PGE Capital Structure
($000)

	2002 UE 115	2003	2004	2005	2006	2007
Long-Term Debt	$887,900	$978,110	$907,917	$862,314	$922,747	$997,280
Preferred	$29,250	$25,089	$21,848	$18,848	$16,598	$6,633
Common Equity	$999,781	$1,255,244	$1,337,584	$1,243,265	$1,242,081	$1,275,487
Total	$1,916,931	$2,258,443	$2,267,349	$2,124,427	$2,181,426	$2,279,400

	2002 UE -115	2003	2004	2005	2006	2007
Long-Term Debt	46.32%	43.31%	40.04%	40.59%	42.30%	43.75%
Preferred	1.53%	1.11%	0.96%	0.89%	0.76%	0.29%
Common Equity	52.16%	55.58%	58.99%	58.52%	56.94%	55.96%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

UE 180 / PGE / 1200
NGUYEN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Ham T. Nguyen

March 15, 2006

Load Forecast

Table of Contents

I. Introduction and Summary

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Ham T. Nguyen. I am employed by PGE as a Senior Economist and am responsible for developing PGE's end-use consumer load forecast. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. My testimony presents and explains the methodology underlying PGE's 2007 test year forecast of 19,658 million kilowatt-hours (kWh), on a cycle-month (billing) basis, delivered to end-use customers, including deliveries to customers who opted out of PGE cost of service rates for direct access under Schedule 483.

Q. What do you conclude?

A. I project that deliveries to all end-use consumers will increase from the 2005 weather-adjusted value of 18,862 million kWh to 19,658 million kWh for test year 2007. This 2007 total kWh delivery accounts for the effect of anticipated higher electricity prices on demand; higher prices reduce demand from the forecast that would otherwise exist, *i.e.*, a non-price forecast. The forecast of total delivery to all end-use customers for test year 2007 remains below the weather-adjusted record of 19,806 million kWh set in 2000 and the UE 115 authorized 2002 test year forecast of 20,227 million kWh.

PGE Exhibits 1201 and 1202 show respectively the values of 2006 and test year 2007 "base" NP (non-price) and PE (price-effect) kWh delivery forecasts in detail. Table 1 below summarizes the kWh delivery forecast in annual percent changes by end-use sector from 2005 through 2007.

Table 1

Percent Change in kWh Delivery from Preceding Year: 2005 - 2007

Sector	2005*	2006(NP)	2006 (PE)	2007 (NP)	2007 (PE)
Residential	(0.7%)	1.2%	1.1%	1.7%	0.9%
Commercial	2.1%	2.5%	2.4%	2.8%	2.8%
Industrial	2.2%	2.2%	2.1%	4.1%	4.0%
Miscellaneous	(1.8%)	7.4%	7.4%	1.3%	1.3%
Total Retail	0.9%	2.0%	1.9%	2.7%	2.3%

* Weather-adjusted actual

Q. Why do you adjust your base forecast for price elasticity effects?

A. The *non-price* or *base* delivery forecast does not take into explicit account the impact of electricity price changes on end-use consumption. The *price-effect* forecast does. PGE expects customers to respond to price increases by making behavioral changes, implementing housekeeping measures and, over time, making changes to the capital stock such as appliances and equipment that would reduce energy consumption. Our experience after the 2001 West Coast energy crisis and since UE 115 indicates that customers respond measurably upon energy price changes. We anticipate similar, but less dramatic, customer reactions upon price increases in 2006 and 2007.

Q. How do you specifically account for the impact of a price change in the test year forecast?

A. We calculate the implied demand elasticity of the price model by varying price levels, e.g., by 10%. Demand elasticity is the ratio of the percent change in demand, kWh delivery in this case, to the percent change in price. For the test year forecast, we first calculated the kWh demand change based on an assumed price change by multiplying it with the elasticity, and then adjusted the base forecast by the demand change estimate.

Q. What price change assumptions did you make to calculate the price impact on demand?

A. We assumed 1.7% and 5.5% price increases to residential and nonresidential customers for 2006, respectively, based on the 2006 RVM. We assumed 12% and 10% price increases to residential and nonresidential, respectively, for 2007 from 2005 rates.

Q. What price elasticities does PGE estimate and use in the forecast?

A. Table 2 below shows the price elasticities PGE used in this filing, as well as those filed in UE 115 and UM 1039 when we last estimated them. The current elasticities are based on a model with the sample period beginning in 1985 for residential and 1990 for nonresidential and ending October 2005 for both. The elasticities submitted in UE 115 used the sample period ending February 2001 and those in UM 1039 used data through March 2002.

Table 2

Price Elasticity

	Current Estimates (Data through 10/2005)	UM 1039 (Data through 3/2002)	UE 115 (Data through 2/2001)
Residential	.09	.09	.07
Nonresidential	.02	.03	.01
PGE System	.05	.05	.03

The price elasticity of .05 means that if electricity prices rose an average of 10%, kWh demand would decline by 0.5%, all else equal. Price elasticity increased in the aftermath of the 2001 West Coast energy crisis and UE 115 implementation, as shown by the higher estimates in UM 1039 than those in UE 115. It has remained stable since 2002, as indicated by the elasticity estimates submitted in this proceeding compared to those from UM 1039. Using our latest estimate of elasticity and assumed price increases, the PE forecast is 0.7% lower than the NP forecast for 2007.

II. Model Mechanics

Q. Please summarize the process you use to develop the retail load forecast.

A. The core retail load model and the forecast process are the same that we have used in previous rate cases and regulatory filings. We re-estimated the model using the most current data, an extended sample period through and including October 2005. Re-estimation is the process of applying regression techniques to obtain, from the updated or extended historical data, the estimate of the coefficients of the equations that constitute the model. We retained the structure (specification) but re-estimated the NP model to include new information, examining for any changes in the coefficients and, if necessary, re-specifying the relevant equations. We re-estimated the PE model using the identical sample period while keeping only those equations with *correct sign* price coefficients. We kept the NP equations for the segments with statistically insignificant price coefficients, those deemed not responsive to price changes. We applied this PE model to calculate the impact of a price change on electricity consumption. Finally, we used the most recently available forecasts of the drivers or independent variables to develop our load forecast.

Q. Are these models new or different from previous PGE load models?

A. Except for the re-estimation of the coefficients aimed to capture any behavioral or structural changes over time, the load forecast model specification remains the same as those used in UE 115 and the Resource Valuation Mechanism (RVM) filings. I described in detail the theory and specification of our load model in my testimony on PGE's load forecast submitted in those proceedings.

Q. Why do you need to re-estimate the load model?

A. To capture evolving changes in customer behavior or mode of operations, PGE re-estimates our load model to reflect the most current customer-to-energy relationships. We re-estimate our model quarterly in conjunction with the company's RVM process to incorporate empirically any behavioral changes as early as possible. These changes become more significant in the events of wars, natural disasters, severe economic downturns or sharp price hikes. If we do not re-estimate our models to reflect such changes, the models will likely produce inaccurate forecasts.

Q. Please summarize the load forecast process.

A. The forecast process basically entails the following nine steps:

1. Divide end-use consumers into three main sectors: a) residential, b) commercial (nonmanufacturing), and c) industrial (manufacturing) plus miscellaneous rate schedules. Within each sector, further separate consumers by common characteristics or use patterns such as dwelling type or business activity.
2. Using a model, forecast the number of occupied residential accounts by dwelling and heat type, forecast electricity use per occupied account, and calculate total residential kWh deliveries.
3. Using a model, forecast electricity deliveries to commercial (non-manufacturing) consumers by North American Industry Classification System (NAICS) group.
4. Using a model, forecast deliveries to all industrial (manufacturing) consumers, also by NAICS group, except the 20 of our largest industrial customers.
5. Forecast deliveries to the 20 of our largest industrial consumers using specific information provided by these customers when available, and a model where

applicable.

6. Project deliveries under existing miscellaneous rate schedules such as street and other lighting (current Schedules 91, 92 and 93) and irrigation (current Schedules 47 and 49) by trending, averaging, or regression technique when appropriate. These types of deliveries generally do not change with the level of economic activity.
7. Apply the projected price response to the *non-price* or base delivery forecast to obtain the "price-effect" or net delivery forecast.
8. Allocate projected deliveries to customers served under PGE Cost-of-Service rate schedules and to Schedule 483 customers.
9. Convert projected kWh deliveries from cycle (billing) basis to calendar basis and add transmission and distribution losses to obtain distribution loads in average MW and peak MW at the bus bar.

Q. What sources of information do you use to forecast electricity deliveries?

A. PGE relies primarily on three sources for economic information to drive our forecast: (1) a national economic forecast, (2) state economic and unemployment forecasts, and (3) a forecast of the California economy. The national forecast is the Global Insight (formerly the WEFA Group) economic forecast issued in December 2005. The state forecasts are the Oregon Economic and Revenue Forecast developed by the Office of Economic Analysis, Department of Administrative Services in December 2005 and a forecast of unemployment prepared by the Oregon Employment Division of the same vintage. The forecast of the California economy is the California Employment Development Department's (EDD) forecast posted on their web site as of December 2005. These are the same sources of information we used in UE 115 and the RVM filing to develop our load forecasts.

Q. Did you make any changes to the model?

A. No. Except for the re-estimation, we made no changes to the model.

Q. Did you change any assumptions that you use to drive the model?

A. Yes. We changed the assumption for the weather variables used to forecast the test year kWh delivery. PGE previously used 30-year moving averages as the predicted weather conditions for the test year. We now use a 15-year moving average for the weather variables in this forecast.

Q. Did the use of a 15-year moving average improve the performance of the weather variable and the forecast?

A. Yes. The accuracy of a forecast depends not only on the performance of its model but also on the performance of the independent variables driving the forecast. In our load model, this would include temperature, among other variables that affect energy use. Because annual average temperatures in Portland have trended upward (warmer) since the 1960s, the use of a 30-year average would likely understate the forward-year temperature prediction. On the other hand, because temperature fluctuates from year to year, a moving average based on a short time horizon, such as 1, 2 or 3 years, may not be a good predictor either. We evaluated various types of moving averages using the Root Mean Square Error (RMSE) criteria and found that the 10-year and 15-year moving averages performed the best as predictors of forward year (one and two years out) temperature conditions. We chose the 15-year moving average because it performed slightly better than the 10-year moving average since the 1970s.

Q. How current are the data you use to estimate the model?

A. We use the most recent historical kWh deliveries and economic data to estimate the model and develop the forecast. For the development of the model in this proceeding, we used data from 1985 through October 2005 for residential equations and data from 1990 through October 2005 for nonresidential equations. The latter choice had to do with the limitation of NAICS-based Oregon employment data.

Q. What end-use sectors do you model in the forecast?

A. Residential consumers are mostly households, but also include dwellings that PGE has connected for electrical service but are not yet occupied. Commercial consumers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government or financial institutions. Industrial consumers are manufacturing businesses. They include manufacturers of paper, lumber, steel, machinery, computers, auto, truck and aircraft parts, and shipyards, among others, that serve national and global markets.

In our model, we group commercial and industrial customers according to the NAICS definition of business segments. We make the kWh projections for these three end-use sectors separately and then sum them together with the forecast of existing miscellaneous schedules (streetlight, irrigation, etc.) to obtain total end-use loads.

Finally, we allocate these NAICS-segment delivery forecasts into voltage-level (rate schedule) kWh deliveries using their respective preceding-year ratios.

III. Residential Forecast

Q. How do you forecast deliveries to residential consumers?

A. We forecast kWh deliveries to residential consumers by multiplying the projected number of occupied accounts, categorized by dwelling type and heating type, by their respective use of electricity. PGE classifies residential consumers into seven categories: single-family heat, single-family non-heat, multi-family heat, multi-family non-heat, manufactured home heat, manufactured home non-heat and "other" residential. The "other" category consists primarily of houseboats. We forecast the number of occupied accounts and the use per occupied account for the first six residential categories on a monthly basis. We forecast the "other" in the aggregate on a monthly basis.

A. Occupied Accounts

Q. How do you forecast the number of residential occupied accounts?

A. We start with the number of residential consumers our billing records show in each category, subtract an estimate of demolished, replaced or converted structures, and add new connects for the current period, whether occupied or vacant. We then estimate vacant accounts from vacancy rates. Next, we subtract vacant accounts from the number of consumers to yield occupied accounts.

We use actual building permits and a projection of building permits to forecast new residential connects by dwelling type. The forecast of building permits uses economic and demographic variables, seasonal variables, the level of employment in the state, the change in employment in Oregon relative to California, and a variable representing the lag between the issuance of a building permit and actual completion. We attempt to capture both the natural increase component of Oregon's population and the migration of people into the state with two sets of employment variables. We use California, versus U.S. employment as an explanatory variable because California historically supplies a large percentage of those who move to Oregon and produces statistically superior results than U.S. Employment.

Next, we forecast the number of vacant accounts, which equals the outstanding number of accounts times the vacancy rates, by dwelling type. Monthly vacancy rates depend on the level of new connects, economic conditions, seasonal variables, and a "lagged" variable representing an adjustment process. This adjustment process is premised on the theory that, at any given time, vacancy rates are usually moving toward, but not reaching, an optimum level because of a lack of information, inertia and the costs of change. Subtracting vacant units from the total outstanding (new and old) stock yields the number of occupied accounts.

The procedure described above has several benefits, including: (1) explicit accounting of occupied and vacant accounts, (2) quick updating based on current construction permit data during the course of the rate case and, (3) a direct link to the state economic forecast. PGE Exhibit 1203 shows building permits, new connects, vacancy rates, and occupied accounts by dwelling type, for the years 2004 through 2007.

Q. Do you use the same procedure to forecast manufactured homes?

A. No. Because manufactured homes account for only a small share of the new connects in our service area, we forecast new manufactured home connects using our judgments based on recent trends and the latest market information.

Q. How do you determine what space heating choice a new consumer will make?

A. This is based primarily on past experience. Electric space heating penetration rates for new single-family homes declined sharply and consistently over the last two decades, down from 61% in 1977 to 14% in 1990 to below 10% since 1994, rebounding slightly to around 10%

since 2004. Space heating penetration rates in the multi-family segment fell from the mid-to upper-90% in the late 1980s to the upper-80% in the 1990s and to the 30% range since 2001, as more new multi-family construction, particularly condominiums, have access to natural gas. As a result of these shifts in space heating choices over time, we used averages of the most recent years, from the last two to five years, as the best estimates of the space heating penetration rates for the immediate future years.

B. Use Per Consumer

Q. How do you forecast use per residential consumer?

A. We define use per residential consumer in terms of use per occupied account, i.e., kWh deliveries divided by the number of occupied accounts. PGE forecasts monthly use per residential consumer separately by dwelling type and by heat type as a function of (1) weather variables such as temperature, wind speed, cooling degree days and (2) unemployment rates. The forecast assumes average weather conditions, defined as the running 15-year average of conditions observed from 1990 to 2004. By including the unemployment rate, with a (polynomial) lag structure, we capture the income-expectation effect on energy use. To the extent possible, we also include other variables to account for specific effects on usage such as the holiday season and post-2001 trends.

C. Results

Q. What are the key results of your residential forecast?

A. We project 2006 deliveries of 7,478 million kWh using the NP model and a PE forecast of 7,467 million kWh to 690,695 residential consumers. For the test year 2007, we forecast deliveries of 7,606 million kWh (NP) and 7,531 million kWh (PE), respectively, to 702,246 residential consumers, indicating 1.7% (NP) and 0.9% (PE) growth from 2006 to 2007, respectively, compared to an actual 0.7% decline in kWh delivery, adjusted for weather, in 2005. Both forecasts include residential outdoor lighting loads. The forecasts include projections of 12,966 new residential connects in 2006 and 12,492 new residential connections in 2007, compared to 12,157 new residential connections in 2005. We forecast growth in the number of residential customers in both 2006 and 2007, offsets projected declines in kWh use per customer. PGE Exhibit 1203 shows the forecast of building permits, new connects and occupied accounts. PGE Exhibit 1204 displays the forecast of kWh use per occupied account and deliveries to residential customers in detail.

IV. Commercial Forecast

Q. How do you forecast deliveries to commercial consumers?

A. We group commercial (non-manufacturing) consumers into 11 clusters based on their type of business:

1. food (grocery) stores
2. government and education
3. health services
4. hotels and motels
5. miscellaneous commercial accounts
6. department stores and malls
7. business offices and financial institutions
8. other (remaining) services
9. other (remaining retail and wholesale) trade
10. restaurants and
11. transportation, communication and utility.

After forecasting monthly deliveries to these 11 clusters individually, we sum them to obtain total deliveries for the commercial sector. We forecast aggregate deliveries for these 11 clusters rather than per average consumer because of the significant diversity in size and kWh consumption among consumers within each cluster. Unlike the residential sector, for which consumption of energy by consumers within a dwelling and heat type falls within a fairly tight band, commercial consumers often have tremendous disparity in consumption. PGE counts an individually metered account as a consumer whether it is a master meter in a large office building or a single meter for a small boutique.

The key inputs in the model are: (1) assumptions about the service area's population growth; (2) the economic activity, as measured by employment, which serves as a proxy for the demand for the services provided by these businesses; (3) trend variables to reflect changes in usage; (4) weather variables such as seasonally differentiated heating degree days and cooling degree days; and (5) specific variables to reflect the seasonal fluctuation of the consumer's business activities. The weather variables are different than those used in the residential model. While cooling remains a relatively small load in the residential sector, it is significant in commercial operations. Commercial sector ventilation operates year round, while heating occurs only in the winter and the late-fall and early-spring months. The model differentiates various seasonal heating effects.

We also include estimates of known commercial expansions such as the South Waterfront and Oregon Health Science University projects that are expected to begin operation in 2006 and 2007.

Q. What are the key results of your commercial forecast?

A. We project deliveries of 7,075 million kWh using the NP model and a PE forecast of 7,067 million kWh for 2006. For test year 2007, we forecast deliveries of 7,276 million kWh (NP) and 7,262 million kWh (PE), respectively. As with residential customers, we expect rising electricity prices to have an impact on kWh delivery to commercial customers, albeit with a lesser degree due to this sector's *inelastic* demand response as shown by our estimate of the relatively small nonresidential price elasticity in Table 2. We forecast growth in this market segment to continue in 2006 and 2007, respectively at 2.4% and 2.8% annually, essentially on pace with recent history. PGE Exhibit 1205 contains the detailed forecast of deliveries to commercial consumers.

V. Industrial Forecast

Q. How do you forecast deliveries to industrial consumers?

A. The forecast of deliveries to industrial (manufacturing) consumers also starts with separating the consumers by type of business into seven clusters. They are:

1. food processors;
2. high-tech (electrical and electronic) manufacturers;
3. lumber mills;
4. metals foundries and fabricators;
5. "other" manufacturing consumers;
6. manufacturers of paper and allied products; and
7. transportation equipment manufacturers (including shipyards).

We further separate our 20 largest industrial consumers from the rest of the sector and forecast their loads separately because some of these consumers dominate their cluster. For example, deliveries to our four top paper manufacturers constitute virtually all of PGE's deliveries to the paper cluster. In other instances, some of the large customers are new accounts with no operation history. Some of the existing key customers could expand or add capacity while others may decide to permanently close certain operations or plants. Separating deliveries to these key accounts from the remaining customers removes much of the lumpiness in data and improves our forecast.

To forecast deliveries to all industrial consumers except the largest 20, we use a "common" industry model. This model projects energy consumption as a function of employment, national and international economic activity, reflecting the markets in which these consumers operate, and seasonal activity, which can be significant in such industries as food processing. Key drivers to this model include the U.S. Gross Domestic Products (GDP), U.S. housing starts, real (currency) exchange rates, (state) employment and prices of the industry's respective products.

For PGE's 20 largest industrial customers, the forecast uses specific confidential information these customers provide to PGE key customer managers, including planned plant expansions or closures, investment in special processes, energy efficiency projects, cogeneration, or plans to displace onsite generation with market power purchases or PGE cost-of-service rates. To the extent that the information is ambiguous or does not translate directly into kWh deliveries, we assume these industrial consumers' electricity consumption to vary at the GDP rate of change or at their most recent historical pace when appropriate. We then combine the forecast for these 20 large consumers with the forecast of the other industrial clusters to obtain the total industrial forecast.

Q. What are the key results of your industrial forecast?

A. We project total deliveries of 4,480 million kWh using the NP model and a PE forecast 4,474 million kWh for 2006. For the test year 2007, we forecast deliveries of 4,662 million kWh (NP) and 4,653 million kWh (PE), respectively. We expect only minimal response to higher electricity prices in both 2006 and 2007. This *inelastic* response is a result of nonresidential customer group's relatively small price elasticity that we estimated and listed in Table 2. We forecast delivery to industrial consumers to increase 2.1% in 2006 and 4.0% in 2007. We include the effect of one large customer's change in a key manufacturing process in 2006. We also assume that PGE will serve a portion of one other large customer's electricity requirement under cost-of-service rates in both 2006 and 2007. PGE Exhibit 1206 contains the detailed delivery forecast of the industrial sector.

VI. Miscellaneous and Direct Access Forecasts

Q. Do you forecast kWh deliveries to existing lighting and miscellaneous rate schedules?

A. Yes, we forecast kWh deliveries under lighting and miscellaneous rate schedules on the latest year base (2005) and updated information, typically by averaging or trending. PGE withdrew Rate Schedule 97 effective January 1, 2006 because the only two customers served under this schedule had previously moved to Schedule 49. PGE Exhibit 1207 contains the detailed deliveries forecast of the miscellaneous sector.

Q. Did you make a separate forecast of delivery to Schedule 483 customers?

A. Yes. PGE separates the loads of customers served under PGE cost-of-service (COS) rates and those few customers who choose service under Schedule 483. Schedule 483 is the only service under which customers may not receive COS pricing. First, we calculate the most recent kWh shares of these customers to their respective service level or revenue class. Next, we apply these shares to the forecast of respective service-level kWh and sum them to get the aggregate delivery forecast to Schedule 483 customers. The COS load forecast results from subtracting Schedule 483 delivery from total PGE delivery. PGE Exhibit 1208 shows forecast of COS and NCOS deliveries for test year 2007.

Q. How do you forecast the ultimate loads delivered to the PGE distribution system?

A. This process involves two steps: (1) aggregate sector kWh deliveries into various voltage service levels, and (2) add transmission and distribution losses to voltage-service level kWh deliveries to calculate system load in average MW and in MW demand.

Q. What is the voltage aggregation process?

A. Different consumers require different voltage levels to run their appliances or equipment. Residential, most commercial, and some industrial consumers require *secondary* voltage services (less than 11,000 volts). Most industrial and some commercial consumers require *primary* voltage services (between 11,000 volts and 57,000 volts). Large industrial consumers require services at "transmission" voltage (equal to or greater than 57,000 volts). We prorate projected kWh deliveries to commercial and industrial consumers by the most recent service-level allocation factors at the NAICS level to obtain the forecast of kWh deliveries by voltage service levels.

Q. How do you calculate the ultimate load?

A. We add transmission and distribution (i.e., line) losses to the kWh deliveries to obtain the *gross* (or upstream) average MW required to meet to the end users' demand. For test year 2007, we use new line loss factors to account for new resources and power contracts. PGE Exhibit 1310 presents the new line-loss study. We use monthly and annual load factors to calculate the monthly MW and annual peak MW based on the projected average MW. PGE Exhibit 1209 displays the forecast of total distribution loads in annual average MW and MW peak demand.

Q. Do you recommend a specific forecast or forecasts of test year 2007 kWh delivery to end-use customers for ratemaking purposes?

A. Yes. I recommend the adoption of the PE forecast of 19,658 million kWh delivery to all customers and the forecast of 19,573 million kWh delivery to COS customers for test year 2007.

VII. Forecast Uncertainty

Q. How do you propose to address forecast uncertainty?

A. We can reduce uncertainty by using more current information, data and forecast drivers because conditions could and will likely change between the time PGE develops this forecast and the start of the test year.

Q. What do you propose to update and when?

A. PGE proposes that, before the close of the record of this proceeding, we update the test year delivery forecast with the most current input assumptions and, if necessary, the model. This would include not only the economic indicators and forecasts but also demand elasticity and price changes.

Q. Is there risk associated with this forecast?

A. The kWh delivery forecast we submit in this filing is our best estimate forecast. As with any estimate, actual conditions may differ from what we assume or anticipate in the forecast, rendering a different outcome.

Q. What are the drivers of the uncertainty of your forecast?

A. Our forecast depends on the stability of our model and the accuracy of input assumptions. Our model typically performs well over the *sample* period, the span over which we estimate the model, as it captures most, if not all, behaviors and relationships such as economic activities or customer response to sharp price increases on energy use. We expect our model to perform equally well over the forecast period if these relationships remain unchanged or *stable*. If such relationships change in the test year period, in response to significant events that were not anticipated or have never occurred over the historical period, our model will become outdated, or *mis-specified* in statistical language, leading to inaccurate forecasts.

The other area of uncertainty, outside of weather variances, involves input assumptions such as the economy, electricity prices, key customers' operation decisions and the absence of unforeseen natural disasters, wars or geopolitical turmoil. These variables could turn out different than forecasted.

Q. Are the input assumptions PGE uses to drive its forecast deterministic or subject to uncertainty?

A. All input assumptions are subject to uncertainty. PGE used as key drivers the December 2005 Global Insight and Oregon OEA *baseline* economic forecasts that could change as these organizations develop newer forecasts. These economic forecasts contain their own issues of uncertainty. Global Insight, for example, assigns 55% probability of occurrence to its *baseline* U.S. economic forecast, 20% probability to its *High Scenario* (Good Times Keep Rolling) and 25% probability to its *Low Scenario* (Stagflation). The Oregon OEA uses *stochastic* techniques to develop its uncertainty band. For 2007, OEA forecasts total Oregon employment to grow 1.4% from 2006 in its *baseline*, bounded by 0.8% growth in the low case (2.5% chance that employment would grow below this rate) and 1.9% growth in the high case (8% chance that employment would exceed this rate). Finally, PGE's key customers could operate differently than planned. They could shut down plant or add new capacity that we did not anticipate or include in the forecast because of their own economics or unique circumstances. These actions could lead to large deviations from the test year forecast.

Q. Is weather also an area of uncertainty?

A. Yes. There are two sources of uncertainty with regard to the forecast of the weather variables: the *average* or the *mean* condition and the *variance* or *departure from the* *average* condition in the forecast year. The impact of this uncertainty, expressed as deviation from the mean, is significant because of the large impact of temperature on kWh usage. PGE estimates that one degree change in temperature could affect kWh usage by as much as 1.3% on peak months and as much as 0.7% on an annual basis.

Q. Why is the *average* weather condition a source of uncertainty?

A. There is really no *typical* or *normal* weather condition, only an *average* condition. The *average* or *mean* condition is simply the average of diverse conditions over the chosen historical period. Furthermore, if a weather trend existed, for example rising temperature over time, the choice of a particular average may not be an accurate predictor of the weather condition in the forecast year. The use of a shorter period average, such as 15 years over 30 years, reduces but does not eliminate the potential forecast error. PGE Exhibit 1210 shows monthly and annual Portland average temperatures per 15-year rolling intervals in 5-year increments from 1971 to 1985 through 1991 to 2005 and the differences between these rolling averages. This exhibit reveals that Portland temperatures have risen over time, particularly in the 1970s and 1980s, across most months and more significantly in January, the coldest month of the year in Portland.

Q. Is temperature volatility another issue of uncertainty?

A. Yes. Not only will the actual weather condition in the forecast year likely be different from the average condition but also its volatility, or departure from the mean or average condition, gets larger as the frequency increases. In other words, the *standard deviation* from the *mean* temperature, which measures volatility, is larger in monthly intervals (frequency) than in annual intervals and larger in daily intervals than in monthly intervals. PGE Exhibit 1211 shows the standard deviations of Portland monthly temperatures calculated from daily and monthly data over 1971 – 2000 (30 years), 1976 – 2005 (30 years) and 1991 – 2005 (15 years) periods. They show that volatility is higher in the peak winter and summer months and significantly larger within the daily intervals, in excess of 5 degrees in most months. Temperature volatility could potentially affect wholesale power prices and management of power costs.

Q. How much can the results vary for these areas of uncertainty?

A. The effect can be substantial. For example, actual kWh deliveries deviated as much as 8.5% below the 2002 test year forecast for several reasons that included the economic downturn, the aftermath of the West Coast energy crisis, the effect of the September 11 attack, and the weather.

VIII. Qualifications

Q. Mr. Nguyen, please describe your qualifications.

A. I received all my undergraduate and graduate education from the University of Oregon. I received my Bachelor of Arts in 1967 and Master of Science in 1972, both in Economics. I also completed all the course work and examinations for a doctoral degree in Economics, except for the dissertation.

I joined Portland General Electric Company in 1979. Prior to joining PGE, I worked as an independent consultant and later with Northwest Natural Gas Company as an economist. I oversee the development of PGE's economic and energy forecasting models and have the overall responsibility for the development of the Company's economic and energy forecasts. I am currently a member of the Governor's Council of Economic Advisors, State of Oregon, and a panelist of the Western Blue Chip Economic Forecast, Economic Outlook Center, Arizona State University. On various occasions I have served as a member of the Regional Forecast Panel, the Pacific Northwest Executive at the University of Washington; a member of the Northwest Power Planning Council's Economic and Demand Forecasting Advisory Committees; and, on the Metropolitan Service District's Regional Growth Forum.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1201	(Non-Price) Delivery Forecast by Market Segment and Service Level
1202	(Price Effect) Delivery Forecast by Market Segment and Service Level
1203	Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
1204	Forecast of Residential Use per Occupied Account and Ultimate Deliveries
1205	Commercial Deliveries Forecast by NAICS Cluster
1206	Industrial Deliveries Forecast by NAICS Cluster
1207	Forecast of Deliveries under Miscellaneous Secondary Rate Schedules
1208	Forecast of Deliveries to Cost-of-Service and Non-Cost-of-Service Customers
1209	Total Delivery and Demand Forecast
1210	Portland Average Temperatures: 1971 – 2005
1211	Standard Deviations from Portland Mean Temperatures

Delivery Forecast (Non-Price) by Market Segment and Service Level

(at average weather)

Non-Price (Base) Forecast

	(in million kWh)				% Change [1]		
	2004	2005[2]	2006	2007	2005	2006	2007
Schedule 7	7,433	7,381	7,471	7,600	(0.7%)	1.2%	1.7%
Residential Lighting	7	7	7	7	0.7%	(2.6%)	(1.2%)
Total Residential	7,440	7,388	7,478	7,606	(0.7%)	1.2%	1.7%
Commercial [3]	6,761	6,902	7,075	7,276	2.1%	2.5%	2.8%
Industrial [3]	4,286	4,382	4,480	4,662	2.2%	2.2%	4.1%
Miscellaneous Customers	198	195	209	212	(1.8%)	7.4%	1.3%
Secondary Voltage	7,194	7,297	7,505	7,713	1.4%	2.9%	2.8%
Total General Service	7,392	7,492	7,714	7,925	1.3%	3.0%	2.7%
Primary Voltage Service	2,676	2,730	2,782	2,866	2.0%	1.9%	3.0%
Transmission Voltage Service	1,178	1,253	1,268	1,358	6.4%	1.3%	7.1%
Total Retail [4]	18,686	18,862	19,242	19,756	0.9%	2.0%	2.7%

1/ calculated from unrounded numbers

2/ includes actual weather-adjusted kWh through December 2005

3/ by NAICS grouping

4/ line 16 equals lines (9 + 10 + 11 + 12) and also equals lines (9 + 14 + 15 + 16); total may not match due to rounding

Delivery Forecast (Price) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity

	(in million kWh)				% Change [1]		
	2004	2005[2]	2006	2007	2005	2006	2007
Schedule 7	7,433	7,381	7,461	7,524	(0.7%)	1.1%	0.9%
Residential Lighting	7	7	7	7	0.7%	(2.6%)	(1.2%)
Total Residential	7,440	7,388	7,467	7,531	(0.7%)	1.1%	0.9%
Commercial [3]	6,761	6,902	7,067	7,262	2.1%	2.4%	2.8%
Industrial [3]	4,286	4,382	4,474	4,653	2.2%	2.1%	4.0%
Miscellaneous Customers	198	195	209	212	(1.8%)	7.4%	1.3%
Secondary Voltage	7,194	7,297	7,493	7,693	1.4%	2.7%	2.7%
Total General Service	7,392	7,492	7,703	7,905	1.3%	2.8%	2.6%
Primary Voltage Service	2,676	2,730	2,780	2,863	2.0%	1.8%	3.0%
Transmission Voltage Service	1,178	1,253	1,268	1,358	6.4%	1.3%	7.1%
Total Retail [4]	18,686	18,862	19,218	19,658	0.9%	1.9%	2.3%

1/ calculated from un-rounded numbers

2/ includes actual weather-adjusted kWh through December 2005

3/ by NAICS grouping

4/ line 16 equals lines (9 + 10 + 11 +12) and also equals lines (9 + 13 + 15 + 16 +); total may not match due to rounding

Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
History and Forecast

	2004	2005[1]	2006	2007[2]
Building Permits [3]				
Single-Family	21,173	24,576	22,422	21,599
Multiple-Family	6,926	7,141	7,538	7,890
New Connects				
Single-Family	6,859	7,645	8,683	7,791
Multiple-Family	4,424	4,139	3,863	4,281
Mobile Home	262	206	240	240
Other	244	167	180	180
Total Connects	11,789	12,157	12,966	12,492
Vacancy Rates (%)				
Single-Family	4.1%	4.0%	4.1%	4.1%
Multiple-Family	11.8%	10.5%	10.0%	9.8%
Mobile Home	9.8%	9.9%	9.5%	9.5%
Number of Occupied Accounts				
Single-Family Heat	103,421	104,011	104,516	105,168
Single-Family Non-Heat	304,682	310,448	316,250	322,555
Multiple-Family Heat	144,283	147,653	149,718	151,201
Multiple-Family Non-Heat	34,966	38,118	40,682	43,222
Mobile Home Heat	28,426	28,389	28,430	28,402
Mobile Home Non-Heat	3,606	3,600	3,587	3,583
Other	4,609	4,957	5,160	5,281
Total Occupied Accounts	623,994	637,179	648,343	659,412
Total Number of Accounts [4]	668,830	680,093	690,695	702,246

1/ includes actuals through December 2005, except for building permits and connects which include actuals through November 2005

2/ identical for both non-price and price-effect forecasts

3/ Oregon

4/ includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Net of Price Elasticity

	2004[1]	2005[2]	2006[3]	2007[4]
Use per Occupied Account (kWh)				
Single-Family Heat	17,366	16,830	16,638	16,474
Single-Family Non-Heat	11,119	10,952	11,030	11,000
Multiple-Family Heat	10,098	9,679	9,543	9,477
Multiple-Family Non-Heat	6,471	6,421	6,385	6,355
Mobile Home Heat	16,759	16,335	15,980	15,720
Mobile Home Non-Heat	11,718	11,520	11,515	11,505
Other	10,344	10,288	9,503	9,158
Average Use per Occupied Account	11,913	11,583	11,507	11,411
Ultimate Deliveries (millions of kWh)				
Single-Family Heat	1,796	1,750	1,739	1,733
Single-Family Non-Heat	3,388	3,400	3,488	3,548
Multiple-Family Heat	1,457	1,429	1,429	1,433
Multiple-Family Non-Heat	226	245	260	275
Mobile Home Heat	476	464	454	446
Mobile Home Non-Heat	42	41	41	41
Other	48	51	49	48
Schedule 7 Deliveries	7,433	7,381	7,461	7,524
Residential Lighting	7	7	7	7
Total Residential Deliveries	7,440	7,388	7,467	7,531

1/ actual weather adjusted

2/ includes actual weather adjusted deliveries through December 2005

3/ price-effect forecast

4/ price-effect forecast

Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity

	(in million kWh)				% Change [1]		
	2004	2005 [2]	2006 [3]	2007 [4]	2005	2006 [3]	2007 [4]
Food Stores	496	487	483	493	(1.8%)	(0.8%)	2.0%
Govt. & Education	954	994	997	1,005	4.1%	0.3%	0.8%
Health Services	604	611	666	721	1.1%	9.0%	8.3%
Lodging	119	106	108	111	(10.8%)	2.0%	2.1%
Misc. Commercial	665	723	726	742	8.6%	0.5%	2.2%
Department Stores/Malls	350	369	381	390	5.6%	3.1%	2.4%
Office & F.I.R.E [5]	940	958	987	1,017	1.9%	3.1%	3.0%
Other Services	786	784	807	831	(0.3%)	3.0%	2.9%
Other Trade	794	810	829	850	2.0%	2.3%	2.6%
Restaurants	438	439	450	460	0.2%	2.6%	2.0%
Trans., Comm. & Utility	614	621	632	643	1.2%	1.8%	1.6%
Total Commercial	6,761	6,902	7,067	7,262	2.1%	2.4%	2.8%

1/ calculated from un-rounded numbers

2/ includes actual weather-adjusted deliveries through December 2005

3/ price-effect forecast

4/ price-effect forecast

5/ Finance, Insurance and Real Estate

Industrial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity

	(in million kWh)				% Change [1]		
	2004	2005 [2]	2006 [3]	2007 [4]	2005	2006 [3]	2007 [4]
Food & Kindred Products	232	220	217	218	(5.1%)	(1.5%)	0.7%
High Tech	1,524	1,592	1,655	1,720	4.5%	3.9%	3.9%
Lumber & Wood	169	155	162	161	(8.7%)	4.6%	(0.4%)
Primary & Fab. Metals	496	508	527	539	2.4%	3.7%	2.4%
Other Manufacturing	599	603	617	634	0.7%	2.3%	2.7%
Paper & Allied Products	1,071	1,106	1,091	1,170	3.3%	(1.4%)	7.3%
Transportation Equipment	196	198	207	210	1.4%	4.2%	1.5%
Total Industrial	4,286	4,382	4,474	4,653	2.2%	2.1%	4.0%

1/ calculated from unrounded numbers

2/ includes actual deliveries through December 2005

3/ price-effect forecast

4/ price-effect forecast

Forecast of Deliveries under Miscellaneous Secondary Rate Schedules

Net of Price Elasticity

	(in million kWh)				% Change[1]		
	2004	2005[2]	2006	2007[3]	2005	2006	2007[2]
Secondary (Residential)							
Outdoor Area Lighting [4]	6.9	6.9	6.8	6.7	0.7%	(2.6%)	(1.2%)
Secondary (Commercial)							
Outdoor Area Lighting [4]	16.7	16.8	16.8	16.8	0.4%	(0.1%)	0.3%
Farm Irrigation et al. [6]	79.3	73.3	89.2	90.9	(7.5%)	21.6%	1.9%
Service to Drainage [7]	0.7	0.4	0.0	0.0	(39.1%)		
Street and Other Lighting [8]	101.7	104.3	103.3	104.3	2.6%	(1.0%)	1.0%
Total Misc. Commercial	198.5	194.9	209.2	212.0	(1.8%)	7.4%	1.3%
All Misc. Schedules [9]	205.4	201.8	216.0	218.7	(1.7%)	7.0%	1.2%

1/ calculated from un-rounded numbers

2/ includes actual deliveries through December 2005

3/ identical for both non-price and price-effect forecasts

4/ existing Schedule 15R

5/ existing Schedules 15C

6/ existing Schedules 47 & 49

7/ existing Schedule 97 (discontinued in 2005)

8/ existing Schedules 91, 92 & 93

9/ equals line 5 + line 11

Forecast of 2007 Deliveries to Cost of Service and Non-Cost-of-Service Customers

Net of Price Elasticity

(in million kWh)

	Cost of Service	Non-Cost of Service	Total Delivery
Residential	7,531.1	0.0	7,531.1
Secondary	7,786.9	14.3	7,801.2
Primary	2,792.8	70.0	2,862.8
Transmission	1,358.2	0.0	1,358.2
Lighting	104.3	0.0	104.3
Total Retail	19,573.4	84.3	19,657.6

Total Delivery and Demand Forecast

(at average weather)

	Million kWh[1]	Average MW[2]	Peak MW[3]
2004	18,686	2,266	3,942
2005	18,862	2,313	3,606
2006[4]	19,218	2,355	3,741
2007[5]	19,658	2,416	3,834

1/ cycle-month basis, at end-user meters; includes actual deliveries through December 2005

2/ calendar basis, delivered to PGE's distribution system weather-adjusted history to November 2005

3/ coincidental annual system peak; includes actual through December 2005, not adjusted for weather

4/ price-effect forecast

5/ price-effect forecast

Portland Average Temperatures: 1971 – 2005

15-Year Moving Averages

	1971-1985	1976-1990	1981-1995	1986-2000	1991-2005
January	39.2	39.8	41.4	41.4	41.5
February	43.6	43.3	43.8	43.6	44.1
March	47.6	48.2	48.8	48.1	48.2
April	51.1	52.4	52.6	52.9	52.5
May	57.5	57.4	58.6	58.4	58.6
June	63.1	63.7	63.7	63.7	63.4
July	68.8	68.2	68.5	68.7	69.5
August	68.8	69.0	69.4	69.5	69.7
September	63.3	63.5	65.4	65.1	65.0
October	54.2	55.2	55.2	55.4	55.2
November	45.4	46.0	46.5	47.2	46.5
December	40.4	39.6	39.8	40.8	41.7
Annual	53.6	53.9	54.4	54.6	54.7

Departure from 1971-1985 Averages

	1971-1985	1976-1990	1981-1995	1986-2000	1991-2005
January	0.0	0.6	2.2	2.3	2.3
February	0.0	(0.3)	0.2	0.0	0.5
March	0.0	0.6	1.2	0.5	0.6
April	0.0	1.2	1.5	1.7	1.3
May	0.0	0.0	1.2	0.9	1.1
June	0.0	0.6	0.7	0.6	0.4
July	0.0	(0.6)	(0.3)	(0.1)	0.7
August	0.0	0.3	0.7	0.8	1.0
September	0.0	0.3	1.2	1.8	1.7
October	0.0	0.9	0.9	1.2	1.0
November	0.0	0.6	1.1	1.8	1.1
December	0.0	(0.8)	(0.7)	0.4	1.3
Annual	0.0	0.3	0.8	1.0	1.1

Standard Deviations from Mean Temperatures

	Calculated from Monthly Data			Calculated from Daily Data		
	(a)	(b)	(c)	(d)	(e)	(f)
	1970-2000	1976-2005	1991-2005	1970-2000	1976-2005	1991-2005
January	3.2	3.3	2.4	5.7	6.2	5.8
February	2.6	2.5	2.5	6.5	5.8	5.2
March	2.2	2.2	2.1	4.6	4.5	4.7
April	2.1	1.9	1.9	5.3	5.3	5.3
May	2.4	2.4	2.8	5.9	5.9	6.0
June	1.9	2.0	2.1	5.4	5.8	6.3
July	2.2	2.3	2.2	5.5	5.3	5.3
August	2.0	1.8	1.3	4.8	4.9	4.5
September	2.3	2.1	2.0	5.1	5.2	5.1
October	1.6	1.6	1.4	5.3	5.4	5.5
November	3.3	3.3	3.0	5.5	6.2	5.4
December	2.9	2.8	1.3	6.3	6.3	5.3

	Vs. (a)	Vs. (b)	Vs. (a)	Vs. (b)	Vs. (c)
January	0.1	(0.8)	2.5	2.9	3.4
February	(0.0)	(0.0)	3.9	3.3	2.7
March	(0.1)	(0.1)	2.4	2.4	2.5
April	(0.2)	(0.2)	3.2	3.4	3.4
May	0.0	0.4	3.5	3.5	3.2
June	0.1	0.1	3.5	3.8	4.2
July	0.1	(0.0)	3.3	3.0	3.1
August	(0.3)	(0.8)	2.8	3.1	3.3
September	(0.2)	(0.3)	2.9	3.1	3.1
October	0.0	(0.2)	3.7	3.8	4.1
November	(0.0)	(0.3)	2.2	2.9	2.5
December	(0.1)	(1.6)	3.3	3.5	3.9

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 180

General Rate Case Filing

PORTLAND GENERAL ELECTRIC COMPANY

Testimony and Exhibits

March 15, 2006

UE 180 / PGE / 1300
KUNS – CODY

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Doug Kuns
Marc Cody

March 15, 2006

Pricing

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Doug Kuns. I am the Manager of the Pricing and Tariffs Department within the Rates and Regulatory Affairs Department. My qualifications are described in Section XII.

My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are described in Section XII.

Q. What is the purpose of your testimony?

A. This testimony and accompanying exhibits demonstrate how our proposed E-18 Tariff recovers PGE's 2007 revenue requirement in a way that achieves just and reasonable prices for all our customers. In addition to estimating the overall effect on customer bills, this testimony also describes the rate design process, the revenue requirement allocation process, and the Marginal Cost Study. Additionally, the testimony and accompanying exhibits describe how PGE provides for stable, predictable energy prices that protect non-participating customers from the resulting effect of customers exercising their energy pricing choices.

Q. Please summarize the proposed tariff changes from PGE's current tariff established in UE 115.

A. The changes are listed below and explained further in the testimony:

- For customers whose Demand exceeds 1,000 kW we add new Schedules 89/589 that better reflect these large customers' distribution costs.
- At the request of numerous commercial and industrial customers, we propose setting our Annual Cost of Service (COS) tariff Energy Charge for each rate schedule based on the unit cost of serving each schedule's energy requirements.

This differs from UE 115 where we set each schedule's COS Energy Charge based on the projected wholesale market forward price and then applied a transition adjustment to yield the effective price.

- Consistent with the change in Energy Charges, we propose applying transition adjustments only to those customers who choose an Energy Charge option other than COS. This differs from UE 115 in that all schedules including Schedule 7, Residential Service, received transition adjustments.
- We propose eliminating the Short-Term Resource Notice provision of the current Schedule 125 because the Notice has not proved to be an accurate indicator of individual customers' energy choices, and because the Notice has had adverse consequences for non-participating customers, specifically increasing price volatility and unpredictability.
- We propose to re-open Schedule 38, Optional Time-of-day Large Nonresidential Standard Service, to new customers whose Demand does not exceed 200 kW. We believe that this will mitigate bill impacts to mid-size seasonal customers.
- We propose to replace our current Resource Valuation Mechanism (RVM) with the Annual Power Cost Update which then separates the annual update of power costs from the transition adjustment.
- We submit a Power Cost Variance Mechanism (PCVM) that applies to all customers except those who have chosen to leave COS for a period greater than one year.

- In order to achieve a more equitable balance of interests between our customers, we include a two-year notice provision in our Schedules 75/575, Partial Requirements Service.
- We propose to modify some of our Rules and Regulations and some of our Schedule 300 charges.

II. Estimated Rate Impacts

Q. Please describe the projected rate impacts for 2007 resulting from the proposed rates.

A. Table 1 below summarizes the rate impacts for 2007 based on the rates proposed in PGE Exhibit 1302. These rate impacts are incremental to rate changes resulting from our prospective 2007 RVM. As such, they measure the true changes resulting from this General Rate Case. The first column contains the estimated percentage changes in base rates. The second column contains the estimated percentage rate changes with all supplemental schedules except the Schedule 115, Low-Income Adjustment (LIA) and the Schedule 108, Public Purpose Charge (PPC). The second column presumes that a Schedule 102, BPA Regional Power Act Credit rate change will occur October 1, 2006, resulting from a change in the Bonneville Power Administration's (BPA) available benefits to PGE's eligible customers. PGE intends to provide updates to these rate impacts during the rate case process. PGE Exhibit 1303 contains additional detail for most of our schedules.

Table 1 Estimated Rate Impacts

	Estimated Rate Change (%) (base rates)	Estimated Rate Change (%) (w/all supplementals)**
Residential*	2.9%	3.2%
Schedule 32	2.6%	2.7%
Schedule 83/89	-0.3%	-0.3%
Overall	1.6%	1.7%

* change assumes Schedule 102 rate change October 1, 2006.
** includes all supplemental schedules except LIA & PPC.

Current prices reflect estimates of prospective 2007 RVM prices
Does not include impact of Port Westward

III. Overview of Rate Schedule Charges

Q. Please explain the general process used to develop proposed rates and charges in this filing.

A. We develop the rate schedule price components in a manner that:

- Builds from the unbundled revenue requirements by major functional cost category,
- Uses each rate schedule's revenue target from the rate spread analysis of unbundled costs,
- Develops rate schedule charges with reference to cost causation principles and customer impacts, and
- To the extent possible, avoids pricing that causes unnecessary switching between schedules.

Q. Please describe the basis of the charges contained in the proposed rate schedules.

A. We base the proposed rate schedules, as much as possible, on cost causation. To accomplish this, we use the following principles:

- A **Basic Charge** that reflects customer-related costs including meters and customer services such as billing and metering.
- A **Transmission and Related Services Charge** that incorporates transmission and ancillary service costs.
- **Distribution Charges** that recover peak and installed capacity costs associated with substations, subtransmission, the 13 kV system, line transformers and service laterals. For certain schedules, the Distribution Charge includes the costs of Trojan decommissioning (Trojan), franchise fees, and the Customer Impact Offset

(CIO). The CIO is the method by which we limit price increases to certain schedules to 2 times the overall change from 2006 prices. The CIO then recovers from other customers the allocated costs that would otherwise be paid under those schedules where rate increases are so limited. Other schedules separately identify the costs of Trojan, franchise fees and the CIO as system usage charges.

- A **Cost of Service (COS) Energy Charge** for each rate schedule based on that schedules' allocated production cost. This allocated cost is comprised of the costs associated with Company-owned generation, contract purchases of energy, transmission and capacity, and market purchases and sales.
- For customers who choose an energy option other than the COS, a **Short-term Annual Transition Adjustment** calculated as the difference between the applicable schedules' COS Energy Charge and the unit cost of supplying those Schedules' energy requirements entirely with wholesale market purchases, therefore the market value of those Schedules.

IV. Rate Schedule Design

Q. Will you please provide a brief summary of the major Cost of Service Rate Schedules?

A. **Schedule 7, Residential Service**, currently consists of a monthly Basic Charge, volumetric Transmission and Distribution Charges, and a two-block energy rate. For reasons discussed below, we recommend a flat Energy Charge.

Schedule 32, Small Nonresidential Standard Service, consists of a monthly Basic Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The Energy Charge is flat across all energy usage.

Schedule 83, Large Nonresidential Standard Service, currently applicable to all Large Nonresidential customers except for certain specialty schedules, consists of more complex charges than Schedules 7 and 32. In addition to the customer charges differentiated by delivery voltage, there is a Transmission Demand Charge based on the highest metered kilowatt (kW) reading for a 30 minute period during the monthly billing cycle. There is also a Distribution Demand Charge based on the same criteria above, and a Distribution Facilities Capacity Charge based on the average of the two greatest monthly Demands within a 12-month period (Facility Capacity). The Energy Charge is flat for all energy usage.

Schedule 89, **Large Nonresidential (>1,000 kW) Standard Service,** a newly proposed schedule for customers whose Facility Capacity exceeds 1,000 kW, contains similar Transmission and Distribution Demand Charges, but we propose to charge only for the 30-minute periods that occur during on-peak intervals, defined as between 6:00 a.m. and 10:00 p.m., Monday through Saturday. The Schedule 89 Distribution Facilities Capacity Charge is calculated in the same manner as for Schedule 83. The Energy Charges will be on- and off-peak differentiated in the same manner as current Schedule 83 Energy Charges are for customers whose Facility Capacity exceeds 1,000 kW.

Q. How did PGE develop the prices for each rate schedule?

A. We explain the development of the prices for each of the major rate schedules below. PGE Exhibit 1304, Rate Design provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Schedule 7 Residential Service Proposed Prices

Category	Prices
Basic Charge Single Phase	$10.00 per customer per month
Basic Charge Three Phase	$13.00 per customer per month
Transmission & Related Services Charge	1.98 mills per kWh
Distribution Charge	31.23 mills per kWh
Energy Charge	56.75 mills per kWh

Q. Please explain how you developed these prices.

A. Although the Marginal Cost Study results suggest a **Basic Charge** of approximately $12.00, we maintain the proposed single phase Basic Charge at the current $10.00 level, which is approximately 90% of cost in order to mitigate bill impacts to lower usage customers. We apply this 90% ratio to develop the three phase customer charge of $13.00 per month.

We develop the **Transmission & Related Services Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 31.23 mills per kWh from the allocated distribution costs and from the allocated costs not recovered by the Basic Charge. The Distribution Charge also includes the allocation of franchise fees and Trojan and a small CIO adder of 0.20 mills per kWh to offset the revenue effects of limiting increases to Schedules 47, 49, 91, 92, and 93. We further discuss the CIO later in this testimony.

We developed the Schedule 7 **Energy Charge** of 56.75 mills per kWh from the allocated generation revenue requirement. Because PGE will not be receiving power from BPA, the same Energy Charge is applicable for all kWh, rather than the current 250 kW blocked rates as stipulated in UE 115, Order No. 01-777. As discussed later in this testimony, we maintain Schedule 7 blocked rates for Schedule 102.

Q. Are you proposing changes to the Schedule 7 Portfolio Options?

A. Yes. We make a minor change to the **Fixed Renewable Portfolio Option**. Currently, monies placed in the renewable fund accrue interest at 2.0% annually. In accordance with recommendation Number 1 from Staff's July 28, 2005, Review of PGE's Renewable Resource Choices for 2005, we proposed that the fund accrue interest at PGE's authorized cost of capital. Otherwise, we propose to offer the same **Renewable Energy Resource Portfolio Options**, and the same structure and pricing logic for the TOU rate, including the same additional meter charges of $1.00 per month for single-phase service and $4.25 per month for three-phase service.

Q. Why do you continue to advocate the recovery of fixed distribution costs on a volumetric basis?

A. Although distribution costs are primarily fixed in nature related to the installed capacity per customer, and as such should be recovered by a fixed charge or a Demand Charge, we choose to continue to endorse volumetric charges because of administrative simplicity, tradition, and because, once again, we wish to mitigate bill impacts to lower usage customers. This argument is true for all rate schedules that contain volumetric Distribution Charges.

Q. Please list the individual prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Schedule 32 Small Nonresidential Service

Category	Price
Basic Charge Single Phase	$12.00 per customer per month
Basic Charge Three Phase	$16.00 per customer per month
Transmission & Related Services Charge	2.14 mills per kWh
Distribution Charge First 5,000 kWh	30.73 mills per kWh
Distribution Charge Over 5,000 kWh	5.65 mills per kWh
Energy Charge	56.05 mills per kWh

Q. Please describe how you developed the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, whose Facility Capacity is less than 30 kW. Schedule 532 (applicable to Direct Access Service) is actually a subset of Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32. Small Nonresidential customers receive service at secondary voltage and do not have Demand meters. Consequently, other than the Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7, the applicable costs are allocated into the Basic, Transmission, Distribution and Energy Charge categories. We set the **Basic Charge** for single and three-phase service at $12 and $16 per month, which is close to the marginal customer-related costs. As with Schedule 7, we capture the difference between the allocated customer-related costs and the Basic Charges revenues within the Distribution Charge.

We compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

We retain the current Schedule 32 **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. We set the second block for usage greater than 5,000 kWh to 3.00 mills/kWh (prior to adding the System Usage Charge) in order to provide a better transition to Schedule 83 for customers whose loads have exceeded 30 kW at least twice during the preceding 13 months. Similar to Schedule 7, we include within the Distribution Charge the costs associated with franchise fees and regulatory assets as well as the CIO adder that offsets the revenue effects of limiting the increase to certain schedules.

We set the **Energy Charge** based on the allocation of generation costs in the same manner as Schedule 7.

Q. Are you proposing changes to the Schedule 32 Portfolio Options?

A. No. PGE proposes to maintain the current TOU pricing structure, including the same Nonstandard Metering Charges of $2.35 and $4.25 for single and three-phase service respectively. PGE also proposes to maintain the same Renewable Resource Portfolio Options and charges.

Q. Briefly describe Schedule 532.

A. Schedule 532 sets out the charges associated with PGE's transmission and distribution services, but excludes energy supply and transmission costs because the customer's Energy Service Supplier (ESS) provides these services.

Schedule 532 includes the same Basic and Distribution Charges as Schedule 32, except that we increase the Basic Charge to reflect the metering required for Direct Access Service. We incorporate a Daily Price Energy Charge into Schedule 32 in order to address the potential cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at least one year of service on Schedule 532. The daily price tracks the daily market price for power and is based on the secondary voltage Daily Price option in Schedule 83.

Q. Please provide the proposed monthly prices for Schedule 83 and describe the customers to whom these prices apply.

A. Schedule 83 applies to all Nonresidential customers with Facility Capacity loads greater than 30 kW and less than or equal to 1,000 kW. Those customers whose load exceeds 1,000 kW will take service under Schedules 89, which we discuss below. We use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these rates.

The Schedule 83 charges include more detail because Large Nonresidential customers are more sophisticated energy users and are more able to react to pricing signals triggered by their peak consumption. Schedule 83 integrates service to secondary and primary delivery voltages into one schedule. To the extent practicable, we base the charges on the Marginal Cost Study, with particular attention given to appropriately pricing the cost differentials between delivery voltages. The prices differentiated by delivery voltage are below:

Schedule 83 General Service 31-1,000 kW		
Category	**Secondary Price**	**Primary Price**
Basic Charge Single Phase	$20.00 per customer per month	$90.00 per customer per month
Basic Charge Three Phase	$25.00 per customer per month	$90.00 per customer per month
Trans. & Related Services	$0.66 per kW peak Demand	$0.66 per kW peak Demand
Facilities Charge	$2.29 per kW Facility Capacity	$2.11 per kW Facility Capacity
Distribution Demand Charge (First 30 kW)	$2.07 per kW peak Demand	$2.07 per kW peak Demand
Distribution Demand Charge (Over 30 kW)	$2.64 per kW peak Demand	$2.64 per kW peak Demand
System Usage Charge	2.16 mills per kWh	2.05 mills per kWh
COS Energy Charge	55.44 mills per kWh	53.44 mills per kWh

Q. Please describe how you developed the Schedule 83 prices.

A. The Schedule 83 **Basic Charges** differ by delivery voltage consistent with current UE 115 rates. For three-phase secondary service, the Basic Charge remains at $25.00 per month in order to enable a smoother transition for Schedule 32 customers whose Demand exceeds 30 kW; this charge recovers about 64% of the marginal customer-related costs. We used this same ratio to develop the primary voltage Basic Charge of $90.00 per month. The Distribution Demand Charge recovers the remaining customer-related costs as well as any other costs either not fully recovered or more than fully recovered through the appropriate charge.

For Schedules 83 and 89, we set the **Transmission & Related Service Charge** to $0.66 per kW in order to make the pricing more consistent for customers who choose Direct Access Service under either Schedule 583 or Schedule 589. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently we flow the over recovery through to the Distribution Demand Charge.

The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility Capacity Charge**. For both secondary and primary voltage customers, we recover the costs associated with the 13 kV system and connect costs through the Facility Capacity Charge. The difference between secondary and primary voltage Facilities Capacity Charges reflect the cost differences in serving the different delivery voltages for customers of equal size.

The **Demand Charges** of $2.07 and $2.64 per kW for both secondary and primary customers recover the allocated revenue requirement of substations and the 115 kV system as well as any under or over recovery of other charges. We set the Demand Charge for the first 30 kW at a lower level than the Demand Charge for over 30 kW in order to once again provide a smooth transition for Schedule 32 customers whose Demand exceeds 30 kW.

Because several energy options are available to Schedules 83 and 583, we separately state the **System Usage Charge** which recovers franchise fees, Trojan, and the CIO.

Q. Please describe the Schedule 83 Energy Charge options.

A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS energy option or from one of PGE's market-based energy options. The market based options include daily pricing based on the prices for the Mid-Columbia hub as reported by the Dow Jones Mid-Columbia Daily On- and Off-Peak Firm Pricing Index (Dow Jones), and monthly price quotes made on or around the 15th of each month. We have decided to eliminate the Quarterly Price option due to a lack of interest from customers. Customers may also choose to receive service from an ESS.

Customers receiving service from an ESS or from a PGE market option will receive the Schedule 128, Short-Term Transition Adjustment. Schedule 128 is discussed later in this testimony.

Q. What schedule is applicable to Schedule 83 customers who wish to pursue the Direct Access energy option?

A. Customers choosing the Direct Access energy option will take service under the provisions of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a company supplied energy price, nor a Transmission & Related Services Charge.

Q. Please provide the proposed monthly prices for Schedule 89 and describe the customers to whom these prices are applicable.

A. Schedule 89 applies to all Large Nonresidential customers whose Facility Capacity loads exceed 1,000 kW. We propose to move customers to this schedule from Schedule 83 in order to better reflect cost differences for these larger customers and to reinstate the on-peak period Demand pricing for Distribution Demand Charges and for Transmission and Ancillary Services Charges. Because of their unique characteristics, we have separately identified the distribution costs for customers whose loads exceed 4,000 kW and integrated these cost differences into the Schedule 89 pricing for service to secondary, primary, and subtransmission delivery voltages. The charges are based on the Marginal Cost Study with attention to billing impacts and the cost differentials between delivery voltages. The Schedule 89 prices differentiated by delivery voltage are below:

Schedule 89 General Service Greater than 1,000 kW

Category	Secondary	Primary	Subtransmission
Basic Charge	$130.00 per month	$230.00 per month	$1,000 per month
Transmission & Related Charge	$0.66 per on-peak kW	$0.66 per on-peak kW	$0.66 per on-peak kW
Facilities First 1,000 kW	$2.33 per kW	$2.17 per kW	$2.17 per kW
Facilities Over 1,000 kW	$0.40 per kW	$0.24 per kW	$0.24 per kW
Distribution Demand Charge	$2.45 per on-peak kW	$2.45 per on-peak kW	$1.28 per on-peak kW
System Usage Charge	2.06 mills per kWh	1.86 mills per kW	1.78 mills per kW
COS Energy Charge On-peak	58.68 mills per kWh	56.58 mills per kWh	55.81 mills per kWh
COS Energy Charge Off-peak	49.73 mills per kWh	47.91 mills per kWh	47.18 mills per kWh

Q. Please describe how you developed the Schedule 89 Charges.

A. We set the **Basic Charges** for both secondary and primary voltage customers at levels that approximate the marginal customer-related costs with any over- or under-collection captured by the Facilities Capacity Charges. Although the Marginal Cost Study indicates a cost of $2,000 per month, we set the subtransmission voltage Basic Charge at only 50% of this level to $1,000 per month, in order to help mitigate price effects for smaller customers at subtransmission voltage who are currently paying a $500.00 Basic Charge. The costs not recovered through the Basic Charge are recovered by the Facilities Capacity Charge.

The **Transmission and Related Service Charge** is calculated in conjunction with Schedule 83 for the reasons previously discussed. Because this charge is less than the allocated costs, the Facilities Capacity Charge recovers the remainder.

The **Distribution Demand Charge** for both secondary and primary voltage customers reflects the marginal cost of providing substations and shared subtransmission facilities.

For customers served at subtransmission voltage who supply their own substation, the Distribution Demand Charge reflects the marginal cost of the shared subtransmission system plus the cost per kW differential between connecting a customer of equal size with a 13 kV feeder or a feeder at 115 kV. This differential of 0.07 cents is added to the Distribution Demand Charge to equalize the Facilities Capacity Charge for primary voltage and subtransmission voltage customers.

The **Facility Charge** for Schedule 89 customers has two blocks: one for the first 1,000 kW, and the second for billing kW greater than 1,000 kW. The first block facilitates the migration of customers from Schedules 83/583, while the second block captures the remaining facilities-related revenue requirements of Schedule 89 customers. Both Facility Capacity Charge blocks reflect the marginal cost difference between providing service at secondary or primary voltage service. As mentioned above, we set the Facility Capacity Charge for subtransmission voltage customers equal to that of primary voltage customers and flow any cost difference to the subtransmission voltage Demand Charge.

The **COS Energy Charge** option for Schedule 89 is on- and off-peak differentiated. Daily and Monthly Price options are also available similar to those described for Schedule 83. Customers who wish to pursue the Direct Access Energy Option will take service under Schedule 589. As with Schedules 83/583, Schedules 89/589 separately identify the System Usage Charge.

Q. Please elaborate the reasons for re-opening Schedule 38 to new customers.

A. We intend to re-open **Schedule 38, Optional Time-of-Day Large Nonresidential Standard Service**, to new customers whose Demand does not exceed 200 kW because this time-of-day rate is an effective option for some of our mid-size customers. In UE 115, we closed this schedule to new customers to prevent other customers from continuing to subsidize this Schedule through the CIO. In this proceeding we propose no CIO subsidy of Schedule 38, but rather set prices at cost, and allow customers to migrate to this schedule if they believe that they will experience savings on their bill. We estimate that approximately 1,000 accounts currently served under Schedule 83 may experience bill savings by switching to Schedule 38.

Q. Through what schedule may a Schedule 38 customer choose Direct Access Service?

A. Schedule 38 customers may choose Direct Access Service through Schedule 583.

Q. Schedule 38 is a time-of-day schedule. How do you propose to bill new customers who do not have the appropriate metering installed?

A. We propose to profile the kWh consumption of these customers into on- and off-peak periods by the rate schedule average profile until such time as PGE can install time-of-use meters. If we install our proposed Advanced Metering Infrastructure (AMI) system, we can then capture these customers' actual on and off-peak consumption. If the Commission does not approve our AMI proposal, we will need to purchase and install other time-of-use meters.

Q. Describe the development of charges for the remaining rate schedules.

A. The remaining proposed rate schedules provide service to lighting and irrigation customers and are discussed below:

We structure **Schedule 15**, **Outdoor Area Lighting Standard Service**, charges in the same manner as the current rate schedule. The Monthly Charge contains all of the allocated costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer class with Direct Access Service charges. PGE Exhibit 1307 includes a summary of the Area Light Cost Study.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose Demand does not exceed 30 kW. We set the monthly Basic Charge at $25.00 per month for the 6 summer months only, an increase of $5.00 per month. We block the Distribution Charge rather than the Energy Charge so that irrigation customers may make more well-informed decisions on the energy pricing options available to them. Schedule 47 customers may take Direct Access Service under Schedule 532. As discussed later in this testimony, consistent with past PGE practice and past Commission decisions, we have held the increase in this schedule to 2 times the average base rate increase of 6.3%; otherwise the proposed rate increase from 2006 prices would be 56.9%.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47, but applies to customers larger than 30 kW. We retain the Basic Charge of $30 per month, summer months only. Similar to Schedule 47, we block the Distribution Charge rather than the Energy Charge. Schedule 549 states the Direct Access charges for these customers. These customers are also eligible for Direct Access Service on Schedule 583. We limited the Schedule 49 price increase to 2 times the average increase instead of the 61.1% indicated by cost-based pricing.

Schedules 91/ 591, Street and Highway Lighting Standard Service, provide municipalities with outdoor lighting service. These schedules are similar in structure to Schedule 15. Each service option monthly rate includes the applicable unbundled costs, based on the monthly kWh usage of the particular type of light. For 2007, we propose to meter new Option C (customer owned and maintained) installations and bill them under the provisions of Schedule 32. Existing option C customers are not affected. We limit this schedule to 2 times the average increase over 2006 prices; otherwise, cost-based pricing would yield an increase of 18.9%. Below we discuss calculating the fixed costs associated with this service.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for un-metered traffic control devices in systems with at least 50 intersections. We retain the energy-only nature of the rate. Again, we hold the increase in this schedule to 2 times the average increase instead of 17.2%.

Schedule 592, Traffic Signals Direct Access Service, provides the Direct Access-related energy-only based charge for this specialty service. Schedules 92/592 remain grandfathered services closed to additional governmental agencies.

Schedule 93, Recreational Field Lighting Standard Service, rate design maintains the Basic Charge of $30 per month, with Distribution and Transmission Charges recovered on a volumetric basis. We limit the price increase for this schedule to 2 times the average increase instead of 21.4% indicated by cost-based pricing.

Q. Please describe the Area and Streetlighting Cost of Service Study.

A. Streetlighting and Area Lighting prices include the costs of investment and maintenance in addition to the Transmission, Distribution and production-related charges that apply to all other schedules. We analyze the investment and maintenance cost components separately. For the investment component, we estimate the total revenue requirement associated with our investment in streetlighting and area lighting equipment for the 2007 test period. We then adjust the investment component of the charges so that prices proposed in this filing fully recover the revenue requirement. Likewise for the maintenance component, we estimate the expected cost of maintaining each type of streetlight equipment based on current costs and anticipated levels of maintenance activity.

PGE Exhibit 1307 summarizes the results of this study. This Exhibit details the energy charges, fixed charges, total charges and total revenues for both Area and Street lighting.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. The pricing for Schedules 47, 49, 91, 92 and 93 is established at rates that are significantly less than the cost to serve. If we were to move these schedules to fully cost-based rates, they would experience significantly greater rate increases than average. This issue has existed for quite some time for Schedules 47, 49 and 93. Over time, by successively pricing these schedules at a multiple of the average increase, we hope to move these schedules closer to cost of service while gradually sending the appropriate price signal. The cost-based increase for Schedule 91 is more than 2 times the average because of large increases in maintenance costs and circuit charges relative to the amount of maintenance costs presumed in current rates for these services. The larger than average cost-based increase for Schedule 92 is due largely to the reduction in consumption per individual signal from UE 115 presumed levels. Customers on this schedule achieved this reduction by changing to Light Emitting Diodes (LED) signals shortly after the implementation of UE 115 rates. The net result of this change is that distribution fixed costs are spread over less energy resulting in a large Schedule 92 distribution price increase.

We increase the System Usage Charges of the remaining schedules to offset the effect of the price mitigation efforts described above. PGE Exhibit 1304 shows the development of this offset.

Q. What adjustment schedules does this filing contain?

A. This filing contains the following adjustment schedules:

- Schedule 102, Regional Power Act Exchange Credit
- Schedule 105, Regulatory Adjustments
- Schedule 108, Public Purpose Charge
- Schedule 115, Low-Income Assistance
- Schedule 125, Annual Power Cost Update (Annual Update)
- Schedule 126, Power Cost Variance Mechanism (PCVM)
- Schedule 128, Short-Term Transition Adjustment
- Schedule 129, Long-Term Transition Cost Adjustment
- Schedule 140, Automatic Tax Adjustment

Q. Please describe Schedule 102 and how you develop the appropriate prices for this Schedule.

A. **Schedule 102, Regional Power Act Exchange Credit**, to qualifying customers, reflects the projected financial benefit from BPA to PGE's qualifying customers. Commencing October 1, 2006, PGE will receive financial benefits from BPA based on an allocation of 560 MWa. These financial benefits will range from a low of $5.20/MWh to a high of $15.59/MWh. The annual monetary benefits will, therefore, range from $25.5 million to $76.5 million. PGE intends to make a rate filing sometime in August of 2006 to reflect the change in the level of BPA benefits, with rates effective October 1, 2006. As represented in PGE Exhibit 1304, in this filing we have estimated the Schedule 102 rate using the $76.5 million estimate of $15.59/MWh. Because we set Schedule 102 rates during the 2006 RVM by spreading the 2006 benefits over 12 months of forecasted consumption, and we propose to change rates after only nine months, PGE will have a BPA balancing account amount of approximately $25 million to refund to customers. We will amortize this balancing account amount over 15 months ending December 2007 when setting the Schedule 102 rates. For all schedules other than Schedule 7 we calculate the Schedule 102 price as a cents per kWh adjustment. Because of the UE 115 Residential Rate Design stipulation, current Schedule 102 rates applicable to Schedule 7 are blocked with the first 250 kWh energy block receiving a substantially higher credit than the over 250 kWh energy block. In order to mitigate the price effects on smaller usage customers we reluctantly propose to maintain the energy blocking nature of the design for Schedule 102 only. Currently the sum of the Energy Charge plus the Schedule 102 adjustment yields a price differential of 25 mills per kWh. We propose to reduce this block differential by half, to 12.50 mills per kWh. Eventually, we hope to eliminate the energy blocking because we believe that it has no cost basis. We will update our Schedule 102 analysis should our estimates of BPA benefits change.

Q. What is the purpose of Schedule 105?

A. The purpose of **Schedule 105, Regulatory Adjustments**, Part A is to collect or refund minor non-recurring items. Part A contains miscellaneous adjustments such as the gain or loss from nonrecurring property transactions, the IT adjustment, and other small adjustments. We calculate Part A by allocating the overall adjustment amount on an equal percentage of revenue to each rate schedule and then expressing it as a cents per kWh adjustment. The charges for Part B consist of costs associated with the implementation of SB 1149. We established this portion of the Schedule in 2004 by a detailed allocation to the classes and we expect it to remain in place until late 2008, when we anticipate full amortization of the SB 1149 implementation costs. We calculate Part C on an equal cents per kWh basis in order to recover the historical and projected costs PGE has or will incur related to the Grid West Regional Transmission Organization.

Q. Please describe Schedule 108.

A. **Schedule 108, Public Purpose Charge,** collects 3% of revenues for public purposes consistent with OAR 860-038-0480.

Q. Please describe Schedule 115 Low-Income Assistance.

A. **Schedule 115, Low Income Assistance,** implements the low-income bill payment assistance provisions in accordance with ORS 757.612(7)(b). We are not proposing to change the adjustment rates for this schedule.

Q. Please explain Schedule 125 Annual Power Cost Update.

A. **Schedule 125, Annual Power Cost Update,** is an automatic adjustment clause that provides for the incorporation of annual updates to projected net variable power costs into rates commencing in 2008. The rationale for this tariff appears in PGE Exhibit 400.

Q. What is the purpose of Schedule 126 Power Cost Variance Mechanism (PCVM)?

A. We describe the purpose and mechanics of this schedule in PGE Exhibits 100 and 400. All customers, with the exception of those receiving service under Schedule 483 or 489, will participate in the PCVM. We do not exempt customers receiving service from an ESS or from a PGE pricing option because those customers receive the benefit of normalized hydro and plant operations through the transition adjustment in a manner similar to those customers choosing the COS option. Also, exempting Direct Access customers from the PCVM would create incentives to choose Direct Access when hydro conditions are expected to be poor and COS when hydro conditions are expected to be good.

Q. Please describe Schedule 128, Short-Term Transition Adjustment.

A. **Schedule 128, Short-Term Transition Adjustment**, applies only to customers who choose to receive service from an ESS or from a PGE market based pricing option. For each schedule, we calculate the annual transition amount by making a monthly comparison of the difference between the COS energy rate and the wholesale market value of each schedule's energy. We then divide the sum of these monthly differences by each schedule's projected annual loads. For the 2007 test period, we present an annual transition adjustment on January 1, 2007, without Port Westward. When Port Westward becomes operational, presumably on March 1, 2007, we will recalculate the annual transition adjustment for the balance of the year using the new COS energy prices. We will calculate the final January transition adjustment in mid-November using then current projections of wholesale market prices. PGE Exhibit 1304 summarizes the preliminary estimates of the transition adjustments for each eligible rate schedule.

Q. What is the purpose of Schedule 129?

A. **Schedule 129, Long-Term Transition Cost Adjustment** applies to customers who choose to receive service under the provisions of Schedule 483 or Schedule 489.

Q. What is the purpose of Schedule 140?

A. **Schedule 140, Automatic Tax Adjustment**, is an automatic adjustment clause proposed in accordance with Senate Bill 408 and adopted by the Commission in temporary rule OAR 860-022-0039. Because this schedule is under review in another proceeding, we have not included Schedule 140 in the filing but have assumed that initially Schedule 140 rates will be zero for purposes of our analyses.

V. Development of Retail Prices

Q. What basic approach did PGE use to establish rates and charges?

A. We take two major steps in establishing rates and charges: First, we allocate the revenue requirements for a function such as transmission or distribution for each proposed rate schedule based on a relevant allocation method. This step is called *cost allocation or rate spread*. Second, we design specific rates and charges based on the allocated target revenue level and marginal costs for each rate schedule, tempered for rate impacts.

Q. What is the source of the unbundled or functionalized, revenue requirements?

A. The unbundled revenue requirements, from PGE Exhibit 1305 Allocation of Costs to Customer Classes, provide the inputs for the rate spread and design process. The unbundled costs do not include any costs or credits for supplemental adjustment schedules such as the Schedule 102, Regional Power Act Exchange Credit, which we handle separately.

Q. How do you determine the unbundled ancillary service costs?

A. We impute a value of $5.4 million for the ancillary services revenue requirement by applying Schedules 1 through 3 of our Open Access Transmission Tariff (OATT) to our 2007 projected 12 coincident peak load. We remove this imputed revenue requirement value from the production function revenue requirement and then spread it to individual rate schedules in the same manner as the generation revenue requirement.

Q. Please summarize the results of the cost allocation or rate spread process.

A. A summary of the cost allocation process for Schedules 7, 32, 83, and 89 is contained in the table below. Rather than list all seven functional unbundling categories, we combine some categories for ease of presentation. For example, we combine transmission and ancillary services together because we put these two together when setting prices; we also place

Metering, Billing, and Other Consumer Services into one category, Customer. We include franchise fees, regulatory assets and the Schedule 129 Long-Term Transition Cost Adjustment within Distribution.

Summary of Rate Spread to Selected Schedules Cycle Basis ($000)

Schedule	Production	Distribution	Transmission & Ancillary	Customer	Total
7	$426,976	$233,259	$14,875	$84,596	$759,707
32	$84,249	$44,374	$3,212	$10,277	$142,112
83	$315,498	$88,985	$9,321	$3,998	$417,802
89	$240,329	$34,190	$6,186	$321	$281,027
System	$1,084,503	$423,991	$33,988	$100,561	$1,643,042

PGE Exhibit 1305 provides more detailed results for all of the Rate Schedules.

Q. How do you allocate the production revenue requirement to individual rate schedules?

A. We allocate the production function based on each schedule's marginal cost, which we define as the cost of meeting each Schedule's energy requirements with market purchases delivered to the meter. PGE Exhibit 1305 provides the detailed calculations for each rate schedule. This Exhibit also contains the allocations for all other functional revenue requirements.

Q. Does this methodology differ from the methodology you employed in UE 115 and in subsequent RVM proceedings?

A. The allocation process we propose, one essentially based upon monthly test-period load shapes and projections of monthly market prices, does differ from the previous UE 115 stipulated methodology (frequently referred to as resource stacking). In UE 115 and in the subsequent annual RVM proceedings, we allocated both the fixed revenue requirement and the output and costs of PGE's long-term (original life of greater than five years) assets to the three classes (Residential, Small Nonresidential and Large Nonresidential) according to a fixed percentage that corresponded to actual and projected loads for the 12-month period ended September 30, 2001. We then allocated BPA Subscription Power according to eligible test period load and finally, we allocated the remaining resources, defined as short term resources, based on remaining monthly load requirements.

Q. Why is the methodology you propose superior to the methodology previously employed?

A. This methodology is superior to the methodology we previously employed because it is more reflective of cost causation. The methodology is based entirely on projected test-period loads rather than being partially based on historical loads that may not reflect anticipated load. Additionally, the old resource stacking methodology is no longer necessary because we no longer will be receiving BPA Subscription Power.

Q. Please explain how you allocate the transmission revenue requirements and the ancillary services revenue requirements.

A. Consistent with FERC methodology, we allocate the transmission revenue requirement of $28.6 million by the percent contribution of each rate schedule to the system's monthly average coincident peak (12CP). We allocate the ancillary services revenue requirement according to the allocation of the production revenue requirement.

Q. How do you allocate the distribution revenue requirement?

A. We allocate the distribution revenue requirement of $380.9 million using an equal percent of marginal costs methodology. To do so, we multiply the unit marginal cost by the applicable usage for each rate schedule to arrive at marginal revenues. We then compare the total marginal revenue from all schedules to the distribution revenue requirement and adjust the marginal revenue on an equal percent basis to achieve the revenue requirement. We allocate franchise fees on a revenue basis and Trojan on an equal cents per kWh basis adjusted for line losses. We allocate the Schedule 129, Long-Term Transition Cost Adjustments applicable to Large Nonresidential Customers on a volumetric basis. Should there be additional participation in the Schedules 483/489 Cost of Service Opt-Out during the September 2006 enrollment process, we will update the COS load forecast and the net variable power costs used in setting base energy rates as well as the Schedule 129 Long-Term Transition Cost Adjustments. This will ensure that PGE projects the correct COS load requirements and accompanying production costs.

Q. How do you allocate the customer service revenue requirement?

A. Similar to the allocation of distribution costs, we allocate the customer service revenue requirements on an equal percent of marginal cost basis.

VI. Marginal Cost of Service Study

Q. Briefly describe the purpose of a Marginal Cost Study.

A. Since the mid-1970s, Oregon utilities have used Marginal Cost Studies for a number of purposes. In this case, PGE uses its Marginal Cost Study to guide the allocation of the distribution system revenue requirements in the rate spread process and to price PGE's unbundled services. The study's results are summarized in Table 8 of PGE Exhibit 1306.

Q. Please discuss the changes to the UE 115 Marginal Cost Study.

A. We improve the study performed in UE 115 by using the following information:

- Feeders that better represent the cost of the Company's 13kV system.
- A separate estimation of the feeder costs of our larger customers (greater than 4 MW) who are on dedicated feeders.
- An incorporation of service laterals and line transformers into a category called connect costs which are classified as facilities-related costs.
- Test-period Marginal Distribution Operation and Maintenance (O&M) allocated to each rate schedule in proportion to each schedule's marginal use of distribution capital.

Q. Please summarize the distribution components of the Marginal Cost Study.

A. The following categories are used to differentiate distribution marginal investment: subtransmission, substations, 13 kV feeders, connect costs, and meters.

Q. How did you calculate the marginal unit costs of subtransmission and substation investment?

A. We calculate marginal subtransmission and substation investment by summing investment for the five-year period 2003-2007, adding a general plant loader, annualizing this investment and then dividing by the growth in system non-coincident peak. For substation marginal investment costs, we exclude the loads for customers served at subtransmission voltage because these customers supply their own substation. Tables 1 and 2 of PGE Exhibit 1306 summarize this portion of the study.

Q. How did you calculate the marginal unit feeder costs?

A. We estimate distribution feeder unit costs by selecting feeders that are representative of the company's system and estimate the costs in 2007 dollars of rebuilding these feeders. We then annualize these costs and express them on a per kW basis for both single and three-phase customers by dividing by the estimated peak loadings of the customers on the selected feeders. For customers greater than 4 MW who are typically on dedicated feeders, we estimate the marginal feeder costs as the average distance between the substation and the customer-owned facilities. Because new customers on dedicated circuits typically have a redundant feeder, we multiply this average distance by two, resulting in a per-customer average of 6,000 feet of dedicated feeders. We then annualize the marginal costs of rebuilding these feeders in today's dollars and express them as a per-customer cost. Finally, we add general plant loaders to the annualized costs of all distribution feeder marginal investment costs. Table 3 of PGE Exhibit 1306 summarizes the marginal cost of distribution feeders.

Q. Please describe marginal connect costs and how you calculate the unit costs.

A. We calculate marginal connect costs by estimating the cost of providing the average customer with a service lateral and a line transformer (secondary delivery voltage only) as well as the service design costs and any wire costs not captured in the feeder portion of the study. For smaller customers, such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to calculate appropriately their connect costs. For customers served at subtransmission voltage, we calculate connect costs as the average distance from the point at which they connect into the subtransmission system to the customers substation multiplied by the average 115 kV line cost in 2007 dollars. After expressing the connect costs in 2007 dollars, we add a general plant loader and annualize the figure. Table 4 of PGE Exhibit 1306 summarizes the marginal connect costs by rate schedule.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the newly installed costs of providing meters to each rate schedule and then add a general plant loader and apply an annual carrying charge. Table 5 of PGE Exhibit 1306 summarizes the meters' marginal cost.

Q. How do you allocate Marginal Distribution O&M to each Rate Schedule?

A. We allocate test-period Marginal Distribution O&M by distribution category to the rate schedules in proportion to each schedules' usage times its marginal capital cost. Table 6 of PGE Exhibit 1306 provides the details of this allocation and the final distribution marginal costs by distribution category.

Q. What is contained in Table 7?

A. Table 7 details the marginal costs of metering data, billing, and customer services functions. The metering data marginal costs consist of the 2007 meter reading expenses and general support expenses. The billing function marginal costs consist of projected billing and collection-related O&M. The other consumer services marginal costs contain the traditional serve and respond functions.

Q. Have you prepared a marginal cost summary table?

A. Yes. Table 8 of PGE Exhibit 1306 summarizes the marginal costs in this study for all distribution and customer cost categories.

VII. Direct Access

Q. Please describe the changes you propose to make regarding Direct Access options and cost allocation.

A. Because commercial and industrial customers have requested it, PGE proposes to continue to offer customers with aggregate load greater than 1 aMW (each point of delivery of at least 250 kW), a three-year and a five-year option to opt out of the COS rate, with a fixed transition adjustment rate under terms similar to the current Schedule 483. In addition, PGE proposes to offer those customers choosing to opt out of COS, a three to five year Market-Based Pricing Option. This is in addition to the currently offered Daily Price option. PGE supplied energy options are explained more fully in both Schedules 483 and 489.

Q. What other Direct Access changes do you propose?

A. Commencing January 2007, PGE proposes to provide eligible COS customers a monthly opportunity to elect Direct Access for the remainder of the calendar year. The window for making a service election will end the business day after the transition adjustment is posted on PGE's web site. We will calculate the transition adjustment in a manner similar to how we propose to calculate the previously discussed annual transition adjustment. Because each enrollment period will have a different market value of energy dependent on the forward price curves used, each enrollment period will have its unique transition adjustment. PGE does not anticipate making a separate advice filing for each monthly enrollment period, but rather anticipates handling the transition adjustment through a web posting on or around the 15th of each month.

Q. Please discuss other proposed Direct Access changes.

A. Commencing with the 2007 service year, PGE proposes to offer customers with aggregate load larger than 10 aMW (each point of delivery of at least 250 kW) and an annual average load factor of at least 60%, the option to purchase flat blocks of energy from an ESS, where Direct Access Service does not exceed 50% of their load and PGE provides the balance of the load, load shaping and other necessary services. The specific details of this option are contained in **Schedule 84, Large Load Split Service Rider Option.**

Q. Are you proposing other changes related to Direct Access options?

A. Yes. We are proposing to eliminate the Short-Term Resource Notice (Notice) contained in current Schedule 125. Our experience with the Notice has demonstrated that it is not an effective indicator of customers' energy pricing selections. Additionally, the availability of this option has resulted in unforeseen consequences to non-participating customers, specifically leaving non-participants with an uncovered price position, and hence, subject to wholesale power market price fluctuations. To elaborate on this point, for purpose of planning to meet COS load within the current RVM process, PGE does not purchase energy for customers who have provided Notice. These customers, however, are entitled to the monetary benefit (or cost) of their allocated portion of PGE's long-term resources. We monetize these claims through the current Schedule 125, Part A price. The power from these resources is allocated to those remaining Large Nonresidential COS customers (who did not provide Notice). Because the value of this power is set at a future date through the RVM process, the cost assigned to those customers who did not provide Notice is not known until that future date. This leaves the non-Notice customers with an uncovered price position equal to the Notice customers' prorated share of long-term resources. This uncovered price position makes the retail prices of COS customers subject to wholesale power market fluctuations and, given the current RVM structure, does not allow PGE to provide effective price certainty.

Finally, we believe that the option is not necessary because PGE has developed offers to qualifying Large Nonresidential customers that provide the opportunity to opt-out of COS for three or five year periods.

Q. Please summarize the proposed changes in pricing options available to eligible customers since UE 115.

A. Beginning with the 2003 service year, PGE has offered eligible customers the option of opting out of COS energy supply for a minimum five-year period with a pre-specified transition adjustment. Commencing with the 2005 service period, we added a three-year COS opt-out provision, again with a pre-specified transition adjustment. In this filing, we propose to allow eligible customers who choose the three- or five-year opt-out the choice of receiving service from the Company at a multi-year, market based energy price. As discussed above, we also propose monthly Direct Access windows and split-load options for eligible customers. Finally, we propose to remove the Schedule 125 Part B opt-out because it has not achieved its intended purpose.

Q. What other changes are you proposing to the Short-Term Transition Adjustment, proposed Schedule 128?

A. We propose to continue applying the Large Nonresidential Load Shift True-up resulting from the annual open enrollment process to proposed Schedule 128. Any true-up resulting from customer's energy supply decisions will apply to those customers choosing an option other than COS. This will ensure that those customers who exercise their choice of energy supply options do not impose costs on those who choose to remain on COS. The Schedule

128 in PGE Exhibit 1302 more specifically details the true-ups associated with the annual and monthly windows.

Q. Why is there no Transmission and Ancillary Services Charge on the Direct Access Service schedules?

A. We do not propose a separate Transmission and Ancillary Services Charge because we wish to simplify the Direct Access Service schedules. With the current ongoing valuation process of determining transition adjustments, we do not believe it necessary to separately identify the ancillary services currently included in our Direct Access Service schedules. Under our proposed Tariff, the ESS will purchase transmission and ancillary services under PGE's OATT. Therefore, we do not include this charge in the retail schedule.

VIII. Partial Requirements

Q. Please describe the changes you are proposing to Schedule 75, Partial Requirements Service and Schedule 575, Direct Access Service Partial Requirements Service?

A. Similar in concept to the notice requirements contained in Schedules 483/489, we propose to add a two-year notice provision to the two Partial Requirements schedules (Schedules 75 and 575) to improve the process for customer-initiated changes to Baseline Demand. This option is necessary because our current schedule does not provide for changes in Baseline Demand due to generator shutdown. Special Conditions 9 and 8 contained in Schedules 75 and 575 respectively state the notice requirements.

Q. Why are the notice requirements necessary?

A. The notice requirements are necessary in order to clearly establish the parameters under which a Partial Requirements customer may receive a COS energy rate. Absent the requirements, a customer's request for a change in Baseline Demand would unduly burden other customers or shareholders by allowing the Partial Requirements customer to optimize in the short-term at the expense of others by changing its Baseline Demand based on short-term natural gas market conditions. Our proposal achieves an equitable balancing of interests between all our customers by 1) allowing customers who install self generation the appropriate access to a COS energy rate while protecting other customers from the Partial Requirement customer constantly switching between the COS energy rate and self generation; and 2) the notice is short enough to not be a disincentive for customers interested in proceeding with self generation.

IX. General Rules and Regulations, Schedule 300 Charges

Q. What Rules are you proposing to change?

A. We are proposing to make limited changes to our General Rules and Regulations. These changes are summarized in PGE Exhibit 1308. The changes to the General Rules and Regulations are intended to:

- Add clarifying language to certain existing terms and conditions
- Make minor updates to better conform to Commission rules
- Consolidate and define frequently repeated terms or conditions
- Reorder certain rules to better reflect the functional applications of rules
- Update rules to better reflect changes to certain operational practices

Q. Please describe the proposed changes to Schedule 300.

A. In order to better reflect costs we propose to change the Returned Payment Charge, the Field Service Connection Charge, and Credit Related and Customer Requested Disconnections and Reconnection Rates. The Pricing work papers summarize the basis for these changes. An estimate of the net additional revenue resulting from the changes to these miscellaneous billing rates is not included in the revenue requirement for this filing, but will be included in a later update.

X. Port Westward Price Changes

Q. Please describe the price changes that will take effect March 1, 2007.

A. After the Commission rules on the Port Westward test-period revenue requirements, PGE will implement changes in COS Energy Charges, Transition Charges, Transmission Charges, and charges related to the changes in the franchise fee revenue requirements associated with Port Westward. For some schedules, this franchise fee related change will result in a change in the Distribution Charge; for other schedules this will result in a change in the System Usage Charge. We intend to allocate the Port Westward functional revenue requirements consistent with how we allocate the revenue requirements without Port Westward. We anticipate that these price changes will take effect March 1, 2007, the projected on-line date of Port Westward.

Q. Have you provided an estimate of the specific price changes for each rate schedule?

A. Yes. PGE Exhibit 1309 summarizes the estimates of the price changes for each rate schedule by category. We estimate that the March 1 price changes will result in an increase of approximately 2.9% overall from the prices that result from this proceeding.

XI. Line Loss Study

Q. Have you performed an update to the current line loss study?

A. Yes. PGE Exhibit 1310 summarizes the results by delivery voltage. Despite a reduction in the percent energy losses within the PGE system, the overall estimate of line losses has increased because energy losses outside of PGE's system (external losses) have significantly increased. The reasons for this increase in external losses include: a) meeting load growth by utilizing BPA transmission, which specifies contractual loss returns of 1.9%; and b) the 1993 closure of the Trojan Generating Station, an internal source of energy at the time of the previous line loss study. The detailed calculations and data used to develop the line loss percents are contained in the Pricing work papers.

Q. How do you use the line loss percents in Exhibit?

A. We use the line loss percents as input to the busbar load forecast. We also use them as an input in establishing the marginal cost of generation for each rate schedule and in energy pricing for variable price option customers.

XII. Qualifications of Witnesses

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Mr. Kuns, please state you educational background and qualifications.

A. I graduated from Linfield College in 1973 with a Bachelor of Arts in Economics. I received a Master in Business Administration degree from Claremont Graduate School.

In 1979, I joined PGE in the Rates and Regulatory Affairs Department and have held various positions in the regulatory, marketing and planning areas. My current position is Manager of Pricing and Tariffs.

Q. Does this complete your testimony?

A. Yes.

I. List of Exhibits

PGE Exhibit	**Description**
1301	List of Exhibits
1302	Proposed Tariffs
1303	Estimated Impact of Proposed Changes on Customers
1304	Rate Design
1305	Allocation of Costs to Customer Classes
1306	Marginal Cost of Service Study
1307	Streetlight and Area Lights
1308	Summary of Changes to Rules and Regulations
1309	Port Westward Price Changes
1310	Line Losses by Delivery Voltage

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SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$10.00	
Three Phase Service	$13.00	
Transmission and Related Services Charge	0.198	¢ per kWh
Distribution Charge	3.123	¢ per kWh
Energy Charge		
Standard Service	5.675	¢ per kWh
or		
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)		
On-Peak Period	9.777	¢ per kWh
Mid-Peak Period	5.675	¢ per kWh
Off-Peak Period	3.259	¢ per kWh
Nonstandard Metering Charge (applicable to TOU)		
Single Phase meter	$1.00	
Three Phase meter	$4.25	

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Continued)

MONTHLY RATE (Continued)

Renewable Portfolio Options
(available upon enrollment in either Energy Charge option)

Renewable Usage	0.800	¢ per kWh in addition to Energy Charge
Fixed Renewable	$3.50	per month per block
Habitat	$2.50	per month and
	0.800	¢ per kWh in addition to Energy Charge

RENEWABLE PORTFOLIO OPTIONS

The Customer will be charged for the Renewable Portfolio Option in addition to all other charges under this schedule for the term of enrollment in the Renewable Portfolio Option.

Habitat Option

The Company will distribute $2.50 per month as received from each Customer enrolled in the Habitat Option to a nonprofit agency chosen by the Company who will use the funds for habitat restoration. The 0.800¢ per kWh will purchase Tradable Renewable Credits (TRCs) and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

Fixed Renewable Option

The Company will purchase 200 kWhs of TRCs and/or renewable energy per block enrolled in the Fixed Renewable Option. All TRCs purchased under this option will come from new renewable resources.

The Company will also place $2.50 of the amount received from Customers enrolled in the Fixed Renewable Option in a new renewable resources development and demonstration fund. Amounts in the fund will be disbursed by the Company to public renewable resource demonstration projects or projects which commit to supply energy according to a contractually established timetable. The Company will report to the Commission annually by April 1st for the preceding calendar year on collections and disbursements. The fund will accrue interest at the Company's authorized rate of return.

Renewable Usage Option

All amounts received from the Customer under the Renewable Usage Option will acquire TRCs and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

SCHEDULE 7 (Continued)

RENEWABLE PORTFOLIO OPTIONS (Continued)
Renewable Usage Option (Continued)

Energy or TRCs supporting the Renewable Portfolio Options will be acquired by the Company such that within two years of a Customer's purchase of renewable energy, the Company will have received sufficient TRCs or renewable energy to meet the purchases by Customers. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

For purposes of these options, renewable resources include wind generation, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. New TRCs or new renewable resources will mean those qualifying resources placed in service after July 23, 1999, as defined in OAR 860-038-0005.

TIME OF USE PORTFOLIO OPTION

Time Periods

On- and Off-Peak Hours

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

** Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a TOU holiday. If a holiday falls on Sunday, the following Monday is designated a TOU holiday.

SCHEDULE 7 (Continued)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks notice prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having a time payment agreement that has not been kept current from month to month, b) having received two or more final disconnect notices in the past 12 months; or c) having been involuntarily disconnected in the past 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

Pertaining to the TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks notice prior to the meter read date. Absent the two week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater.

SCHEDULE 7 (Concluded)

SPECIAL CONDITIONS (Continued)
Pertaining to the TOU Option (Continued)

4. The Customer must have a meter provided by the Company which is capable of recording interval usage. Because of the special metering requirements of this option, the Company anticipates that a delay may occur from the time a Customer requests service under this option until the Company can provide it. In the interim, Customers will continue to receive service under Standard Service.

5. The Customer must provide the Company access to the meter on a monthly basis.

6. After a Customer's initial 12 months of service on the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. The Nonstandard Metering Charge will be excluded from the bill comparisons. No refund will be issued for Customers not meeting the 12 month requirement.

7. The Company will recover lost revenue from the TOU Option through Schedule 105.

8. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date.

9. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

SCHEDULE 10
GENERLINK™
(NO NEW SERVICE)

PURPOSE

Provision of generator connection to facilitate Customer use of a generator during power outages and protection for Company employees from back feed caused when a Customer improperly connects a generator.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Single Phase Residential and Small Nonresidential Customers receiving service on Schedule 7 or 32. This schedule is available only to those Single Phase Residential and Small Nonresidential Customers receiving service under Schedule 10 as of April 20, 2005.

SERVICE DESCRIPTION

GenerLink™ automatically disconnects a Customer from the Company's Electricity Service whenever the Customer's generator is operating.

BILLING RATES

Installation Charge	$65.00

The Installation Charge may be paid in 4 monthly installments of $16.25

Monthly Lease Fee	$9.50

SPECIAL CONDITIONS

1. The GenerLink™ capacity is 30 amps.

2. Generators are not provided by the Company.

3. Customers will be provided with an operator's manual that describes how the GenerLink™ unit works and how to operate it safely.

4. GenerLink™ installation requires the written authorization of the homeowner or Small Nonresidential Customer. Where the residence or business is a rental, the landlord must sign the application prior to installation.

SCHEDULE 10 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The Company will retain ownership of the GenerLink™ unit at all times.

6. Only Company approved personnel may install and remove the GenerLink™ unit.

7. The Customer assumes all responsibility for safely operating and maintaining the GenerLink™ unit.

8. GenerLink™ installation assumes Customer agreement not to connect a generator to their home's electrical system without using GenerLink™.

9. The Company will be responsible to replace GenerLink™ units that fail during normal use. If the Customer's activities have damage the GenerLink™ unit, the Customer is responsible to pay for the costs of replacing or repairing the unit.

10. Customers who move within the Company's service territory and would like the GenerLink™ unit transferred to their new residence, will be charged the installation fee.

11. Service under this schedule will be terminated and the GenerLink™ unit will be removed if the Customer fails to pay the charges for a period of 90 days.

12. The Company reserves the right to offer incentives including but not limited to rebates.

TERM

Customers receiving service under this rate schedule will sign an initial two year service agreement. After the completion of the initial agreement, service will be provided on a month to month basis.

After the initial two year term, Customers must give 30 days notice in order to terminate service under this schedule.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.097	¢ per kWh
Distribution Charge	3.476	¢ per kWh
Cost of Service Energy Charge	5.366	¢ per kWh

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate [(1)] Per Luminaire
Cobrahead				
Mercury Vapor	175	7,000	67	$12.30[(2)]
	400	21,000	149	19.78[(2)]
	1,000	55,000	379	41.25[(2)]
HPS	70	6,300	31	8.89[(2)]
	100	9,500	43	10.06
	150	16,000	63	11.88
	200	22,000	80	13.88
	250	29,000	103	15.99
	310	37,000	125	18.77[(2)]
	400	50,000	165	21.56
Flood, HPS	100	9,500	43	10.47
	200	22,000	80	13.95[(2)]
	250	29,000	103	16.29
	400	50,000	165	21.86
Shoebox (bronze color; HPS flat lens or drop lens, multi-volt)	100	9,500	43	11.00
	150	16,500	63	13.10
Special Acorn Type HPS	100	9,500	43	13.94
	150	16,500	63	15.42
	200	22,000	80	16.94
	250	29,000	103	19.15
Early American Post-Top HPS				
Black	100	9,500	43	10.99
Special Types				
Cobrahead, Metal Halide	175	12,000	72	12.86
Flood, Metal Halide	400	40,000	158	21.17
Flood, HPS	750	105,000	289	35.61

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]
Special Types (Continued)				
HADCO Independence	100	9,500	43	$13.03
Early American	150	16,000	63	14.84
HADCO Techtra HPS	100	9,500	43	20.68
	150	16,000	63	22.49
	250	29,000	103	33.12
KIM Archetype HPS	250	29,000	103	20.65
	400	50,000	165	26.01
Holophane Mongoose, HPS	150	16,000	63	14.27
	250	29,000	103	17.94
	400	50,000	165	23.53

Rates for Area Light Poles [2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$ 6.30
	55 or less	7.91
Wood, Painted for Underground	35 or less	7.37[3]
Wood, Curved Laminated	30 or less	9.15[3]
Aluminum, Regular	16	7.79
	25	12.68
	30	13.71
	35	15.10
Aluminum, Fluted Ornamental	14	14.82

(1) See Schedule 100 for applicable adjustments.
(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lights Poles[1] (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Aluminum Davit	25	$13.09
	30	13.96
	35	15.43
	40	18.84
Aluminum Double Davit	30	16.80
Aluminum, HADCO, Fluted Ornamental	16	14.18
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	26.49
Concrete Ameron Post-Top	25	31.32
Fiberglass Fluted Ornamental; Black	14	8.65
Fiberglass, Regular		
Black	20	5.48
Gray or Bronze	30	7.34
Other Colors (as available)	35	9.98
Fiberglass, Anchor Base Gray	35	15.98
Fiberglass, Direct Bury with Shroud	18	8.30

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 15 (Concluded)

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installations or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. Electricity delivered to the Customer under this schedule may not be resold by the Customer.

4. If the Customer requests removal of Lighting Service equipment within five years of its installation, the Customer will be responsible for the costs of removal.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$12.00	
Three Phase Service	$16.00	
Transmission and Related Services Charge	0.214	¢ per kWh
Distribution Charge		
First 5,000 kWh	3.073	¢ per kWh
Over 5,000 kWh	0.565	¢ per kWh
Energy Charge		
Standard Service	5.605	¢ per kWh
or		
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)		
On-Peak Period	9.537	¢ per kWh
Mid-Peak Period	5.605	¢ per kWh
Off-Peak Period	3.178	¢ per kWh
Nonstandard Metering Charge (applicable to TOU)		
Single Phase meter	$2.35	
Three Phase meter	$4.25	

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

MONTHLY RATE (Continued)

Renewable Portfolio Options (available upon enrollment in either Energy Charge Option)

Renewable Usage	0.800	¢ per kWh in addition to Energy Charge
Fixed Renewable	$3.50	per month per block
Habitat	$2.50	per month and
	0.800	¢ per kWh in addition to Energy Charge

RENEWABLE PORTFOLIO OPTIONS

The Customer will be charged for Renewable Portfolio Option in addition to all other charges under this schedule for the term of enrollment in the Renewable Portfolio Option.

Habitat Option

The Company will distribute $2.50 per month as received from each Customer enrolled in the Habitat Option to a nonprofit agency chosen by the Company who will use the funds for habitat restoration. The 0.800¢ per kWh will purchase Tradable Renewable Credits (TRCs) and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

Fixed Renewable Option

The Company will purchase 200 kWhs of TRCs and/or renewable energy per block enrolled in the Fixed Renewable Option. All TRCs purchased under this option will come from new renewable resources.

The Company will also place $2.50 of the amount received from Customers enrolled in the Fixed Renewable Option in a new renewable resources development and demonstration fund. Amounts in the fund will be disbursed by the Company to public renewable resource demonstration projects or projects which commit to supply energy according to a contractually established timetable. The Company will report to the Commission annually by April 1st for the preceding calendar year on collections and disbursements. The fund will accrue interest at the Company's authorized rate of return.

Renewable Usage Option

All amounts received from the Customer under the Renewable Usage Option will acquire TRCs and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

SCHEDULE 32 (Continued)

RENEWABLE PORTFOLIO OPTIONS (Continued)
Renewable Usage Option (Continued)

Energy or TRCs supporting the Renewable Portfolio Options will be acquired by the Company such that within two years of a Customer's purchase of renewable energy, the Company will have received sufficient TRCs or renewable energy to meet the purchases by Customers. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

For purposes of these options, renewable resources include wind generation, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. New TRCs or new renewable resources will mean those qualifying resources placed in service after July 23, 1999, as defined in OAR 860-038-0005.

TIME-OF-USE (TOU) OPTION

Time Periods

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

** Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a TOU holiday. If a holiday falls on Sunday, the following Monday is designated a TOU holiday.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price and Nonstandard Metering charges of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.236¢ per kWh for wheeling
- times a loss adjustment factor of 1.0834

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

SCHEDULE 32 (Continued)

SPECIAL CONDITIONS (Continued)

Pertaining to Renewable Portfolio Options (Continued)

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having a time payment agreement that has not been kept current from month to month, b) having received two or more final disconnect notices in the past 12 months; or c) having been involuntarily disconnected in the past 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

Pertaining to the TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater. Single phase 2-wire grounded service is not eligible because of special metering requirements.

4. The Customer must have a meter provided by the Company which is capable of recording interval usage. Because of the special metering requirements of this option, the Company anticipates that a delay may occur from the time a Customer requests service under this option until the Company can provide it. In the interim, Customers will continue to receive service under the Standard Cost of Service Option.

5. The Customer must provide the Company access to the meter on a monthly basis.

SCHEDULE 32 (Concluded)

SPECIAL CONDITIONs (Continued)

Pertaining to the TOU Option (Continued)

6. At the end of the Customer's first 12 months of service under the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. The Nonstandard Metering Charge will be excluded from the bill comparisons. No refund will be issued for Customers not meeting the 12-month requirement.

7. The Company will recover lost revenue from the TOU Option through Schedule 105.

8. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date.

9. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$20.00	
Three Phase Service	$25.00	
Transmission and Related Services Charge	0.086	¢ per kWh
Distribution Charge	3.405	¢ per kWh
Energy Charge**		
On-Peak Period	6.091	¢ per kWh
Off-Peak Period	5.193	¢ per kWh

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Service under this schedule will begin on the first day of the Customer's regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

2. Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 49% on-peak and 51% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$25.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.181	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand	3.714	¢ per kWh
Over 50 kWh per kW of Demand	1.714	¢ per kWh
Energy Charge***	5.096	¢ per kWh

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 47 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$30.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.180	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand	3.000	¢ per kWh
Over 50 kWh per kW of Demand	1.000	¢ per kWh
Energy Charge***	5.064	¢ per kWh

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 54
LARGE NONRESIDENTIAL
TRADABLE RENEWABLE CREDITS RIDER

PURPOSE

This rider is an optional supplemental service that supports the development of New Renewable Energy Resources as defined in ORS 757.600. Under this Schedule a Large Nonresidential Customer may purchase Tradable Renewable Credits (TRCs) based on a percentage of the Customer's load, subject to a minimum purchase. The purchase guarantees an equivalent amount of generation from qualified renewable resources will be transmitted within the Western Electricity Coordinating Council.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Large Nonresidential Customers.

RATE

A Customer may purchase TRCs at:

1.7¢ per kWh

A minimum TRC purchase of 1,000 kWh times 1.7¢ ($17.00) per month is required. For larger purchases, volume discounts may be available, subject to negotiation, pursuant to the execution of a written contract.

SPECIAL CONDITIONS

1. The Customer may enroll to purchase TRCs on a month to month basis or sign an annual contract to pay annually or monthly. Service will become effective upon execution of a signed agreement.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having received two or more final disconnect notices in the past 12 months; or b) having been involuntarily disconnected in the past 12 months.

3. The Company makes no representations as to the impact on the development of renewable resources from Customer participation.

SCHEDULE 54 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

6. A TRC purchase by the Company sufficient to meet the total of all Customer purchases of TRCs will occur, at least, on an annual basis.

6. All incremental costs and revenues associated with the provision of services under this schedule will be appropriately charged or credited to nonutility accounts.

7. Upon Customer written or verbal permission, the Company may use Customer proprietary information gathered for the provision of Electricity Services as long as it provides the same information under the same terms and conditions to alternative TRC providers.

8. The Company will communicate to its Customers or potential Customers, both in its verbal conversations and in its written materials that: the Customer may buy TRCs from other providers; and Customers are not required to buy TRCs from the Company in order to continue to receive the Company's safe and reliable Electricity Service.

9. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other TRC providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Large Nonresidential TRC program.

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 1 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.66	$0.66	$0.66
Distribution Charges			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
Generation Contingency Reserves Charges			
Spinning Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢
Energy Charge			
per kWh	See Energy Charge Below		

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating. The Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for generator operations, will be used to calculate the Baseline Demand. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

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

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 1,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's load reduction plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating. Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable. Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.236¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

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

LOSSES

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

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SCHEDULE 75 (Continued)

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

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

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

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

6. The Customer will not use Scheduled Maintenance Energy, Unscheduled Energy or Reserved Capacity to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

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

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

8. The Customer's Baseline Demand may be modified as requested by the Customer upon the addition of permanent energy efficiency measures, load shedding, or the removal of equipment. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation.

9. A change in Baseline Demand related to modifications in generating capacity or generation operations may be made provided the Customer provides not less than two calendar years prior notice to the Company of such change. Any subsequent notice by the Customer under this special condition must be made no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand.

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

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

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

TERM

A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:

Transmission and Related Services Charge		
per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.026	
Daily ERP Demand Charge		
	Delivery Voltage	
	Secondary and Primary	Subtransmission
per kW of Daily ERP Demand during On-Peak hours per day*	$0.095	$0.050
System Usage Charge		
per kWh of ERP		0.178 ¢
Transaction Fee		
per Energy Needs Forecast (ENF)		$50.00
Energy Charge**		
per kWh of ERP	See below for ERP Pricing	

* Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

** See Schedule 100 for applicable adjustments.

SCHEDULE 76R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 75). The Customer must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that ERP is requested.

Each ENF will be based on the Customer's expected Energy requirements and the Customer will use best efforts to conform actual Energy usage to the ENF and utilize Energy imbalances to the minimum extent reasonably possible.

The ENF will specify the expected ERP needed by hour. The Customer will deliver the ENF to the Company in accordance with Company procedures. The Company will inform the Customer as to the availability of ERP at the time of the ENF request. The Company can choose to provide all or a portion of the ENF and will inform the Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

Economic Replacement Power Pricing

Energy will be priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.236¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

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

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

SCHEDULE 76R (Continued)

IMBALANCE CHARGES

Imbalance Amount = The absolute value of (ENF minus ERP)

Imbalance Amount	Adjustment Amount
Less than 7.5% of Energy Needs Forecast	zero
Greater than 7.5% of Energy Energy Needs Forecast	10% of Hourly Price applied to Imbalance Amount greater than 7.5% of Energy Needs Forecast

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

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

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 76R (Concluded)

SPECIAL CONDITIONS (Continued)

3. All charges and requirements of Schedule 75 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

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

6. The Customer must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than five MW that are expected to last one hour or longer. The Company may require the Customer to change its forecast if the Company believes the forecast does not adequately represent the expected load.

7. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 75 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

8. The Company is not responsible for providing market information to Customer.

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

10. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule K Curtailment Plan and Rule C Emergency Curtailment.

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.236 ¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

ANCILLARY SERVICES

Customers receiving this service are required to pay for Ancillary Services at the rates determined by the Company's Open Access Transmission Tariff (OATT), Original Volume 8 (PGE-8) Transmission Services.

SCHEDULE 81 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will terminate five business days from initial purchase.

RULES AND REGULATIONS

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

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage	
	Secondary	Primary
Basic Charge		
Single Phase Service	$20.00	
Three Phase Service	$25.00	$90.00
Transmission and Related Services Charge		
per kW of monthly Demand	$0.66	$0.66
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity	$2.29	$2.11
per kW of monthly Demand		
First 30 kW of Demand	$2.07	$2.07
Over 30 kW of Demand	$2.64	$2.64
Energy Charge		
Cost of Service Option per kWh	5.544 ¢	5.344 ¢
See below for Daily or Monthly Pricing Option descriptions.		
System Usage Charge		
per kWh	0.216 ¢	0.205 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option except as provided below under the Monthly Direct Access Election Enrollment Window. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.236¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 83 (Continued)

NOVEMBER ELECTION WINDOW

A Customer may change Energy Charge options by notifying the Company of his/her choice during the November Election Window.

The November Election Window begins at 2:00 p.m. on November 15th (or the following work day if the 15th falls on a weekend or holiday) and continues until 5:00 p.m. at the close of the fifth consecutive business day.

A Customer who elects an Energy Charge Option during the November Election Window must complete the specified term of their current option.

MONTHLY DIRECT ACCESS ELECTION ENROLLMENT WINDOW

For the remaining 11 months, the Monthly Direct Access Election Enrollment Window is applicable to Customers who have a historical usage or have demonstrated that projected usage in the current calendar year is at least 8,760,000 (1MWa) from one or more PODs. Each POD must have a Facility Capacity of at least 250 kW.

A Monthly Direct Access Election Enrollment Window will open at 12:00 p.m. PPT on the 15th of each month and remain open until 5:00 p.m. the next business day. If the 15th falls on a weekend or holiday, the window will be begin on the next business day. Customers may make a service election during a Monthly Direct Access Election Enrollment Window through the Company website (www.PortlandGeneral.Biz).

By 12:00 p.m. on the day of each Monthly Direct Access Enrollment Window, the Company will make available and post on its website (www.PortlandGeneral.Biz) the Schedule 128, Transition Adjustment applicable to those Customers electing discontinuation of Cost of Service.

During the Monthly Direct Access Election Enrollment Window, Cost of Service Customers may choose at this time discontinuation of Cost of Service. The elected service option will become effective the first calendar day of the month, approximately 45 days from the date of the Direct Access Election Enrollment Window. A Customer making a monthly election under this option may not return to the Cost of Service Option until the following calendar year, subject to the requirements of making an annual Cost of Service election.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW for primary voltage service.

SCHEDULE 83 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

A Customer served under the Daily or Monthly Option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 84
LARGE NONRESIDENTIAL
LARGE LOAD SPLIT SERVICE RIDER OPTION

PURPOSE

The Large Load Split Service Rider Option allows a Customer to receive Direct Access Service for a percentage of its usage, while the remainder is served on the Cost of Service option.

APPLICABILITY

To Large Nonresidential Customers served on Schedule 83 or 89 that demonstrate the following:

1) Usage in the most recent 12 months or, projected annual usage or where 12 months of usage history is not available, of at least 87,600,000 kWh (10 MWa) from one or more participating Points of Delivery (PODs);
2) An election to maintain at least 10 MWa usage on this option;
3) A Facility Capacity of at least 250 kW at each participating POD; and
4) An average non-coincident monthly load factor for the aggregated PODs participating of at least 60%, determined by the Company based the historical usage information.

DESCRIPTION OF SERVICE OPTION

A Customer receiving service under this rider must elect 10% to 50% of eligible load to be served on Direct Access Service. All remaining load will be served by the Company.

DIRECT ACCESS BLOCK

The Direct Access Block is a fixed kWh served on Direct Access Service.

The Customer will choose the percentage of load to be served on Direct Access Service. The Company will determine the Direct Access Block by multiplying that percentage by the Customer's annual historical kWh usage for all participating PODs with the result divided by 8,760 hours, subject to the following limits:

- A Direct Access Block will not result in more than 50% of the annual historical usage.
- A POD may not have more than five consecutive days (or 120 hours) where the Direct Access Block is greater than the historical usage. When this occurs, the percentage that determines the Direct Access Block will be reduced for all of the Customer's PODs.

The Direct Access Block will remain unchanged for the calendar year [which may be less than 12 months if an Electricity Service Supplier (ESS) does not make a timely submittal of the required Direct Access Service Requests (DASRs)].

SCHEDULE 84 (Continued)

COMPANY SERVED LOAD

The Company Served Load is the difference between the Direct Access Block and the metered interval load data for each POD by hour. If actual usage in an hour is less than the Direct Access Block, the Company supplied Energy is deemed to be zero for the hour.

DIRECT ACCESS SERVICE

The Customer must arrange for an ESS to provide Direct Access Service for the Direct Access Block. The ESS is responsible for enrolling each participating POD in Direct Access Service and meeting all requirements defined in Rule K for timely DASR submittals. Beginning on January 1st, all participating POD(s) will be billed at the Daily Price until Direct Access Service commences for the participating PODs.

MONTHLY RATE

The Monthly Rate is the sum of the following charges:

Energy Charge

For the Company Served Load, the Cost of Service Monthly Energy Charge from the applicable Schedule 83 or 89 rates (for the appropriate Delivery Voltage) will apply.

The Customer's ESS will bill separately for Energy provided for the Direct Access Block.

Other Charges

The following charges will be applied to the Customer's total usage for each POD: The applicable Schedule 83 or 89 Basic Charge, Transmission and Related Services Charge, Distribution Charge, System Usage Charge, Reactive and other applicable charges except the Energy Charge and including supplemental adjustments applied to each POD's total Energy, Demand, Facility Capacity and Reactive Demand.

Schedule 128, Short-Term Transition Adjustment, will apply only to the Energy provided for the Direct Access Block.

A credit will be applied to the Direct Access Block billing for Transmission and Related Services. The credit will be equal to the Schedule 83 or 89 Transmission and Related Services Charge applied to the Direct Access Block Demand.

SCHEDULE 84 (Concluded)

ENROLLMENT

The Company will provide a list of eligible PODs to Customers by September 15th of each calendar year (or the following business day if the 15th falls on a weekend or holiday).

By 5:00 p.m. on September 29th (or 10 business days from the date of Notification), the Customer must provide written notification to the Company verifying the following:

1) The Customer's intent to elect the service under this Rider.
2) A list of the PODs the Customer intends to enroll under this service option during the November Election Window (as defined in Schedules 83 and 89).
3) The proposed percentage of load to be served on Direct Access Service. This designation will be used by the Company to determine the Direct Access Block.

By October 15th (or the following business day if the 15th falls on a weekend or holiday), the Company will confirm receipt of the election and the PODs the Customer intends to enroll. In order to receive service under this rider, the Customer must confirm enrollment during the November Election Window. After the Customer selection is confirmed during the November Election Window, the Company will provide the Customer with POD identification (PODID) numbers to be used by an ESS to enroll the Direct Access Block PODs in Direct Access. The Customer is responsible for furnishing this information to its selected ESS.

SET UP FEE

Customers notifying the Company of their intent to receive service under this rider will be charged a one-time non-refundable fee of $70 per each designated POD. This fee will be due with the Customer's written notification in September for a service election in November and service the following January.

TERM

All of the Customer's enrolled PODs will remain on this option for the entire calendar year.

SCHEDULE 86
NONRESIDENTIAL
DEMAND BUY BACK RIDER

PURPOSE

This rider is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce their Electricity usage in return for a payment, at times and at prices determined by the Company. The Company will notify participating Customers of the opportunity to reduce Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Customers served under Schedules 38, 83, 84 and 89 who satisfy the conditions contained in this rider. Customers must execute a Demand Buy Back Agreement prior to receiving service and have the capability to reduce not less than 250 kW at each metered location for each hour during a Buy Back Event. At the Company's discretion, new Customers that can establish a Baseline Usage and reduce a minimum of 250 kW per hour may take service under this rider.

BUY BACK CREDIT DETERMINATION

Energy Price

The Energy Price will be a price or prices quoted by the Company for a specified Buy Back Event, subject to requirements and other conditions described in Special Conditions.

Hourly Credit Rate

		Customer's Rate Schedule		
Energy Price	**less**	Energy Price	=	Hourly Credit Rate (¢/kWh)

The Hourly Credit Rate will be determined by subtracting the Energy Charge the Customer would pay on their otherwise applicable rate schedule from the Energy Price. This calculation is performed for each hour during the Buy Back Event. In circumstances when the Company cancels all or a portion of a Buy Back Event, the Hourly Credit Rate will be determined as described in Buy Back Event Cancellation.

Hourly Credit

Buy Back Amount (kWh) **X** Hourly Credit Rate **=** Hourly Credit

SCHEDULE 86 (Continued)

BUY BACK CREDIT DETERMINATION (Continued)
Hourly Credit (Continued)

The Hourly Credit is the amount owed to the Customer for each hour of the Buy Back Event. The Hourly Credit is determined by multiplying the Buy Back Amount by the Hourly Credit Rate. The Hourly Credit will not be less than zero.

Buy Back Credit

The Buy Back Credit is the amount paid to the Customer for its Electricity reduction during a Buy Back Event and is the sum of each Hourly Credit during such event (minus any amounts owed as a result of failure to comply during an Extended Buy Back Event).

PAYMENTS

The Company will pay the Buy Back Credit to the Customer within 60 days of the Buy Back Event.

BUY BACK AMOUNT

The Buy Back Amount will be the difference between the Customer's Baseline Usage and the Customer's measured hourly load during the term of the Buy Back Event. The Customer will participate by operating below its Baseline Usage for the length of the requested Buy Back Event. A participating Customer's measured load for purposes of determining a Buy Back Amount must be zero kW or greater.

BASELINE USAGE

The Customer's Baseline Usage is dynamic and is defined as the average Energy usage for each hour for a minimum of approximately 14 typical operational days prior to the Buy Back Event. Typical operational days exclude days that a Customer has participated in a Buy Back Event. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Usage when the Customer's Energy usage is highly variable.

BUY BACK PLEDGE

The Buy Back Pledge is the amount of Energy the Customer commits to curtail when it agrees to participate in a Buy Back Event. The Buy Back Pledge must be greater than a 250 kW reduction and can vary by hour. The Customer must submit to the Company the amount of the Buy Back Pledge prior to the Buy Back Event through the specified notification method. The Customer will receive an acceptance confirmation for its pledge prior to the start of the event. A Buy Back Pledge cannot exceed Baseline Usage and is the expected Buy Back Amount for the Buy Back Event. The Company reserves the right to reject a Buy Back Pledge.

SCHEDULE 86 (Continued)

RATE SCHEDULE ENERGY PRICE

The Rate Schedule Energy Price is the Energy Charge contained in the rate schedule under which the Customer is served. For rate schedules that contain on- and off-peak charges, the on-peak Energy price will be the Rate Schedule Energy Price during on-peak hours of a Buy Back Event and the off-peak Energy price will be the Rate Schedule Energy Price during off-peak hours of a Buy Back Event. No supplemental adjustments will be applied to the Energy Charge when determining the Rate Schedule Energy Price.

NOTIFICATIONS

The Company will utilize a secured Internet web site as the primary method to notify participants of Buy Back Events and to receive Customer notification of participation in a Buy Back Event. The Company's notification will include a time and date by which the participating Customers must submit a Buy Back Pledge. The Company will provide the Customer with access codes to the secured Internet web site. Other methods of notification such as, facsimile, telephone and electronic mail, may be utilized at the discretion of the Company.

BUY BACK EVENT

The Company is not obligated to call a Buy Back Event and the Customer is not obligated to reduce Energy upon being advised of a Buy Back Event. The Company will not be liable for failure to advise a Customer of a Buy Back Event.

Buy Back Event Cancellation

The Company reserves the right to cancel all or a portion of a Buy Back Event upon notification to participating Customers (i.e., those that have a Buy Back Pledge accepted by the Company), except that an Extended Buy Back Event will be cancelled only upon mutual agreement of the Customers participating in the particular Extended Buy Back Event and the Company. Upon notification of a cancellation, the Customer may resume its normal operations or continue with load reductions consistent with the requirements of its Buy Back Pledge. A Customer that elects to resume its normal operations will not receive a Buy Back Credit. A Customer that continues with load reductions will receive a Buy Back Credit for the amount of Energy reduced during the cancelled hours of the event. Such credit will be based on an Hourly Credit Rate determined by the amount of advance notice the Company provides the Customer prior to the start of the cancellation as written below. In no circumstance will the Company notify the Customer less than two hours prior to the start of a cancellation.

SCHEDULE 86 (Continued)

BUY BACK EVENT (Continued)
Buy Back Event Cancellation (Continued)

For a Customer that provides load reductions during non-cancelled hours of a partially cancelled Buy Back Event, the Company will pay the Customer for such load reductions at the Hourly Credit Rate quoted by the Company for the event.

For an announced cancellation to become effective:

1) In two hours, the Hourly Credit Rate is 7.0 ¢ per kWh; or

2) Between two hours and four hours, the Hourly Credit Rate is 5.0 ¢ per kWh; or

3) Between four hours and six hours, the Hourly Credit Rate is 3.5 ¢ per kWh; or

4) If more than six hours, no Hourly Credit is provided.

FAILURE TO COMPLY WITH BUY BACK PLEDGE

Single Day Buy Back Event

If a Customer's Buy Back Amount for any hour is less than 90% of the Customer's Buy Back Pledge, the Company may refuse to accept future pledges from the Customer until the capability to meet their pledge is demonstrated in a manner acceptable to the Company. After the third occurrence of nonperformance, the Company may refuse to allow the Customer to participate in future Buy Back Events.

Extended Buy Back Event

If a Customer's actual Buy Back Amount for any hour of an Extended Buy Back Event (as defined below in Special Condition 3 below) is less than the Buy Back Pledge, the Customer will pay to the Company an amount equal to the applicable Dow Jones Mid-Columbia Daily Electricity Firm On-Peak Price Index, plus 5%, multiplied by the difference between the Buy Back Pledge and the actual hourly Buy Back Amount for all of the hours during the Extended Buy Back Event that the pledge is not met. The Company may for any Extended Buy Back Event explicitly establish other lesser consequences for noncompliance.

SCHEDULE 86 (Continued)

DEMAND BUY BACK AGREEMENT

The Customer and Company must execute a written Demand Buy Back Agreement.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The portion of the Customer's load that is billed according to a Daily Price Option is not eligible to participate in a Buy Back Event.

2. Metering and Communications Equipment. The Customer may not participate in this rider until the Company has installed metering that records usage in 15 minute intervals. The Customer will provide communication service to the meter if requested by the Company. Service under this rider is subject to meter availability.

3. Buy Back Event. A Buy Back Event specifies the dates, times and duration of a Company requested load reduction and will be for one or more consecutive hours. A Buy Back Event with a duration of more than 24 consecutive hours is an Extended Buy Back Event. An Extended Buy Back Event may include requirements for a single, continuous Buy Back Pledge to which the participant must comply for the duration of the event. More than one Buy Back Event may occur in one day and more than one Buy Back Event may be in effect simultaneously.

4. Notification. The Company is not responsible for any load reduction that has not been confirmed and accepted by the Company.

5. Liability. The Company is not responsible for any consequences to the participating Customer that result from a Buy Back Event or the Customer's effort to reduce Energy in response to a Buy Back Event.

6. System Emergencies. Where the Company requests load interruptions for a system emergency, this rider is not applicable.

7. Third Party Management. The Company may utilize a third party to provide program management support for this rider. The Company has the right to provide the Customer's Energy consumption data to a third party for the purpose of providing service under this rider. Such information will be provided to a third party subject to confidentiality requirements.

SCHEDULE 86 (Concluded)

SPECIAL CONDITIONS (Continued)

8. Load Shifting. The Company may quote a separate Energy Price for Customers that shift load in conjunction with a Buy Back Event. Load shifting is the change in a Customer's Energy usage during non-Buy Back Event hours to compensate for reduced Energy usage during the Buy Back Event. For purposes of this rider, load shifting occurs when the Customer's Energy usage during the 24 hours preceding or following a Buy Back Event (or any day of an extended Buy Back Event) increases from the applicable hourly Baseline Usage by more than 50% of the Buy Back Amount.

9. Testing. The Company and the Customer will test the Customer's ability to reduce Energy usage prior to the Customer's participation in a Buy Back Event.

10. Eligibility for Other Schedules. If a Customer takes service under a Direct Access Service schedule (when available), it is no longer eligible to participate in this rider.

11. Billing Errors. Should an error occur in the calculation of the Buy Back Credit or any of the underlying components, the Company will provide written notice to the Customer detailing the circumstances and amount of adjustment. The Customer will return the overpayment to the Company or the Company will pay the underpayment to the Customer, as applicable, within a period of time agreed to by the Customer and the Company after notice has been given.

TERM

Service under this schedule will not be for less than one year term.

SCHEDULE 87
LARGE NONRESIDENTIAL
(> 1000 MW DEMAND)
EXPERIMENTAL REAL TIME PRICING (RTP) SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To the first six Large Nonresidential Customers with Facility Capacity greater than 1,000 kW Demand that apply and are accepted by the Company. Customers applying for service under this schedule must be able to demonstrate their ability to respond to market price signals. The Company will create a unique consumption baseline for each participating Customer. Each Customer will have different capabilities to respond to the hourly prices and thus will be considered a separate Customer class under this schedule. Customers participating in Schedules 84, 86, 88 or 200 are not eligible for service under this schedule.

MONTHLY BILL

The Monthly Bill consists of a Standard Bill, Administrative and Reactive Demand Charges, Adjustments, and a charge or credit based on the difference between a Customer's actual usage and their Customer Baseline Load (CBL) in each hour and the hourly Energy prices provided during the Billing Period. The Monthly Bill is calculated using the following formula:

$$\text{Bill}_{\text{Mo.}} = \text{Standard Bill}_{\text{Mo}} + \sum \text{Price}_{\text{Hr}} \times [\text{Load}_{\text{Hr.}} - \text{CBL}_{\text{Hr.}}]$$
$$+\text{Administrative Charge} + \text{Reactive Demand Charge}$$
$$+ \text{Adjustments}$$

Where:

Bill $_{\text{Mo.}}$	=	Customer's Monthly Bill for service under this schedule
Standard Bill $_{\text{Mo.}}$	=	Customer's bill based on usage as defined by the CBL and billed under the Annual Cost of Service under Schedule 83 or 89
$\sum$	=	Sum over all hours of the monthly Billing Period
Price $_{\text{Hr.}}$	=	Hourly price based on marginal Energy costs
Load $_{\text{Hr.}}$	=	Customer's actual load in an hour
CBL $_{\text{Hr.}}$	=	Customer's baseline load shape on an hourly basis

SCHEDULE 87 (Continued)

STANDARD BILL

The Standard Bill is calculated by applying the Annual Cost of Service Option under Schedule 83 or 89 to a CBL for each month of the year, excluding the Reactive Demand Charge and Adjustments identified in Schedule 100. If prices are revised, those changes will be reflected in the Customer's Standard Bill based on the CBL for a given month. Hourly Energy prices are applied only to kWh usage changes from the CBL in each hour.

CUSTOMER BASELINE LOAD (CBL)

The CBL is the Customer's hourly load for a 12-month period at typical levels of operation. It is developed based on the Customer's specific hourly load data or monthly billing data allocated to hours based on the consumption pattern agreed to by the Customer and the Company as typical of the Customer's operation.

Agreement to a CBL is a precondition for service under this schedule. The CBL is proprietary and will not be released to any other entity without the approval of the Customer and the Company. In order that the CBL reflect the Customer's Energy and Demand as accurately as possible, the Customer may request adjustments to the CBL for the following reasons:

1. The installation of permanent energy efficiency measures either as a participant in Energy Trust of Oregon programs or other verifiable conservation or technology improvement measures.
2. The addition or removal of equipment that results in a permanent change in the Customer's expected electricity consumption.

If the Customer leaves the program, he/she may not be allowed to return for a minimum of 12 months. A new CBL will be calculated in such cases based on the most recent usage. At a minimum, the CBL will be reviewed every three years and may be adjusted.

HOURLY ENERGY PRICE

Hourly Energy Prices are determined each day for the following day using Mid-Columbia Day Ahead Prices for on- and off-peak periods shaped to hourly prices based on the reported hourly Mid-Columbia prices from preceding days. The following charges will be added to the shaped hourly prices, 0.236 ¢ per kWh for wheeling, plus losses and the System Usage Charge as specified in Schedule 83 or 89. If prices are not reported for a particular day or days, the Company will estimate and shape prices from its hourly Energy price projections.

In addition to the above charges, consumption of Energy above the CBL will be billed a 0.300¢ per kWh recovery factor. For consumption of Energy below the CBL, a 0.300¢ per kWh recovery factor will be subtracted from the Hourly Energy Price.

SCHEDULE 87 (Continued)

REVENUE NEUTRALITY

The Customer's bill under Schedule 87 will equal the Customer's bill under the Annual Cost of Service Option under Schedules 83 or 89 assuming the Customer uses Electricity according to the CBL plus the Administrative Charge.

ADMINISTRATIVE CHARGE

The Customer will pay an Administrative Charge of $155 per month to cover additional billing, administrative and communication costs associated with this service schedule.

REACTIVE DEMAND CHARGE

The Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand in the Billing Period.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100. Applicable adjustments are applied only to actual usage. When the adjustment is based on factors other than usage, such as Schedule 108, the adjustment will be applied to the monthly bill, after including all other applicable adjustments.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. Customers who request service under this schedule will be selected to participate in this experiment in accordance with this schedule. In addition to the previously specified qualifying criteria, Customers that have intermittent or highly seasonal loads, cannot demonstrate price response capability, or intend to undertake load (capacity) reductions under another Company schedule or through a Company contract pursuant to a solicitation for Demand response may not participate in this experiment.

3. The Company will make hourly Energy prices available to customers by 4:00 p.m. for the following day, via a method specified by the Company. Except during unusual circumstances, the Company will make available prices for Saturday through Monday on the previous Friday. More than day-ahead pricing may also be available for holiday periods. Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25).

SCHEDULE 87 (Concluded)

SPECIAL CONDITIONS (Continued)

4. The Company is not responsible for a Customer's failure to receive and act upon hourly prices. If a Customer does not receive these prices, it is the Customer's responsibility to inform the Company of any failure to receive the hourly prices by 5:00 p.m. the day before they become effective so the prices may be supplied.

5. The Customer will notify the Company's Merchant Power Operations at a phone number specified as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer.

6. If the Company is required to install new distribution facilities based upon an increase in the Customer's load, the Company may require an update of the CBL.

7. Customers must be on Schedule 83 or Schedule 89, Annual Cost of Service Option to be eligible for this schedule.

TERM

Service under this schedule will be for a minimum of one year with annual renewal rights.

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

The Load Reduction Program is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce Electricity usage to a Company-determined level during an Emergency Curtailment as described in Rule C(2)(B) in exchange for partial exemption from Emergency Curtailments.

AVAILABLE

In all territory served by the Company but total pledges will not exceed 5% of Company primary voltage circuits.

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 89, 583 and/or 589 from one or more Point(s) of Delivery (PODs)but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple PODs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule.

BASELINE USAGE

The Baseline Usage is defined as the average usage for each hour for a minimum of 14 typical operational days prior to the Emergency Curtailment. Typical operational days exclude days that a Customer has participated in either an Emergency Curtailment or a Demand Buy Back Event (Schedule 86). Holidays and weekends will be excluded when determining the Baseline Usage except when the Emergency Curtailment includes weekends or holidays. The Customer may request that specific days be excluded from the 14-day baseline calculation upon demonstrating to the Company's satisfaction that the specific days are not similar days. The Company and Customer may mutually agree to use an alternate method to determine Baseline Usage when the Customer's usage is highly variable.

LOAD REDUCTION DETERMINATION

During an Emergency Curtailment, the individual Customer or group of Customers will be required to reduce Baseline Usage to a Company-determined Maximum Circuit Load (MCL). The MCL is the Customer's or group of Customer's Baseline Usage minus the necessary load reduction of 5, 10 or 15%.

Schedule 88 (Continued)

LOAD REDUCTION DETERMINATION (Continued)

The Company may choose at any time during an Emergency Curtailment to increase the load reduction percentage. Upon notification of an MCL change, the Customer/Lead Customer has one-half hour (30 minutes) to meet the new MCL. The Company may only make one notification of an increased increment of reduction per hour.

If the Customer is participating in Demand Buy Back Rider (Schedule 86), Baseline Usage will be determined after subtracting the Buy Back amount stipulated under that schedule. State mandated curtailments as defined under Rule N will also be subtracted before determining Baseline Usage.

LOAD REDUCTION PLAN

Participation depends upon the Company approval of a single submitted Load Reduction Plan. A renewed plan is due annually on March 15th.

A Lead Customer will submit one Load Reduction Plan for the group of Customers served on the same dedicated primary circuit and jointly participating. The Lead Customer assumes responsibility for submitting the group's Load Reduction Plan, managing the load reduction and paying all noncompliance charges.

The Load Reduction Plan must include the following:

1) Customer or Lead Customer's name;
2) A list of all other participating Customers, their account numbers, service and mailing addresses, and contact information;
3) The Customer or Lead Customer's alphanumeric pager and facsimile numbers to be used for notification of an Emergency Curtailment;
4) A Company and Customer mutually agreed upon Baseline Usage;
5) An estimated MCL for the 5, 10 and 15% load reduction levels. The MCL for the 5% load reduction is equal to the Baseline Usage times 0.95; 10% load reduction is Baseline Usage times 0.90; 15% reduction is Baseline Usage times 0.85; and
6) Specific quantifiable measures to be utilized by the Customer to reduce load to or below each MCL.

NOTIFICATION

The Company will notify the Customer/Lead Customer as to the percent of load reduction needed by alphanumeric pager and/or facsimile. The Customer/Lead Customer is responsible for keeping the pager and facsimile functioning and able to receive notification.

Schedule 88 (Continued)

NOTIFICATION (Continued)

Upon notification, the Lead Customer will be responsible for contacting all other Customers participating under that plan. Upon notification, the Customer/Lead Customer will have 30 minutes to establish the determined MCL.

METERING EQUIPMENT

Customers on a dedicated circuit with one POD will have load reduction compliance audited by an interval meter with remote access capacity. The Company will install metering that records usage in 15-minute intervals. The Customer will provide communication service to the meter if requested by the Company. Participation under this schedule is subject to meter availability.

Customers on a dedicated circuit with more than one POD will have compliance monitored from individual meters or electronic recording equipment located at Company substations. Where the circuit does not have electronic recording equipment to monitor its load, the Company will install such equipment subject to availability. The Customer/Lead Customer will provide communication service when requested by the Company.

A Customer/Lead Customer will not be allowed to participate in any Load Reduction Programs until the proper monitoring equipment is installed and operational.

FAILURE TO COMPLY

Failure to meet the required MCL, to maintain the MCL for the duration of the Emergency Curtailment or to meet the required MCL within the required 30 minutes after notification will result in a noncompliance penalty. The penalty is equal to two times the baseline circuit load (BCL) on the applicable circuit, less the required MCL by hour, times the market price (MP) for power during the Emergency Curtailment as determined by an appropriate index such as the Dow Jones Mid-Columbia Daily Electricity Firm Price Index:

$$\text{Penalty} = 2[MP(BCL - MCL)]$$

Such penalties will be in addition to all other Company charges for Electricity Service.

After two noncompliance penalties, the Customer/Lead Customer will be removed from the program. Failure to pay noncompliance penalties may result in the termination of the Customer's/Lead Customer's Electricity Service.

Schedule 88 (Concluded)

ADJUSTMENTS

Supplemental adjustment schedules are applicable to the Customer's underlying rate schedule and not applicable to this schedule unless approved by the Commission.

SPECIAL CONDITIONS

1. The Company may not be able to supply advance notice of an Emergency Curtailment. Participation in this program does not guarantee that the Customer or group of Customers will not be subject to outages related to maintenance, storms or system emergencies caused by natural catastrophes.

2. The Company is not liable for any damage to Customer's property resulting from participation in this program.

TERM

Service under this schedule will be for a term of one year. Service thereafter may be extended after Company review of Customer's/Lead Customer's annually updated Load Reduction Plan. Customer/Lead Customer's decision to leave the program at any time may limit its eligibility to participate in the program in the future.

SCHEDULE 89
LARGE NONRESIDENTIAL (>1,000kW)
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.66	$0.66	$0.66
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
Energy Charge			
On-Peak Period***	5.868 ¢	5.658 ¢	5.581 ¢
Off-Peak Period***	4.973 ¢	4.791 ¢	4.718 ¢
See below for Daily or Monthly Pricing Option descriptions.			
System Usage Charge			
Per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.236 ¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment

SCHEDULE 89 (Continued)

NOVEMBER ELECTION WINDOW

A Customer may change Energy Charge options by notifying the Company of his/her choice during the November Election Window.

The November Election Window begins at 2:00 p.m. on November 15th (or the following work day if the 15th falls on a weekend or holiday) and continues until 5:00 p.m. at the close of the fifth consecutive business day.

A Customer who elects an Energy Charge Option during the November Election Window must complete the specified term of their current option.

MONTHLY DIRECT ACCESS ELECTION ENROLLMENT WINDOW

The Monthly Direct Access Election Enrollment Window is applicable to Customers who have a historical usage or have demonstrated that projected usage in the current calendar year is at least 8,760,000 (1MWa) from one or more POD. Each POD must have a Facility Capacity of at least 250 kW.

A Monthly Direct Access Election Enrollment Window will open at 12:00 p.m. PPT on the 15th of each month and remain open until 5:00 p.m. the next business day. If the 15th falls on a weekend or holiday, the window will be begin on the next business day. Customers may make a service election during a Monthly Direct Access Election Enrollment Window through the Company website (www.PortlandGeneral.Biz).

By 12:00 p.m. on the day of each Monthly Direct Access Enrollment Window, the Company will make available and post on its website (www.PortlandGeneral.Biz) the Schedule 128, Short-Term Transition Adjustment.

During the Monthly Direct Access Election Enrollment Window, Cost of Service Customers may choose at this time discontinuation of Cost of Service. The elected service option will become effective the first calendar day of the month, approximately 45 days from the date of the Direct Access Election Enrollment Window. A Customer making a monthly election under this option may not return to the Cost of Service Option until the following calendar year and subject to the requirements of making an annual Cost of Service election.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

SCHEDULE 89 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

A Customer served under the Daily or Monthly Option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 91
STREET AND HIGHWAY LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control or time switch to be mutually agreeable to the Customer and Company for an average of 4,150 hours annually.

SERVICE OPTIONS

The Company has the following service options available for lighting:

Option A is for luminaires owned, maintained and supplied with Electricity by the Company.

Option B is for maintenance and Electricity supplied to Customer-owned equipment.

Option C is a grandfathered option, available only where Option C service was initiated prior to December 31, 2006. Option C is the provision of Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles.

MAINTENANCE

Maintenance of Option A luminaries includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance also includes repair of an inoperable luminaire. This means that any failed part (e.g., lamp, photoelectric controller, starter, ballast, refractor, power door) will be replaced, or the entire failed luminaire will be replaced with in-kind equipment, if it is more practical to do so.

SCHEDULE 91 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Transmission and Related Services Charge	0.109 ¢ per kWh
Distribution Charge	2.803 ¢ per kWh
Energy Charge	
Cost of Service Option	5.380 ¢ per kWh

Daily Price Option – Available only to Customers with an average load of five MW or greater. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.236¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

SCHEDULE 91 (Continued)

MONTHLY RATE (Continued)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month. The on- and off-peak usage will be calculated using Sunrise Sunset Tables with adjustments of 15 minutes before Sunrise and 15 minutes after Sunset.

For Customers billed on the Daily Energy Rate Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the above applicable Daily Price by 1.0834.

To begin service under this option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Cobrahead Power Doors **	100	9,500	43	*	$3.23
	150	16,000	63	*	3.25
	200	22,000	80	*	3.30
	250	29,000	103	*	3.28
	400	50,000	165	*	3.29
Cobrahead	100	9,500	43	$6.09	3.31
	150	16,000	63	6.12	3.33
	200	22,000	80	6.58	3.37
	250	29,000	103	6.63	3.37
	400	50,000	165	6.66	3.39
Flood	250	29,000	103	6.92	3.39
	400	50,000	165	6.95	3.42

* Not offered.
** Service is only available to Customers with total power door luminaries in excess of 2,500.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Early American Post-Top	100	9,500	43	$6.55	$3.31
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	100	9,500	43	6.99	3.38
	150	16,000	63	7.29	3.42

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.38	$0.15
Fiberglass, Bronze	30	5.85	0.20
Fiberglass, Gray	30	5.86	0.20
Wood, Standard	30 to 35	5.04	0.16
Wood, Standard	40 to 55	6.32	0.21

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Special Acorn-Types					
HPS	100	9,500	43	$9.81	$3.62
HADCO Independence HPS	100	9,500	43	8.93	3.41
	150	16,000	63	8.95	3.43
Special Architectural Types					
HADCO Victorian HPS	150	16,000	63	9.51	3.61
	200	22,000	80	9.51	3.57
	250	29,000	103	9.66	3.63

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
HADCO Techtra HPS	100	9,500	43	$16.27	$4.00
	150	16,000	63	16.29	4.02
	250	29,000	103	23.06	4.71
KIM Archetype HPS	250	29,000	103	*	3.73
	400	50,000	165	*	3.74
Special Types					
Cobrahead, Metal Halide	175	12,000	72	6.28	3.41
Flood, Metal Halide	400	40,000	158	6.89	3.49
Flood, HPS	750	105,000	289	9.55	4.60
Holophane Mongoose, HPS	150	16,000	63	8.42	3.61
	250	29,000	103	8.50	3.62
	400	50,000	165	8.56	3.65

* Not offered.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	16	$ 6.23	$0.21
	25	10.13	0.34
	30	10.96	0.37
	35	12.06	0.40
Aluminum Davit	25	10.46	0.35
	30	11.15	0.37
	35	12.32	0.41
	40	15.05	0.50
Aluminum Double Davit	30	13.42	0.45

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, HADCO, Fluted Victorian Ornamental	14	$12.26	$0.28
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	21.53	0.50
Aluminum, HADCO, Fluted Ornamental	16	12.81	0.30
Aluminum, Painted Ornamental	35	33.55	0.78
Concrete, Ameron Post-Top	25	24.80	0.57
Fiberglass, HADCO, Fluted Ornamental Black	14	9.65	0.22
Fiberglass, Regular			
color may vary	22	5.89	0.14
color may vary	35	11.36	0.26
Fiberglass, Anchor Base, Gray	35	12.22	0.28
Fiberglass, Direct Bury with Shroud	18	7.15	0.17

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Cobrahead, Mercury Vapor	100	4,000	40	*	*
	175	7,000	67	$ 6.18	$3.17
	250	10,000	95	7.22	3.44
	400	21,000	149	6.32	3.32
	1,000	55,000	379	7.21	3.67
Special Box Similar to GE "Space-Glo"					
Sodium Vapor	70	6,300	31	9.91	3.31
Mercury Vapor	175	7,000	67	10.17	3.31

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Special Box, Anodized Aluminum Similar to GardCo Hub					
HPS	70	6,300	31	*	*
	100	9,500	43	*	$3.59
	150	16,000	63	*	3.61
	250	29,000	103	*	*
	400	50,000	165	*	*
Metal Halide	250	20,500	101	*	3.74
	400	40,000	158	*	4.19
Cobrahead, Dual Wattage HPS					
70/100 Watt Ballast	100	9,500	43	*	3.31
100/150 Watt Ballast	100	9,500	43	*	3.31
100/150 Watt Ballast	150	16,000	63	*	3.33
Special Architectural Types					
KIM SBC Shoebox HPS	150	16,000	63	*	3.95
Special Acorn-Type HPS	70	6,300	31	$9.66	3.31
Special GardCo Bronze Alloy					
HPS	70	5,000	31	*	*
Mercury Vapor	175	7,000	67	*	*
Special Acrylic Sphere					
Mercury Vapor	400	21,000	149	*	*
Early American Post-Top HPS					
Black	70	6,300	31	5.97	3.32
Rectangle Type	200	22,000	80	*	*
Incandescent	92	1,000	32	*	*
	182	2,500	63	*	*
Town and Country Post-Top					
Mercury Vapor	175	7,000	67	6.31	3.19

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Flood, HPS	70	6,300	31	$6.61	$3.36
	100	9,500	43	6.49	3.34
	200	22,000	80	6.92	3.39
Cobrahead, HPS					
Non-Power Door	70	6,300	31	5.99	3.31
Power Door	310	37,000	125	7.44	3.77
Special Types Customer Owned & Maintained					
Ornamental, HPS		9,500	43	*	*
Twin Ornamental, HPS	200	22,000	80	*	*
Compact Flourescent	28	N/A	12	*	*

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B
Aluminum Post	30	$ 6.24	*
Bronze Alloy GardCo	12	*	$0.25
Concrete, Ornamental	35 or less	10.13	0.34
Steel, Painted Regular **	25	10.13	0.34
Steel, Painted Regular **	30	10.96	0.37
Steel, Unpainted 6-foot Mast Arm **	30	*	0.37
Steel, Unpainted 6-foot Davit Arm **	30	*	0.37
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41
Wood, Laminated without Mast Arm	20	5.67	0.15
Wood, Laminated Street Light Only	20	4.38	*

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (Continued)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Wood, Curved Laminated	30	7.31	0.27
Wood, Painted Underground	35	5.04	0.21
Wood, Painted Street Light Only	35	5.04	*

* Not offered.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Special Architectural Types Including Philips QI Induction Lamp Systems					
HADCO Victorian QL	85	6,000	35	$12.00	$2.41
	165	12,000	61	13.87	2.46
HADCO Techtra QL	85	6,000	35	15.77	2.53
	165	12,000	61	16.60	2.61

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Design services for Customer-owned streetlight equipment.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 91 (Concluded)

SPECIAL CONDITIONS

1. The Company may offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one-year at which time the lighting service equipment will either be removed at Customer expense or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment.

5. If Customer-owned (Option B) streetlighting equipment or poles are removed or relocated at the Customer's request, the Customer is responsible for the costs associated with the change.

6. If circuits or poles are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

7. For Option C lights: When the Company provides the circuit, the Customer will incur a circuit charge of $1.52 per luminaire per month.

8. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaries owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

TERM

A Customer served under the Daily or Monthly Pricing option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Transmission and Related Services Charge	0.130	¢ per kWh
Distribution Charge	1.803	¢ per kWh
Energy Charge	5.480	¢ per kWh

* See Schedule 100 for applicable adjustments.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Customer will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

SCHEDULE 92 (Concluded)

SPECIAL CONDITIONS (Continued)

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule, using sampling techniques to determine whether in the Company's opinion the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Electricity use as it may deem to be satisfactory or discontinue service to the Customer under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 93
RECREATIONAL FIELD LIGHTING, PRIMARY VOLTAGE
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for recreational field lighting and related incidental lighting.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$30.00	
Transmission and Related Services Charge	0.220	¢ per kWh
Distribution Charge	8.596	¢ per kWh
Energy Charge	5.332	¢ per kWh

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge, if necessary, to justify the Company's investment in service facilities.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITION

The Customer's electrical equipment and its installation must be approved by the Company. All service under this schedule at any one location will be supplied through one meter.

TERM

Service under this schedule will not be for less than a one year.

SCHEDULE 99
SPECIAL CONTRACTS

PURPOSE

This schedule describes contracts between the Company and Customers at rates other than those contained in standard schedules. These descriptions do not include all terms and conditions in the contracts and are intended only as summaries. If there are any conflicts between these summaries and provisions in the contracts, the contracts will be controlling. The Company maintains for public inspection copies of special contracts at offices where the Tariff is available.

APPLICABLE

To those Customers that can meet the eligibility criteria established in Commission Order 87-402 and ORS 757.230, as well as the eligibility criteria listed below.

CONTRACTS

Port of Portland/Cascade General, Inc. (Portland)

Effective Date

February 21, 1996.

Term

Effective as long as Customer purchases Electricity Service from the Company under mutually agreed to Tariff.

Rate

Schedule 89 - General Service, Primary Voltage.

Special Conditions

Customer to supply Electricity for resale to his/her "Customers" at his/her Repair Facility. Customer will be allowed to reflect charges over and above the Company's price for electricity in order to recover the costs of the Customer's electrical distribution system as outlined in the Portland Ship Repair Yard Price Schedule. As a result, bills received by his/her "Customers" may show a kWh charge above that which is charged by the Company.

Eligibility Criteria

1. Customer engaged in sales for resale prior to November 5, 1973.

2. Customer has significant investment in distribution facilities requiring additional cost recovery from its "Customers".

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

APPLICABLE ADJUSTMENT SCHEDULES

Schedules	102 (1)	105	108 (5)	115 (6)	125 (1)	126	128 (7)	129 (1)
7	x	x	x	x	x	x		
15	x	x	x	x	x	x		
32	x	x	x	x	x	x	x	
38	x	x	x	x	x	x		
47	x	x	x	x	x	x		
49	x	x	x	x	x	x		
75(2)	x(4)	x(4)	x	x	x(4)	x(4)	x	
76R(2)	x	x	x	x		x		
83	x	x	x	x	x	x	x	
89	x	x	x	x	x	x	x	
87(2)	x(4)	x(4)	x	x		x(4)		
91		x	x	x	x	x	x	
92		x	x	x	x	x		
93		x	x	x	x	x		
483	x	x	x	x				x
489	x	x	x	x				x
515	x	x	x	x		x	x	
532	x	x	x	x		x	x	
549	x	x	x	x		x	x	
575(3)	x(4)	x(4)	x	x		x(4)	x	
576R(3)	x	x	x	x		x		
583	x	x	x	x		x	x	
589	x	x	x	x		x	x	
591		x	x	x		x	x	
592		x	x	x		x	x	

(1) Where applicable.
(2) The applicable adjustment rate for Schedules 75, 76R and 87 will be as listed for Schedule 83 or 89 on each adjustment schedule.
(3) The applicable adjustment rate for Schedules 575 and 576R will be as listed for Schedule 583 or 589 on each adjustment schedule.
(4) These adjustments are applicable only to the Customer Baseline and Scheduled Maintenance Energy. Scheduled Maintenance Energy is optional under Schedule 75.
(5) Schedule 108 applies to the sum of all charges less taxes, Schedule 115 charges and one-time charges such as deposits.
(6) Except for Schedule 7 which receives a set monthly charge for Schedule 115, Schedule 115 is applicable to the lesser of the total kWh, or the first 1,515,152 kWh used per PODID or Site (where applicable).
(7) Applicable to Nonresidential Customer who receive service at Daily or Monthly pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 483 and 489).

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits provided in accordance with the terms of the Settlement Agreement between the Company and the BPA.

The credit, inclusive of an adjustment of (0.014) ¢ per kWh for interest is:

Schedule 7

First 250 kWh	2.294	¢ per kWh
Over 250 kWh	0.763	¢ per kWh
All other schedules	1.176	¢ per kWh

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 102 (Concluded)

FARM IRRIGATION AND DRAINAGE PUMPING SERVICE

Farm Irrigation and Drainage Pumping Service means Electricity Service to a parcel of land used for the raising of crops, livestock, or pasturage and includes service to irrigation pumps.

FARM SERVICE

Farm Service means Electricity Service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting and selling crops; or by the feeding, breeding, management and sale of, or the produce of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and his/her disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

SPECIAL CONDITIONS

1. The Credit will be applied to residential and farm usage; however, irrigation for farm use is limited to the first 400 horsepower per farm. The 400-horsepower limitation will be converted to maximum monthly kWh usage according to the following formula:

   400 hp x .746 x (24 hrs x days in Billing Period) = maximum kWh but not to exceed 222,000 kWh in any month

2. The credit is no longer applicable upon determination that the service no longer constitutes residential or farm usage. The Customer or ESS will notify the Company of any change of the type of service on the Customer's Premises. The credit and eligibility for the adjustment are subject to review and approval by the BPA and the Commission.

SCHEDULE 105
REGULATORY ADJUSTMENTS

PURPOSE

The purpose of this schedule is to reflect the effects of regulatory adjustments such as net gains from nonrecurring property transactions, true-ups to UE 115 CIS/IT capital costs, and costs associated with the implementation of SB 1149.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – MISCELLANEOUS ADJUSTMENTS

Part A is a compilation of nonrecurring regulatory adjustments including a credit for information technology (IT) and gains on property sales. Part A will be adjusted annually.

PART B – SB 1149 COSTS

Part B consists of costs incurred with SB 1149 implementation. Part B is based on a projected five year collection period.

PART C – GRID WEST COSTS

Part C consists of prior loan amounts and projected 2006 and 2007 amounts incurred as the Company's share of the research and development performed by Grid West, the Regional Transmission Organization (RTO) and its predecessor, RTO West.

ADJUSTMENT RATES

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

Schedule	Part A	Part B	Part C	Adjustment Rate	
7	(0.046)	0.027	0.009	(0.010)	¢ per kWh
15	(0.086)	0.036	0.009	(0.041)	¢ per kWh
32	(0.043)	0.039	0.009	0.005	¢ per kWh
38	(0.043)	0.039	0.009	0.005	¢ per kWh
47	(0.043)	0.039	0.009	0.005	¢ per kWh
49	(0.032)	0.039	0.009	0.016	¢ per kWh
83					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A	Part B	Part C	Adjustment Rate	
89						
	Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
	Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
	Subtransmission	(0.026)	0.039	0.009	0.022	¢ per kWh
91		(0.076)	0.039	0.009	(0.028)	¢ per kWh
92		(0.033)	0.039	0.009	0.015	¢ per kWh
93		(0.072)	0.039	0.009	(0.024)	¢ per kWh
483						
	Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
	Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
489						
	Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
	Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
	Subtransmission	(0.026)	0.039	0.009	0.022	¢ per kWh
515		(0.086)	0.036	0.009	(0.041)	¢ per kWh
532		(0.043)	0.039	0.009	0.005	¢ per kWh
549		(0.032)	0.039	0.009	0.016	¢ per kWh
583						
	Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
	Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
589						
	Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
	Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
	Subtransmission	(0.026)	0.039	0.009	0.022	¢ per kWh
591		(0.076)	0.039	0.009	(0.028)	¢ per kWh
592		(0.033)	0.039	0.009	0.015	¢ per kWh

SCHEDULE 108
PUBLIC PURPOSE CHARGE

PURPOSE

To collect funds associated with activities mandated for the benefit of the general public pursuant to OAR 860-038-0480. Activities include Energy conservation, new market transformation, new renewable energy resources and new low-income weatherization.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except Nonresidential Customers qualifying as a Self-Directing Customer may be partially exempt.

PUBLIC PURPOSE CHARGE

The Public Purpose Charge will be 3% of total revenue billed to the Customer "for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs that were included in electric rates on July 23, 1999" as specified in OAR 860-038-0480 (2).

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a Self-Directing Customer (SDC), the Large Nonresidential Customer must have a load that exceeds one aMW and receive certification from the Oregon Department of Energy (ODOE) as an SDC. Beginning November 30, 2004, the Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDCs monthly Public Purpose Charge.

SPECIAL CONDITIONS

1. Electricity Service Suppliers (ESS) – Each ESS that provides Direct Access Service in the Company's service territory will collect a Public Purpose Charge from its Direct Access Customers. The ESS will remit monthly to the Company the Public Purpose Charges it collects from Customers.

SCHEDULE 108 (Concluded)

SPECIAL CONDITIONS (Continued)

2. Disbursement of Funds – The Company will distribute monthly, Public Purpose funds collected, minus reasonable administrative costs, as outlined in OAR 860-038-0480 and required by ORS 757.612:

   - The funds for conservation in schools to the education service districts located in the Company's service territory = 10.0%;
   - The funds for local and market transformation conservation will be allocated as directed by the Commission = 56.7%;
   - The funds for renewable energy resources will be allocated as directed by the Commission = 17.1%;
   - The funds for low-income weatherization will be allocated to the Housing and Community Services Department = 11.7%; and
   - The funds for low-income housing will be allocated to the Housing and Community Services Department Revolving Account = 4.5%.

TERM

This Schedule will terminate on February 29, 2012.

SCHEDULE 115
LOW-INCOME ASSISTANCE

PURPOSE

The purpose of this rate schedule is to implement the low-income bill payment assistance provisions in accordance with Section 3(7) of House Bill 3633.

APPLICABLE

To all bills for Electricity Service calculated under all rate schedules and contracts, except those Customers explicitly exempted. Based on House Bill 3633 provisions, this rate schedule is also applicable to Direct Service Industries (DSIs) located within the Company's service territory.

ADJUSTMENT RATES

The applicable Adjustment Rates are listed below. As specified in House Bill 3633, Customers will not be required to pay more than $500 per month per Site for low-income Electricity bill payment assistance.

Schedule	Adjustment Rate
7	33¢ per month
All other Schedules, including DSIs	0.033¢ per kWh for the first 1,515,152 kWh

SPECIAL CONDITION

On a monthly basis, on or before the last day of the month, the Company will forward an amount to the Oregon Housing and Community Services Department based on billings to Customers for the previous month less a reserve for uncollectable amounts.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49 83, 89, 91, 92, and 93.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs 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.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts.
- No other changes or updates will be made in the annual filings under this schedule.

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC are defined as the projected per unit change in NVPC from the per unit NVPC used to develop the Energy Charge for the applicable rate schedules. Unit NVPC are defined as the total NVPC divided by the projected retail calendar loads. Projected retail calendar loads include the projected loads of all the Company's Customers except those served under Schedule 483 or Schedule 489.

SCHEDULE 125 (Concluded)

FILING AND EFFECTIVE DATE

On or before July 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final unit change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be the final unit change in NVPC times a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectables applied to each of the above Schedules on an equal cents per kWh basis.

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh [1]
7		0.000
15		0.000
32		0.000
38	Large Nonresidential	0.000
47		0.000
83	Secondary	0.000
	Primary	0.000
89	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
93		0.000

SCHEDULE 126
POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates differences in actual net variable power costs from those assumed in base energy rates adjusted pursuant to Schedule 125. This adjustment mechanism becomes effective with service on and after January 1, 2007. This Schedule is an “automatic adjustment clause” as defined in ORS 757.210, and is subject to review by the Commission at least once every two years.

APPLICABLE

To all bills for Electricity Service except those served under the provisions of Schedules 76R, 576R, 483 and 489.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) represent the power costs 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 BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses 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 deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 83 and 89 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 483 and 489 as an offset to NVPC.

ACTUAL NVPC

Incurred cost of power based on the definition for NVPC described above.

ACTUAL LOADS

Actual loads are total annual retail loads adjusted as follows:

- Exclude loads from Schedule 483, Schedule 489, 76R, Schedule 83 and Schedule 89 options other than Cost of Service and any Direct Access 500 series schedules.

SCHEDULE 126 (Continued)

BASE UNIT NVPC

The Base Unit NVPC are defined as the NVPC used to develop existing rate schedules divided by the calendar basis retail loads used to develop existing rate schedules including Schedule 125. Each adjustment period will be for 12 months and correspond to the calendar year.

The Base Unit NVPC for 2007 is $XX.XX.

The NVPC used to calculate the Base Unit NVPC for the years 2007, 2008, 2009 and 2010 will be adjusted by PGE by an amount (increase or decrease) that removes the power supply cost impact resulting from the difference between the forecast and actual forced outage rates of PGE's owned thermal generating resources for the years 2002, 2003, 2004, 2005 and 2006.

POWER COST VARIANCE (PCV)

The Power Cost Variance (PCV) is calculated annually based on the following formula:

(Actual Unit NVPC - Base Unit NVPC) * Actual Loads

ADJUSTMENT AMOUNT

Adjustment Amount will be to 90% of the PCV times a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectables.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record overcollections and undercollections. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. Interest will accrue on the account at the Company's authorized rate of return. To account for the time value of money during the year, at the end of each year the Adjustment Amount for the calendar year will be multiplied by ½ year's worth of interest at the Company's authorized cost of capital and such amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission. Annually, the Company will recommend to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

SCHEDULE 126 (Continued)

EARNINGS REVIEW

The recovery from or refund to customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Adjusted Authorized ROE plus 100 basis points.

Should the Company's Actual ROE exceed its Adjusted Authorized ROE by more than 100 basis points, the Company will refund to Customers revenues representing 50% of the earnings exceeding the 100 basis point threshold.

Actual ROE will be based on the Company's ROE for utility operations adjusted for any expenses or rate base disallowed as inappropriate for utility operations by the Commission in the Company's last general rate case.

Adjusted Authorized ROE is the Authorized ROE determined by the Commission in the Company's most recent rate proceeding less the difference in the average of five-, seven-, and ten-year US Treasury debt used to determine authorized ROE and the actual average of five-, seven-, and ten-year US Treasury debt for the year that the power costs were incurred. The actual Treasury debt will be the annual rates reported by the Federal Reserve in their H15 Constant Maturity Statistical Releases.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

Included in this filing will be the following information:

1) A transmittal letter that summarizes the proposed changes.
2) Revised Power Cost adjustment rates.
3) Work papers supporting the calculation of the revised PCV rates.

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis applicable to all schedules except Schedules 76R, 576R, 483 and 489. The PCV Rates, applicable for service on and after the effective date of this schedule will be:

Schedule		Adjustment Rate
7		0.000 ¢ per kWh
15		0.000 ¢ per kWh
32		0.000 ¢ per kWh
38		0.000 ¢ per kWh
47		0.000 ¢ per kWh
49		0.000 ¢ per kWh
83	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
89	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
515		0.000 ¢ per kWh
532		0.000 ¢ per kWh
549		0.000 ¢ per kWh
583	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
589	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
	Subtransmission	0.000 ¢ per kWh
591		0.000 ¢ per kWh
592		0.000 ¢ per kWh

TERM

Effective for service on and after January 1, 2007 and continuing until terminated by the Commission.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily or Monthly pricing (other than Cost of Service) on Schedules 32, 75, 83, 89, 91; or Direct Access service on Schedules 515, 532, 549, 575, 583, 589, 591 and 592. This Schedule is not applicable to Customers served on Schedules 483 and 489.

TRANSITION ADJUSTMENT

The Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

2007 12-MONTH TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service for 2007, the 12-Month Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2007:

Schedule		Annual ¢ per kWh [1]
32		(1.341)
83	Secondary	(1.326)[2]
	Primary	(1.278)[2]
89	Secondary On-Peak	(1.402)
	Secondary Off-Peak	(1.192)
	Primary On-Peak	(1.353)
	Primary Off-Peak	(1.146)
	Subtransmission On-Peak	(1.334)
	Subtransmission Off-Peak	(1.129)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Customer's Baseline Load for Customers served on Schedule(s) 75, 76R, 87, 575 and, or 576R.

SCHEDULE 128 (Continued)

2007 12-MONTH TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh [1]
91		(1.287)
515		(1.283)
532		(1.341)
549		(1.212)
583	Secondary	(1.326) [2]
	Primary	(1.278) [2]
589	Secondary On-Peak	(1.402)
	Secondary Off-Peak	(1.192)
	Primary On-Peak	(1.353)
	Primary Off-Peak	(1.146)
	Subtransmission On-Peak	(1.334)
	Subtransmission Off-Peak	(1.129)
591		(1.287)
592		(1.310)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Customer's Baseline Load for Customers served on Schedule(s) 75, 76R, 87, 575 and, or 576R.

12-MONTH TRANSITION ADJUSTMENT REVISIONS

(November Election Window as defined in Schedules 83 and 89)
The 12-Month Transition Adjustment rate will 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. Indicative, non-binding estimates for the 12-Month Transition Adjustment will be posted by the Company two months and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

Monthly Transition Adjustment Election Window as defined in Schedules 83 and 89)
The Company will file and post the balance of year Transition Adjustments on its website (www.PortlandGeneral.biz) by 12:00 p.m. PPT on the first business day of the Monthly Direct Access Election Window.

SCHEDULE 128 (Concluded)

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

The Company may revise the 12-Month Transition Adjustment after the close of the November election window if the deviation in costs is greater than $240,000 based on the deviation between actual market prices experienced and market prices used to set the 12-Month Transition Adjustment associated with acquiring or disposing of power. The Transition Adjustment for all other monthly windows will be adjusted on the same basis as the November window, except the threshold amount will be $20,000 times the number of months to which the Transition Adjustment is applicable.

CHANGES TO TRANSITION ADJUSTMENT RATES

The 12-Month Transition Adjustment and Monthly Transition Adjustments are subject to modification to reflect any changes to the Energy Charge(s) of the Cost of Service Option that serve as the basis for the calculation of the Transition Adjustment. No change will be made, however, to the market price of power used to determine the applicable adjustment rate.

RESOURCE CHANGES

The Transition Adjustment Rate will be modified at any time to reflect changes in the Company's Schedule 125, Schedule 126, 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, the Transition Adjustment will be adjusted by replacing the variable costs of the resource with the cost of replacement power.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedule 483 and 489.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Period A (2002), the Transition Cost Adjustment will be:

0.061 ¢ per kWh	January 1, 2003 through December 31, 2007
0.000 ¢ per kWh	after December 31, 2007

For Enrollment Period B (2003), the Transition Cost Adjustment will be:

(0.154) ¢ per kWh	January 1, 2004 through December 31, 2004
(0.136) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.062) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.046) ¢ per kWh	January 1, 2007 through December 31, 2007
(0.032) ¢ per kWh	January 1, 2008 through December 31, 2008
0.000 ¢ per kWh	after December 31, 2008

For Enrollment Period C (2004), the Transition Cost Adjustment will be:

(0.763) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.564) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.447) ¢ per kWh	January 1, 2007 through December 31, 2007
(0.398) ¢ per kWh	January 1, 2008 through December 31, 2008
(0.301) ¢ per kWh	January 1, 2009 through December 31, 2009
0.000 ¢ per kWh	after December 31, 2009

SCHEDULE 129 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)
Three-Year Opt-Out Option

For Enrollment Period A (2002): Not available

For Enrollment Period B (2003): Not available

For Enrollment Period C (2004), the Transition Cost Adjustment will be:

(0.763) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.564) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.447) ¢ per kWh	January 1, 2007 through December 31, 2007

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 483 or 489.

SCHEDULE 200
DISPATCHABLE STANDBY GENERATION

PURPOSE

To provide the Company with additional generation capacity during times of peak demand and/or peak wholesale prices by contracting with Large Nonresidential Customers for the right to operate their standby or backup generator(s) for up to 400 hours annually.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers with 250 kW or greater of permanently installed standby or backup generation capacity in place or planned for installation within 24 months.

CUSTOMER RESPONSIBILITIES

The Customer will grant the Company access to its generation such that the Company can operate the generator(s) at the site or remotely operate the generator(s) in parallel with the Company's distribution system from the Company's dispatch center for up to 400 hours per year.

The Customer may operate the generator(s) at the site as needed for a limited number of hours per year, as specified in the service agreement.

COMPANY RESPONSIBILITIES

The Company will conduct an analysis of the Customer's generator project and develop a cost estimate. The Company will be responsible for providing engineering and funding based on the cost estimate not to exceed the Funding Level for the installation of the equipment necessary for participation in the program. The Company will pay for and own all communications and metering equipment.

In addition, the Company is responsible for routine maintenance of the generator(s) including overhauls over the term of the service agreement. The Company will also pay for all fuel used to operate the Customer's generator(s) throughout the term of the service agreement. The Company will perform monthly full-load testing of the Customer's generator(s) and control system and testing of the Company's dispatch control and interconnection facilities. The Company will provide power quality monitoring and data reporting of the Customer's facility and generator system.

The Company's design will be such that during outage situations, the Customer's generator(s) will automatically start and provide backup power to the Customer for as long as needed.

SCHEDULE 200 (Continued)

FUNDING LEVEL

The Company's Funding Level is based on the cost of Company owned equipment necessary for parallel operations, system protection, safety provisions and communications, related administrative costs and the generator and switchgear modifications, wiring and conduit necessary to permit Customer's generator(s) to run in parallel with the Company's system.

The Funding Level is set for each project. The Customer will be responsible for unique costs components that bring the total project costs above the Company's Funding Level. Due to the individual nature of each project, specifics on Company Funding and Customer payment responsibilities will be contained in the service agreement.

Upon termination of the agreement, the Company may remove its equipment.

SPECIAL CONDITIONS

1. The Customer's charges for Electricity Service under any of the Company's Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

2. Parallel operation of generators must satisfy Company interconnection requirements.

3. The Customer will ensure that the generator(s), communications equipment, switchgear and metering equipment are accessible to the Company at all times.

4. Prior to receiving service on this schedule, the Customer and the Company must enter into a written service agreement, signed by the Customer.

5. The Customer must obtain all required permits prior to service initiation to allow a minimum of 400 hours per year of parallel generator operation. The Company will reimburse the Customer for any DEQ and land-use compatibility permits specifically required for this service, including renewals during the term of the service agreement.

6. The Company may operate the generator(s) at any time and will notify the Customer by telephone, fax or e-mail a minimum of 24 hours before starting the generator(s) for the Company's purposes. Notice is deemed given when the Customer confirms notice either verbally or by e-mail.

7. Customers receiving service under this schedule will agree to an initial multi-year term for the service agreement, with options to renew. Should the Customer terminate the service agreement before the end of the initial term, the Customer will reimburse the Company for a portion of the capital investment plus a removal fee as specified in the service agreement.

SCHEDULE 200 (Concluded)

SPECIAL CONDITIONS (Continued)

8. The Company will have the right to refuse to fund projects for any reason; including, but not limited to projects deemed high-risk, not cost effective, of poor equipment quality, an excessive environmental risk, or unable to run 400 hours annually. Reasons for funding denial will be provided in writing to the Customer.

SCHEDULE 201
QUALIFYING FACILITY
POWER PURCHASE INFORMATION

PURPOSE

To provide information about Avoided Costs, Standard Contracts and negotiated Power Purchase Agreements, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Sellers of generation from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, the energy is delivered to the Company's system and made available for Company purchase, and the Seller meets all requirements herein described including establishing credit, providing proof of insurance, executing an interconnection agreement, a transmission agreement and a Power Purchase Agreement, where applicable.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard Contract Power Purchase Agreement (Standard Contract) as discussed below, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security as deemed sufficient by the Company as set out in the Standard Contract.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

SCHEDULE 201 (Continued)

POWER PURCHASE AGREEMENT

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a Power Purchase Agreement with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A Seller whose QF has a nameplate capacity rating of 10 mW or less may elect the Standard Contract option.

Any Seller may elect to negotiate a Power Purchase Agreement with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC) and the Commission. Negotiations for power purchase pricing will be based on the filed Avoided Costs in effect at that time. Filed Avoided Costs may be modified in negotiated Power Purchase Agreements by factors described in 18 CFR 292.304(e), *Factors Affecting Rates for Purchases,* which may be referenced through www.gpoaccess.gov/cfr/index.html.

STANDARD CONTRACT (Nameplate capacity of 10 mW or less)

A Seller choosing a Standard Contract will complete all informational and price option selection requirements in the agreement (Appendix 1) and submit the executed agreement to the Company prior to service under this schedule.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase rates are based on the Company's Avoided Costs. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

SCHEDULE 201 (Continued)

BASIS FOR POWER PURCHASE PRICE (Continued)
AVOIDED COST SUMMARY (Continued)

The Avoided Costs as listed in Tables 1 and 2 below include monthly On- and Off-Peak prices.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Avoided Costs are based on forward market price estimates through December 2008, the period of time during which the Company's Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the period 2009 through 2025, the Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

The CCCT Avoided Cost estimates beginning in 2009 include the avoidable power supply costs assumed to be represented by new generating capacity consistent with the Company's Integrated Resource Plan's Final Action Plan Acknowledged in Commission Order No. 04-375.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS

Pricing options represent the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard Contract up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard Contract pricing will be based on the Avoided Cost in effect at the time the agreement is executed.

Four pricing options are available for Standard Contracts. The pricing options include one Fixed Rate Option and three Market Based Options.

1) **Fixed Price Option**

The Fixed Price Option is based on Avoided Costs including forecasted natural gas prices.

This option is available for a maximum term of 15 years. Sellers with contracts exceeding 15 years will make a one time election at execution to select a Market-Based Option for all years up to five in excess of the initial 15. Under the Fixed Price Option, prices will be as established at the time the Standard Contract is executed and will be equal to the Avoided Costs in Tables 1 and 2 effective at execution for a term of up to 15 years.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
FIXED PRICE OPTION (Continued)

TABLE 1 Avoided Costs Fixed Price Option On-Peak Forecast ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	67.97	66.95	64.20	69.29	74.39
2006	77.96	74.39	69.29	59.10	49.42	50.44	69.04	75.92	72.40	69.04	71.08	74.13
2007	76.43	72.86	67.77	57.58	47.90	48.91	68.02	74.90	71.38	68.02	70.06	73.12
2008	74.90	71.33	66.23	56.04	46.36	47.38	66.49	73.37	69.85	66.49	68.53	71.58
2009	64.40	64.36	63.78	59.56	59.02	59.18	59.33	59.47	59.40	59.50	60.84	62.17
2010	60.39	60.33	59.78	56.25	55.77	55.90	56.03	56.14	56.10	56.19	57.41	58.58
2011	66.34	66.28	65.62	61.46	60.89	61.04	61.20	61.33	61.28	61.38	62.82	64.20
2012	69.28	69.21	68.51	64.09	63.48	63.65	63.81	63.95	63.90	64.01	65.54	67.01
2013	75.03	74.95	74.16	69.13	68.45	68.63	68.82	68.97	68.92	69.04	70.78	72.45
2014	80.36	80.28	79.40	73.82	73.06	73.26	73.47	73.64	73.59	73.72	75.65	77.50
2015	81.36	81.27	80.40	74.80	74.04	74.24	74.45	74.62	74.56	74.70	76.63	78.49
2016	73.15	73.08	72.37	67.88	67.27	67.43	67.60	67.74	67.69	67.80	69.35	70.85
2017	77.09	77.01	76.25	71.42	70.76	70.93	71.11	71.26	71.21	71.33	73.00	74.61
2018	84.84	84.75	83.86	78.17	77.40	77.61	77.81	77.99	77.93	78.07	80.04	81.92
2019	92.90	92.79	91.76	85.21	84.31	84.55	84.79	85.00	84.93	85.09	87.35	89.53
2020	98.17	98.06	96.94	89.85	88.88	89.14	89.40	89.62	89.55	89.72	92.17	94.53
2021	100.74	100.63	99.48	92.21	91.22	91.48	91.75	91.98	91.90	92.08	94.59	97.01
2022	103.25	103.14	101.97	94.51	93.49	93.77	94.04	94.27	94.20	94.38	96.95	99.43
2023	105.95	105.83	104.63	96.98	95.94	96.22	96.50	96.74	96.66	96.85	99.49	102.03
2024	108.35	108.23	106.99	99.16	98.09	98.38	98.67	98.91	98.83	99.02	101.73	104.33
2025	111.18	111.06	109.80	101.77	100.67	100.97	101.26	101.51	101.43	101.62	104.40	107.06

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SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
FIXED PRICE OPTION (Continued)

TABLE 2 Avoided Costs Fixed Price Option Off-Peak Forecast ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	56.76	55.74	54.01	58.59	64.45
2006	65.98	62.93	59.87	49.93	42.29	39.23	58.59	61.14	59.61	57.58	59.61	63.18
2007	63.43	60.38	57.32	47.90	40.25	37.20	57.83	60.38	58.85	56.81	58.85	62.42
2008	61.90	58.85	55.79	46.36	38.72	35.66	56.30	58.85	57.32	55.28	57.32	60.88
2009	38.83	38.79	38.21	33.98	33.44	33.61	33.75	33.90	33.83	33.92	35.27	36.59
2010	34.18	34.12	33.57	30.03	29.55	29.68	29.81	29.92	29.89	29.97	31.19	32.36
2011	39.47	39.41	38.75	34.59	34.02	34.17	34.33	34.46	34.41	34.51	35.95	37.34
2012	41.74	41.67	40.97	36.55	35.94	36.10	36.27	36.41	36.36	36.47	38.00	39.47
2013	46.80	46.72	45.93	40.90	40.22	40.40	40.59	40.74	40.69	40.81	42.55	44.22
2014	51.43	51.34	50.46	44.88	44.12	44.33	44.53	44.71	44.65	44.78	46.71	48.57
2015	51.70	51.62	50.74	45.14	44.38	44.58	44.79	44.96	44.91	45.04	46.97	48.83
2016	42.85	42.78	42.07	37.58	36.97	37.13	37.30	37.44	37.39	37.50	39.05	40.54
2017	45.83	45.75	44.99	40.16	39.50	39.67	39.85	40.00	39.95	40.07	41.74	43.35
2018	52.90	52.81	51.92	46.23	45.46	45.67	45.88	46.05	45.99	46.13	48.10	49.98
2019	60.16	60.06	59.03	52.47	51.58	51.82	52.06	52.26	52.19	52.35	54.62	56.79
2020	64.72	64.61	63.50	56.40	55.43	55.69	55.95	56.17	56.10	56.27	58.72	61.08
2021	66.34	66.23	65.09	57.81	56.82	57.09	57.35	57.58	57.51	57.68	60.20	62.61
2022	68.00	67.88	66.71	59.25	58.24	58.51	58.79	59.02	58.94	59.12	61.70	64.17
2023	69.70	69.58	68.38	60.73	59.69	59.97	60.25	60.49	60.41	60.60	63.24	65.77
2024	71.43	71.30	70.07	62.24	61.17	61.46	61.75	61.99	61.91	62.10	64.81	67.41
2025	73.22	73.09	71.83	63.80	62.71	63.00	63.30	63.55	63.46	63.66	66.43	69.10

Under the Fixed Price Option, the Company will pay Seller the Off-Peak Avoided Cost pursuant to Table 1 for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

Advice No. 06-8
Issued March 15, 2006
Pamela Grace Lesh, Vice President

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on and after April 14, 2006

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

MARKET BASED PRICE OPTIONS:

Market Based Price Options include Option 2, Deadband Index Gas Price; Option 3, Index Gas Price; and Option 4, Dow Jones Mid-Columbia Daily On- and Off-Peak Electricity Firm Price Index (DJ-Mid-C Firm Index). The price components for pricing Options 2 and 3 are defined as follows:

On Peak Price:	P_{Peak}
Off Peak Price:	P_{Off}
Variable Operating and Maintenance, Fixed Costs, and Gas Transportation (Table 6):	VFG
Capacity Value (Table 7):	C
Heat Rate:	HR = 6,776 BTU/kWh
Losses:	1.9%
Forecasted Gas Price (Table 5):	GP_F
First of Month* Northwest Pipeline Corp. Canadian Border Index as Reported in Platts Inside FERC's Gas Market Report	GP_{Sumas}
First of Month* one-month spot price averages for AECO/NIT transactions as Reported in Canadian Gas Price Reporter Natural Gas Market Report (in US dollars):	GP_{AECO}
Monthly Indexed Gas Price:	$GP_{MI} = (GP_{Sumas} + GP_{AECO})/2$
Deadband Gas Index:	GP_{DB}

Where:
If $GP_{MI} > GP_F$
GP_{DB} = Minimum of (GP_{MI} or $1.1 * GP_F$)
Otherwise
GP_{DB} = Maximum of (GP_{MI} or $.9 * GP_F$)

* "First of Month" means the first such monthly issuance.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Tables 3 and 4 below list applicable rates for Options 2 (Deadband Index Gas Price Option) and 3 (Index Gas Price Option) for the period through 2008. The monthly On- and Off-Peak prices will be applied for all Market Based Price Options.

TABLE 3												
On-Peak Resource Sufficiency Rate ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	67.97	66.95	64.20	69.29	74.39
2006	77.96	74.39	69.29	59.10	49.42	50.44	69.04	75.92	72.40	69.04	71.08	74.13
2007	76.43	72.86	67.77	57.58	47.90	48.91	68.02	74.90	71.38	68.02	70.06	73.12
2008	74.90	71.33	66.23	56.04	46.36	47.38	66.49	73.37	69.85	66.49	68.53	71.58

TABLE 4												
Off-Peak Resource Sufficiency Rate ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	56.76	55.74	54.01	58.59	64.45
2006	65.98	62.93	59.87	49.93	42.29	39.23	58.59	61.14	59.61	57.58	59.61	63.18
2007	63.43	60.38	57.32	47.90	40.25	37.20	57.83	60.38	58.85	56.81	58.85	62.42
2008	61.90	58.85	55.79	46.36	38.72	35.66	56.30	58.85	57.32	55.28	57.32	60.88

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

2) Deadband Index Gas Price Option

The Deadband Index Gas Price Option bases the fuel price component of the Energy rate on comparisons between the Forecast Gas Price (Table 5) and the simple average of the First of Month gas indices for Sumas and AECO trading hubs. The Northwest Pipeline Gas Index (Sumas) will be as reported in Platts Inside FERC's Gas Market Report. The AECO/NIT (AECO) Gas Index will be as reported in Canadian Gas Price Reporter Natural Gas Market Report (in US dollars). The fuel price component used will be bound between 90% and 110% of the natural gas price forecast but based on the then current gas price.

The price paid per MWh will be:

$$P_{Peak} = GP_{DB}*HR/1{,}000/(1\text{-Losses}) + VFG + C$$
$$P_{Off} = GP_{DB}*HR/1{,}000/(1\text{-Losses}) + VFG$$

Under the Deadband method, the Company will pay Seller the Off-Peak prices for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

3) Index Gas Price Option

The Index Gas Price Option is the simple average of the First of Month gas indices for Sumas and AECO trading hubs used in establishing the Avoided Costs. The Sumas Gas Index will be as reported in Platts Inside FERC's Gas Market Report. The AECO Gas Index will be as reported in the Canadian Gas Price Reporter Natural Gas Market Report (in US dollars).

The price paid per MWh will be:

$$P_{Peak} = GP_{MI}*HR/1,000/(1\text{-Losses}) + VFG + C$$
$$P_{Off} = GP_{MI}*HR/1,000/(1\text{-Losses}) + VFG$$

Under the Index Gas Price, the Company will pay Seller the Off-Peak Prices for: (a) for all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to the provisions of Section 4.3 of the Standard Contract; (d) for Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

4) Mid C Index Price Option

Under this option, prices paid per MWh will be based on the DJ-Mid-C Firm Index plus 0.204 ¢ per kWh for wholesale wheeling.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

The tables below contain the pricing components for Option 1 (Fixed Price Option) Option 2 (Deadband Index Gas Price Option) and Option 3 (Index Gas Price Option).

TABLE 5												
Forecasted Gas Price - GP_F($/MMBTU)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	4.778	4.772	4.689	4.088	4.011	4.035	4.056	4.076	4.066	4.079	4.271	4.459
2010	4.097	4.089	4.011	3.508	3.440	3.458	3.476	3.492	3.487	3.499	3.673	3.840
2011	4.832	4.823	4.730	4.137	4.057	4.078	4.100	4.119	4.112	4.127	4.332	4.528
2012	5.136	5.126	5.027	4.398	4.312	4.335	4.358	4.378	4.371	4.386	4.604	4.813
2013	5.836	5.825	5.713	4.997	4.900	4.926	4.952	4.974	4.967	4.984	5.232	5.469
2014	6.475	6.462	6.337	5.543	5.435	5.464	5.494	5.518	5.510	5.529	5.804	6.067
2015	6.493	6.481	6.356	5.559	5.451	5.480	5.509	5.534	5.526	5.545	5.820	6.085
2016	5.213	5.203	5.103	4.463	4.376	4.400	4.423	4.443	4.436	4.452	4.673	4.885
2017	5.615	5.604	5.496	4.807	4.713	4.739	4.764	4.785	4.778	4.795	5.033	5.261
2018	6.599	6.586	6.459	5.650	5.540	5.569	5.599	5.624	5.616	5.635	5.915	6.184
2019	7.608	7.594	7.447	6.514	6.387	6.421	6.456	6.485	6.475	6.498	6.820	7.130
2020	8.236	8.220	8.061	7.051	6.914	6.951	6.988	7.019	7.009	7.033	7.382	7.717
2021	8.441	8.425	8.263	7.227	7.086	7.124	7.162	7.195	7.184	7.209	7.567	7.910
2022	8.653	8.636	8.469	7.408	7.264	7.302	7.341	7.375	7.364	7.389	7.756	8.108
2023	8.869	8.852	8.681	7.593	7.445	7.485	7.525	7.559	7.548	7.574	7.950	8.311
2024	9.091	9.073	8.898	7.783	7.631	7.672	7.713	7.748	7.736	7.763	8.148	8.519
2025	9.318	9.300	9.120	7.978	7.822	7.864	7.906	7.942	7.930	7.957	8.352	8.731

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 6 contains the Variable O&M and Fixed Costs that are derived from a natural gas-fired CCCT as identified in the Company's 2004 Integrated Resource Plan.

TABLE 6

Variable O &M, Fixed Costs and Gas Transportation Forecast – VFG ($/MWH)

	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	5.83	5.83	5.82	5.75	5.74	5.74	5.74	5.74	5.74	5.74	5.77	5.79
2010	5.87	5.87	5.86	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.82	5.84
2011	6.09	6.09	6.08	6.01	6.00	6.00	6.01	6.01	6.01	6.01	6.03	6.06
2012	6.26	6.26	6.25	6.17	6.16	6.16	6.17	6.17	6.17	6.17	6.20	6.22
2013	6.49	6.49	6.47	6.39	6.38	6.38	6.38	6.38	6.38	6.39	6.42	6.44
2014	6.71	6.70	6.69	6.59	6.58	6.58	6.59	6.59	6.59	6.59	6.63	6.66
2015	6.85	6.85	6.84	6.74	6.73	6.73	6.73	6.74	6.74	6.74	6.77	6.80
2016	6.84	6.84	6.83	6.75	6.74	6.74	6.74	6.75	6.75	6.75	6.77	6.80
2017	7.05	7.05	7.03	6.95	6.94	6.94	6.95	6.95	6.95	6.95	6.98	7.01
2018	7.32	7.32	7.31	7.21	7.20	7.20	7.20	7.21	7.20	7.21	7.24	7.27
2019	7.61	7.60	7.59	7.47	7.46	7.46	7.47	7.47	7.47	7.47	7.51	7.55
2020	7.84	7.83	7.82	7.69	7.68	7.68	7.69	7.69	7.69	7.69	7.73	7.77
2021	8.04	8.04	8.02	7.89	7.87	7.88	7.88	7.89	7.89	7.89	7.93	7.97
2022	8.24	8.23	8.21	8.09	8.07	8.07	8.08	8.08	8.08	8.08	8.13	8.17
2023	8.44	8.44	8.42	8.28	8.27	8.27	8.28	8.28	8.28	8.28	8.33	8.37
2024	8.64	8.63	8.61	8.48	8.46	8.47	8.47	8.47	8.47	8.48	8.52	8.57
2025	8.86	8.86	8.83	8.70	8.68	8.68	8.69	8.69	8.69	8.69	8.74	8.79

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 7 represents the variable C in the formulas for the Option 2 (Deadband Index Gas Price Option) and Option 3 (Index Gas Price Option).

TABLE 7												
Capacity Value - C ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57
2010	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21
2011	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87
2012	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54
2013	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23
2014	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94
2015	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66
2016	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30
2017	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26
2018	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94
2019	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74
2020	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45
2021	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39
2022	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25
2023	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25
2024	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92
2025	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard Contract:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on his/her own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for wheeling power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in an Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Concluded)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established in Rule C or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

The Seller may be required to execute a generation interconnection agreement.

SPECIAL CONDITIONS

1. Under negotiated agreements, Seller will execute a written Power Purchase Agreement with the Company. The contract will outline specific requirements including but not limited to the term of the agreement, nameplate capacity of the QF, the amount of power the QF agrees to sell, the Pricing Option chosen by the Seller, the default security requirements, the insurance requirements, and the means by which the QF owner established credit with the Company.

2. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

3. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

4. Contracts entered into pursuant to this schedule will not terminate prior to the Power Purchase Agreement's termination date if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

STANDARD CONTRACT POWER PURCHASE AGREEMENT

THIS AGREEMENT, entered into this _______ day, _____________ 200____, is between _________________________ ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties").

RECITALS

Seller intends to construct, own, operate and maintain a _____________ facility for the generation of electric power located in _______________ County, _____________ with a Nameplate Capacity Rating of ___________________ kilowatt ("kW"), as further described in Exhibit B ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller will sell and PGE will purchase the entire Net Output, as such term is defined in Section 1.14, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms will have the following meanings:

1.1. "As-built Supplement" means the supplement to Exhibit B provided by Seller in accordance with Section 4.4 following completion of construction of the Facility, describing the Facility as actually built.

1.2. "Billing Period" means a period between PGE's readings of its power purchase billing meter at the Facility in the normal course of PGE's business. Such periods typically vary and may not coincide with calendar months.

1.3. "Capacity Value" has the meaning provided for in the Tariff (as defined below).

1.4. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable which will require, among other things, that all of the following events have occurred:

1.4.1. PGE has received a certificate addressed to PGE from a Licensed Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement (certifications required under this Section 1.4 can be provided by one or more LPEs);

1.4.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.22;

1.4.3. After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement uninterrupted for a Test Period at a rate in kW of at least 75 % of average annual Net Output divided by 8,760 based upon any sixty (60) minute period for the entire testing period. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the operation of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility will promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;

1.4.4. PGE has received a certificate addressed to PGE from an LPE stating that, in accordance with the Generation Interconnection Agreement, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PGE's electric system;

1.4.5. PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;

1.4.6. Notwithstanding the foregoing, Sellers with projects delivering Net Output to PGE prior to the Effective Date and with less than 100 Kw Nameplate Capacity will be deemed to have established a Commercial Operation date identical to the Effective Date.

1.5. "Contract Price" means the applicable price for Net Output as stated in Sections 5.1, 5.2, 5.3 and 5.4.

1.6. "Contract Year" means each twelve (12)- month period commencing at 00:00 hours on January 1 and ending on 24:00 hours on December 31 falling at least partially in the Term of this Agreement.

1.7. "Effective Date" has the meaning set forth in Section 2.1.

1.8. "Facility" has the meaning set forth in the Recitals.

1.9. "Generation Interconnection Agreement" means the generation interconnection agreement to be entered into separately between Seller and PGE, providing for the construction, operation, and maintenance of PGE's interconnection facilities required to accommodate deliveries of Seller's Net Output.

1.10. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer will be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.

1.11. "Lost Energy Value" means for a Contract Year: zero, unless the Net Output is less than Minimum Net Output and the mean Dow Jones Mid C Index Price is greater than the Contract Price, in which case Lost Energy Value equals: (Minimum Net Output - Net Output) X (Mean Dow Jones Mid C Index Price – Mean Contract Price). If PGE is in a Resource Sufficient Position as defined in the Tariff for a Contract Year, Lost Energy Value is deemed to be zero for that Contract Year.

1.12. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which will not exceed 10,000 kW.

1.13. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.

1.14. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses and other adjustments, if any.

1.15. "Off-Peak Hours" has the meaning provided in the Tariff.

1.16. "On-Peak Hours" has the meaning provided in the Tariff.

1.17. "Point of Delivery" means the high side of the generation step-up transformer(s) located at the point of interconnection between the Facility and PGE's distribution or transmission system, as specified in the Generation Interconnection Agreement.

1.18. “Prime Rate” means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate will be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.

1.19. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.

1.20. “Recoupment Value” means, on a date during a Contract Year, the On-Peak Net Output generated and delivered from the Facility to the Point of Delivery during such Contract Year up to and including such date multiplied by the applicable Capacity Value.

1.21. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, and maintenance of the Facility including without limitation those set forth in Exhibit C.

1.22. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit D.

1.23. “Tariff” will mean PGE rate Schedule 201 filed with the Oregon Public Utilites Commission in effect on the Effective Date of this Agreement and attached hereto as Exhibit E.

1.24. “Term” will mean the period beginning on the Effective Date and ending on the Termination Date.

1.25. “Test Period” will mean a period of 60 days or a commercially reasonable period determined by the Seller.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement will become effective upon execution by both Parties ("Effective Date").

2.2 Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,

2.2.1 By ________ [*date to be determined by the Seller*] Seller will begin initial deliveries of Net Output; and

2.2.2 By ________ [*date to be determined by the Seller*] Seller will have completed all requirements under Section 1.4 and will have established the Commercial Operation Date.

2.3 This Agreement will terminate on _________, ____ [*date to be chosen by Seller*], up to 20 years from the Effective Date, or the date the Agreement is terminated in accordance with Section 10 or 12.2, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 Seller represents, covenants, and warrants to PGE that:

3.1.1 Seller is a __________ duly organized under the laws of __________.

3.1.2 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.1.3 The Facility is and will for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.

3.1.4 Seller has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this agreement current on all of its financial obligations.

3.1.5 During the Term of this Agreement, all of Seller's right, title and interest in and to the Facility will be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility.

3.1.6 Seller will design and operate the Facility consistent with Prudent Electrical Practices.

3.1.7 The Facility has a Nameplate Capacity rating not greater than 10,000 kW.

3.1.8 Net Dependable Capacity of the Facility is ____________kW.

3.1.9 Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is __________ kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.

3.1.10 Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of _______kWh of Net Output during each Contract Year ("Maximum Net Output").

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Effective Date and continuing through the Term of this Agreement, Seller will sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.

4.2 Provided Seller has elected the Contract Price options in Section 5.1, 5.2, or 5.3, Seller will make available from the Facility either a) a minimum of seventy-five percent (75%) of its average annual Net Output or b) the Alternative Minimum Amount as defined in Exhibit A during each Contract Year (hereinafter "Minimum Net Output"), provided that such Minimum Net Output for the first or last Contract Year during which Commercial Operations begins will be reduced pro rata to reflect the Commercial Operation Date, and further provided that such Minimum Net Output will be reduced on a pro-rata basis for any periods during a Contract Year that the Facility was prevented from generating electricity for reasons of Force Majeure. All deliveries of Net Output are subject to the Contract Price.

4.3 Provided Seller has elected the Contract Price options in Section 5.1, 5.2, or 5.3, Seller agrees that if Seller does not deliver the Minimum Net Output each Contract Year, PGE will suffer losses equal to the Lost Energy Value. As damages for Seller's failure to deliver the Minimum Net Output (subject to adjustment for reasons of Force Majeure as provided in Section 4.2) in any Contract Year, notwithstanding any other provision of this Agreement the purchase price payable by PGE for all deliveries in the Contract Year following the year in which Seller failed to deliver such Minimum Net Output will be the Off-Peak Price of the applicable Contract Price option until Recoupment Value equals Lost Energy Value. If during such succeeding Contract Year Seller succeeds in delivering the Minimum Net Output for that Contract Year, then the purchase price payable by PGE for all deliveries in such Contract Year occurring after the Billing Period in which Seller first succeeds in delivering the Minimum Net Output for such Contract Year will be as set forth in Section 5.1, 5.2, or 5.3, as applicable.

4.4 Upon completion of construction of the Facility, Seller will provide PGE an As-built Supplement to specify the actual Facility as built. Seller will not increase the Nameplate Capacity Rating above that specified in Exhibit B or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.10 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with the written consent of PGE.

4.5 To the extent not otherwise provided in the Generation Interconnection Agreement, all costs associated with the modifications to PGE's interconnection facilities or electric system occasioned by or related to the interconnection of the Facility with PGE's system, or any increase in generating capability of the Facility, or any increase of delivery of Net Dependable Capacity from the Facility, will be borne by Seller.

SECTION 5: CONTRACT PRICE

PGE will pay Seller for the price options 5.1, 5.2, 5.3 or 5.4, as selected below, pursuant to the Tariff. Seller will indicate which price option it chooses by marking its choice below with an X. If Seller chooses the option in Section 5.1, it must mark below a single second option from Section 5.2, 5.3, or 5.4 for all Contract Years in excess of 15 until the remainder of the Term. Except as provided herein, Sellers selection is for the Term and will not be changed during the Term.

5.1 ______ Fixed Price.
5.2 ______ Deadband Index Gas Price.
5.3 ______ Index Gas Price.
5.4 ______ Mid-C Index Rate Price.

SECTION 6: OPERATION AND CONTROL

6.1 Seller will operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE will have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's non-compliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE will not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.2 Seller agrees to provide 60 days written advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time. If the Facility ceases operation for unscheduled maintenance, Seller immediately will notify PGE of the necessity of such unscheduled maintenance, the time when such shutdown has occurred or will occur and the anticipated duration of such shutdown. Seller will take all reasonable measures and exercise its best efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller will immediately notify PGE and will promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: senior lien, step in rights, a cash escrow or line of credit. The amount of such default security that will be acceptable to PGE will be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Minimum Net Output / 8760).

SECTION 8: METERING

8.1 PGE will design, furnish, install, own, inspect, test, maintain and replace all metering equipment at Seller's cost and as required pursuant to the Generation Interconnection Agreement.

8.2 Metering will be performed at the location and in a manner consistent with this Agreement and as specified in the Generation Interconnection Agreement. All Net Output purchased hereunder will be adjusted to account for electrical losses, if any, between the point of metering and the Point of Delivery, so that the purchased amount reflects the net amount of power flowing into PGE's system at the Point of Delivery.

8.3 PGE will periodically inspect, test, repair and replace the metering equipment as provided in the Generation Interconnection Agreement. If any of the inspections or tests disclose an error exceeding two percent (2%) of the actual energy delivery, either fast or slow, proper correction, based upon the inaccuracy found, will be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction will be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) months, in the amount the metering equipment will have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records will be made in the next monthly billing or payment rendered. Such correction, when made, will constitute full adjustment of any claim between Seller and PGE arising out of such inaccuracy of metering equipment.

8.4 To the extent not otherwise provided in the Generation Interconnection Agreement, all PGE's costs relating to all metering equipment installed to accommodate Seller's Facility will be borne by Seller.

SECTION 9: BILLINGS, COMPUTATIONS AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PGE will send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement, the Generation Interconnection Agreement, and any other agreement related to the Facility between the Parties or otherwise.

9.2 Any amounts owing after the due date thereof will bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate will at no time exceed the maximum rate allowed by applicable law.

SECTION 10: DEFAULT, REMEDIES AND TERMINATION

10.1 In addition to any other event that may constitute a default under this Agreement, the following events will constitute defaults by Seller under this Agreement:

10.1.1 Seller's failure to meet the requirements as provided in Section 2.2.

10.1.2 Breach by Seller of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.

10.1.3 Seller's failure to provide default security, if required by Section 7, prior to delivery of any Net Output to PGE or within 10 days of notice.

10.1.4 Seller's failure to deliver the Minimum Net Output for two consecutive Contract Years.

10.1.5 If Seller modifies the Facility such that the Nameplate Capacity Rating exceeds 10,000 kW.

10.1.6 If Seller is no longer a "Qualifying Facility".

10.2 In the event of a default hereunder, PGE may immediately terminate this Agreement at its sole discretion by delivering written notice to Seller and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. Such termination will be effective upon the date of delivery of notice, as provided in Section 21.1. The rights provided in this Section 10 are cumulative such that the exercise of one or more rights will not constitute a waiver of any other rights.

10.3 If this Agreement is terminated by PGE as provided in this Section, PGE will make all payments, within 30 days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of Seller's receipt of notice of default. PGE will not be required to pay Seller for any Net Output delivered by Seller after such notice of default.

10.4 In the event PGE terminates this Agreement pursuant to this Section 10, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller will do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.

10.5 Sections 10.1, 10.3, 10.4, 11, and 20.2 will survive termination of this Agreement.

SECTION 11: INDEMNIFICATION AND LIABILITY

11.1 Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.

11.2 PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.

11.3 Nothing in this Agreement will be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement will constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.

11.4 NEITHER PARTY WILL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 12: INSURANCE

12.1 Prior to the connection of the Facility, provided such Facility has a design capacity of 200 kW or more, to PGE's electric system, Seller will secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "A" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance will include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of insurance interest clause; and provisions that such policies will not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section will be $1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

12.2 Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller will secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "A" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly will notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller will repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination will be effective upon receipt by PGE of written notice from Seller. Seller will waive its insurers' rights of subrogation against PGE regarding Facility property losses.

12.3 Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller will provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 13: FORCE MAJEURE

13.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it will be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility or changes in market conditions that affect the price of energy or transmission, and obligations for the payment of money when due. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party will be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party will re-commence performance of such obligation, provided that:

13.1.1 the non-performing Party, will, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

13.1.2 the suspension of performance will be of no greater scope and of no longer duration than is required by the Force Majeure; and

13.1.3 the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.

13.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance will be excused as a result of the Force Majeure.

13.3 Neither Party will be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 14: SEVERAL OBLIGATIONS

Nothing contained in this Agreement will ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party will be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 15: CHOICE OF LAW

This Agreement will be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 16: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement will remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties will enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 17: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver will not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 18: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller will at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and will provide upon request copies of the same to PGE.

SECTION 19: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof will be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party will become effective without the written consent of the other Party being first obtained and such consent will not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 20: ENTIRE AGREEMENT

20.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement will be effective unless it is in writing and signed by both Parties.

20.2 By executing this Agreement, Seller releases PGE from any claims related to the Facility, known or unknown, that may have arisen prior to the Effective Date.

SECTION 21: NOTICES

21.1 All notices except as otherwise provided in this Agreement will be in writing, will be directed as follows and will be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller: ______________________________
____
____
____

with a copy to: ______________________________
____
____
____

To PGE: Contracts Manager
QF Contracts, 3WTCBR06
PGE - 121 SW Salmon St.
Portland, Oregon 97204

21.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 21.

SECTION 22: SUBJECT TO OPUC INVESTIGATION

22.1 The seller and PGE acknowledge that the rates, terms and conditions specified in this agreement and the related tariffs are being investigated by the Oregon Public Utility Commission. Upon a decision by the Oregon Public Utility Commission in the investigation, PGE will notify the seller within ten calendar days. The seller will have thirty calendar days from the effective date of the revised standard contract and tariffs complying with the Commission's order to amend this agreement if the seller so chooses to adopt the revised standard contract and/or the revised rates, terms and conditions in the tariff approved by the Oregon Public Utility Commission as a result of the investigation.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE

By: ________________________
Name: ______________________
Title:________________________

__________________________.
(Name Seller)

By: ________________________
Name: ______________________
Title:________________________

EXHIBIT A
MINIMUM NET OUTPUT

Seller may designate an alternative Minimum Net Output to seventy-five (75%) percent of annual Net Output in this exhibit ("Alternative Minimum Amount"). Such Alternative Minimum Amount, if provided, will exceed zero, and will be established in accordance with Prudent Electrical Practices and documentation supporting such a determination will be provided to PGE upon execution of the Agreement. Such documentation will be commercially reasonable, and may include, but is not limited to, documents used in financing the project, and data on output of similar projects operated by seller, PGE or others.

EXHIBIT B

DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

EXHIBIT C

REQUIRED FACILITY DOCUMENTS

[Seller list all permits and authorizations required for this project]

EXHIBIT D

START-UP TESTING

[Seller identify appropriate tests]

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable):

1. Pressure tests of all steam system equipment;
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;
3. Operating tests of all valves, operators, motor starters and motor;
4. Alarms, signals, and fail-safe or system shutdown control tests;
5. Insulation resistance and point-to-point continuity tests;
6. Bench tests of all protective devices;
7. Tests required by manufacturer of equipment; and
8. Complete pre-parallel checks with PGE.

Required start-up test are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PGE's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;
3. Brake tests;
4. Energization of transformers;
5. Synchronizing tests (manual and auto);
6. Stator windings dielectric test;
7. Armature and field windings resistance tests;
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load;
9. Heat runs;
10. Tests required by manufacturer of equipment;
11. Excitation and voltage regulation operation tests;
12. Open circuit and short circuit; saturation tests;
13. Governor system steady state stability test;
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;
15. Auto stop/start sequence;
16. Level control system tests; and
17. Completion of all state and federal environmental testing requirements.

EXHIBIT E

TARIFF

[Attach currently in-effect rate Schedule 201]

SCHEDULE 203
NET METERING SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

Net Metering power production is generation made available to the Company from a Customer that owns and operates a generating facility using solar power, wind power, fuel cells, hydroelectric power, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis or low-emission, nontoxic biomass based on solid organic fuels from wood, forest or field residues with a generating-installed capacity of 25 kW or less. The facility must operate in parallel with the Company's existing Facilities and be primarily intended to offset part or all of the Customer's own electrical requirements. The Company will make this optional service available to Customers on a first-come, first-serve basis until the time that the total rated generating capacity equals 20,365 kilowatts. This schedule is offered in compliance with ORS 757.300, as amended by Senate Bill 84, May 2005.

DEFINITION

Net metering measures the difference between the Electricity supplied by the Company and the Electricity generated by a Customer-generator and fed back to the Company over the monthly Billing Period.

MONTHLY BILLING

Each Customer-generator will pay monthly charges as applicable in accordance with the Customer's service option selection.

Energy:

1. During a monthly Billing Period, should the Company supply a Customer-generator more energy than the Customer-generator feeds back to the Company, the Customer-generator will be charged for the net energy supplied in accordance with the Customer's service option selection.

2. During a monthly Billing Period, should a Customer-generator feed back more Energy than the Company supplies, the Customer will be billed the appropriate monthly charges (including Basic, Demand, Facilities, and Reactive Demand charges as applicable) and will be credited for the excess Energy at Schedule 201, Qualifying Facility Power Purchase Information, weighted rates.

SCHEDULE 203 (Concluded)

MONTHLY BILLING (Continued)

Energy: (Continued)

3. Where the Customer is a Direct Access Customer, the Electricity Service Supplier (ESS) will preschedule and deliver Energy into the Company's control area incorporating an individualized forecast applicable to the Customer selecting this service daily. Payments to the Customer will be based on an analysis of the forecast compared to the Customer's actual usage.

SPECIAL CONDITIONS

1. A Net Metering Facility will meet all applicable safety and performance standards established in the Oregon State Building Code. The standards will be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories or other similarly accredited laboratory. The Net Metering Facility must also be in compliance with the applicable provisions of Schedule 201, Qualifying Facility Power Purchase Information and Rule C, Conditions Governing Customer Attachment to Facilities.

2. Prior to interconnection, the owner of a Net Metering Facility intending to sell Electricity to the Company under this rate schedule will execute a written Net Metering Agreement with the Company.

3. The customer-generator is responsible for obtaining all necessary government approvals relating to its net metering facility.

4. The customer-generator is responsible for all costs associated with its facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company for purposes of safety and reliability.

5. Company approved switching equipment capable of isolating the Net Metering Facility from the Company's system will be provided by the customer-generator and will be accessible to the Company at all times.

6. The Company maintains the right to approve the facilities for interconnection, and to inspect the facilities at any time and for any reason.

7. The Company maintains the right to disconnect, without liability, the customer-generator for issues relating to safety and reliability.

8. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a Net Metering Facility, or for the acts or omissions of the customer-generator that cause loss or injury, including death, to any third party.

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON DEPOSITS (See Rules D and H)

2% per annum.

BILLING RATES (Rules C, E, H, I and J)

Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours (1)	No charge
Other than Scheduled Crew Hours (1)	$170.00
Returned Payment Charge	$ 30.00
Special Meter Reading Charge	$ 35.00
Meter Test Charge	$ 75.00
Late Payment Charge	1.7% of delinquent balance
Field Service Collection Charge	$ 30.00
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule E)	$ 32.00
Portfolio Enrollment Charge	$ 5.00
Customer Interval Data (12 months) to Customers	$100.00
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price
Switching Fee	$20.00

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 6:30 a.m. to 10:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule F)

Disconnects at Meter Base	
8:00 a.m. – 5:30 p.m. Monday through Friday (excluding holidays)(1)	No charge
All Other Hours	$240.00
Disconnects at Other Than Meter Base	
8:00 a.m. – 5:30 p.m. Monday through Friday (excluding holidays)(1)	No charge
All Other Hours	$450.00
Reconnects at Meter Base	
7:00 a.m. – 7:00 p.m. Monday through Friday (excluding holidays)(2)	$ 45.00
Weekends and Holidays	$240.00
Reconnects at Other Than Meter Base	
8:00 a.m. – 5:30 p.m. Monday through Friday (excluding holidays) (2)	$115.00
Weekends and Holidays	$450.00
Unauthorized Service Reconnect Charge	$ 75.00
(See Rule F for conditions under which these charges apply.)	
Reconnect Visit	$ 30.00
(See Rule F for conditions under which these charges apply.)	

(1) Scheduled Crew Hours for Credit Related Disconnection Rates.
(2) Scheduled Business Hours during which time Customers may call to provide proof of payment and request service reconnection. Upon receiving a valid request for service reconnection, the Company will make a reasonable attempt to reconnect service prior to the close of the next business day.

SCHEDULE 300 (Continued)

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule F)[1]

Disconnects at Meter Base [2]	
7:00 a.m. - 3:30 p.m., Monday through Friday (excluding holidays) [3]	No charge
All Other Hours	$240.00
Disconnects at Other Than Meter Base [2]	
7:00 a.m. - 3:30 p.m., Monday through [3]	No charge
All Other Hours	$450.00
Reconnects at Meter Base [2]	
Safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	No charge
Non-safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	$ 45.00
All Other Hours	$240.00
Reconnects at Other Than Meter Base [2]	
Safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	No charge
Non-safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	$115.00
All Other Hours	$450.00

(1) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.
(2) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule F(6).
(3) Scheduled Crew Hours for Customer Requested Disconnection and Reconnection Rates.

SCHEDULE 300 (Continued)

METER INSTALLATION RATES (Rule I)

Meter Verification Charge	$ 33.00 per Unit
Pole Metering Rates[1]	
Single-phase meter per each installation - 120, 240, or 480 volts	$ 670.00
Three-phase meter per each installation 120, 240 or 480 3 or 4 wire	$ 740.00
Single-phase primary voltage service per each installation	$1,200.00
Three-phase primary voltage service per each installation	$1,990.00
Vault Metering Rates[1]	
Single-phase meter per each installation - 120, 240, or 480 volts	Estimated Actual Cost
Three-phase meter per each installation - 208, 240, or 480 volts	Estimated Actual Cost
Primary voltage service per each Meter installation	Estimated Actual Cost
Pad-Mounted Metering Rates[1]	
Primary voltage per each installation	$8,225.00 – 200 amp, single phase $9,030.00 – 200 amp, single phase
other sizes	Estimated Actual Cost

(1) Excludes costs of current transformers, potential transformers, and meters.

SCHEDULE 300 (Continued)

METER RENTAL RATES (Rule I)

Where the Company rents meters to Customers engaged in resale prior to November 5, 1973:

Self-contained watt-hour meter rated up to 200 amperes	$ 1.00 per month
Interval Meter Rates	
Meter Installation	$100.00
Monthly Charge	$ 6.00
Pulse Output Metering	
Meter Installation	$500.00

MISCELLANEOUS EQUIPMENT RENTAL (Rule C)

Rental of transformers, single-phase to three-phase inverters, capacitors, and other related equipment	1-2/3% per month of current replacement cost at time of installation

TRANSFORMERS (Rule G)

Submersible Transformers[1]

Subdivision - five dwelling units or more	$ 150.00 per lot $1,050.00 minimum
Mobile Home - five spaces or more	$ 150.00 per space $1,050.00 minimum
Multi-Family Units - nine units or more	$ 75.00 per family unit $1,050.00 minimum

(1) For all other applications, which include but are not limited to network service areas and densely populated urban areas, that require submersible transformers, the charge will be the calculated difference in cost between submersible and pad-mount transformer installations including the costs of future maintenance.

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule G)

Line Extension Allowance (Section 2)

Residential Service	$1,514.00 / dwelling unit
Small Nonresidential Service (Schedules 15, 32 & 47)	$ 0.1129 /estimated annual kWh
Large Nonresidential Service Secondary Voltage Service (Schedules 38, 49, 83, 89 & 91)	$ 0.0524 /estimated annual kWh
Large Nonresidential Primary voltage service (Schedules 38, 49, 83 & 89)	$ 0.0295 /estimated annual kWh

Trenching or Boring (Section 3)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:	
Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 /foot
Mainline trenching, boring and backfilling	Estimated Actual Cost

Lighting Underground Service Areas[1]

Installation of conduit on a wood pole for lighting purposes	$ 75.00 per pole

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

(1) Applies only to 1-inch conduit without brackets.

SCHEDULE 300 (Concluded)

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$ 300.00
Permanent Customer obtained	$ 185.00
Existing service	$ 80.00

Enhanced Temporary Service

Fixed fee for 12-month period	$ 210.00

Temporary Area Lights	$ 400.00 (first luminaire)
	$ 345.00 (each additional luminaire)
	$ 450.00 (first pole)
	$ 400.00 (each additional pole)

SCHEDULE 310
DEPOSITS FOR RESIDENTIAL SERVICE

PURPOSE

The purpose of this schedule is to list the deposits for residential service referred to in Rule D of the General Rules and Regulations.

DEPOSIT AMOUNTS	Average Deposit
Single-Family Dwellings	
All electric (electric heat, hot water, range, and lights)	$229.00
Electric heat but not all electric	$177.00
Electric hot water, range, and lights	$160.00
Any other combination	$132.00
Multiple-Family Dwellings	
All electric	$129.00
Electric heat but not all electric	$108.00
Electric hot water, range, and lights	$108.00
Any other combination	$72.00
Mobile Homes	
All electric	$203.00
Any other combination	$130.00
Houseboats	
All electric	$122.00
Any other combination	$89.00

The deposit amounts represent one-sixth (1/6) of average annual bills for the various dwelling types. When one-sixth (1/6) of the actual annual bill for a particular dwelling is significantly greater or less than the average deposit listed, the Company may request a deposit amount that more accurately represents one-sixth (1/6) of the anticipated annual usage.

SCHEDULE 320
METER INFORMATION SERVICES

PURPOSE

This schedule describes Meter Information Services available to Large Nonresidential Customers.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Large Nonresidential Customers.

PROGRAM DESCRIPTION

Meter Information Services is the provision of electric, gas, water usage and other relevant data, such as weather conditions, through an on-line energy management system.

Large Nonresidential Customers requesting service under this schedule must have an ability to capture and transmit interval usage data. The Company will advise the Customer on equipment specifications and subsequent changes necessary to meet these service requirements.

Meter Information Services provides Large Nonresidential Customers with interval usage data depicted in charts and graphs. Meter Information Services enables Large Nonresidential Customers to compare their current usage with historic data, identify anomalies in their usage, track savings from energy efficiency projects and understand their energy usage.

Customers may choose between the basic service option or enhanced service:
1) Standard Package – Data is updated on a weekly basis.
2) Enhanced Service – Data is updated on a daily basis.

Customers may also choose Energy Worksite which is an optional feature that offers more automated tracking capability including the ability to track projects, manage preventative maintenance and track work orders and energy bills. The Energy Worksite offer is customized for each Customer.

BILLING RATES

Meter Information Services is billed monthly on the Customer's bill for Electricity Service. Customers may choose to be separately billed for Meter Information Services for an additional $8 per bill.

SCHEDULE 320 (Continued)

BILLING RATES (Continued)

Standard Package

Set Up Fee:	$250.00 for the first meter $50.00 for each additional meter
Monthly Fees per meter:	
1 to 5 meters	$50.00
6 to 10 meters	$45.00
11 to 15 meters	$40.00
16 to 20 meters	$35.00
21 or more meters	$30.00

Enhanced Service – These costs are in addition to cost for the Standard Package.

	Monthly Cost per meter	Start Up Fee per meter
Daily Information	$10.00	$100.00
Hourly Airport Weather Data	$25.00	$50.00

Additional Customer Support or Training $125.00 per hour

Customized data, including Energy Worksite, may be provided at a mutually agreed price.

SPECIAL CONDITIONS

1. Customers who request service both inside and outside of the service territory will have all Points of Delivery (POD) receiving service on Schedule 725 and on this Schedule, added together to determine the appropriate monthly rate per meter.

2. Service under this schedule requires interval metering and meter communications be in place prior to the initiation of Meter Information Services.

3. Because of the meter and/or software installation required for this service, the Company anticipates a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.

4. Meter Information Services requires that the Customer have certain minimum computer system requirements and an ability to capture and transmit interval usage data. Specifications will be provided upon request. The Customer will at its expense provide the necessary communications equipment.

SCHEDULE 320 (Concluded)

SPECIAL CONDITIONS (Continued)

5. Customers may request a submeter be installed for the purpose of receiving Meter Information Services from a specified location behind the Company meter. However, the ability to install a submeter will be at the discretion of the Company. Customers choosing submetering will incur charges for all associated labor and materials needed to install the meter. The Customer is responsible for ownership and maintenance of the submeter.

6. The Company will disclose to Customers in any written or electronic marketing communications of more than minor length that: a) the Customer is free to procure similar services from other providers; and b) the Customer is not required to purchase Meter Information Services in order to receive regulated electricity services from the Company.

SCHEDULE 402
PROMOTIONAL CONCESSIONS
RESIDENTIAL PRODUCTS AND SERVICES

PURPOSE

This schedule describes the Company's promotional concession program for enhancing the purchase of products and services.

APPLICABLE

To Residential Customers, qualified engineers, equipment vendors, installers, builders, contractors, and to commercial Customers for residential-type appliances, products, and services.

DESCRIPTION OF CONCESSION

From time to time, the Company will provide incentives to promote the purchase and installation of selected electrical appliances, products, and services. Incentives may include, but are not limited to, contests, discounts, rebates, gift certificates, free merchandise, etc.

In compliance with OAR 860-026-0025, the Company will submit a description of each concession to the Commission. In addition, the Company will furnish a copy of the description to any other energy utility providing service in any portion of the Company's service territory.

EXPIRATION / REVIEW DATE

This program will be offered as necessary to encourage installation of energy-efficient appliances and products, and support the introduction of new products and services.

ACCOUNTING TREATMENT

Project costs associated with selling and promoting Company products and services will be assigned to Account 416.0 (Costs and Expenses of Merchandising). Other costs will be assigned to Account 426.5 (Other Income Deductions).

SCHEDULE 403
HEAT PUMP PROMOTIONAL CONCESSION

PURPOSE

This schedule describes the Company's Heat Pump Promotional Concession that will provide Customers with information and incentives for the installation of qualifying heat pumps.

APPLICABLE

To Residential Customers who install qualifying heat pumps at a service address within the Company's service territory where the currently installed heat source is electric.

DESCRIPTION OF CONCESSION

The Company will provide a $200 cash rebate to qualifying Customers who install heat pumps that meet the 2006 Federal Standard for Heating Season Performance Factor (HSPF 7.7) and Seasonal Energy Efficiency Ratio (SEER 13).

The Company will maintain a list of approved contractors that must meet certain performance standards, will be subject to random installation inspections and will be eligible for cooperative advertising, when available.

SPECIAL CONDITION

The Company will annually report to the Commission the number of program inquiries received and rebates issued.

ACCOUNTING TREATMENT

Project costs associated with selling and promoting Company products and services will be charged to non-utility accounts.

SCHEDULE 483
LARGE NONRESIDENTIAL
(< 1,000 kW)
COST-OF-SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceed 1,000 kW more than once within the proceeding 13 months and who has chosen the Company's transition plan during one of the enrollment periods specified below. Customers must have historical usage or have a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1MWa) from one or more Points of Delivery (PODs). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 489. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option.

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: Applicable to any Customer who enrolled prior to November 8, 2002, with a minimum service period from January 1, 2003 through December 31, 2007.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Fixed Three-Year Option

This option was not available during Enrollment Periods A and B.

SCHEDULE 483 (Continued)

OPT-OUT SERVICE TERM OPTIONS

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage	
	Secondary	Primary
Basic Charge		
Single Phase	$20.00	
Three Phase	$25.00	$90.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity	$2.29	$2.11
per kW of monthly Demand		
First 30 kW	$2.07	$2.07
Over 30 kW	$2.64	$2.64
System Usage Charge		
per kWh	0.216 ¢	0.205 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 483 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

The Customer may choose the Company Supplied Energy Charge options of either Daily or Extended Fixed Pricing subject to the requirements for the options.

1) Daily Pricing

The Daily Pricing Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. The election will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

2) Extended Fixed Pricing

Upon Customer request during a November Election window, the Company will provide a fixed Energy Charge quote based on market conditions at the time of the quote for either a 3 or 5 year term effective January 1st. The price quote will be available to the Customer for acceptance through close of business on the day the Company issues the quote. The quote may specify monthly and on- and off-peak prices. The Customer must provide the Company with a monthly on- and off-peak usage forecast of at least 10 MWa usage prior to the Company providing a price quote.

The Customer must execute a Schedule 483 Fixed Price Service Agreement including but not limited to the specifications for all applicable Points of Delivery, the desired term (3 or 5 years), the accepted Energy Charge quote, the monthly on- and off-peak Energy forecast at the meter, the average daily minimum and maximum Energy Usage (equivalent to 10% above and below the Energy forecast, respectively), required credit standard representations, the early termination fee description and the means for load imbalance reconciliation.

SCHEDULE 483 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy (Continued)

Extended Fixed Pricing (Continued)

Energy usage greater than the maximum will be served at the Daily Price of this schedule. For Energy usage less than the minimum, Customer will pay an addition charge equal to 75% of the difference (only if positive) between the price quote and the Daily Price applied to the difference between minimum and actual usage.

Early termination of the Fixed Price Service Agreement will require a lump-sum payment by Customer if the price quote is greater than 90% of the then-current forward market curve, adjusted for delivery to the Customer. The difference will be applied the Customer's estimated monthly usage for each remaining month of the fixed Energy Charge quote. The Customer will then be served under the Daily Price Option.

Wheeling Charge

The Wheeling Charge will be $1.487 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW for primary voltage service.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 483 (Continued)

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a written service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the minimum Five-Year Option must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

SCHEDULE 483 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 489
COST-OF-SERVICE OPT-OUT
LARGE NONRESIDENTIAL (>1000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months and who has chosen the Company's transition plan during one of the enrollment periods specified below. Customers must have historical usage or have a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 483. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option.

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: Applicable to any Customer who enrolled prior to November 8, 2002, with a minimum service period from January 1, 2003 through December 31, 2007.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Fixed Three-Year Option

This option was not available during Enrollment Periods A and B.

SCHEDULE 489 (Continued)

OPT-OUT SERVICE TERM OPTIONS

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Effective January 1, 2005, upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge options of either Daily or Fixed Pricing. The election of either option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

1) Daily Pricing

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

2) Extended Fixed Pricing

Upon Customer request during a November Election, the Company will provide a fixed Energy Charge quote based on market conditions at the time of the quote for either a 3 or 5 year term beginning with the calendar year. The price quote will be available to the Customer for acceptance through close of business on the day the Company issues the quote. The quote may specify monthly and on- and off-peak prices. The Customer must provide the Company with a monthly on- and off-peak usage forecast of at least 10 MWa usage prior to the Company providing a price quote.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)
Company Supplied Energy (Continued)
Extended Fixed Pricing (Continued)

The Customer must execute a Schedule 489 Fixed Price Service Agreement including but not limited to the following specifications for all applicable POD:

a) The desired term (3 or 5 years);
b) The accepted Energy Charge quote;
c) The monthly on- and off-peak Energy forecast at the meter;
d) The average daily Minimum Energy Usage (equivalent to 10% above the Energy forecast);
e) The average daily Maximum Energy Usage (equivalent to 10% below the Energy forecast);
f) Required credit standard representations;
g) The early termination fee description; and
h) The means for load imbalance reconciliation.

Energy usage greater than the Maximum Energy Usage will be served at the Daily Price of this schedule. For Energy usage less than the Minimum Energy Usage, Customer will pay an addition charge equal to 75% of the difference (only if positive) between the price quote and the Daily Price applied to the difference between minimum and actual usage.

Early termination of the Fixed Price Service Agreement will require a lump-sum payment by Customer if the difference between the price quote and 90% of the then current forward market curve, adjusted for delivery to the Customer, if the difference is a positive number. The difference will be applied the Customer's estimated monthly usage for each remaining month of the fixed Energy Charge quote.

Wheeling Charge
The Wheeling Charge will be $1.487 per kW of monthly Demand.

Transmission Charge
Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 489 (Continued)

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

SCHEDULE 489 (Concluded)

SPECIAL CONDITIONS (Continued)

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire
Cobrahead				
Mercury Vapor	175	7,000	67	$ 8.64(2)
	400	21,000	149	11.64(2)
	1,000	55,000	379	20.54(2)
HPS	70	6,300	31	7.20(2)
	100	9,500	43	7.71
	150	16,000	63	8.44
	200	22,000	80	9.51
	250	29,000	103	10.36
	310	37,000	125	11.95(2)
	400	50,000	165	12.55

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire
Flood , HPS	100	9,500	43	8.12(2)
	200	22,000	80	9.58(2)
	250	29,000	103	10.66
	400	50,000	165	12.85
Shoebox (bronze color, flat lens, HPS	100	9,500	43	8.65
or drop lens, multi-volt)	150	16,500	63	9.66
Special Acorn Type HPS	100	9,500	43	11.59
	150	16,500	63	11.98
	200	22,000	80	12.57
	250	29,000	103	13.52
Early American Post Top, HPS, Black	100	9,500	43	8.64
Special Types				
Cobrahead, Metal Halide	175	12,000	72	8.92
Flood, Metal Halide HPS	400	40,000	158	12.54
Flood, HPS	750	105,000	289	19.83
HADCO Indepedence, Early American	100	9,500	43	10.68
	150	16,000	63	11.40
HADCO Techtra HPS	100	9,500	43	18.33
	150	16,000	63	19.05
	250	29,000	103	27.49
KIM Archetype HPS	250	29,000	103	15.02
	400	50,000	165	17.00
Holophane Mongoose HPS	150	16,000	63	10.83
	250	29,000	103	12.31
	400	40,000	165	14.52

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$6.30
	55 or less	7.91
Wood, Painted Underground	35 or less	7.37 [2]
Wood, Curved laminated	30 or less	9.15 [2]
Aluminum, Regular	16	7.79
	25	12.68
	30	13.71
	35	15.10
Aluminum, Fluted Ornamental	14	14.82
Aluminum Davit	25	13.09
	30	13.96
	35	19.43
	40	18.84
Aluminum Double Davit	30	16.80
Aluminum, HADCO, Fluted Ornamental	16	14.18
Aluminum, HADCO, Non-fluted	18	26.49
Concrete, Ameron Post-Top	25	31.32
Fiberglass Fluted Ornamental; Black	14	8.65
Fiberglass, Regular		
Black,	20	5.48
Gray or Bronze;	30	7.34
Other Colors (as available)	35	9.98
Fiberglass, Anchor Base Gray	35	15.98
Fiberglass, Direct Bury with Shroud	18	8.30

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

SCHEDULE 515 (Concluded)

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12 month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installation or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. If the Customer requests removal of Lighting Service equipment within five years of its installation, the Customer will be responsible for the costs of removal.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

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

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	
Single Phase	$14.35
Three Phase	$20.25
Distribution Charge	
First 5,000 kWh	3.073 ¢ per kWh
Over 5,000 kWh	0.565 ¢ per kWh

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 532 (Concluded)

SPECIAL CONDITION

Unmetered service may be provided under this schedule to fixed loads with fixed periods of operation, including, but not limited to, telephone booths and television amplifiers, which are unmetered for the convenience and mutual benefit of the Customer and the Company. The average monthly usage to be used for billing will be determined by test or estimated from equipment ratings and will be mutually agreed upon by the Customer and the Company.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

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

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	
Summer Months**	$30.00
Winter Months**	No Charge
Distribution Charge	
First 50 kWh per kW of Demand	3.000 ¢ per kWh
Over 50 kWh per kW of Demand	1.000 ¢ per kWh

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 549 (Concluded)

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITION

The Customer is also responsible for notification to the Company of any change in type of service provided to the Customer's premises.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 1 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

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

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge			
Three Phase Service	$130.00	$230.00	$1,000.00
Distribution Charge			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
Generation Contingency Reserves Charges***			
Spinning Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 575 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand of the Large Nonresidential Customer when the Customer's generator is operating. The Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for generator operations, will be used to calculate the Baseline Demand. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. The Baseline Demand may be modified consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 576R, monthly Demand charges under Schedule 575 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

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

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 575 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves transition a Customer's load to Unscheduled Power. Customers on Schedule 575 must have Spinning Reserves in all Billing Periods that their generator is expected to be operating either provided by their ESS or the Company. Spinning Reserves are not required for Customers with Reserved Capacity of 1,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's load reduction plan must be approved by the Company.

Self-Supplied Reserves

Customers with Nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission, and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575 (Continued)

MINIMUM CHARGE

The Minimum Charge will be the Basic, Ancillary Services, Distribution, and Contingency Generation Reserves Charges, where applicable. In addition, the Company may require the Customer to specify a higher Minimum Charge, if necessary to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the Actual Monthly Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

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

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

3. Direct Access Service is available only upon acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

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

SCHEDULE 575 (Concluded)

SPECIAL CONDITIONS (Continued)

5. If during a Billing Period, the Customer or its ESS is billed for Ancillary Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Ancillary Services Charge under this schedule. The credit will be the actual OATT charges incurred but will not to exceed the Monthly Demand for the Schedule 575 monthly Ancillary Services Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Ancillary Services Charge incurred under this schedule. No credit will be provided against any Energy Imbalance Service charges.

6. Failure to inform the Company of use of on-site generation by a Customer will not relieve the Customer of responsibility for the charges and requirements under this schedule.

7. The Customer's Baseline Demand may be modified as requested by the Customer upon the addition of permanent energy efficiency measures, load shedding, or the removal of equipment. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation.

8. A change in Baseline Demand related to modifications in generating capacity or generation operations may be made provided the Customer provides not less than two calendar years prior written notice to the Company of such change. Any subsequent notice by the Customer under this special condition must be made no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand.

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

10. If the Customer is receiving service under this schedule and Schedule 576R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 576R Special Conditions.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

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

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Delivery Voltage	
Daily Economic Replacement Power (ERP) Demand Charge	Secondary and Primary	Subtransmission
per kW of Daily ERP Demand during On-Peak hours per day**	$0.095	$0.050
System Usage Charge		
per kWh of ERP		0.178 ¢
Transaction Fee		
per Energy Needs Forecast (ENF) submission or revision		$50.00

* See Schedule 100 for applicable adjustment.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 576R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 575). The Customer, or its agent, must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that ERP is requested.

Each ENF will be based on the Customer's expected energy requirements and the Customer will use best efforts to conform actual Energy usage to the ENF.

The ENF will specify the expected ERP needed by hour. The Customer, or its agent, will deliver the ENF to the Company in accordance with Company procedures. The Company can choose to allow delivery of all or a portion of the ENF and will inform Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 575 Baseline Energy.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Customer is taking ERP less the sum of the Customer's Schedule 575 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Customer is taking ERP.

If the sum of the Customer's Unscheduled and Schedule 575 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for any power cost adjustment for costs incurred while the Customer is taking Service under this schedule.

SCHEDULE 576R (Concluded)

SPECIAL CONDITIONS

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

2. Service under this schedule applies only to prescheduled ERP supplied to the Customer pursuant to this schedule and agreement. All other Energy delivered will be made under the terms of Schedule 575. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. Customer is required to maintain Schedule 575 service unless otherwise agreed to by the Company.

3. All charges and requirements of Schedule 575 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

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

6. The Customer, or its agent, must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer. The Company may require the Customer to change its forecast if the Company believes the forecast does not adequately represent the expected load.

7. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 575 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

8. The Company is not responsible for providing market information to Customer.

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

10. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceeded 1,000 kW more than once in the proceeding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

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

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage	
	Secondary	Primary
Basic Charge		
Single Phase Service	$20.00	
Three Phase Service	$25.00	$90.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity	$2.29	$2.11
per kW of monthly Demand		
First 30 kW	$2.07	$2.07
Over 30 kW	$2.64	$2.64
System Usage Charge		
per kWh	0.216 ¢	0.205 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 583 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW for primary voltage service.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

SCHEDULE 583 (Concluded)

SPECIAL CONDITIONS (Continued)

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 589
LARGE NONRESIDENTIAL
(>1000 kW)
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

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

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly on-peak Demand	$2.45	$2.45	$1.28
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

SCHEDULE 589 (Concluded)

SPECIAL CONDITIONS (Continued)

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 591
STREET AND HIGHWAY LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control or time switch to be mutually agreeable to the Customer and Company for an average of 4,150 hours annually.

SERVICE OPTIONS

The Company has the following service options available for lighting:

Option A is for luminaires owned, maintained and supplied with Electricity by the Company.

Option B is for maintenance and Electricity supplied to Customer-owned equipment.

Option C is a grandfathered option, available only where Option C service was initiated prior to December 31, 2006. Option C is the provision of Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles.

MAINTENANCE

Maintenance of Option A luminaries includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance also includes repair of an inoperable luminaire. This means that any failed part (lamp, photoelectric controller, starter, ballast, refractor, power door, etc.) will be replaced, or the entire failed luminaire will be replaced with in-kind equipment, if it is more practical to do so.

SCHEDULE 591 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Distribution Charge	2.803 ¢ per kWh
Energy Charge:	Provided by Energy Service Supplier

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead Power Doors **	100	9,500	43	*	$4.44	$1.21
	150	16,000	63	*	5.02	1.77
	200	22,000	80	*	5.54	2.24
	250	29,000	103	*	6.17	2.89
	400	50,000	165	*	7.91	4.62
Cobrahead	100	9,500	43	$7.30	4.52	1.21
	150	16,000	63	7.89	5.10	1.77
	200	22,000	80	8.82	5.61	2.24
	250	29,000	103	9.52	6.26	2.89
	400	50,000	165	11.28	8.01	4.62
Flood	250	29,000	103	9.81	6.28	2.89
	400	50,000	165	11.57	8.04	4.62
Early American Post-Top	100	9,500	43	7.76	4.52	1.21
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	100	9,500	43	8.20	4.59	1.21
	150	16,000	63	9.06	5.19	1.77

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.38	$0.15
Fiberglass, Bronze	30	5.85	0.20
Fiberglass, Gray	30	5.86	0.20
Wood, Standard	30 to 35	5.04	0.16
Wood, Standard	40 to 55	6.32	0.21

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Acorn-Types						
HPS	100	9,500	43	$11.02	$4.83	$1.21
HADCO Independence	100	9,500	43	10.14	4.62	1.21
	150	16,000	63	10.72	5.20	1.77
Special Architectural Types						
HADCO Victorian HPS	150	16,000	63	11.28	5.38	1.77
	200	22,000	80	11.75	5.81	2.24
	250	29,000	103	12.55	6.52	2.89
HADCO Techtra HPS	100	9,500	43	17.48	5.21	1.21
	150	16,000	63	18.06	5.79	1.77
	250	29,000	103	25.95	7.60	2.89
KIM Archetype HPS	250	29,000	103	*	6.62	2.89
	400	50,000	165	*	8.36	4.62
Special Types						
Cobrahead, Metal Halide	175	12,000	72	8.30	5.43	2.02
Flood, Metal Halide	400	40,000	158	11.32	7.92	4.43
Flood, HPS	750	105,000	289	17.65	12.70	8.10
Holophane Mongoose, HPS	150	16,000	63	10.19	5.38	1.77
	250	29,000	103	11.39	6.51	2.89
	400	50,000	165	13.18	8.27	4.62

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum, Regular	16	$6.23	$0.21
	25	10.13	0.34
	30	10.96	0.37
	35	12.06	0.40
Aluminum Davit	25	10.46	0.35
	30	11.15	0.37
	35	12.32	0.41
	40	15.05	0.50
Aluminum Double Davit	30	13.42	0.45
Aluminum, HADCO, Fluted Victorian Ornamental	14	11.84	0.40
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	21.16	0.71
Aluminum, HADCO, Fluted Ornamental	16	11.33	0.38
Aluminum, Painted Ornamental	35	29.22	0.98
Concrete, Ameron Post-Top	25	25.03	0.84
Fiberglass, HADCO, Fluted Ornamental Black	14	6.91	0.23
Fiberglass, Regular,			
color may vary	22	3.39	0.11
color may vary	35	7.98	0.27
Fiberglass, Anchor Base, Gray	35	12.77	0.43
Fiberglass, Direct Bury with Shroud	18	6.63	0.22

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of with Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead, Mercury Vapor	100	4,000	40	*	*	$1.12
	175	7,000	67	$8.06	$5.05	1.88
	250	10,000	95	9.88	6.10	2.66
	400	21,000	149	10.50	7.50	4.18
	1,000	55,000	379	17.83	14.29	10.62
Special Box Similar to GE "Space-Glo"						
Sodium Vapor	70	6,300	31	10.78	4.18	0.87
Mercury Vapor	175	7,000	67	12.05	5.19	1.88
Special box, Anodized Aluminum						
Similar to GardCo Hub						
HPS	70	6,300	31	*	*	0.87
	100	9,500	43	*	4.80	1.21
	150	16,000	63	*	5.38	1.77
	250	29,000	103	*	*	2.89
	400	50,000	165	*	*	4.62
Metal Halide	250	20,500	101	*	6.57	2.83
	400	40,000	158	*	8.62	4.43
Cobrahead, Dual Wattage HPS						
70/100 Watt Ballast	100	9,500	43	*	4.52	1.21
100/150 Watt Ballast	100	9,500	43	*	4.52	1.21
100/150 Watt Ballast	150	16,000	63	*	5.10	1.77
Special Architectural Types						
KIM SBC Shoebox HPS	150	16,000	63	*	5.72	1.77

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Acorn-Type HPS	70	6,300	31	$10.53	$4.18	$0.87
Special GardCo Bronze Alloy						
HPS	70	5,000	31	*	*	0.87
Mercury Vapor	175	7,000	67	*	*	1.88
Special Acrylic Sphere						
Mercury Vapor	400	21,000	149	*	*	4.18
Early American Post-Top HPS						
Black	70	6,300	31	6.84	4.19	0.87
Rectangle Type	200	22,000	80	*	*	2.24
Incandescent	92	1,000	32	*	*	0.90
	182	2,500	63	*	*	1.77
Town and Country Post-Top						
Mercury Vapor	175	7,000	67	8.19	5.07	1.88
Flood, HPS	70	6,600	31	7.48	4.23	0.87
	100	9,500	43	7.70	4.55	1.21
	200	22,000	80	9.16	5.63	2.24
Cobrahead, HPS						
Non-Power Door	70	6,300	31	6.86	4.18	0.87
Power Door	310	37,000	125	10.94	7.27	3.50
Special Types Customer Owned & Maintained						
Ornamental	100	9,500	43	*	*	1.21
Twin ornamental	200	22,000	80	*	*	2.41
Compact Fluorescent	28	N/A	12	*	*	0.34

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum Post	30	$ 6.23	*
Bronze Alloy GardCo	12	*	$0.25
Concrete, Ornamental	35 or less	10.13	0.34
Steel, Painted Regular **	25	10.13	0.34
Steel, Painted Regular **	30	10.96	0.37
Steel, Unpainted 6-foot Mast Arm **	30	*	0.37
Steel, Unpainted 6-foot Davit Arm **	30	*	0.37
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41
Wood, Laminated without Mast Arm	20	5.67	0.15
Wood, Laminated Street Light Only	20	4.38	*
Wood, Curved Laminated	30	7.31	0.27
Wood, Painted Underground	35	5.04	0.21
Wood, Painted Street Light Only	35	5.04	*

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C
Special Architectural Types Including Philips QI Induction Lamp Systems						
HADCO Victorian QL	85	6,000	35	$12.98	$3.39	$0.98
	165	12,000	61	15.58	4.17	1.71
HADCO Techtra QL	85	6,000	35	16.75	3.51	0.98
	165	12,000	61	18.31	4.32	1.71

SCHEDULE 591 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Design services for Customer-owned streetlight equipment.
- Painting or staining of wood and steel streetlight poles.

ESS Charges

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment.

5. If Customer-owned (Option B) streetlighting equipment or poles are removed or relocated at the Customer's request, the Customer is responsible for all costs associated with the change.

SCHEDULE 591 (Concluded)

SPECIAL CONDITIONS (Continued)

6. If circuits or poles are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

7. For Option C lights: When the Company provides the circuit, the Customer will incur a circuit charge of $1.52 per luminaire per month.

8. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaries owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

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

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Distribution Charge	1.803 ¢ per kWh

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 592 (Concluded)

SPECIAL CONDITIONS

1. The Customer or ESS will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule using sampling techniques to determine, whether in the Company's opinion, the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Energy use as it may deem to be satisfactory or remove the Customer from service under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 600
ENERGY SERVICE SUPPLIER CHARGES

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electric Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff.

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). Transmission services include:

(a) Transmission as further described under Special Conditions;
(b) Scheduling, System Control and Dispatch Service;
(c) Reactive Supply and Voltage Control Service;
(d) Regulation and Frequency Response Service*;
(e) Energy Imbalance Service*;
(f) Operating Reserve - Spinning Reserve Service*; and
(g) Operating Reserve - Supplemental Reserve Service*.

* When provided by the Company.

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company.

SCHEDULE 600 (Continued)

ESS SUPPORT SERVICES

The following charges are applicable to Scheduling and Non-Scheduling ESSs:

(1)	Application Processing Fee	$400.00 with Application
(2)	Registration Renewal Fee	$200.00
(3)	Electronic Data Interchange Testing	$100.00 per man-hour for all hours in excess of 16 hours annually
(4)	Change of Effective Date Request (Rule K)	$ 35.00
(5)	Switching Fee (Rule K) (Applicable for each Enrollment or Drop DASR, not applicable for Rescind or Change DASRs)	$ 20.00

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$ 0.63 per bill
(2)	Late Pay Charge	1.7 % of delinquent balances for products and services purchased under this Tariff, excluding products and services listed in the 700 series.

CUSTOMER INFORMATION

ESS Web Portal Historical Usage Download for Interval Data Charge	$ 20.00 per PODID

BILLING AND PAYMENT

Charges incurred for Schedule 600 services are the responsibility of the ESS for which service was provided and are due and payable as described in the Company's General Rules and Regulations.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE SYSTEM LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's system:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Losses:	6.28%	2.82%	1.31%

SCHEDULE 710
UTILITY ASSET MANAGEMENT (UAM)

PURPOSE

To assist utilities and other pole owners in recovering lost revenue, reducing regulatory penalties and increasing efficiency and effectiveness by managing poles, pole attachments and providing wireless service management.

AVAILABLE

To utilities and other pole owners in the State of Oregon.

CHARACTER OF SERVICE

Services available under this schedule include:

1. **Pole Management and Pole Maintenance Services** include processing pole attachment permits, field inspection, engineering, maintenance, construction, managing contracts, billing, GIS data and mapping, pole inspection and analysis, treatment and attachment auditing.

2. **Rental Services** include initiating contracts for pole owners prior to attachment installation, calculating pole attachment rates, managing the permit process, performing site inspections and load analysis and installing poles and lines in compliance with National Electric Safety Codes (NESC).

3. **Wireless Service Management** includes identifying clients for possible attachment sites, site identification design and load verification grounding analysis, zoning assistance and tower construction.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. All fully distributed costs and revenues associated with the provision of Utility Asset Management (UAM) will be charged or credited to non-utility accounts.

3. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other pole management providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's UAM program.

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.
2. All fully distributed costs and revenues associated with the provision of Electrical Equipment Services will be charged or credited to non-utility accounts.
3. Electrical Equipment Services will not use the Company's proprietary Customer information for the marketing of its products or services.
4. The Company's employees providing utility services will inform Customers about their choices to use other available service providers for these types of services.
5. There will be no tying of the provision of Electrical Equipment Services with the provision of Electricity Service.
6. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services.

SCHEDULE 720
EFFICIENCY SERVICES

PURPOSE

Provide cost-effective and innovative services to assist Customers, utilities, agencies, cities and other entities in managing energy and water consumption, improving indoor air quality and positively influencing the practices that impact the environment; and to offer ideas and solutions to meet goals for Energy savings and resource efficiency that emphasize cost-effective operations and long-term value, respectively.

AVAILABLE

To all Customers, utilities, agencies and cities in the State of Oregon.

SERVICES TO CUSTOMERS

Services from energy efficiency audits to large-scale mechanical systems retrofits, tailored services are provided to meet the needs of the recipient. These services include, but are not limited to:

1. Energy and facility audits to identify cost-effective opportunities for increased energy and water efficiency and enhanced working conditions, including: energy efficiency audits, facility management audits, and water efficiency studies.

2. Specification and/or project management for lighting, water and mechanical systems retrofits including facilitation and training, cash flow management and arrangement of financing.

3. Turnkey general contracting for lighting, water and mechanical systems retrofits in order to create a single-source high-performance building solution.

4. Consulting and technical services to support building certification under the Earth Advantage™ program or other third party guidelines.

SERVICES TO UTILITIES / AGENCIES / CITIES

Services are provided to respond to a variety of project sizes and scopes from specific consultations to turnkey operations, and are determined to best meet the utilities'/recipient's needs. Services include, but are not limited to:

1. Creation and management of comprehensive efficiency programs to meet the needs of the recipient's customers or constituency. Efficiency Services develops customized programs as well as full turnkey programs and operations including: lighting retrofits, industrial process, systems commissioning, water efficiency and new construction.

SCHEDULE 720 (Concluded)

SERVICES TO UTILITIES / AGENCIES / CITIES (Continued)

2. Earth Advantage™ new construction licensing program for commercial construction.

3. Technical services support existing programs or evaluate performance, including Energy audits for project identification, commissioning for quality control and project verification.

4. Training and consultations for internal teams or customer groups. Training is created to enhance the skills of program teams, design teams, contractors and facility managers, and is focused on understanding electricity, program management, sales training, lighting design, systems integration, motors and motor controls, green building and resource efficiency. Consulting services help develop and successfully manage customized efficiency programs and support program development, program management or program sales and marketing.

BILLING RATES

Services will be contractually negotiated.

SPECIAL CONDITIONS

All services provided under this schedule require a signed contract.

1. All fully distributed costs and revenues associated with the provision of Efficiency Services will be charged or credited to non-utility accounts.

2. Efficiency Services will not use the Company's proprietary Customer information for the marketing or provision of its products or services, with the exception of any proprietary Customer information made available to Efficiency Services in the event they are providing services to the Energy Trust of Oregon (ETO).

3. Marketing materials for efficiency products or services sold within the Company's service territory and not under contract with the ETO will contain the disclaimer statement, "You do not need to purchase this product to continue to receive safe and reliable power from PGE."

4. Efficiency Services will not tie the provision of its products or services with incentives or rebates to Electricity Services.

5. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other efficiency services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Efficiency Services program.

SCHEDULE 725
E-MANAGER

PURPOSE

Provide electric, gas, water usage and other relevant data, such as weather condition through an online energy maintenance system.

AVAILABLE

In all parts of Oregon except the territory served by the Company.

APPLICABLE

To Customers or utilities.

PROGRAM DESCRIPTION

E-Manager service provides Customers with interval usage data depicted in charts and graphs for the purpose of comparing current and historic load data, identifying anomalies in usage, tracking savings from energy efficiency projects, and understanding their energy usage.

Two service options are available:
1) Standard Package – Data is updated on a weekly basis.
2) Enhanced Service – Data is updated on a daily basis.

An optional feature called Energy Worksite that offers more automated tracking capability including the ability to track projects, manage preventative maintenance and track work orders and energy bills is also available.

BILLING RATES

Standard Package

Set Up Fee:	\$250.00 for the first meter \$ 50.00 for each additional meter
Monthly Fees per meter:	

Standard Package

1 to 5 meters	\$ 50.00
6 to 10 meters	\$ 45.00
11 to 15 meters	\$ 40.00
16 to 20 meters	\$ 35.00
21 or more meters	\$ 30.00

SCHEDULE 725 (Concluded)

BILLING RATES (Continued)

Enhanced Service – These costs are in addition to cost for the Standard Package.

	Monthly Cost per meter	Start Up Fee per meter
Daily Information	$10.00	$100.00
Hourly Airport Weather Data	$25.00	$ 50.00

Additional Customer Support or Training $125.00 per hour

Customized data, including Energy Worksite, may be provided at a mutually agreed price.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. All fully distributed costs and revenues associated with the provision of E-Manager will be charged or credited to non-utility accounts.

3. If the Company chooses to use bill inserts to market this schedule, it will allow other Meter Information Service providers access to place inserts in the Company's bills under the same prices, and terms and conditions that apply to the Company's E-Manager program.

4. Service under this schedule requires interval metering and meter communications be in place prior to the initiation of E-Manager service.

5. Because of the meter and/or software installation required for this service, the Company anticipates a delay may occur from the time service under this schedule is requested until the Company can provide it.

6. E-Manager service requires certain minimum computer system requirements and an ability to capture and transmit interval usage data. Specifications will be provided upon request. The Customer must provide the necessary communications equipment as well.

7. If E-Manager services are requested from a specified location behind the meter, the Company will install a submeter at the discretion of the Customer or the utility serving the customer. All associated labor and materials to install the submeter as well as the cost of any future maintenance are the responsibility of the Customer or the utility.

8. Customers who request service both inside and outside the service territory will have all Points of Delivery (POD) receiving service on Schedule 320 and on this schedule added together to determine the appropriate monthly rate.

SCHEDULE 730
POWER QUALITY PRODUCTS AND SERVICES

PURPOSE

To provide Customers with products that protect their electronic equipment or their entire electrical system from potential power surges, spikes and outages.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicability is dependent upon the specific product.

PROGRAM DESCRIPTION

Customers may choose any or all of the following products:

Meter Socket Adapter (MSA) Surge Suppressors are devices installed beneath the 200 amp, single phase Electricity meter that protect the Customer's electrical system from high voltage surges or spikes.

Home Surge Protection Center (HSPC) Surge Suppressors are devices installed near a 320 amp Electricity meter and provide electricity surge suppression, with the option to purchase telephone and/or cable surge protection.

Inside Outlet Surge Suppressors provide additional protection for sensitive electronic equipment, phone and cable television (CATV) protection. Features include surge protection that exceeds the Company's recommended standard, safety fusing for protection elements and a warranty on surge suppressor or product damage.

Uninterruptible Power Supply (UPS) provides Customers with a secondary power supply and surge protection which protects Customer equipment from damage caused by power outages or voltage instability. The following two devices are available:

UPS800 – This model is an automatic voltage regulator UPS that can support up to 800 VA and 480 watts of customer equipment for approximately 20 minutes.

UPS500 – This model provide standby UPS for 500 VA and 300 watts of customer equipment for approximately five minutes.

SCHEDULE 730 (Continued)

BILLING RATES

Meter Socket Adapter (MSA) Surge Suppressor

Installation Charge	$ 65.00

The Installation Charge is in addition to the cost to either Purchase or Lease the MSA Surge Suppressor.

Customers leasing the MSA may choose to pay the Installation Charge in four monthly installments of $16.25.

Purchase	$128.00
Lease	$ 5.95 per month

Home Surge Protection Center (HSPC) Surge Suppressor

HSPC device	$350.00
Shipping	$ 7.00

(Shipping charge applicable when a Customer chooses to hire a certified electrician to install the device rather than to have the Company install it.)

Installation	$125.00
Phone Connection Installation	$ 30.00
Cable Television (CATV) installation	$ 30.00

Inside Outlet Surge Suppressor

Models available:

1) eight outlet surge suppressor with phone jack	$ 30.00
2) eight outlet surge suppressor with digital satellite, cable TV and phone protection	$ 39.00
3) one outlet surge suppressor	$ 6.50
4) one outlet surge suppressor with phone jack	$ 7.00
5) one outlet surge suppressor with cable TV protection	$ 7.50

An additional $8 for shipping and handling will be added to the total cost of a Customer's order of Inside Outlet Surge Suppressors.

SCHEDULE 730 (Continued)

BILLING RATES (Continued)

Surge Protection Package[1]

Purchase

MSA and Outlet Devices	$196.00
Installation Fee (required)	$65.00
Shipping and handling	$8.00
TOTAL	$269.00

Lease

MSA Monthly Lease	$5.95 per month
Plus:	
Outlet Devices	$71.00
Installation Fee (required)	$65.00[2]
Shipping and handling	$8.00
TOTAL	$144.00

(1) Includes MSA Surge Suppressor and inside outlet surge suppressor model numbers 1, 2 and 5.
(2) Customers leasing the MSA may choose to pay the Installation Charge in four monthly installments of $16.25.

The Company will install Underwriter's Laboratories (UL) listed meter socket adapter surge suppressors other than those offered by the Company for an installation charge of $100.

UPS Devices

Purchase

UPS800 $150.00

An additional $17 for shipping and handling will be added to the total cost for each UPS800 purchase.

UPS500 $ 75.00

An additional $12 for shipping and handling will be added to the total cost for each UPS500 purchase.

Schedule 730 (Continued)

SPECIAL CONDITIONS

General

1. All fully distributed costs and revenues associated with the provision of products and services under this schedule will be charged or credited to non-utility accounts.

2. The Company will include in all of its written and verbal communications regarding its Power Quality products and services a statement that addresses the following two points: a) that the purchase of this service is not necessary for a Customer to continue to receive safe and reliable power from the Company; and b) that the Customer may buy similar products and services from other providers.

3. Any incentives or rebates offered will not be tied to the provision of Electricity Services.

4. If a Customer desires that any listed device be installed at a rented or leased dwelling, the landlord or property owner must agree in writing to the terms and conditions contained herein.

5. All products are warranted through the manufacturer. The Customer agrees that the Company will not be liable for any and all claims, costs, expenses, damages and liabilities, including reasonable attorney fees at trial and on appeal, resulting from, or alleged to be caused, directly or indirectly, by use, operation, or failure of any of the products or services offered under this schedule except when caused by sole negligence of the Company. The Customer will look solely to the manufacturer for any recovery of liability claims.

6. The Customer acknowledges and agrees that the Company makes no warranties of any kind, express or implied, regarding the condition or performance of the devices, including, but not limited to, any warranty of merchantability or fitness for a particular purpose.

MSA Surge Suppressor

1. Only Company employees may install, remove or otherwise work on the MSA Surge Suppressor device.

2. Customers will be responsible for checking the indicator lights periodically to ensure that the device is working properly.

SCHEDULE 730 (Concluded)

SPECIAL CONDITIONS (Continued)
MSA Surge Suppressor (Continued)

3. Customers leasing an MSA Surge Suppressor will be considered in default if any payment owed is not received within 90 days of the due date. Upon default the Company may repossess the device, and the Customer will remain responsible for all missed payments owed up to the date of repossession.

4. Customers leasing an MSA Surge Suppressor may terminate the service agreement for any reason within 30 days after installation but will owe the installation charge regardless of whether or not the service agreement has been terminated. After 30 days, the Customer is bound by the terms of the service agreement.

TERM

Customers who choose the lease option for the MSA Surge Suppressor must sign a two-year service agreement. At the completion of the two-year term, the lease agreement will remain in effect on a month by month basis until the Customer notifies the Company of their request to cancel service under this schedule.

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RULE

RULE A
INTRODUCTION

1. **General**

   These General Rules and Regulations provide the terms and conditions related to services offered by the Company under this Tariff.

2. **Territory Served**

   The Company supplies Electricity Service in incorporated and unincorporated portions of Clackamas, Columbia, Hood River, Marion, Multnomah, Polk, Washington, and Yamhill counties, Oregon. The Company may also provide certain non-utility services in its 700 series schedules in other parts of Oregon.

3. **Commission Rules, Regulations and Orders**

   Existing and future lawful rules, regulations, and orders of the Commission will be considered a part of this Tariff.

4. **Tariff Compliance**

   Service and rates are subject to all applicable General Rules and Regulations contained in the Tariff of which each schedule is a part.

5. **Relationship to Rate Schedules**

   If a rate schedule provision conflicts with a provision in these General Rules and Regulations, the rate schedule provision will apply.

RULE A (Concluded)

RULE B
DEFINITIONS

The terms listed below, which are used frequently in the Tariff, have the stated meanings:

1. **Ancillary Services**

   Services necessary or incidental to the transmission and delivery of Electricity from resources to retail Electricity Customers, including but not limited to scheduling, frequency regulation, load shaping, load following, spinning reserves, supplemental reserves, reactive power, voltage control and energy balancing services.

2. **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.

3. **Basic Charge**

   A monthly amount, specified in certain rate schedules, which is charged regardless of the amount of Energy consumed. The charge represents a part of the Company's fixed costs of making service available, such as meter reading and billing costs.

4. **Billing Period**

   A time interval, which may vary between 27 and 34 days, between successive billing dates.

5. **Commission**

   The Public Utility Commission of Oregon.

6. **Company**

   Portland General Electric Company.

7. **Customer**

   An individual, partnership, corporation, organization, government, governmental agency, political subdivision, municipality, or other entity who has applied for, been accepted, and is currently receiving Electricity Service at a Point of Delivery. A Customer who voluntarily terminates service and subsequently requests service with the Company at a new or existing location within 20 days after terminating service retains Customer status. For purposes of Schedule 201 and the Company's 700 series schedules, a Customer may not be receiving Electricity Services from the Company.

8. **Customer Service Agreement**

An Agreement with a Customer that specifies Utility Provided Service or Direct Access Service terms and conditions for service under this Tariff.

9. **Day of Flow**

The day in which Electricity deliveries are made; measured as the time period beginning immediately after midnight for the hour ending 0100 and ending at exactly the end of the 2400 hour Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

10. **Demand**

The maximum rate of delivery of Electricity metered for purposes of billing, measured in whole kilowatts (kW) registered over a nominal 30-minute interval.

11. **Demand Charge**

A charge for registered Demand normally assessed to Customers with Demands greater than 30 kW.

12. **Direct Access Service**

The delivery by the Company of Electricity and applicable Ancillary Services by the Company that a Nonresidential Customer has purchased from an ESS.

13. **Direct Access Service Request (DASR)**

Electronic notification provided by an ESS to the Company that a Customer has selected the notifying ESS as its supplier of Electricity Service. DASRs are also required for a Customer to terminate Direct Access Service and begin or resume receiving Electricity Service from the Company, rescind a previously submitted DASR, change the effective date of the enrollment DASR, or update the Customer's account information when the Customer is receiving Direct Access Service.

14. **Electricity**

Electric energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh); or electric capacity, measured in kilowatts (kW) or megawatts (MW), or both.

15. Electricity Schedule

A Scheduling ESS's projection of its hourly Electricity deliveries, measured in megawatt-hours (MWh), that are necessary to meet the aggregate hourly load of its Customers and the Customers of any Non-Scheduling ESS for which it provides scheduling service. The Electricity Schedule is for a Day of Flow and is provided to the Company in accordance with Western Electricity Coordinating Council (WECC) and National Energy Reliability Council (NERC) operating standards.

16. Electricity Service

The provision of Electricity to Customers by the Company or by an ESS using the Company's Facilities.

17. Electricity Service Supplier (ESS)

A provider of Electricity Service including a Large Nonresidential Customer that has obtained all necessary approvals to do business in the State of Oregon, is certified by the Commission if applicable, has met the Company's requirements for providing service and executed an ESS Service Agreement with the Company. The Company, when supplying Electricity to Nonresidential Customers in its own service territory, is not considered an ESS. The Company will classify ESSs as one of the following:

Scheduling ESS

An ESS that provides its own Electricity Schedule to the Company.

Non-Scheduling ESS

An ESS that does not provide the Company with a Schedule and relies on a Scheduling ESS for services related to scheduling and settlement.

18. Energy

Electric energy commonly measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

19. Energy Charge

A variable charge billed on the basis of a Customer's metered or estimated kilowatt-hours (kWh) usage.

20. Emergency Default Service

A service option provided by the Company to a Nonresidential Customer that requires Utility Provided Service with less than five business days' notice to the Company by the Customer or its ESS. This service is available to the Customer for a maximum of five consecutive days from initial purchase.

21. ESS Service Agreement

An agreement between the Company and an ESS specifying terms and conditions for service under this Tariff.

22. Facilities

Transmission and distribution plant and equipment owned and operated by the Company.

23. Facility Capacity

The Facility Capacity is the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

24. Farm Service

Nonresidential electric service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting, and selling crops; or by the feeding, breeding, management and sale of, or the producing of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and their disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

25. Kilovar (kVAr) A unit of reactive power equal to 1,000 reactive volt amperes.

26. Kilowatt (kW) A unit of power equal to 1,000 watts.

27. Kilowatt-Hour (kWh) The amount of Energy delivered in one hour when power is delivered at a constant rate of 1 kW.

28. **Large Nonresidential Customer**

A Nonresidential Customer whose monthly Demand has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service whose Demand has exceeded 30 kW.

29. **Nonresidential Customer**

A Customer that does not meet the definition of a Residential Customer.

30. **Operational Order to Deliver Electricity**

An order issued by the Company to scheduling ESSs to deliver additional Electricity for purposes of maintaining the integrity of the Company's facilities.

31. **Point of Delivery (POD)**

Unless otherwise designated by agreement, the first point of connection of the Company's service drop, service lateral or bus to the Customer's service entrance conductors or equipment determined without regard to the location of the meter or metering equipment.

32. **Point of Delivery Identification (PODID)**

A code that identifies each unique Point of Delivery and associated Company meter location (if applicable).

33. **Portfolio**

A set of product and pricing options provided to Residential Customers and Small Nonresidential Customers.

34. **Premises**

Real and personal property owned and/or used by a Customer at a single location, which contains a Point of Delivery.

35. **Reactive Demand**

The maximum rate of delivery of kilovolt-amperes reactive (kVars) measured over a nominal 30-minute interval. Reactive Demand must be supplied to most types of magnetic equipment, such as motors. It is supplied by generators or by electrostatic equipment, such as capacitors, motors or transformers. It is recognized as a necessary Ancillary Service.

36. Reactive Demand Charge

A charge for Reactive Demand assessed to Customers with loads that are supplied Reactive Demand on the Company's system.

37. Residential Customer

A Customer that has applied for and been accepted to receive service at a dwelling primarily used for residential purposes, including, but not limited to, single family dwellings, separately metered apartment units, mobile homes, and houseboats, but excluding dwellings employed for Transient Occupancy, such as hotels, motels, camps, lodges, and clubs.

For purposes of this rule, a dwelling must contain permanent facilities for sleeping, bathing, and cooking.

Boarding houses with no more than four separate sleeping quarters for use by people who are not members of the Residential Customer's family and "adult foster homes" (defined in ORS 443.705 as a home or facility in which residential care is provided for five or fewer adults who are not related to the Residential Customer by blood or marriage) are residential dwellings.

When there is nonresidential use of Electricity at a dwelling used primarily for residential purposes, the Company will classify the Customer as residential if the Company determines that Electricity consumed in a typical month for residential use exceeds that consumed for nonresidential use, and if the nonresidential use is carried out primarily by the occupants of the dwelling.

Individual dwelling units in newly constructed multi-family residential buildings will be individually metered and billed as Residential Customers. Service through one meter to two dwelling units will be classified as one Residential Customer where an existing dwelling unit is or has been divided into two dwelling units, provided the ampacity of the service equipment is not increased. In the case where service is supplied through one meter to two or more new dwelling units, or to three or more existing dwelling units, service will be classified as nonresidential service.

Service through additional meters to other than dwellings on residential premises will be classified as nonresidential.

38. Scheduled Crew Hours

Those times that Company service crew personnel are working at their regular rate of pay. Scheduled Crew Hours may vary by location and type of work.

39. Site

A. Buildings and related structures that are interconnected by facilities owned by a single retail electricity Customer and that are served through a single electric meter; or

B. A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that

1) Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

2) Buildings and structures in the Site, and land containing and connecting buildings and structures in the Site, are owned by a single retail electricity Customer who is billed for electricity use at the buildings and structures; and

3) Land will be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as streetlighting, sewerage transmission, and roadway controls), will not be considered contiguous.

40. Small Nonresidential Customer

A Nonresidential Customer who does not meet the definition of a Large Nonresidential Customer, which means the Nonresidential Customer has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service had not exceeded 30 kW.

41. Standard Service

A service option provided by the Company to a Nonresidential Customer who elects to purchase Electricity from the Company rather than from an ESS.

42. Summer Months

Summer Months are the six regular Billing Periods from May through October. In 2007, the Summer Months will begin with regular meter readings on Month XX, 2007.

43. Tariff

This Tariff, including all schedules, rules and regulations as they may be modified or amended from time to time.

44. Theft of Service

Theft of Service occurs when an Applicant or Customer initiates or maintains Electricity Service through fraudulent means, including but not limited to providing false identification or false information to establish an account or credit, paying for Electricity Service with a stolen financial account, tampering with Company equipment including but not limited to the meter, or diverting service.

45. Tradable Renewable Credits

Tradable Renewable Credits (TRCs) consist of the non-power attributes resulting from the generation of Energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a TRC purchaser.

Non-power attributes include, but are not limited to, any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO_2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. These non-power attributes are expressed in MWh.

Non-power attributes do not include any energy, reliability, scheduling, shaping or other power attributes.

46. Transient Occupancy

Tenancy at a Premise for a duration of less than 30 days.

47. Utility Provided Service

The provision of Electricity Service to a Customer by the Company.

48. Winter Months

Winter Months are the six regular Billing Periods from November through April. In 2007, the Winter Months will begin with regular meter readings on Month XX, 2007.

RULE C
CONDITIONS GOVERNING CUSTOMER ATTACHMENT TO FACILITIES

1. **Acceptance of Electricity Service**

   By establishing or requesting a POD or by continuing an existing Point of Delivery (POD) to the Company's Facilities, an owner or tenant of the property agrees to the following:

   A. To be bound by the conditions of this Tariff including payment of costs for Electricity Service delivered at the rates and under the terms and conditions of this Tariff as in effect from time to time and all applicable Commission rules;

   B. To pay any costs incurred by the Company to provide Electricity Service if Electricity is taken and there is no Customer; and

   C. To have Electricity Service discontinued by the Company if there is no Customer.

2. **Continuity of Electricity Service**

   A. **Generally**

   Unless otherwise specified in a Customer Service Agreement, the Company intends to make Electricity Service available continuously at standard voltages on the Company's distribution system. The Company does not guarantee constant or uninterrupted delivery of Electricity, the constancy of its voltage or frequency, or against the loss or reversal of one or more phases in a three-phase service. The Company's obligation to provide or continue to provide Electricity Service is subject to the applicable provisions of this Tariff. During periods of imminent or actual system emergencies, the Company may curtail or interrupt service to the Customer in order to maintain system integrity.

B. **Emergency Curtailment**

During system emergencies, including but not limited to those caused by extremely cold weather, the temporary loss of a major generating plant or transmission facilities, or conditions that violate the Willamette Valley/Southwest Washington Area (WILSWA) or Western Electricity Coordinating Council (WECC) standards, the Company may find it 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 interconnected by initiating an Emergency Curtailment. The Company will contact the Commission prior to an Emergency Curtailment unless circumstances deem prior notice impractical. Upon the instigation of an Emergency Curtailment, the Company will begin complying with its Curtailment Operating Procedures in order to restore system stability.

The Company's Curtailment Operating Procedures include, but are not limited to, steps for implementing rotating outages. During rotating outages the Company would discontinue Electricity Service to a specific number of circuits for approximately one-hour periods. If after the first hour, system integrity were still in jeopardy, the circuits initially curtailed would have service restored while a second block of circuits would simultaneously have service discontinued. This cycle would continue until the Company determined that system emergency conditions no longer existed. Facilities deemed necessary to public health, safety and welfare are excluded from the rotating outage, as well as feeders serving Customers participating in the Schedule 88, Load Reduction Program.

During system emergencies, Customers having their own generation facilities or access to Electricity from non-utility power sources may choose to use energy from those other sources.

The Company will not initiate its Curtailment Operating Procedures to avoid the purchase of high priced power. The Curtailment Operating Procedures are periodically updated and submitted to the Commission.

C. **Limitation of Liability**

The Company is not liable to Customers, ESSs or any other person or entity for any interruption, suspension, curtailment or fluctuation in Electricity Service, or for any loss or damage caused thereby, resulting from:

1) Causes beyond the Company's reasonable control;
2) Repair, maintenance, improvement, renewal, or replacement of Facilities, or any discontinuance of service that the Company determines is necessary to permit repairs or changes to its Facilities or to eliminate the possibility of injuries to persons or damage to the Company's property or property of others. To the extent practical, such work will be done in a manner that will minimize inconvenience to the Customer, and whenever practical and applicable, the Customer will be given reasonable notice of such work, repairs, or changes;
3) An ESS's failure to abide by the terms of the ESS Service Agreement or the Tariff;
4) Automatic or manual actions taken by the Company, including but not limited to Emergency Curtailments, that in its opinion, are 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 interconnected; and
5) Actions taken by the Company to curtail Electricity use at times of anticipated resource deficiency in accordance with the applicable provisions of this Tariff.

D. **Company's Right to Remove Facilities**

The Company may remove its Facilities as specified in a Customer Service Agreement or when no longer used.

E. **No Customer**

The Company may refuse to maintain Facilities in place or to continue the availability of Electricity Service at any Premises for which the Company has No Customer.

3. Delivery Voltages

A. Generally

Electricity delivered under this Tariff is provided at alternating current, 60 hertz, single- or three-phase, at one of the following standard voltages:

B. Secondary Voltages

1) **Generally**

Single-phase, 120/240 volts, 3-wire, grounded
Single-phase, 240/480 volts, 3-wire, grounded
Three-phase, 208/120 volts, 4-wire, grounded wye
Three-phase, 240/120 volts, 4-wire, grounded delta
Three-phase, 480/277 volts, 4-wire, grounded wye
Three-phase, 480/240 volts, 4-wire, grounded delta

2) **In Some Locations**

Single-phase, 480 volts, 2-wire (no new service)
Single-phase, 120/208 volts, 3-wire
Three-phase, 240 volts, 3-wire (no new service)
Three-phase, 480 volts, 3-wire (no new service)

C. Primary Voltages

1) **Generally**

Three-phase, 12,470/7,200 volts, 4-wire, grounded

(2) **In Some Locations**

11,000/6,350 volts, 4-wire, grounded service

(New installations will not be supplied at 2,400 or 4,160/2,400 volts.)

D. Subtransmission Voltage

At 59.8-kV, voltage range is: 56.81-kV to 62.79-kV

At 115-kV, voltage range is: 109.25-kV to 120.75-kV

E. Selection of Voltage Furnished

The voltage to be furnished is at the Company's option and will depend upon the characteristics of the Company's distribution system near the POD, the applicable rate schedule and the Customer's service requirements.

4. Conditions for Receiving Service

A. **Generally**

This section describes the physical and technical requirements necessary to interconnect the Company's Facilities with the POD.

B. **Rights-of-Way and Access**

The Customer must provide, without cost to the Company, all rights-of-way and easements on the Premises to be served for the construction, maintenance, repair, replacement, or use of any or all Facilities necessary or convenient for the supply of Electricity. The Customer must grant the Company free and unrestricted access to the Premises at all reasonable times for purposes of reading meters, trimming trees, and inspecting, testing, repairing, removing or replacing any or all Facilities of the Company.

C. **Customer-Supplied Equipment**

1) **Customer's Responsibility**

The Customer will, at the Customer's risk and expense, furnish, install, inspect, and maintain in a safe condition all wiring, equipment, apparatus, protective devices, raceways, and enclosures which may be required beyond the POD for receiving and using Electricity. The Company may, at its option, install and maintain Facilities beyond the POD where deemed necessary to provide adequate Electricity Service.

2) **Conformance with Codes**

Before the Company will provide Electricity Service, the Customer's wiring and equipment must conform to applicable municipal, county and state requirements, and to accepted standards of the National Electrical Safety Code, the National Electric Code, the Company's published "Electric Service Requirements and Guidelines," and Company standards and practices. As required by law, the Customer or its agent must obtain a certificate of electrical inspection before the Company will provide Electricity Service.

3) **Company's Right to Inspect**

The Company has the right, but is not obligated, to inspect any Customer-owned installation, including all wiring, conduit, meter-bases or supporting equipment up to the electric meter and/or POD, at any reasonable time.

4) **Effect of Customer's Load**

The Customer must reasonably balance load between phases of a three-phase service or between ungrounded conductors of a single-phase, three-wire service. The Customer's equipment must not cause excessive voltage fluctuations on the Company's lines. The Company has the right to refuse, discontinue or to regulate hours of Electricity Service to loads that could, in the Company's opinion, impair Electricity Service to other Customers.

5) **Notice of Changes in Customer Load**

A Customer must give the Company prior written notice before making any material change in either the amount or character of the Customer's electrical appliances, apparatus or equipment, thereby allowing the Company to ascertain whether any changes are needed in its Facilities and to make such alterations in the charges for Electricity Service as may be required by this Tariff for the changed installation. If damage results to Facilities owned by the Company through failure of the Customer to notify the Company, the repair and, or replacement costs of such Facilities will be paid by the Customer.

6) **Trouble Calls**

When the Company, in responding to a report of an outage or other continuity of Electricity Service problem, determines the cause of the service problem to be solely in the Customer's equipment, the Company will bill the Customer for charges as listed under Schedule 300.

7) **Miscellaneous Equipment Rental**

When available, the Customer may elect to rent equipment from the Company including, but not limited to, transformers, single-phase to three-phase inverters, capacitors, and other related equipment in accordance with charges specified under Schedule 300 and the terms and conditions of the equipment rental agreement.

D. **Hazardous Substances**

1) **Evaluation of Job Sites**

The Company reserves the right, but is not obligated, to evaluate the job site of any new line extension request or of any required maintenance or repairs of existing Facilities for the purpose of identifying any hazardous wastes, hazardous substances or contaminants ("hazards") in soils or surface at the job site, as such hazards are defined under state or federal law.

2) **Information About Hazards**

Information about hazards may include the following:

a) The job site is within an area designated or listed as a hazardous site by a state or federal environmental agency; or

b) The Customer, Applicant or an employee of the Company or agent of the Company, Customer or Applicant reports unusual or inappropriate odor, color or material in, or adverse physical reaction to, soil or surfaces at the job site.

3) **Treatment of Information About Hazards**

If the Company receives information that hazards may exist at a job site, and such hazards may, in the Company's determination based upon applicable state, federal and industry standards, cause a risk to the health or safety of its employees or agents or the viability of equipment in the installation, maintenance, or repair of service, the Company will specify mandatory conditions for the protection of its employees, agents, or equipment. The Company also may require that the Customer or Applicant indemnify the Company against future claims related to the existence of the hazard. The cost of complying with the Company's conditions and with following state and federal regulations for the handling of the hazard, including, but not limited to, the cost of testing, handling, transporting and disposing of contaminated soil will be borne by the Customer or Applicant.

4) **Remediation of Hazardous Conditions**

The Company may require the Customer or Applicant to bear the cost of remediation or relocation of Company Facilities, if conditions cannot be prescribed which, in the Company's judgment, will adequately protect its employees or agents against hazards.

5) **Remediation Costs**

Nothing contained in this Tariff will be construed as obligating the Company to pay any remediation costs relating to hazards.

6) **Hazards in Public Right-of-Way**

This Tariff does not apply to hazards in a public right-of-way, either for purpose of recovery of extraordinary costs associated with installation, maintenance or repair, or for indemnification against future costs, except where the Customer's or Applicant's Premises are the source of the hazards in the right-of-way.

5. Interconnection of Customer-Generator Facilities

The following will apply to all interconnected Customers unless they are covered by an Interconnection Agreement entered into pursuant to the Company's Open Access Transmission Tariff (OATT) on file with the Federal Energy Regulatory Commission (FERC).

A. **Conformance with Regulations**

In order to ensure system safety and reliability of interconnected operations, the facility will be constructed, interconnected, and operated in accordance with all applicable federal, state, local laws and regulations, including the Company's Interconnection Guidelines, as may be amended from time to time.

B. **Control and Protective Devices**

The Customer will furnish, install, operate, and maintain in good order and repair without cost to the Company such switching equipment, relays, locks and seals, breakers, automatic synchronizers, and other control and protective apparatus as shown by the Company to be reasonably necessary for the operation of the facility in parallel with the Company's system. In all cases, the protective relaying design and equipment proposed for the interconnection of generator(s) must be approved by the Company.

C. **Cost Responsibilities**

The Customer is responsible for all costs of interconnection including any costs incurred by the Company. Additionally, the Customer is responsible for any modification to the Customer's facility that may be required by the Company for purposes of safety and reliability. The Customer will also reimburse the Company for administrative costs the Company incurs in this process.

D. **Conformance with Codes**

A facility will meet all applicable safety and performance standards established in the Oregon State Building Code. The standards will be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories or other similarly accredited laboratory.

E. **Isolating Equipment**

A readily accessible, lockable and visible-break isolation device will be provided by the Customer at the point of interconnection for the Company's use and will be accessible to the Company at all times. At the Company's option, the Company may operate the isolating equipment if, in the sole opinion of the Company, continued operation of the qualifying facility in connection with the Company's system may create or contribute to a system emergency. At the Company's option, Customers installing small photovoltaic generators may customize their isolating equipment.

6. Transformers

A. **Generally**

Transformers furnished by the Company will be sized to the Customer's kVA requirement as determined by the Company. Transformers furnished by the Customer must be approved by the Company prior to connection.

B. **Restrictions on Transformer Types**

The Company will not furnish transformers with unusual specifications or connections, transformers with voltages not provided by the Company, or transformers insulated with gases or fluids other than oil. Dry-type transformers will be furnished only if:

1) A dry-type transformer installed by the Company prior to October 1, 1975, fails while in service.
2) A Company-owned, dry-type transformer requires replacement because of overload, provided no increase in the ampacity of the Customer's service entrance equipment has been made.
3) Multiple transformations are required to provide 120/240-volt single-phase service to load centers located throughout a residential building over five stories where the tenants are directly metered.

7. Relocation or Removal of Facilities

A. **Generally**

Any relocation of Facilities for a requesting party, including builders, developers, Customers or Customers' agents, that is for their convenience will be performed by the Company at the requesting party's expense. The Company may require payment in advance of a sum equal to the estimated original cost of installed Facilities to be removed, less estimated salvage and less depreciation, plus estimated removal cost, plus any operating expense associated with the removal or relocation.

B. **Public Works Project**

Under the following circumstances, the cost for relocation or removal of Facilities within the public right-of-way will be borne by the Company unless an ordinance, legislation or private agreement specifies other cost responsibilities:

1) The rearrangement can be identified to be for a Public Works Project. Examples of Public Works Projects include but are not limited to public transit or a road widening financed by public funds;
2) Reasonable notice is provided to the Company;
3) The overall project can generally be scheduled during normal work hours (excluding load transfers which may need to be performed outside of normal work hours); and
4) The Public Works Project does not require the Company to make temporary relocations.

C. **Easement**

Costs for permanently relocating Facilities on a private easement will be borne by the requesting party regardless of status as Public Works Project or otherwise.

D. **Permit Job**

Where it can be identified that the requesting party has received a permit through a city or county for work within the public right-of-way that is required for the requesting party's construction project, the requesting party is responsible for all of the costs associated with the necessary rearrangement of Facilities.

E. **Relocation of Overhead or Underground Facilities at Company Expense**

If the necessary work can be performed by Company crews in a single trip to the requesting party's Premises during Scheduled Crew Hours (7:00 a.m. to 3:30 p.m., Monday through Friday, except Company recognized holidays) relocation or removal of overhead or underground service distribution Facilities on or adjacent to the Premises will be performed at Company expense, under the circumstances listed below. For underground relocations, the requesting party is responsible for any necessary trenching, boring, backfilling, conduit, paving, vaults and pads.

1) Such Facilities are idle, meaning not receiving Electricity Service for more than six months, except in the case of conversion from overhead to underground service; or

2) The location of such Facilities in the street area deprive the requesting party of reasonable ingress to or egress from the Premises, provided such Facilities are not on a property line or a property line extended. Generally, one driveway is considered reasonable ingress or egress; or

3) Such Facilities occupy space on the requesting party's Premises that will be used for an expansion of the requesting party's building or plant. In these cases, the Line Extension Allowance will apply for the expansion. Costs exceeding the Line Extension Allowance must be borne by the Customer; or

(4) The purpose is to relocate a meter to a more accessible location approved by the Company; or

(5) Relocation of a service drop is the only work requested.

If more than one trip is required to accommodate the Customer, the Customer will be billed all costs plus loadings incurred for the additional trips.

F. **Temporary Relocations**

Where the Company is required to temporarily move its Facilities either because the Company cannot move its Facilities to the new permanent placement or the Facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of its status as a Public Works Project or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

8. Service Restoration

A. **Generally**

During a major outage due to events such as a major storm, the Company will follow priorities for service restoration as provided below. These restoration procedures are followed in order to restore service to the greatest number of Customers as quickly as possible with special consideration given to Customers that are critically essential to public welfare.

The Company maintains a list of critical Customers such as hospitals, airports, 911 dispatch centers, fire and police stations, water and sewage treatment plants, radio and television stations, newspapers and telephone exchanges. The Company will then repair other main distribution lines.

B. **Service Priority**

The priorities for service restoration are generally as follows:

1) **Protect Public Safety**

The Company will clear downed power lines and ensure that Facilities such as hospitals, fire and police departments, and utilities have power.

2) **Repair Transmission Lines to Substations**

The Company will first make the necessary repairs to the transmission system connecting generation facilities to substations in order to ensure system stability. The Company will then make the necessary repairs to transmission lines, substations, and distribution facilities that connect substations to critical Customers. Next, the Company will continue to repair remaining transmission lines and substations after service is restored to critical Customers' service addresses.

3) **Repair Substations**

The Company will repair substations making it possible to restore service to large numbers of Customers.

4) **Repair Distribution Lines**

The Company will repair distribution lines serving critical Customers as well as lines that may be blocking streets or highways.

5) **Repair of Tap Lines**

After the Company repairs distribution lines, it will repair tap lines that serve smaller groupings, such as Residential Customers.

6) **Repair of Individual Service Connections**

The Company will repair individual service connections last. If Customer-owned equipment has been damaged, such as the meter base, a licensed electrician must repair it before the Company can restore service. Such repairs are the responsibility of the Customer.

C. **Other**

The Company will not give priority restoration to any Customer, non-utility generator or ESS, but will employ the above process over the Company's entire territory served.

RULE C (Concluded)

RULE D
APPLICATION FOR ELECTRICITY SERVICE

1. **Notification Requirement**

   An Applicant must provide the Company with five business days notice of intent to purchase Utility Provided Service.

2. **Required Residential Identification Standards**

   In order to establish Electricity Service, an Applicant must provide identification as outlined below as well as meet the credit requirements as established in Rule E.

   A. **Residential Applicants**

      1) A Residential Applicant must provide the following information for the person(s) responsible for payment of the account:

         a) Name(s);
         b) Name to be used to identify the account, if different than the actual name(s) provided under (1)(a);
         c) Date(s) of birth;
         d) Social Security Number(s);
         e) Current, valid Driver's License Number(s) or other current, valid state or United States Federal identification containing the name and photograph of the person(s) responsible for payment on the account;
         f) Service address;
         g) Preferred mailing address; and
         h) Telephone number(s) where the Applicant may be reached.

      2) In lieu of providing either a current, valid identification as required in Section (2)(A)(1)(e) or a Social Security Number as required in Section (2)(A)(1)(d), an Applicant will provide at least two of the following three:

         a) Original or certified copy of the Applicant's birth certificate;
         b) Current photo identification from school or employer; and
         c) Name, address and telephone number of a professional person who can verify the Applicant's identity, such as a teacher, employer or caseworker.

d) Other information deemed sufficient by the Company to establish the Applicant's identification.

B. **Nonresidential Applicants**

Sole proprietors must provide the identification required under (2)(A) of this rule as well as meet the credit requirements as established in Rule E. All other Nonresidential Applicants must provide the following information for the person(s) responsible for payment of the account:

1) Company name and, if applicable, name used for Doing Business As (DBA);
2) Service address;
3) Preferred mailing address;
4) State of incorporation;
5) Name of an officer or other responsible employee; and
6) A current, valid telephone number(s) where the officer or other employee named for (5) may be reached.

3. Forms of Requests for Electricity Service

1) An Applicant may request Utility Provided Service from the Company by telephone, electronically or in person at one of the Company's offices. The Company has the discretion to require an Applicant to fill out and sign a written application form.
2) The Company may accept complete third party applications for residential Utility Provided Service. The Company may refuse to process such an application until it receives satisfactory evidence of the third party's authority to request such service.
3) When a Nonresidential Applicant selects Direct Access Service through an ESS, the ESS must submit a Direct Access Service Request (DASR) under the provisions of Rule K prior to initiation of Direct Access Service.

4. Effect of Application

An application does not bind the Company to provide service and does not bind the Applicant to remain a Customer for a period longer than the minimum term specified in the applicable rate schedule.

5. **Customer Service Agreements**

In most cases, the Company will not require a written Customer Service Agreement as a condition of providing Electricity Service. Certain rate schedules and Rule I of these General Rules and Regulations may require a written Customer Service Agreement.

6. **Consequences of Accepting Electricity Service**

Any person who occupies or is responsible for Premises where Electricity Service is supplied and/or delivered by the Company where the Company has no accepted current application for Electricity Service is liable for all charges for such Electricity Service, based on the applicable rate schedule. Such persons, however, do not have the rights and privileges accorded to Customers.

7. **Refusal of Electricity Service**

The Company may refuse an application for Electricity Service until it receives full payment of any past due amount or other obligation related to a Customer's/Applicant's prior account or as also set forth in OAR 860-021-0335.

RULE D (Concluded)

RULE E
ESTABLISHING CREDIT

1. Residential Credit Standards

A. Generally

Before the Company accepts an application for Electricity Service, it may require the Applicant to establish credit standing. OAR 860-021-0200 (hereinafter referred to as "Commission Credit Rules") determines the criteria for establishing credit.

The establishment or reestablishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. Establishing Credit

A Residential Applicant may establish credit standing for new or continuing service by providing one of the following:

1) An Applicant may submit an authorized letter from his/her previous electric utility, on the utility's letterhead, verifying all of the following:
   a) The dates the Applicant received service;
   b) That the Applicant was the responsible person on a service account where 12 months of continuous, equivalent Electricity Service was received within the prior 24 months;
   c) That the Applicant did not have service disconnected for Theft of Service; and
   d) That the Applicant did not have service disconnected for nonpayment during the final 12 months that service was received.
2) If the Applicant has previously received Electricity Service from the Company, then the Company may verify the Applicant's creditworthiness based on the same standards listed above;

3) A letter from the Applicant's employer, income provider or authorized representative verifying the Applicant's ability to pay. A letter from an employer must state that the Applicant is currently employed and has been employed the entire 12 months prior to the application, and must contain a telephone number for an authorized representative of the employer. The Company must be able to verify the Applicant's employment; or

4) Payment of a Deposit as detailed below in Section C.

C. **Two-Month Deposit Requirement**

In general, the Commission Credit Rules require that deposits be equal to two months' estimated billings (1/6 of the estimated annual usage) at the service address. When a deposit is required, the charges specified in Schedule 310 may apply. A deposit is required if any of the following is true about the Applicant or Customer:

1) Does not establish credit as set forth in Subsections (1) through (3) of Section B above;

2) Received equivalent Electricity Service from the Company or the same type of utility service from an Oregon-regulated utility within the preceding 24 months and, at the time service was terminated, the Customer owed an account balance that was not paid according to its terms. This does not apply to Customers who registered a dispute with the Commission within 60 days after service terminated and who promptly paid all undisputed or adjudicated amounts;

3) Was previously terminated for Theft of Service by the Company or any Oregon-regulated utility or was otherwise found to have tampered with the meter, other utility facilities or diverted utility service; or

4) Moves and the anticipated bill at the new residence will be at least 20% greater than that upon which any current deposit was based.

D. **Payment of Residential Deposit**

An Applicant or Customer who is required to pay a deposit or additional deposit may:

1) Pay the deposit in full prior to receiving service;

2) Enter into an agreement to pay the deposit in three installments, except where a deposit is required to reconnect service after disconnection for nonpayment (OAR 860-021-0335), in which case the whole deposit is due prior to reconnection; or

3) Provide a letter of guaranty.

If the Applicant or Customer chooses to enter into a deposit installment agreement they must do so within five business days from the date of notice from the Company that a deposit is required. Except for the last payment, installments must be the greater of $30 or 1/3 of the deposit. The Applicant or Customer must pay the first installment immediately. The remaining installments will be due 30 and 60 days after the first installment payment. If a Customer has an existing deposit on file with the Company, and an additional amount is being added to the deposit due, any additional installment payment(s) will be adjusted to include the additional deposit; however, two payments will not be required within the same 30 day period.

If a Customer fails to abide by the terms of a deposit installment agreement, the Company may disconnect service after making a good-faith effort to contact the Customer in person or by mailing a notice no less than six business days before disconnection. Should disconnection for nonpayment of a deposit occur, the Customer is required to pay: the full amount of the unpaid deposit balance, any applicable Reconnection charge, Late Payment Charge, and 1/2 of any past due amount before service is restored. The balance of the past due amount is to be paid within 30 days of the date service is restored. A Customer may continue with an existing time payment agreement by paying all past-due installments along with the full deposit and other applicable charges [OAR 860-21-0205(7)].

If an Applicant/Customer pays a deposit or an outstanding bill from a prior account by making a noncash payment which is subsequently returned for insufficient funds by the Applicant's/Customer's financial institution, the Applicant/Customer is subject to immediate disconnection and does not obtain/retain Customer status. The Company will make a good-faith attempt to notify the Applicant/Customer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day following notification. Because the Applicant does not obtain Customer status, the Applicant does not have the right to a time payment agreement or a medical certificate.

E. **Letter of Guaranty**

In lieu of paying a deposit, a Customer or Applicant may provide the Company with a personal Letter of Guaranty from a responsible party to secure payment in an amount equal to two months' average billings as listed in Schedule 310. A responsible party is a Customer who has received continuous service for 12months from the Company with no late payment. For the purposes of this rule, a Customer has had a late payment if he/she has had one or more notices of pending disconnection generated for his/her account.

When the Customer who has established credit with a Letter of Guaranty has his/her Electricity Service disconnected for nonpayment, the responsible party is charged the two months average billing as listed in Schedule 310. The money paid by the responsible party will be applied to the Customer's balance owing. When the Customer requests reconnection of Electricity Service, any additional monies will be applied to the costs of the Customer's reconnection charges and other costs of establishing credit. When service reconnection is not requested, the responsible party who has paid the Letter of Guaranty amount is refunded any excess amount.

2. Nonresidential Credit Standards

A. Generally

Before an application for Electricity Service is accepted, the Nonresidential Applicant must establish credit as defined below in this rule. The establishment or reestablishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. Establishing Credit

A Nonresidential Applicant or Customer may establish credit for new or continuing service by:

1) Demonstrating that the Applicant or Customer has received 12 months continuous and equivalent Electricity Service from the Company or another electric utility during the preceding 12 months, and did not receive more than two late payment notices or two five-day disconnection notices within the 12-month period. If the service was provided by another electric utility, the Applicant must provide the Company acceptable written verification from the other electric utility;
2) Providing an irrevocable Letter of Credit in a form acceptable to the Company guaranteeing payment in an amount equal to the deposit that would otherwise be assessed;
3) Providing a surety bond or other form of guarantee acceptable to the Company in an amount equal to the deposit that would otherwise be assessed; or
4) Payment of a deposit.

The Company may verify the Customer's creditworthiness at any time. If the Customer is unable to maintain creditworthiness, the Customer may be required to provide a deposit as discussed in Section C below.

C. **Deposit Requirement**

Except for seasonal Applicants or Customers, a deposit equal to a maximum of two average month's billings for Company charges is required when the Applicant or Customer:

1) Does not satisfy the credit criteria as defined in Subsections (1) through (3) of Section (2)(B);
2) Was previously exempted from paying a deposit based upon false information given at the time of application;
3) Is involved in a liquidation, bulk transfer, or financial reorganization or if a receiver is appointed in a state court proceeding involving the Applicant or Customer; or
4) Has sought any form of relief under the federal bankruptcy laws, or is brought within the jurisdiction of the bankruptcy court for any reason in an involuntary manner; then deposit may be demanded as allowed by the Federal Bankruptcy Act of 1978 and, in particular, 11 USC § 366.

In the case of seasonal Applicants or Customers, the maximum deposit amount will be based on the two highest months of usage.

D. **New or Additional Deposits**

A Customer may be required to reestablish credit where conditions of Electricity Service or the basis upon which credit was originally established have materially changed. For the purposes of this rule, conditions are considered to have materially changed if any of the following exist:

1) The Customer's Electricity use is such that the Company does not have a deposit that equals 1/6 of the estimated annual usage where a deposit has been paid, or the Customer must establish credit at a different service address;
2) The expected billings to the Customer have changed as a result of the Customer's enrollment in Direct Access Service, Portfolio or other Electricity Service options; or
3) The Customer returns to Standard Service from Direct Access Service or Emergency Default Service.

F. **Payment of Deposit**

A Nonresidential Applicant who is required to pay a deposit must pay the deposit in full within five business days of the service request if the Applicant has an account balance from a prior service account that was not paid according to its terms. Absent an account balance from a prior service, if the service is connected at the requested service address, the deposit must be paid with the first bill for the new service regardless of whether or not the first month's billing is for a full Billing Period. If service is not connected at the service address, the deposit must be paid in full before the service will be turned on.

An existing Nonresidential Customer who has its Electricity Service disconnected for nonpayment of a deposit will be required to pay the full amount of the deposit, plus any applicable Reconnection Charge, Late Payment Charge, and past due amount before service is restored. Written notice of disconnection for nonpayment of deposit will be provided to Nonresidential Customers five days before service disconnection. The procedures in OAR 860-021-0505 will be used in issuing the notice of disconnection.

E. **Like Ownership**

If the Company, in its discretion, determines that principals of a corporation, partnership, or other commercial enterprise are substantially the same as another corporation, partnership, or commercial enterprise that either is receiving or has at one time received Electricity Service, they are deemed to be the same corporation, partnership, or commercial enterprise for the purposes of this rule.

3. Treatment of Residential and Nonresidential Deposits

A. **Generally**

The Company will furnish a receipt upon payment of deposit and will hold the deposit until credit is satisfactorily established or reestablished. For the purposes of this section of the rule, credit is considered to be established or reestablished if, at the end of 12 months after a deposit is paid in full:

1) The account is current;

2) The Customer has not been issued more than two five-day disconnection notices during the previous 12 months; and

3) The Customer was not disconnected for nonpayment during the previous 12 months.

In the event the Customer moves to a new address within the Company's Service Territory and the Company is holding a deposit in accordance with this rule, the deposit, plus accrued interest, will be transferred to the new account.

B. **Interest Accrual**

Deposits will accrue interest at a rate prescribed by order of the Commission and set forth in Schedule 300. If a deposit is held beyond 12 months, accrued interest will be paid by a credit to the Customer's account on the next bill for service following the anniversary of the accrual date. Interest will be prorated on deposits held by the Company for less than a full 12 months.

C. **Delinquent Accounts**

When service is terminated, the Company will refund a Customer deposit with interest accrued at the rate as listed in Schedule 300, except that such refund will first be applied to reduce or eliminate any unpaid balance on the Customer's account. The Company is under no obligation to draw on deposits to cure delinquency of an active Customer account.

RULE E (Concluded)

RULE F
BILLINGS

1. **Basis for Billing**

A. **Generally**

Unless specifically provided otherwise in a rate schedule or in a contract, the Company's rates are based upon the furnishing of continuous Electricity Service to the Customer's Premises at a single Point of Delivery (POD), and at a single voltage and phase. If the Company agrees to additional PODs, each POD is separately metered and billed and treated as a separate Line Extension under the provisions of Rule I.

B. **Individual Metering**

Each separately operated business activity and each separate building is individually metered and billed except:

1) Where two or more buildings on one Premises are occupied and used by one Customer in the operation of a single and integrated business enterprise, the Company may furnish Electricity Service for the entire group of buildings through one service connection at one POD; and

2) Where a site has service measured and billed from a single meter, a Customer will furnish Electricity to the tenants on its Premises, provided the cost to the tenant for such Electricity is included as a general cost in the rent and is not separately billed or paid.

C. **Continuing Nature of Charges**

Disconnect and reconnect transactions do not relieve a Customer from the obligation to pay Basic or Minimum Charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Customer.

D. **Tax Adjustment**

A separately stated tax adjustment is billed in any community or area where a governmental authority imposes a tax or assessment in excess of the limit established by the Commission in OAR 860-022-0040 and 0045.

E. **Restrictions on Resale**

Electricity Service will not be supplied for resale, except on Premises and through installations where a Customer engaged in resale to tenants prior to November 5, 1973. In such cases, the Customer will bill the tenants at the Company's applicable rates or, if approved by the Company, at the Customer's average rate per kWh (the Customer's total bill for Electricity including all charges, adjustments and taxes divided by the associated kWh). The Company will allow billing at the Customer's average rate when the Customer does not have adequate metering to bill tenants at applicable rates or the usage characteristics of the tenants do not lend themselves to standard billing.

2. Customer to be Billed; Responsibility for Payment

The Customer receiving Electricity Service is responsible for payment of all Company charges except when an ESS is providing consolidated billing as specified in Section (2) of Rule G. In such case, the ESS is responsible for payment of Direct Access Service and other Company charges.

Customers are responsible for checking their billings and verifying their accuracy.

When a change in occupancy occurs or the Customer otherwise chooses to close an account, the Customer must provide five business days' notice to the Company, before the change will go into effect. 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. The outgoing Customer (or serving ESS if it is providing a Consolidated Bill) is held responsible for all service supplied to the Premises until the account is closed.

3. Application for Site

In order for multiple accounts to be billed as a Site, the Customer must either obtain Site certification through the Oregon Department of Energy (ODOE) or request Company certification.

To request Company certification, the Customer must provide a list of all account numbers and maps or other supporting documentation to demonstrate that these accounts comprise a Site. The Customer will be required to sign and return a letter of understanding before any billing changes are effective.

As a Site, the Customer's primary account will be assessed the maximum $500 Schedule 115 charge. When the Customer's usage is seasonal, the Company will review the usage from all accounts comprising the Site and assess the maximum or less than the maximum charge as applicable. For nonseasonal Customers, if the combined usage from all accounts comprising the Site is such that the total Schedule 115 charge based on kWh would be less than $500 a month, the Customer is responsible to provide sufficient documentation to the Company in order to be refunded any overpayment. For purposes of Schedule 108, the Customer must be certified as a Site with ODOE and have completed a certified project. Once the project is certified, the Customer must notify and provide documentation to the Company before Schedule 108 billing changes will be made.

4. Meter Readings

A. **Generally**

The Company will keep a record of at least three years of meter readings. Meter readings are the basis for determining all bills rendered for metered service.

B. **Assessed Demand**

At the Company's option, Demand may be determined by test or assessment. The assessed Demand of each motor is the nameplate horsepower of the motor multiplied by 0.825 rounded to the nearest whole kW.

C. **Estimated or Prorated Meter Readings**

The amount of Electricity, Demand or Reactive Demand used by the Customer is estimated by the Company from the best available sources and evidence in the following circumstances:

1) Where a meter is inaccessible due to conditions on the Customer's Premises; or
2) When it is determined that the amount of Electricity, Demand, or Reactive Demand used was different from that recorded or billed; or
3) In preparing opening and closing bills. It is the normal practice of the Company, however, to make reasonable efforts to prepare opening and closing bills from actual meter readings.

D. **Incorrect Metering or Billing**

When Electricity Service has been unmetered or incorrectly metered or billed, regardless of cause, or when a meter is found to be more than 2% fast or slow, the Company will adjust its billings and notify the Customer and any serving ESS. Any such adjustment will be for a period not exceeding six months, unless it can be shown that the error was due to a specific cause, the date of which can be fixed, in which case the actual date will be used. In no event, however, will an overbilling or underbilling be for more than three years' usage.

E. **Special Meter Reading**

The Special Meter Reading Charge, as set forth under Schedule 300, is applied when a Customer has requested more than one Special Meter Reading during the preceding 12-month period to verify the accuracy of a previous meter reading. If the Special Meter Reading results in a billing correction, the Company will waive the Special Meter Reading Charge.

F. **Unmetered Loads**

Electricity Service to fixed loads with fixed periods of operation, such as streetlights, Schedule 92 traffic lights, television amplifiers and other similar installations, may be unmetered for the convenience and mutual benefit of the Customer and Company. Monthly usage is billed in accordance with the Customer's applicable rate schedule. Customers have the responsibility of notifying the Company of changes in connected load. Without such notice, the Company is not obligated to make retroactive adjustments to billings or continue to offer unmetered service to the fixed load.

G. **Special Demand**

All rate schedules are based upon loads for which standard Demand measurements reflect adequately the burden imposed on the Company's system. If a Customer has a load with large short-period fluctuations, the Company reserves the right to employ a Special Demand determination.

H. **Reactive Demand**

All rate schedules assume that the Customer takes a minimum of Reactive Demand. Charges in the rate schedules for Reactive Demand are separate from and in addition to charges under the monthly rate for Demand and Electricity or under any minimum charge. Where the Customer installs equipment to supply part or all of its Reactive Demand requirement, such equipment must be switched in a manner acceptable to the Company. Separate charges for Reactive Demand will not be made when the Customer's Reactive Demand is 30 kVar or less.

5. Presentation and Payment of Bills

A. **Generally**

The rate schedules in this Tariff set forth the rates for one Billing Period. However, the Company may read meters and render bills for a period shorter or longer than one Billing Period, in which case the charges based on one month of service (e.g. monthly Basic Charges, charges for Facility Capacity and other Demand related charges) and the number of kWh in each of the rate blocks of the rate schedules will be prorated by multiplying by the number of days in the period and dividing by 30. The number of days in the Billing Period must be less than 27 or more than 34 for a bill to be prorated.

B. **Prorating Initial and Closing Bills**

Initial and closing bills are prorated, unless the time between initial and final use of service is less than 27 days.

C. **Prorating for Tariff Changes**

Changes in Tariff charges or provisions which become effective with service rendered as of a particular date rather than upon the date of meter readings or billings are prorated based on the number of days during the Billing Period that service was provided under the former and revised rate schedules unless the Company is billing on a daily basis using daily readings.

D. **Payment of Bills**

All bills, except closing bills, are due and payable at the Company's offices or authorized pay stations within 15 days of the date of presentation, unless otherwise specified on the bill. Closing bills are due and payable upon presentation. The date of presentation is the date on which the Company mails the bill.

Non-cash payments remitted by Customers in payment of bills are accepted conditionally. A Returned Payment Charge, set forth under Schedule 300, is assessed when the Customer's financial institution refuses to pay as charged.

A Field Service Collection Charge, as specified in Schedule 300, is charged for each visit to a service address by a Company representative to disconnect service for nonpayment of past due amounts where such visit does not result in disconnection of service due to collection of payment from the Customer or representative regarding payment by the Customer.

If a Customer's non-cash payment is returned by the Customer's financial institution within the last 12 months, future payments must be made in cash, money order, verified credit card payment or cashier's check.

E. **Processing of Payments**

The Company will allocate payments from Customers in the following order:

1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

F. Budget Pay Plans

Budget Pay Plans are available to Residential Customers who have satisfactory credit and have no past due balance on their account. At the Company's option, Small Nonresidential Customers that are not receiving Direct Access Service may also be offered these plans. No additional charges will be made for rendering bills under a Budget Pay Plan. The Company may adjust a Customer's budget pay amount if changes in the Customer's usage patterns or other factors cause the budget pay amount to no longer accurately reflect the Customer's actual billings.

The Company may discontinue a Customer's Budget Pay Plan if the Customer fails to pay the monthly budget pay amount in full by the due date. Customers may discontinue participation in the Budget Pay Plan upon notification to the Company. If a Budget Pay Plan is discontinued, the Customer must pay any unpaid balance determined by subtracting the total amount paid under the Budget Pay Plan from the total amount the bills would have been, based on the actual kWh used. If a budget pay plan is voluntarily or involuntarily discontinued, the Company is not obligated to offer another Budget Pay Plan to that Customer for a period of 12 months from the time the plan was discontinued. Other monthly charges, such as financing contract and area light charges, will be added to the Customer's monthly bill but are not included when computing the monthly budget pay amount. The Company offers:

1) **Average Pay Plan**

Bills for service under this plan are rendered on a 12-month average basis. The average pay amount is calculated each month and is equal to the average consumption of the preceding 12-months (actual or estimated) or less (based on the number of months available), multiplied by the current rate, plus up to 1/10 of any then-outstanding debit or credit balance.

2) **Equal Pay Plan**

The monthly payment amount is based upon 1/12 of the anticipated annual bill, adjusted as necessary for Tariff changes. Annually, Customer accounts are reviewed to determine the equal pay amount for the subsequent 12 months. At the time of the annual review and at the Customer's request, a present account balance can be settled; otherwise, any remaining balance will be included in estimating the equal payment for the following year. Adjustments in the equal pay amount may be made by the Company at times other than annually if the Customer's actual bill would differ significantly from their previously calculated anticipated annual bill.

G. **Time Payment Agreements**

Residential Customers who are notified of pending disconnection may choose between two Time Payment Agreement options: a levelized payment plan and an arrearage plan as described in OAR 860-021-0415.

H. **Credit Balance**

Except where a Customer is on a Time Payment Agreement, an amount paid in excess of what is owed the Company for services rendered and other applicable charges will be carried as a credit balance on its account and applied to bills for future service unless the Customer requests a cash refund. When a customer on a Time Payment Agreement pays more than the billed amount, the excess payment will be applied to the principle due.

I. **Forced Shutdown of Customer's Operations**

If a Nonresidential Customer's productive operations are completely shut down for a continuous period of more than 15 days solely by reason of fire, flood, wind, action of the elements, acts of God, or other accident or casualty beyond the Customer's control, and the Customer so notifies the Company in writing immediately upon the Customer's knowledge of such event, any minimum charge provision of the applicable rate schedule will be waived during the time of such shutdown. During such time, bills will be computed on the basis of actual Demand and Electricity use and prorated to the number of days involved. The Customer will give notice to the Company prior to resumption of any productive operations.

J. **Late Payment Charge**

A Late Payment Charge may be assessed against any Residential Customer's account that has an unpaid balance carried forward for two consecutive monthly due dates. A Nonresidential Customer may be assessed a late payment charge against any account that is not paid in full each month. The charge will be computed on the delinquent balance at the time of preparing the subsequent month's bill at the rate specified as the Late Payment Charge in Schedule 300. Customers who participate in a Time Payment Agreement [Section (5)(G) of this rule and OAR 860-021-0415] or budget pay plans [Section (5)(F)] are exempted from the late payment charge as long as they are current with their scheduled payments; however, they are assessed a Late Payment Charge on any delinquent balances.

K. **Bill History Information Service Charge**

Advance payment of the Bill History Information Service Charge, as specified in Schedule 300, is required for each year of requested prior bill information beyond the most recent 12 months. No charge is assessed when the billing information is required to resolve billing disputes filed with the Commission. The Company will provide unformatted and unanalyzed interval usage data, if available, to a Customer who requests such data for the Customer Interval Data Charge specified in Schedule 300. In the case where a Customer requests formatted and analyzed interval data, the charge will be based on a mutually agreeable charge.

RULE F (Concluded)

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 483 and 489.

A. **Enrollment**

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

(1) **Company/ESS Split Bill**

When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.

(2) **ESS Consolidated Bill**

When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

B. **ESS Billing Responsibilities**

An ESS is responsible for the following:

1) Confirming receipt of Customer usage data within 12 hours of transmittal from the Company;
2) Responding to Customer inquiries regarding ESS charges; and
3) Under the ESS Consolidated Bill option, issuing a timely corrected bill to the Customer when the Company provides revised billing information.

C. **Company Billing Responsibilities**

The Company will provide usage data to the ESS within two business days of the Customer's meter reading. When the ESS provides an ESS Consolidated Bill, the Company will provide bill-ready data within two business days of the Customer's meter reading. The Company is not responsible for computing or determining the accuracy of ESS charges.

D. **Information Included in Billing**

ESS billing for Customers will include the following information:

1) The beginning and ending dates of the Billing Period;
2) The number of units of service supplied;
3) The telephone number, identified as a Company number, to call for outage reporting and other local electrical utility matters;
4) The PODID(s) of the Customer;
5) The price and amount due for each service or product the Customer is purchasing;
6) Price, power source and environmental impact information in accordance with Oregon Administrative Rule 860-038-0300; and
7) The amount of the Public Purpose Charge, if any.
8) When the Customer receives an ESS Consolidated Bill, the bill will include the following additional information:
   a) Any tax adjustments;
   b) The amount of any transition charge or credit; and
   c) Mandated legal and safety notices in the format provided by the Company.

3. **Customer Responsibility**

Customers are responsible for checking their billings and verifying their accuracy. Questions regarding ESS charges must be directed to the ESS and questions regarding Company charges must be directed to the Company.

Rule G (Concluded)

RULE H
DISCONNECTION AND RECONNECTION

1. **Grounds for Disconnection of Electricity Service**

Electricity Service may be disconnected:

A. When a Customer/Applicant fails to pay a Company required deposit or make payments in accordance with the terms of a deposit payment arrangement with the Company (OAR 860-021-0205);

B. When service is being received after having obtained Customer status through the provision of false identification or verification of identity;

C. Where Customer facilities provided are unsafe or do not comply with state and municipal codes governing service or the rules and regulations of the Company (OAR 860-021-0335);

D. Where the Customer does not cooperate in providing access to the meter (OAR 860-021-0120);

E. When a Customer requests the Company to disconnect or close an Electricity Service account (OAR 860-021-0310);

F. When a joint account is closed and any remaining Customer(s) fails to reapply for Electricity Service within 20 days, so long as the Company has provided a notice of pending disconnection;

G. Where dangerous or emergency conditions exist at the Premises (OAR 860-021-0315);

H. For failure to pay Oregon Tariff charges due for Electricity Service rendered (OAR 860-021-0405; OAR 860-021-0505);

I. For meter tampering, diverting Electricity Service or other Theft of Service;

J. For failure to abide by the terms of a time payment agreement [OAR 860-021-0410(6); OAR 860-021-0415(5)]; or

K. When the Commission approves the disconnection of Electricity Service.

2. Procedures for Disconnection and Reconnection of Electricity Service

The Company will discontinue and reconnect Electricity Service in accordance with the rules of the Commission. These rules, copies of which may be obtained from the Company, are contained in OAR 860-021-0305 through 860-021-0505.

A Customer who has avoided disconnection, established credit, or gained reconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Customer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a good-faith attempt to notify the Customer 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 Customer shall make the payment in either cash, money order, cashier's check or verified credit card payment.

3. Disconnection and Reconnection Charges

A. The Company may impose a charge for reconnection of Electricity Service to an Applicant to whom prior Electricity Service has been disconnected involuntarily. These charges are set forth under Credit-Related Disconnection and Reconnection Rates in Schedule 300. The charge is assessed based on the time the Customer calls to request service reconnection.

The Company prioritizes credit-related reconnection by the time the Customer provides the Company with verification of sufficient payment for reconnection, and the service addresses' proximity to other service requests so as to assure efficient scheduling of field crews.

In cases where the disconnection is performed at the meter base, the Reconnects at Meter Base Charge as listed in Schedule 300 will be imposed in order to reconnect service.

Should it become necessary to disconnect the Electricity Service at other than the meter base, the Schedule 300 Reconnects at Other Than Meter Base Charge will be imposed in order to reconnect service. Should this require a second trip to the Premises to perform the disconnection, the Reconnects at Other than Meter Base Charge is in addition to the normal charge under Reconnects at Meter Base.

Should other than authorized Company personnel unlawfully attempt reconnection of the Electricity Service, the Customer shall additionally incur the Unauthorized Service Reconnect Charge set forth in Schedule 300.

B. No charge is imposed for a reconnection performed during scheduled business hours in order to provide Electricity Service to a new Applicant. If such a reconnection is performed outside of Scheduled Business Hours, a charge set forth under Disconnection and Reconnection Rates of Schedule 300 is imposed.

C. In the case where a building owner or manager requests reconnection of Electricity Service for cleaning, showing the unit, or any other purpose other than to provide Electricity Service to an occupant, a charge for reconnection as specified in Schedule 300 will be imposed.

D. In cases where the Company has been requested to reconnect Electricity Service after it has been disconnected at the meter and the visit has not resulted in a reconnection of service due to Customer action or inaction, a Field Visit Charge is assessed as specified in Schedule 300.

4. Nonwaiver of Right to Disconnect Service

The Company has the option, but is not obligated, to seek disconnection of Electricity Service if grounds exist. Delay or failure on the Company's part to exercise the option does not constitute a waiver of its right to do so at a later time.

5. Other Remedies

The Company reserves the right to pursue all other legal remedies available to it if grounds for disconnection of Electricity Service exist, whether or not it exercises its right to disconnect service.

6. **Disconnection and Reconnection at the Customer's Request**

At the Customer's request, the Company will disconnect and reconnect Electricity Service to ensure safe working conditions. The disconnection and reconnection will be done without charge if the work can be completed on the initial trip or on a second trip scheduled during Scheduled Crew Hours and at the Company's convenience. If, at the Customer's request, the disconnection and reconnection are performed during other than Scheduled Crew Hours or for reasons other than to ensure safe working conditions, Schedule 300 charges for disconnection and reconnection apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In all cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

RULE H (Concluded)

RULE I
LINE EXTENSIONS

1. **Purpose**

This rule establishes procedures and defines respective cost responsibilities to provide a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. **Generally**

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements.

When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension.

B. **Definitions**

1) **Applicant**

For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:

a) Serve new construction; or

b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.

2) **Distribution Facilities**

Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

3) **Line Extension**

A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company has determined has adequate capacity for the Applicant's planned Electricity needs to the Applicant's Point of Delivery (POD). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. However, any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension.

4) **Line Extension Allowance**

The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant.

5) **Line Extension Cost**

A Line Extension Cost is the Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension. Line Extension Costs include, but are not limited to, labor costs, the cost of transformers, primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs,. of the existing transformer. Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule.

6) **Long Side Service Connection**

A service connection, which runs parallel to the street, rather than perpendicular to the street.

7) **Primary Voltage Project**

A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.

8) **Public Thoroughfare**

A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.

9) **Residential Subdivision**

A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

10) **Unity Service**

Unity Service is the simultaneous installation of Electricity and gas utilities.

C. Company Requirements

1) **Company to Determine Route**

The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.

2) **Company Ownership**

The Company will own and maintain all Facilities to the POD.

3) **Company Installation**

The Company will install all Facilities to the POD except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:

a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying;

b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;

c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and

d) Following receipt of the title, the Company will energize the Line Extension to make Electricity Service available to the Applicant.

e) If, within 24 months of the time the Company energized the Line Extension, it determines that the overhead Distribution Facilities are deficient in materials or workmanship, the Applicant must pay the cost to correct the deficiency to the Company's satisfaction.

4) **Unusual Distribution Facilities or Nonstandard Construction**

The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. If, at the Applicant's request, the Company installs Facilities which are in addition to, or in substitution of, the standard Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 6 of Rule C applies.

2. Applicant Cost Responsibilities

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension.

B. **Applicants for New Permanent Service**

1) **Individual Applicants**

Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

2) **Other than Individual Applicants**

The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300.

C. <u>Existing Customers</u>

1) **Nonresidential**

Where an Applicant is an existing Nonresidential Customer requesting an additional POD, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges.

2) **Residential**

Where an Applicant is a Residential Customer requesting additional capacity at the same POD, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

3. Special Conditions for Underground Line Extensions

A. **Applicability**

Underground Line Extensions will be made:

1) When required by a governmental authority having jurisdiction;

2) When required by the Company for reasons of safety or because the extension is from an existing underground system; or

3) When otherwise mutually agreed upon by the Company and the Applicant.

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.

2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors.

3) Where the Company provides trenching and backfilling for installation of applicable residential underground service laterals, the charges specified in Schedule 300 will apply. Where electricity and gas utilities are to be installed, Applicant can contact the Company for simultaneous installation through the Company's Unity Service. Estimated actual costs will apply where the Company provides trenching, and backfilling beyond the service lateral installation process. The Applicant will be responsible for all additional costs of excavating rock, furnishing and installing raceway, excavating to a depth in excess of Company standards, manual digging, and the repair of paved roads, walks, and driveways when such work must be performed.

4) Where no other restrictions apply and the Applicant is only considering submersible transformers for aesthetic reasons, the Applicant may request the installation of submersible transformers instead of standard pad-mounted transformers. In this event, the cost set forth under the Transformers Section of Schedule 300 will be paid by the Applicant.

5) Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 will be as follows:
   a) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;
   b) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and
   c) At the commencement of pathway construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company.

   The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (3)(B)(5) are not refundable.

C. **Additional Services**

1) **Service Locates**

Before installing Unity Service, the Company will locate underground water, sewer and water runoff services along the Applicant's proposed trench route on the Applicant's property if requested by the Applicant. The cost set forth in Schedule 300 will be paid by the Applicant.

2) **Service Guarantee/Wasted Trip Charge**

The Company will begin the installation of residential single family underground service laterals within seven working days following the date an Applicant requests such service, except during periods of major storms or other such conditions beyond the Company's control. If the Company does not meet this standard, the Company will pay the Applicant the Service Guarantee Charge in Schedule 300. If, however, Company resources are dispatched to install the residential single family service lateral within the seven-day period and the Applicant's site or other facilities are not ready for service, the Applicant will be assessed the Wasted Trip Charge in Schedule 300.

3) **Long-Side Service Connection Charge**

Where the Applicant requests that the Company provide trenching and conduit for a long-side service connection the charge in Schedule 300 will apply.

4) **Joint Trench Installation Charge (for other than Unity Service)**

Upon mutual agreement between the Company and the Applicant, the Company may install telephone and cable services during the installation of the underground service lateral. The parties involved will mutually agree to the price for such service.

4. **Refunds**

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:

1) The original Line Extension has been in service for less than five years when the additional connections are made;

2) The original Line Extension has been in service less than six years when the application for refund is made; and

3) The payment made by the original Applicant was $100 or more.

B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:

1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and

2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant.

5. **Special Conditions for Portland River District Undergrounding Project**

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A[(1)], the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $33,280.00[(2)] for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area.

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(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2007. Beyond 2007, the charge will be escalated annually by the Company's then authorized cost of capital.

6. Conversion from Overhead to Underground Service

A. General

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

B. Payment for Service Changes

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. Special Conditions

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:
   a) All existing overhead communication equipment and Distribution Facilities in such district are removed;
   b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer's Premises in order to receive service from the Company's underground Facilities as soon as available; and
   c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.

2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.

3) When the local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.

4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an allocation or assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

7. Nonpermanent Line Extension

A. **General**

A Line Extension is nonpermanent when the Company believes service for its intended purpose by the Applicant will continue for less than five years. If the Company believes a requested Line Extension is nonpermanent, the Company will require a cash advance of the entire Line Extension Cost, plus payments to third parties for easements and those costs outlined under Section 3, plus the estimated cost of removing the Line Extension, less any salvage value. If service is used for the intended purpose by the Line Extension Applicant for a period of five years, that portion of the amount advanced by the Applicant which was in excess of the amount that would have been charged for a permanent Line Extension will be refunded to the Applicant with interest.

B. **Greater than 1 MWa Nonresidential Nonpermanent Service**

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\left[\frac{(5 - \text{Years Served})}{5} * \text{LEA}\right]$$

8. Excess Capacity

Excess Capacity will be determined to exist where:

A. The characteristics of the Customer's load require the Company to install Facilities larger than the kVA demand of the load for voltage regulation or other reasons;

B. The Customer requests additional capacity due to planned expansion needs that have not yet occurred; or

C. The Customer requests Facilities that are in excess of what the Company determines is required based on the Company's analysis of the Customer's planned load.

When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period.

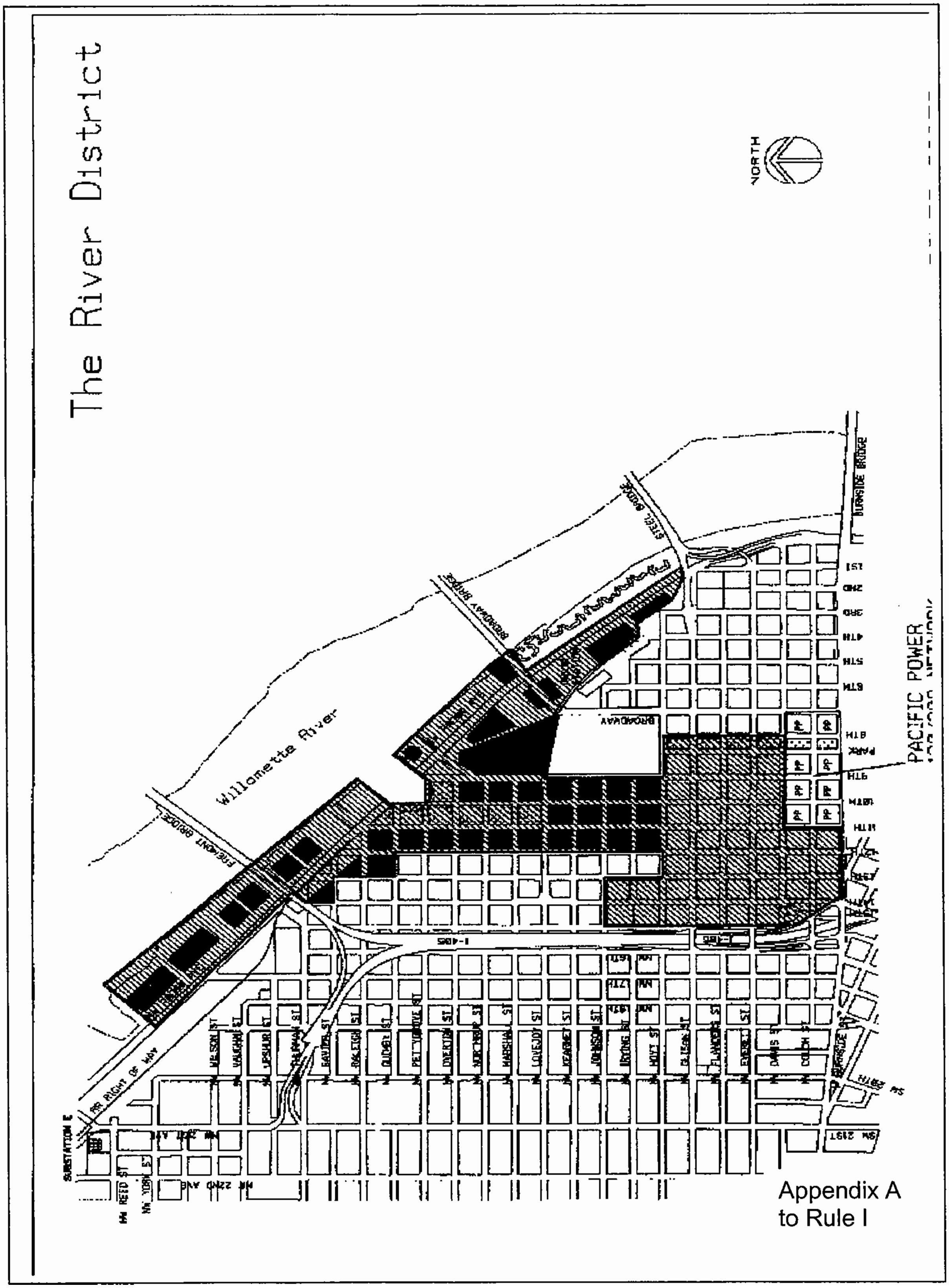
9. Rules Previously in Effect

Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract.

RULE I

APPENDIX A

RULE I (Concluded)


The River District
NORTH
Willamette River
FREMONT BRIDGE
BROADWAY BRIDGE
STEEL BRIDGE
BURNSIDE BRIDGE
BROADWAY
I-405
RR RIGHT OF WAY
SUBSTATION E
PACIFIC POWER
Appendix A
to Rule I

RULE J
STANDARD SERVICE AND PORTFOLIO OPTIONS

1. **Standard Service**

   A. **Eligibility**

   A Large Nonresidential Customer may select Standard Service.

   B. **Enrollment**

   Standard Service will automatically be provided to a Large Nonresidential Customer who has received Emergency Default Service for five business days and/or does not select Direct Access Service.

   A Large Nonresidential Customer that is receiving Direct Access Service may move to Standard Service upon 10 days' notice to the Company. The Customer will be charged a Switching Fee as specified in Schedule 300.

   C. **Term**

   A Large Nonresidential Customer must remain on Standard Service until he/she has met the notice and term requirements of the Standard Service option selected.

2. **Portfolio Options**

   A. **Eligibility**

   A Residential or Small Nonresidential Customer is eligible for service under one or more Portfolio Options in addition to the Standard Cost of Service as contained in the applicable rate schedule.

   B. **Enrollment**

   Residential and Small Nonresidential Customers may select a Portfolio Option via telephone, in person, over the Internet or by other Company-approved means. The Portfolio Enrollment Charge as specified in Schedule 300 will be incurred for any requested portfolio enrollment change other than the initial enrollment and the first requested change per year.

   A Small Nonresidential Customer will be charged a Switching Fee, as specified in Schedule 300, when moving between Direct Access Service and a Portfolio Option or Standard Cost of Service.

RULE J (Concluded)

RULE K
REQUIREMENTS RELATING TO ESSs

1. Purpose

A. Generally

Prior to providing Electricity Service to Customers, an Electric Service Supplier (ESS) must be certified by the Commission, if applicable, and meet the Company's requirements for providing service. The Company may provide information to the Commission certification process, if applicable, regarding the ESS's scheduling capabilities, electronic data transmission capabilities, insurance coverage and credit.

B. Requirements for Providing Service

To provide Electricity to a Customer an ESS must:

1) Be certified by the Commission, if applicable;
2) Complete the Company's business application form and submit an Application Processing Fee or Renewal Fee as listed in Schedule 600;
3) Establish creditworthiness as set forth in the ESS Credit Requirements provision of this rule;
4) Demonstrate the capability to meet the information exchange requirements of the Company. A Setup and Verification Fee may be charged to the ESS as listed in Schedule 600;
5) Name the Company as an additional insured in the amount of at least $10 million on the ESS's general liability policy;
6) Execute an ESS Service Agreement with the Company confirming the terms and conditions of the service(s) elected and agree to abide by the terms and conditions of the Company's Tariff and the Oregon Administrative Rules;
7) If a Scheduling ESS, execute a transmission service agreement under the Company's Open Access Transmission Tariff; and
8) If a Non-Scheduling ESS, provide the name of the Scheduling ESS.

2. ESS Credit Requirements

A. **Credit Review/Applicability**

An ESS's participation in Direct Access Service is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement. The Company will determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company will enter into an ESS Service Agreement after ESS's credit has been established, collateral has been obtained and ESS certification by the Commission is complete. The Company will continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

B. **Credit Exposure**

An ESS must establish and maintain creditworthiness relative to the Company's credit exposure to the ESS. Credit exposure will include, but not be limited to, the expected liabilities of the ESS.

C. **Establishment of Credit**

An ESS must establish its creditworthiness as described below.

1) **Creditworthiness Requirements**

Each ESS, or guarantor, must meet the Company's creditworthiness requirements by satisfying all of the criteria below. An ESS who cannot meet the requirements below will provide a collateral deposit as described in item (4) below.

a) Credit Evaluation

An ESS seeking to enter into a new ESS Service Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application if the ESS's ESS Service Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice.

The credit evaluation will be conducted by the Company. This evaluation will be completed within 10 Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b) Required Credit Information

Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

c) Rating Agency

An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d) Tangible Net Worth

An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two-year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e) Credit History

An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

2) **Unsecured Credit**

For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying the above requirements, a maximum unsecured credit limit will be established by the Company according to the following table. The S&P and Moody's rating is based on the ESS's long-term senior unsecured debt rating. If an ESS is split rated, the applicable credit limit will be based on the lower debt rating.

S&P / Moody's Ratings	Unsecured Credit Limit
> A+ / A1	$15MM
=A / A2	$10MM
=A- / A3	$7MM
=BBB+ / Baa1	$5MM
=BBB / Baa2	$4MM
=BBB- / Baa3	$3MM
<BBB- / Baa3	$0MM

The Company may increase the maximum unsecured credit limit on a case by case basis using accepted commercial credit standards and based on the following criteria: (1) financial performance; (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis.

3) **Collateral Requirements**

The ESS will be required to post or increase collateral under any of the following conditions:

a) The ESS does not meet the minimum creditworthiness standards established above;

b) The ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in this Tariff and the ESS Service Agreement;

c) The ESS experiences a material adverse change. A material adverse change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody's below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS's ability to fulfill its payment and credit obligations; or

d) The Company's total credit exposure to the ESS exceeds the ESS's unsecured credit limit and/or any existing Collateral Deposit.

4) **Collateral Deposits**

If collateral is required, the ESS will submit and maintain a collateral deposit as described below.

a) Amount of Collateral Deposit

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) For ESSs billing customers for services provided by the Company, three times the estimated maximum monthly customer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next 12 months;

(ii) All other charges from the Company to an ESS as estimated over a 90 day period; and

(iii) All invoiced and non-invoiced receivables due from the ESS; or

(iv) Not less than $500,000.

b) Form of Collateral Deposit

Collateral deposits will be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

c) Collateral Deposit Payment Timetable

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement. Collateral deposit increases and/or adjustments must be received within two calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five days of expiration of a collateral deposit.

d) Interest on Cash Deposit

The Company will pay interest on cash collateral deposits. Interest will be calculated according to the interest rate prescribed in Schedule 300.

5) **On-going Maintenance of Credit**

a) The Company may review the ESS's creditworthiness, credit limits and the Company's credit exposure on a daily basis. The Company may request an increase in the collateral deposit by providing notice to the ESS that an increase is required as the ESS enrolls additional Customers, the ESS no longer satisfies the minimum criteria commensurate with its unsecured credit line as described above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's credit exposure to the ESS increases.

b) To assure continued validity of established unsecured credit, the ESS will promptly notify the Company if the ESS (i) experiences any material adverse change; (ii) has its long-term, senior unsecured debt rating downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from Non-Scheduling to Scheduling or vice versa.

c) The ESS will provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of this Section; upon the occurrence of any event listed in Section (2)(C)(3)(c); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.

d) The ESS will review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.

e) All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required initial collateral deposit at the time the ESS enters into and signs an ESS Service Agreement. The Company will notify the ESS of any needed adjustments.

6) **Re-establishment of Credit**

An ESS whose ESS Service Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in item C above.

D. **Additional Documents**

The ESS will execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

3. Electronic Data Transfer Interchange (EDI)

All electronic communications between the Company and the ESS must conform to industry standard electronic data interchange protocols. The ESS must demonstrate its ability to successfully exchange test data for all transactions before the first Direct Access Service Request (DASR) is processed. The ESS will also provide a point of contact to resolve daily electronic data interchange problems. If the ESS is certified, but does not have active enrollments within a six-month period, the Company will request that the ESS retest the interchange.

The ESS must notify the Company of plans to modify its electronic data interchange systems such as the installation of new software or upgrades to software as well as any plans to change system subcontractors when such plans may affect data transfers between the Company and the ESS. The Company may require retesting of data transfers under such circumstances. Where retesting is required, the ESS will be subject to the set-up and verification charge contained in Schedule 600.

When the Company makes any changes to its interchange systems or changes subcontractors, it will promptly notify all ESSs. If the changes require retesting of systems, the Company will not charge ESSs for this testing.

4. Electricity Service Supplier Decertification

A. **Notice to ESS**

The Company may recommend to the Commission decertification of an ESS that the Commission has certified at times other than the annual renewal date. The Company will notify the ESS that it is initiating such action, if applicable.

B. **Criteria for Recommending Decertification**

The Company may recommend decertification, if applicable, of an ESS to the Commission when the ESS fails to comply with the terms and conditions under this Tariff, or fails to perform obligations under the transmission service agreement or ESS Service Agreement. The following are examples of when the Company may recommend decertification of an ESS:

1) Failure to submit an Electricity Schedule that meets the requirements of Section 11;
2) Failure to deliver Electricity according to its Electricity Schedule;
3) Submission of a DASR not authorized by a Customer;
4) Failure to conform with industry electronic data interchange protocols;
5) Failure to comply with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) operating procedures;
6) Failure to pay for services rendered by the Company;
7) The ESS makes a general assignment or arrangement for the benefit of creditors;
8) The ESS becomes bankrupt, a debtor in a bankruptcy proceeding, insolvent, however evidenced, or is unable to pay its debts as they fall due;
9) The ESS files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;
10) The ESS has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets;
11) Evidence that indicates the ESS has violated any state or federal customer protection laws or rules, including antitrust laws, during the past three years;
12) The ESS has materially failed to meet its obligations under terms of the ESS Service Agreement so as to constitute an event of default;

13) The ESS engages in unauthorized use of Electricity or a Customer of the ESS engages in unauthorized use of Electricity and the ESS knew about it;

14) Failure to provide a complete, accurate and truthful credit application;

15) Failure to maintain credit requirements; and

16) At the general discretion of the Company.

C. **Notice to Customers**

The Company, upon consultation with the Commission, may transfer the ESS's Customers to the applicable Utility Provided Service prior to ceasing to provide service to the ESS. The Company will notify the ESS's Customers of the transfer in writing as soon as possible. The ESS will be charged a Switching Fee for each Customer transferred as listed in Schedule 600.

D. **Decertification**

Upon decertification, the ESS may no longer serve Customers, and all amounts billed or owed by the ESS are immediately due. The Company will move all Customers served by the ESS to Emergency Default Service and the ESS will be charged the Switching Fee listed in Schedule 600 for each Point of Delivery that moves to Emergency Default Service.

5. Pre-enrollment Information Provided to ESS

With the Customer's authorization, the Company may provide account-specific information, including one year of monthly usage history but excluding credit information, to an ESS. The ESS will be charged the ESS Web Portal Data Access Fee as listed in Schedule 600 for such requests.

6. Customer Enrollment

A. **ESS/Company Relationship**

The ESS may not state or in any way imply that it has been given preferential status by the Company.

B. **ESS Liability**

The ESS will defend, indemnify and hold the Company harmless against all claims of loss made by any Customer arising from claims of inappropriate switching from the Company or another ESS in violation of the solicitation or verification provisions of the Commission, regardless of whether the person or entity doing the marketing or solicitation was an independent contractor of the ESS.

C. **Enrollment DASR**

The ESS must submit to the Company an Enrollment DASR which, at a minimum, includes the Customer's name, Company account number, service address, mailing address, type of service being purchased, name of the ESS, name of Scheduling ESS if different, proposed effective date, Customer's billing preference, and Point of Delivery Identification (PODID) for each Customer that elects service from the ESS.

1) Unless the Company deems otherwise, the Company will activate only one (1) Enrollment DASR per PODID per meter reading cycle. When multiple Enrollment DASRs for the same PODID are received during the same meter reading cycle, the Company will activate the first Enrollment DASR received. The Enrollment DASR must be submitted at least 13 business days prior to the effective date. The Company will notify the ESS of Enrollment DASR acceptance or rejection within three business days of its receipt. For Enrollment DASRs submitted during the annual enrollment window, the three business day notice period does not begin until the end of the enrollment period. The Company will notify the ESS as to the date the Customer will begin Direct Access Service once interval metering is verified.

2) The Company will charge the ESS the Switching Fee listed in Schedule 600 for each Enrollment DASR received whether accepted or rejected.

3) Upon acceptance of an Enrollment DASR the Company will provide notice within three business days to the Customer's current ESS, if any, of the pending change to a new ESS.

D. **Refusal of Enrollment DASR**

The Company may refuse to accept an Enrollment DASR when:

1) The Company has not received full payment from the Customer for past-due amounts or other obligations owed by it related to regulated charges from the Customer's prior Electricity Service account(s) unless such charges are part of a pending Customer dispute;
2) The Company has not received full payment or the Customer has not made an arrangement to pay the balance owed by the Customer on an existing Budget Payment Option or other agreements;
3) The Enrollment DASR is not accurate and/or complete;
4) The ESS has not complied with provisions of the ESS Service Agreement;
5) The Customer has not completed any term obligation under Standard Service; or
6) The ESS is not certified by the Commission.

E. **Change DASR**

A Change DASR must be submitted when the ESS is requesting a modification. The Change DASR requires up to 13 business days to process. The Change DASR may only be submitted after receipt of the assigned effective date of the information subject to modification and must be submitted at least 13 business days prior to the requested effective date of the Change DASR. There is no charge for submitting a Change DASR. However, when a Change DASR is submitted to change the assigned enrollment effective date to a date that is not a regular meter read date, a Change of Effective Date charge as listed in Schedule 600 will be imposed.

F. **Other DASRs**

The Other DASR forms are as follows:

1) **Rescind DASR**

A Rescind DASR is a request to withdraw an Enrollment DASR and it must be submitted prior to the issuance of an Direct Access effective date. No charge is assessed for a Rescind DASR. A Rescind DASR requires three business days to process. If the Company does not have three business days to process before the effective date is issued, a Cancel DASR is required.

2) **Cancel DASR**

A Cancel DASR is a request for cancellation of Direct Access Service that has been submitted after the Direct Access Service effective date has been issued. No charge is assessed for a Cancel DASR. A Cancel DASR requires three business days to process. Failure to provide adequate notice may require the Customer to take Direct Access Service and/or move to Emergency Default Service until processing is complete.

3) **Drop DASR**

A Drop DASR is a request to stop Direct Access Service and return to Standard Service or to close the service account. A Drop DASR must be submitted at least 13 business days before the requested effective date. Failure to provide adequate notice may require the Customer to continue Direct Access Service and/or move to Emergency Default Service until the Drop DASR process can be completed. The Customer or ESS, whichever initiates the Drop DSAR, is charged the Switching Fee as listed in Schedule 300 or Schedule 600.

The Company may submit a Rescind, Cancel, or Drop DASR on behalf of the Customer to nullify an Enrollment DASR submitted for a Customer without their consent. The Customer will not be charged the Schedule 300 Switching Fee and the Customer's service will not be switched regardless of the required processing timeframes described above.

G. **Customer Information**

The Customer consents to the release by the Company to its ESS monthly usage data when it agrees to take Direct Access Service. Upon acceptance of an Enrollment DASR, the Company may provide to the ESS account-specific information, including one year of monthly usage history, excluding credit information.

H. **Return of Customer Deposits**

Following acceptance of an Enrollment DASR, the Company will return any Customer deposit, net of any amounts owing when the ESS is providing Consolidated Billing. When the Company is continuing to bill the Customer or the Customer has requested split billings between the ESS and the Company, the Company will retain the portion of the deposit appropriate for two months of regulated Electricity Service billings from the Company and credit the excess deposit, if any, to the Customer's account.

I. **Customer Change of Location**

When a Customer moves to a new service location, the Customer's ESS must submit an Enrollment DASR for the new service location if the Customer elects to continue Direct Access Service.

7. ESS Service to Single Point of Delivery

Only one ESS may serve any single Point of Delivery. If the Customer is receiving products and services from more than one ESS, the ESS that submitted the accepted Enrollment DASR is responsible for the coordination of services including, but not limited to billing, payment, delivery and scheduling.

8. Discontinuance of ESS Service

Upon determination by an ESS that it will discontinue service to a Customer because of nonpayment of charges or other reasons provided for in the ESS/Customer Agreement, the ESS will provide the Company with ten business days' notice of such discontinuance. The Company will subsequently move the Customer to Standard Service in the absence of an accepted Enrollment DASR. The Switching Fee listed in Schedule 600 will be charged to the ESS in conjunction with moving the Customer to Standard Service.

9. Company Billings to the ESS

The ESS is responsible for payment of all charges assessed to it by the Company. All bills issued under this Tariff are due and payable through electronic payment within 15 days of presentation. Billings unpaid by the due date are subject to a late payment charge as described in Schedule 600. When the ESS disputes charges assessed to it by the Company, the ESS is still responsible to make payment of such charges within 15 days of presentation.

10. Processing of Payments

Unless otherwise specified, the Company will allocate payments from ESSs in the following order:

1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

11. ESS Scheduling Responsibilities

At least one day prior to the Day of Flow, in accordance with the ESS Service Agreement and transmission service agreement, each Scheduling ESS will provide the Company with an Electricity Schedule of the expected aggregated hourly load requirements of the Customers for which it has scheduling responsibility subject to the following terms and conditions:

A. **Scheduling Period: Day of Flow**

Each daily scheduling period will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

B. **Changes in Load**

The Company may require a Scheduling ESS to change its Electricity Schedule if the Company determines the Electricity Schedule does not adequately represent the expected ESS Customer load. If a Customer or Customers are served under an interruptible arrangement by the ESS, the ESS will notify the Company of any interruption coincident with its notification to those Customers and will adjust its Electricity Schedule accordingly.

C. **Failure to Schedule**

An ESS that fails to submit an Electricity Schedule is subject to applicable charges and immediate termination of the ESS Service Agreement. The Customers served by the ESS will be moved to Emergency Default Service.

D. **Confirmation**

The Company reserves the right to confirm with appropriate transmission service providers each Electricity Schedule provided by ESSs and to reject any Electricity Schedule that cannot be confirmed.

E. **Conformance with Regional Requirements**

The ESS will conform to FERC, NERC and WECC scheduling, operating and reporting requirements.

F. **ESS Control Information**

An ESS that chooses to self-provide ancillary services will provide the Company a real-time load and power factor signal via electronic means.

12. Company Scheduling Responsibilities

A. **Change in Load**

The Company will notify an ESS as soon as practical of a planned outage when such outage affects its Customer(s) with a load greater than one megawatt.

B. **Major Outage Procedures**

The Company will attempt to maintain system balance during a major outage using all appropriate methods available according to utility practices. 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. In such case, the Company will notify the ESS when it can resume normal scheduling. The Company will waive related imbalance penalty adjustment provisions during such event. The Company is responsible for responding to inquiries related to major outages. Customers who contact their ESS regarding major outages should be referred to the Company.

13. Settlement

The Company will reconcile total Electricity delivered by the ESS with the total Electricity consumed by the Customers for which the ESS has scheduling responsibility in accordance with Schedule 600 of this Tariff. Customer Electricity consumption will be measured accordingly:

A. **Interval-Metered Electricity**

Where the Customer has an interval-meter installed, Electricity consumed is equal to the metered quantity plus losses as specified in Schedule 600.

B. **Profiled Electricity**

Where interval-meter data is missing, hourly consumption will be estimated using load profiles and adjusted based on available metered data plus losses as specified in Schedule 600. For unmetered loads, consumption will be based on a test or estimated from equipment ratings, adjusted for losses, and allocated to each hour based on hours of usage and whether the equipment is operational during that hour.

14. Operational Order to Deliver Electricity

A. **General**

An "Operational Order to Deliver Electricity" may be issued by the Company upon one hour's notice for purposes of maintaining the integrity of its electrical distribution system.

B. **Action by the ESS**

Upon receiving an Operational Order to Deliver Electricity, the ESS will endeavor to deliver its full capability for all its Customers served by adjusting its Electricity Schedule.

C. **Compensation**

The Company will waive all energy imbalance service charges and penalty provisions for an ESS that demonstrates substantial compliance with an Operational Order to Deliver Electricity. Compensation for excess Electricity delivered in accordance with the Company's Operational Order to Deliver Electricity will be at a rate equal to the higher of:

1) The ESS's direct cost of such Electricity; or
2) The highest incremental cost of Electricity purchased by the Company during each hour of the Operational Order to Deliver Electricity.

15. Preemption

In addition to an Operational Order to Deliver Electricity, the Company may take automatic or manual actions that, in its opinion, are necessary or prudent to protect the performance, integrity, reliability or stability of its electrical system or any electrical system with which it is interconnected. During such period, delivery of Electricity to Customers may be curtailed or interrupted by the Company even though the ESS continues to supply Electricity to the Company. The payment for such Electricity will be made at a rate equal to the higher of:

A. The ESS's direct cost of such Electricity; or
B. The highest incremental cost of Electricity purchased by the Company during each hour of the preemption.

16. Dispute Resolution

A Dispute Resolution process is contained in the ESS Service Agreement.

RULE K (Concluded)

RULE L
SPECIAL TYPES OF ELECTRICITY SERVICE

1. Service of Limited Duration (Temporary Service)

A. **Definition**

"Service of Limited Duration" or "Temporary Service" means Electricity Service to a Customer who, in the Company's opinion, will not continue to receive service for the minimum of five years.

B. **Availability**

Service of Limited Duration includes installations requiring only an overhead service drop, a service lateral to existing underground Facilities, or service to Premises where Facilities are in place, whether or not a meter setting is required. Charges will be in accordance with Schedule 300. Where Facilities other than those specified above are needed to provide service, the provisions of Rule I, Line Extensions, will apply.

1) The Company provides Standard Temporary Service as well as an optional Enhanced Temporary Service subject to the following conditions.

a) Standard Temporary Service will be provided to Applicant-supplied service entrance equipment in accordance with applicable codes and regulations. Electricity Service will be metered and billed according to the applicable rate schedule until the account is closed or converted to permanent service.

b) Nonresidential Customers may receive Standard Temporary Service from an ESS and are required to pay for the installation and removal of interval metering and meter communications (telephone or other method) necessary to deliver such service.

c) Enhanced Temporary Service is provided on an optional basis for the construction of residential single-family and multi-family dwellings in underground service areas. Under Enhanced Temporary Service, the Company will provide and install an unmetered service pedestal for use until the permanent service is installed.

d) The fixed charges for Enhanced Temporary Service specified in Schedule 300 include Electricity usage for up to 12 months. After 12 months, a permanent connection is required.

C. In order to qualify for Enhanced Temporary Service, the Applicant must agree to the following:

1) Service will be used only for lights, tools, and equipment necessary for the construction of residential dwellings;
2) Service will not be used for the operation of permanently installed appliances or equipment or to heat or dry structures under construction;
3) For multi-family construction, the number of unmetered service pedestals can vary depending on the necessary service outlets per units/buildings under construction; and
4) Unless the trenching or boring work is provided by the Company under the terms of Schedule 300, the Applicant will provide a continuous underground conduit, suitable for Electricity Service, from the permanent meter base to the location of the Enhanced Temporary Service pedestal for the Company to use in later providing the permanent service.

In the event that Enhanced Temporary Service is used for purposes other than those specified, the Company will estimate the amount of Electricity used and bill according to the applicable rate schedule. The Company may restrict future availability of Enhanced Temporary Service in such cases.

2. Emergency Service

A. **Definition**

"Emergency Service" means Electricity Service supplied or made available to load devices which are operated only in emergency situations or in testing to respond to such situations. Electricity Service for freeze protection or similar applications likely to occur annually and/or only in the coldest time of the year is not an Emergency Service.

B. **Availability**

Emergency Service will be provided only to permanent Customers. Where the Company must furnish, install and maintain additional or specific facilities or capacity to provide Emergency Service, the Customer must pay the entire cost of the Line Extension and is ineligible for the Line Extension Allowance as described in Rule I. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Emergency Service including the maintenance charge will be refunded to the Customer.

3. Intermittent Use Service

A. **Definition**

"Intermittent Use Service" means continually available Electricity Service which a Customer uses intermittently for a short duration and at a high Demand level such that standard Energy or Demand measurement does not adequately reflect the burden imposed on the Company's equipment and facilities. Examples of Intermittent Use Service include service to test facilities, elevator or hoist motors, welding equipment, x-ray equipment and whole house instant or tankless hot water heaters with a Demand of 18 kW or greater.

B. **Availability**

Intermittent Use Service will be furnished only to permanent Customers. Where the Company must furnish, install, and maintain additional or specific facilities or capacity to provide Intermittent Use Service, the Customer must pay the entire cost of the portion of the Line Extension associated with such service and is ineligible for a Line Extension Allowance for that portion of the service. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Intermittent Use Service including the maintenance charge will be refunded to the Customer.

4. Alternate Service

A. **Definition**

"Alternate Service" means Electricity Service to a Customer from a second independent primary voltage circuit for which the Company provides a second path for supply of service in the event of the failure of the first electrically independent circuit. Alternate Service facilities include, but are not limited to, the substation and distribution line capacity reserved for the Customer's exclusive use, plus any additional metering or switching equipment required which is beyond the Company's normal responsibility.

B. **Availability**

The Company will provide Alternate Service at the request of a Customer who demonstrates a requirement for a higher than normal degree of service continuity. The Company will maintain Alternate Service to the best of its ability consistent with the need to operate and maintain its overall distribution system and will notify the Customer if the Alternate Service is to be discontinued for any extended period of time. Alternate Service will be provided only under a contract between the Company and a Customer.

C. **Contract Provisions**

Alternate Service contracts will provide generally as follows:

1) The Customer will specify its Alternate Service kVA Demand requirement and the period of time for which Alternate Service is required;

2) The design and arrangement of both the preferred and alternate circuits will be at the option of the Company. The Customer will install and maintain an automatic transfer switch. The characteristics, arrangement, and operation of such switch and the associated circuits will be subject to the Company's approval.

3) The Customer will pay the Company either a monthly charge or a lump sum payment to cover the Company's cost to provide the Alternate Service. The rate of the monthly charge, per kVA of alternate capacity required, will be the levelized future revenue requirements imposed on the Company by its investment in Alternate Service facilities and all future maintenance of those facilities. The lump sum amount will be the present worth of the items used to determine the monthly charge.

4) The kVA Demand on the Alternate Service will be measured by separate kW and kVAr Demand meters. Should the Customer impose a kVA Demand on the Alternate Service facilities that is in excess of the amount contracted for, the Customer will pay the Company an additional monthly charge per kVA of excess Demand for that month and the succeeding 11 months. The amount will be determined by multiplying the excess Demand by the monthly rate per kVA as determined in (4)(C)(3) above. In addition to this monthly charge, the Customer must either promptly modify plant operation to prevent future excess kVA Demand or execute a supplemental agreement with the Company for the additional amount of Alternate Service required. The facilities cost for Alternate Service will be based on the costs of the Company in effect at that time and will be calculated and billed as determined in (4)(C)(3). The Customer will be billed the actual cost of any damage to the Company's facilities caused by the Customer's Alternate Service Demand in excess of the contracted amount.

5) The Customer may terminate the agreement for Alternate Service upon 30 days' written notice to the Company. If the Customer is making monthly payments for the Alternate Service, it will, upon termination, pay to the Company the amount that the Company's present-day investment in such facilities exceeds the value to the Company at that time. A Customer who has made a lump sum prepayment to the Company will, upon termination, receive from the Company an amount equal to the current value to the Company for those facilities dedicated to the Alternate Service. Such amount will not exceed the amount of the initial prepayment.

D. **Existing Alternate Service Customers**

Unless otherwise specifically provided, a Customer receiving Alternate Service on or before August 1, 1975 will continue to receive Alternate Service without charge subject to the conditions listed below.

1) Should the nature of the Premises change, Alternate Service without charge will be discontinued after 30 days' written notice by the Company.

2) Should an additional investment be required of the Company to continue to furnish Alternate Service, the Customer will be so notified and given the option of limiting the kVA Demand of Alternate Service required to that which is available from the Company at no charge or executing an agreement with the Company for Alternate Service in accordance with this rule.

3) Should a Customer receiving Alternate Service without charge modify its facilities such that an increase in Alternate Service requirement occurs, the Customer must execute an agreement with the Company for Alternate Service in accordance with this rule.

5. Distribution Facilities Service

A. **Definitions**

"Distribution Facilities Service" means the installation, operation, maintenance and ownership by the Company of Distribution Facilities that are dedicated solely to service on a Customer's site for the Customer's exclusive use, and located on the Customer's side of the POD. "Distribution Facilities" includes primary and secondary cable, distribution transformers, and associated equipment terminating at Customer-owned service entrance or meter base for each building or structure.

B. **Availability**

The Company will provide Distribution Facilities Service on an optional basis to Customers with a minimum installed transformer capacity of 500 kVA as mutually agreed to by contract between the Company and Customer. Upon request of a Customer and agreement by the Company, Distribution Facilities Service will be provided to an existing Customer-owned distribution facilities installation subject to all conditions of this rule and subject to Company determination that the existing system meets Company Distribution Facilities requirements.

If the Customer's existing system does not meet the Company's current standards but is otherwise acceptable to the Company, with respect to safety and reliability, the Company may choose to offer Distribution Facilities Service to the Customer provided that a mutually agreeable plan to upgrade the system, as necessary, is developed and included in the Distribution Facilities Service Charge.

C. **Contract Provisions**

Distribution Facilities Service contracts will provide generally as follows:

1) **Distribution Facilities requirements**

The Distribution Facilities, on the Customer's side of the Point of Delivery (POD), will meet Company distribution system requirements in a manner consistent with Company practices, Company overhead and underground construction standards, applicable standards of the National Electric Safety Code (NESC), American National Standards Institute (ANSI) and the Oregon Electric Service Requirements.

2) **Facilities design and installation**

The design and arrangement of the Distribution Facilities will be as agreed to by the Customer and the Company. The Company will generally meter Electricity Service at the POD.

3) **Memorandum of Agreement**

A Memorandum of Agreement will be filed with the appropriate county in order to provide notice of the existence of the Distribution Facilities Service contract.

4) **Access**

The Customer will provide the Company access to the Distribution Facilities on the Customer's premises without restrictions or structural impediments for purposes of maintenance and repair of the Distribution Facilities.

5) **Distribution Facilities Service Charge**

The Customer must pay the Company a monthly charge to cover the Company's cost to provide the Distribution Facilities Service. The rate of the monthly charge will be the levelized revenue requirements imposed on the Company by its investment in Distribution Facilities and all future maintenance of those facilities. This charge is in addition to any charges for the furnishing or delivery of Electricity to the POD. No Line Extension Allowance as described in Rule I will be applied to Distribution Facilities.

6) **Load Requirements**

The Customer will promptly notify the Company of any changes in electrical load. The Customer will reimburse the Company for all costs of modification, replacement or repair of any transformers or other Distribution Facilities necessitated by increased electrical load.

7) **Maintenance and Repair**

The Company and Customer will be responsible for components of maintenance and repair as set out in the contract. All modifications or enhancements to the Distribution Facilities will be performed by the Company unless otherwise agreed to, in writing, by the Company.

8) **Termination**

The Customer may terminate the contract for Distribution Facilities Service upon purchase of the Distribution Facilities at a purchase price specified, and on terms set out, in the contract or as otherwise mutually agreed upon. Transfer of Distribution Facilities to Customer ownership may occur only after the Distribution Facilities have been approved by local authorities as meeting all applicable codes and requirements for such non-utility owned distribution facilities. Any costs to modify the facilities are the obligation of the Customer.

RULE L (Concluded)

RULE M
METERING

1. Generally

A. **Company Responsibility**

The Company will own/lease, install, test, read, remove, replace and maintain meters for each Customer receiving metered Electricity Service. The meters and any meter transformers installed remain the Company's property and may be removed by the Company upon discontinuance of service.

B. **Customer Responsibility**

The Customer will, at Customer's expense, furnish, install and maintain the meter socket and all raceways and enclosures necessary to accept the Company's meters and metering transformers. The Company will provide metering transformers when required for installation by the Customer. The Customer will exercise proper care to protect Company property installed on the Premises, will not break the Company's seal or seals, and will pay for all loss or damage to such property caused by the Customer's negligence or misuse.

C. **Meter Accuracy and Testing**

The Company will, at a Customer's or ESS's request, test the accuracy of the registration of a meter once per 12-month period. If a Customer or ESS requests such a test more than once in a 12-month period, the Company will impose a Meter Test Charge listed in Schedule 300. The Company will refund to the Customer or ESS the Meter Test Charge if the meter is found to be more than 2% fast or 2% slow.

D. **Meter Verification Charge**

Where multiple meters are installed at a location with multiple units, such as for residential multi-family units, it is the developer/owner's responsibility to ensure that each meter socket is correctly labeled for the associated service. The Company may check such meter installations to ensure they are correctly labeled. The Company will charge the Meter Verification Charge, as set forth in Schedule 300, to the developer/owner for each meter installation checked. If all meters at a building location are correctly labeled for each unit, the Company will waive the Meter Verification Charges for that building.

The Company will also impose the Meter Verification Charge at the time addresses are changed for multiple units when the change is a result of other than a government requirement. When locations with multiple units are sold and the new owner requests that service connections to each unit be verified, the Company may also impose the Meter Verification Charge on the new owner.

2. **Metering Requirements**

A. **Standard**

The Company will install at the Customer's Point of Delivery (POD) a meter capable of registering kWh usage. Meters capable of registering Demand, Reactive Demand, and time of use or interval usage will be installed when required due to the Customer's Electricity usage or rate schedule.

B. **Interval Metering**

The Company will meter Electricity usage in intervals of 30-minutes or less for Customers that purchase Electricity Service from an ESS, with the exception of unmetered loads. Where an interval meter does not exist at the time the Company receives a DASR, the Company has 30 days from the date the DASR is accepted to install such meter. Once installed, the Customer may begin purchasing Electricity from the ESS. A Customer who would not normally receive interval metering may, at its request, have an interval meter installed at the charge established in Schedule 300.

C. **Pulse Output Metering**

The Company will provide a connection to its metering facilities to supply kWh data pulses to Customer-owned load control equipment. The Company will also supply a Demand interval timing pulse, provided the Customer's load-control equipment is of the ideal curve or forecasting type. A Customer may have a pulse output metering installed for the charge established in Schedule 300.

D. **Nonstandard Metering**

The Company installs metering that corresponds to the Customer's Electricity usage and rate schedule requirements. If an ESS requests that the Company offer a specific meter capability, function or metering service not currently supported, the Company must approve or deny the request within 10 days. If the request is approved, the Company will file with the Commission to offer such meter or metering service within 30 days. If the request is denied, the ESS may appeal the decision to the Commission.

3. Meter Location

A. **Generally**

Meters are to be installed on the outside of buildings at a location which is easily and conveniently accessible by Company personnel and by the Company's distribution lines; however, with the Company's prior approval, meters for nonresidential buildings may be located indoors if accessible to Company personnel during Scheduled Crew Hours.

B. **Locating Meter on Company's Pole, Pad, or Vault**

If no satisfactory location for the meter is available on or in the Customer's building, the meter and related equipment may, at the Company's option, be installed on the Company's pole or in a Company vault or enclosure. In such event, the Customer will pay the charge specified under Meter Installation Rates of Schedule 300.

C. **Inaccessible Meters**

When in the Company's opinion a meter is inaccessible, the Company may:

(1) Permit the Customer to read the meter and supply meter readings to the Company, subject to actual verification by the Company, not less than once every four months; or

(2) Require the Customer, at the Customer's expense, to relocate the meter socket to an accessible location satisfactory to the Company.

D. **Metered on the Non-Service Side of Transformation**

If the Company installs or maintains the metering equipment on the primary voltage side of the meter and the Customer is receiving service at secondary voltage, billing will be based on meter registration less 1-1/2%. If the meter is located after the occurrence of transformation, and the Customer is receiving service at primary voltage, the billing will be based on meter reading plus 1-1/2%. These billing adjustments compensate for transformer losses or gains.

4. Meter Rentals

The Company will rent meters to Customers engaged in resale prior to November 5, 1973 at rates specified in Schedule 300.

RULE M (Concluded)

RULE N
CURTAILMENT PLAN

1. Purpose and Overview of the Curtailment Plan

This plan identifies the process by which the Company would initiate and implement load curtailment during a protracted regional Electricity shortage to ensure uniform treatment of all regional Customers. This plan would be activated only when declared necessary by State authorities.

The goal of this plan is to accomplish Curtailment while treating Customers fairly and equitably, minimizing adverse impacts from Curtailment, complying with existing State laws and regulations, and providing for smooth, efficient and effective Curtailment administration.

2. Definitions

The following definitions apply to terms used in this plan:

A. **Base Billing Period**

One of the Billing Periods that comprises the Base Year. Base Billing Period data are weather-normalized before being used to calculate the amount of Curtailment achieved.

B. **Base Year**

Normally, the 12-month period which immediately precedes imposition of State-initiated load curtailment.

C. **Critical Load Customer**

A Customer that supplies essential services relating to public health, public safety, welfare, or Electricity production.

D. **Curtailment**

Reduction in Electricity usage irrespective of the means by which that reduction is achieved.

E. **Curtailment Target**

The maximum amounts of Electricity that the Customer may use and still remain in compliance with State Action. The Curtailment Target is figured individually for each Customer by Base Billing Period.

F. **Excess Power Consumption**

The lower of the following two values for loads subject to penalty:

1) The difference between the Customer's actual (or metered) consumption level during a Billing Period and the Curtailment Target; or

2) The difference between the Customer's weather-normalized Electricity usage during a Billing Period and the Curtailment Target.

G. **General Use Customer**

Any Nonresidential Customer who purchased less than five average megawatts (43,800 MWh) during the Base Year.

H. **Major Use Customer**

A Customer who purchased more than five average annual megawatts (43,800 MWh) during the Base Year.

I. **Plan**

The Curtailment Plan.

J. **Region**

The states of Washington, Oregon, and Idaho, and those portions of Montana that are west of the Continental Divide and/or within the control area of the Montana Power Company.

K. **Regional Plan**

The Regional Electric Energy Curtailment Plan as adopted by the Commission.

L. **State**

The Public Utility Commission of Oregon.

M. **State-Initiated**

Actions taken by the State to implement individual load curtailment plans within its jurisdiction.

N. **Threshold Consumption Level**

The maximum amount of Electricity that a Customer can use during mandatory load curtailment without being subject to penalties under this Plan.

O. **Utility Coordinator**

The Director of the Northwest Power Pool.

P. **Utility Curtailment Reports**

Report(s) summarizing Curtailment data, such reports are to be submitted monthly to the Commission and the Utility Coordinator.

Q. **Weather-Normalization**

The procedure used to reflect the impact of weather on load levels. Sometimes referred to as weather-adjustment.

3. Curtailment Stages

State curtailment directives apply to all retail loads served within the State of Oregon. Under the Plan, Curtailment is requested or ordered as a percentage of historical, weather-normalized (Base Billing Period) Electricity consumption. The curtailment stages are associated with increasing Electricity deficits. The five stages of Curtailment are:

Stage	Nature	Curtailment Requirement	Curtailment Type
Stage 1	Voluntary	No Specified %	Uniform Among All Regional Customers
Stage 2	Voluntary	5% or Greater	Uniform Among All Regional Customers
Stage 3	Mandatory	5 to 15%	Uniform Among All Regional Customers
Stage 4	Mandatory	15% 15% or Greater 15% or Greater	Residential Customers General Use Customers Major Use Customers
Stage 5	Mandatory	% Associated with Stage 4 Plus Additional Curtailment	Continued Customer Curtailment Plus Utility Action, Including Plant Closures and Possible Blackouts

4. Initiation of Load Curtailment

Curtailment will be initiated when directed by State authorities. However, nothing precludes the Company from requesting voluntary load reduction at any time.

5. Administration of State-Initiated Curtailment

A. **Stage-By-Stage Utility Administrative Obligations**

Upon notice from the State to initiate load curtailment, the Company will immediately begin complying with the directives of this Plan. All requirements for lower-level stages continue to apply to higher-level stages. Throughout a period of Curtailment, the Company will provide Electricity Service Suppliers (ESSs), Customers and the general public with as much useful information as can reasonably be supplied. The requirements specified below represent the minimum actions to be taken.

1) **Stage 1**

The Company will begin, or continue if it has already begun, providing Curtailment information to ESSs, Customers and the general public. The Company will also assist the State, as appropriate, in briefing the media about the shortage.

2) **Stage 2**

In Stage 2, the Company will:

a) Notify ESSs, Customers and the general public of the percentage level of voluntary curtailment stemming from State Action;

b) Provide Curtailment tips to ESSs, Customers and the general public;

c) Answer Customer questions about Curtailment;

d) Provide Curtailment reports to the State and the Utility Coordinator; and

e) Provide more detailed information to the media than provided in Stage 1.

3) **Stage 3**

In Stage 3, the Company will:

a) Notify ESSs, Customers and the general public of the percentage level of State-ordered mandatory Curtailment;

b) Calculate weather-normalized Base Billing Period data and Curtailment Targets for all Customers who will be audited in the current billing period;

c) Provide Curtailment Targets to ESSs and all Customers who request such data for their own accounts;

d) Provide audited Customers with information about how to apply for exemption and adjustment of Base Year data;

e) Process requests for exemption and Base Year data adjustments from those Customers selected for audit who would otherwise be subject to penalties; and

f) Implement the penalties aspect of the Plan.

4) **Stage 4**

In Stage 4, the Company will notify ESSs, Customers and the general public of any applicable changes in State-initiated mandatory curtailment.

5) **Stage 5**

In Stage 5, the Company will collaborate with the State to develop and implement the most effective methods to secure the required Electricity Curtailment while minimizing, to the extent possible, any economic and human hardships of the last stage of load curtailment.

B. **Suggested Curtailment Actions**

Information will be disseminated to Customers regarding actions that they can take to reduce their Electricity consumption. The Company will work with the State to develop this material. The recommendations will be based on the actions described in Appendix C of the Regional Plan.

6. Base Year Data and Curtailment Targets

A. **Identification of the Base Year**

The Base Year for a shortage will be established by the State. Base Year and Base Billing Period data shall be weather-normalized.

B. **Estimating Base Billing Period Data for Customers for Whom No Base Billing Period Data Exists**

Base Billing Period data must be obtained or developed for any Customer who is audited under this Plan. Although the Company has the option of excluding residential and General Use Customers without actual Base Billing Period data from the random sample of audited Customers, Base Billing Period data will be estimated for any audited Customer for whom actual data does not exist or is found to be inaccurate.

C. **Communicating Curtailment Target Information to Customers**

During mandatory Curtailment, retrospective, current billing period, and forthcoming billing period Curtailment Target information will be provided to any Customer who requests such information. Retrospective Curtailment Target information will be provided to any audited Customer who will be issued a warning or penalty. At its option, the Company may provide Curtailment Target information to other Customers or Customer classes as well.

7. Auditing Customers for Compliance With State Orders for Mandatory Load Curtailment During Curtailment Stages 3-5

A. Each billing period, at least one percent of residential users, five percent of General Use Customers, and 100 percent of Major Use Customers (including those Major Use Customers with estimated Base Billing Period data) plus any Customers penalized in the previous billing period will be audited. The number of Customers exempted or excluded from audit will not affect the sample size.

B. New compliance samples shall be drawn each month. Customers penalized under this Plan shall continue to be audited until their Energy use falls below the Threshold Consumption Level. Once their Energy use falls below that level, they will be audited again only if selected by random sample.

C. Unless the Company is auditing 100 percent of its residential users and General Use Customers, all such Customers selected for audit shall be chosen on a random sample basis, except that the following Customers are to be excluded: (a) Customers granted an exemption under this Plan; and (b) Customers with an estimated power bill in the current billing period. At its option the Company may also choose to exclude Customers with estimated Base Billing Period data, if the State does not require their inclusion in the pool of Customers subject to audit.

8. Penalties for Noncompliance

A. **Nature of Penalties**

The following penalties will be assessed under this Plan to Excess Power Consumption as defined below:

Violation	Penalty
First Bimonthly Violation	10¢ per kWh of Excess Use
Second Bimonthly Violation	20¢ per kWh of Excess Use
Third Bimonthly Violation	40¢ per kWh of Excess Use
Fourth Bimonthly Violation	1 Day Disconnection Plus 40¢ per kWh of Excess Use
Fifth Bimonthly Violation	2 Days Disconnection Plus 40¢ per kWh of Excess Use
Sixth and all Subsequent Violations	Penalties are Determined by the State; Civil Penalties or Other Corrective Actions would be possibilities.

The penalty for violators who are billed every two months will escalate on every power bill in which they are subject to penalty. Customers billed on a monthly basis will be assessed the same penalty on two successive occasions before incurring the next higher level penalty. During any continuous period of curtailment, assessed penalties remain on the record for the purposes of administration of subsequent penalties, even if there has been an intervening period of compliance.

Standard disconnect criteria and procedures will be used whenever disconnecting Customers in accordance with this Plan. Health, safety, and welfare considerations will be taken into account, and Customers will be billed for normal disconnect and reconnect charges.

B. **Calculation of Financial Penalties**

Financial penalties will be calculated by multiplying the Customer's Excess Electricity Consumption each billing period by the appropriate penalty level identified above.

1) **Threshold Consumption Level**

The Threshold Consumption Level assigned to each Customer class is identified as:

a) Residential Customers,
10% Above Curtailment Target.

b) General Use Customers,
10% Above Curtailment Target.

c) Major Use Customers,
2% Above Curtailment Target.

These values may be changed by the State so as to effect better compliance with the curtailment order.

2) **Excess Power Consumption Calculation**

Penalties will not be assessed if a Customer's load (either actual load or weather-normalized load) is equal to, or less than, the Threshold Consumption Level. Excess Power Consumption is the lower of the following two values for each sampled load subject to penalty: (a) (Actual Load) minus (Curtailment Target) or (b) (Weather-Normalized Load) minus (Curtailment Target).

3) **Assessment of Penalties**

Penalties Vs Warnings. Customers will be assessed penalties only if they have Excess Electricity Consumption and if they are to be penalized based on the penalty assessment procedures described below. Any sampled Customer who is not penalized and whose use exceeds the Curtailment Target will receive a warning.

C. **Penalty Assessment Procedures**

Sample at the mandated minimum percentages for each section as specified in this Plan [1%-5%-100%] (or as otherwise specified by the State) and assess penalties on all Customers with Excess Power Consumption.

At its option, the Company may sample at higher percentages of Customers than the minimum required by Section 7 above and may choose among the following penalty assessment options:

1) **Option (1)**

Assess penalties on all sampled Customers with Excess Power Consumption (this methodology must be used for Major Use Customers even if the utility chooses Option (2), below, for its other Customer sectors); or

2) **Option (2)**

Develop a ratio of the minimum percentage sample size to the actual percentage sampled for the Residential and/or General Use Customer sectors. Multiply the resulting percentages by the total number of violators in each respective Customer sector to determine the minimum number of penalties that must be assessed in each sector. Calculate the percentage violation for each individual Customer that has been sampled (Excess Power Consumption divided by Curtailment Target) and apply penalties to the worst offenders in the overall sample based on their percentage Excess Power Consumption. Also penalize all Customers who were penalized in the previous billing period and who still have Excess Power Consumption.

D. **Billing Customers for Penalties**

The penalty on the power bill may be described as State-mandated and shall include any State-provided material describing the penalty aspect of the Plan as a bill stuffer in the bills of penalized Customers. If the Customer is receiving an ESS Consolidated Bill, the ESS will bill the Customer for any penalties incurred by that Customer. The bills shall include any Commission-provided material describing the penalty aspect of the Plan, such as a bill stuffer. When the Company is billing the Customer, the bills shall note that failure to pay penalties will result in service disconnection in accordance with standard disconnect criteria and procedures.

E. **Treatment of Penalties Pending Adjustment / Exemption Determinations**

A Customer that has applied for adjustment of Base Billing Period data and/or exemption from mandatory Curtailment may request a stay of enforcement of the penalty aspect of the Plan pending a final decision regarding its request. Any Customer who has been granted such a stay will be subject to retroactive penalties as applicable if the request is ultimately denied.

F. **Use of Funds Collected Under the Penalty Provisions of the Plan**

Funds collected under the State-ordered penalty provisions of this Plan shall be set aside in a separate account. The ultimate disposition of these funds will be determined by the Commission.

9. Exemptions and Adjustments

A. **Customer Application for Exemption/Adjustment**

Customers will be informed of how to apply for exemption from Plan requirements or adjustments of Base Billing Period data. At its option, the Company may elect to process exemptions and adjustments only for audited Customers. Customers seeking an exemption or adjustment shall apply first to the Company and then, if dissatisfied with that outcome, to the Commission.

At its option, the Company may provide for a credit against future curtailment for a Customer who has already accomplished a reduction in Demand for the utility's service by installing an alternative Energy device or by weatherization or other installed conservation measures equivalent to the proposed level of curtailment. Where the level of curtailment exceeds the Demand reduction produced by the conservation measures or installed alternative Energy device of the Customer, the Company may provide for credit against the level of curtailment ordered to the extent of the Demand reduction produced by the conservation measure or alternate Energy device.

B. **Granting Customer Requests for Exemption From Mandatory Curtailment**

No automatic Customer exemptions will be granted under mandatory State-initiated load curtailment. Exempted Customers should be informed that exemption may not protect them from Stage 5 blackouts.

1) Critical Load Customers

Critical Load Customers may be exempted once the Customers have demonstrated to the Company that they have eliminated all nonessential Energy use and are using any reliable, cost-effective backup Energy resources.

2) Other Customers

Exemptions for Customers not qualifying as Critical Load Customers under the Plan will be evaluated based on whether Curtailment would result in unreasonable exposure to health or safety hazards, seriously impair the welfare of the affected Customer, cause extreme economic hardship relative to the amount of Energy saved, or produce counterproductive results.

C. **Utility Record Keeping Relative to Customer Exemptions**

Records regarding exemption determinations will be made available to the Commission upon request.

10. Measurement of the Amount of Curtailment Achieved and Determination of Compliance

At all times during State-initiated regional load curtailment, the Commission and the Utility Coordinator will be provided with consumption and savings data on a monthly basis in the form specified in Appendix D of the Regional Plan. To the extent that circumstances at the time of actual load curtailment dictate the need for additional data or more frequent data submittal, a best effort to comply with the Commission request will be made.

11. Special Arrangements

A. **Use of Customer-Owned Generation Facilities**

Consistent with the need for safety and system protection, Customers having their own generation facilities or access to electricity from non-utility power sources may choose to use Energy from those other sources to supplement their curtailed power purchases from their electric utility under any protracted regional shortage situation.

B. **Curtailment Scheduling**

During periods of mandatory Curtailment, a Customer is obligated to provide the requisite amount of curtailment within each billing period. Within that period, and subject to equipment limitations and the Company's rules on load fluctuations, Customers are free to schedule their curtailment so as to minimize the economic cost, hardship or inconvenience they experience as a result of the mandatory curtailment requirement.

C. **Related Curtailment Information**

The Regional Electric Energy Curtailment Plan is included, by reference. That plan contains additional information on curtailment administration.

RULE N (Concluded)

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2007 COS ONLY

		Forecast SDEC05E07		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	**RATE SCHEDULE**	CONSUMERS	MWH SALES	w/ Sch. 125	w/ Sch. 125	AMOUNT	PCT.
Residential	7	702,246	7,524,421	$740,053,842	$761,181,928	$21,128,086	2.9%
Employee Discount				($794,568)	($817,793)	($23,225)	
Subtotal				$739,259,274	$760,364,135	$21,104,860	2.9%
Outdoor Area Lighting	15	1,351	23,496	$4,294,792	$4,450,894	$156,102	3.6%
General Service <30 kW	32	81,581	1,503,045	$138,782,619	$142,416,923	$3,634,304	2.6%
Opt. Time-of-Day G.S. >30 kW	38	1,255	105,829	$9,603,445	$10,093,196	$489,751	5.1%
Irrig. & Drain. Pump. < 30 kW	47	3,090	22,922	$2,044,310	$2,159,459	$115,149	5.6%
Irrig. & Drain. Pump. > 30 kW	49	1,410	67,951	$4,651,515	$4,890,594	$239,079	5.1%
General Service >30 kW							
Secondary	83-S	11,768	5,402,871	$396,300,285	$398,171,209	$1,870,924	0.5%
Primary	83-P	143	298,570	$20,115,831	$20,692,372	$576,541	2.9%
Schedule 89 > 1 MW							
Secondary	89-S	101	667,477	$48,904,310	$46,932,813	($1,971,496)	-4.0%
Primary	89-P	115	2,494,263	$159,262,193	$155,759,641	($3,502,552)	-2.2%
Subtransmission	89-T	9	1,358,222	$77,606,964	$78,565,798	$958,834	1.2%
Street & Highway Lighting	91	206	97,806	$14,948,255	$16,392,774	$1,444,518	9.7%
Traffic Signals	92	14	5,939	$416,502	$440,258	$23,756	5.7%
Recreational Field Lighting	93	27	565	$82,060	$89,672	$7,612	9.3%
TOTAL (CYCLE YEAR BASIS)		803,314	19,573,378	$1,616,272,356	$1,641,419,738	$25,147,381	1.6%
CONVERSION ADJUSTMENT				$2,327,327	$2,363,537		
TOTAL (CALENDAR YEAR BASIS			19,601,562	**$1,618,599,683**	**$1,643,783,275**	**$25,183,592**	1.6%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2007 COS ONLY

		Forecast SDEC05E07		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	**RATE SCHEDULE**	CONSUMERS	MWH SALES	w/ Sch. 125, Sch 102	w/ Sch. 125, Sch 102	AMOUNT	PCT.
Residential	7	702,246	7,524,421	$651,608,629	$672,736,715	$21,128,086	3.2%
Employee Discount				($703,084)	($726,310)	($23,225)	
Subtotal				$650,905,545	$672,010,405	$21,104,860	3.2%
Outdoor Area Lighting	15	1,351	23,496	$4,216,188	$4,372,291	$156,102	3.7%
General Service <30 kW	32	81,581	1,503,045	$136,044,251	$139,678,555	$3,634,304	2.7%
Opt. Time-of-Day G.S. >30 kW	38	1,255	105,829	$9,528,180	$10,017,931	$489,751	5.1%
Irrig. & Drain. Pump. < 30 kW	47	3,090	22,922	$1,793,868	$1,909,017	$115,149	6.4%
Irrig. & Drain. Pump. > 30 kW	49	1,410	67,951	$3,955,456	$4,194,534	$239,079	6.0%
General Service >30 kW							
Secondary	83-S	11,768	5,402,871	$392,827,058	$394,697,982	$1,870,924	0.5%
Primary	83-P	143	298,570	$20,005,306	$20,581,847	$576,541	2.9%
Schedule 89 > 1 MW							
Secondary	89-S	101	667,477	$48,904,310	$46,932,813	($1,971,496)	-4.0%
Primary	89-P	115	2,494,263	$159,262,193	$155,759,641	($3,502,552)	-2.2%
Subtransmission	89-T	9	1,358,222	$77,606,964	$78,565,798	$958,834	1.2%
Street & Highway Lighting	91	206	97,806	$14,948,255	$16,392,774	$1,444,518	9.7%
Traffic Signals	92	14	5,939	$416,502	$440,258	$23,756	5.7%
Recreational Field Lighting	93	27	565	$82,060	$89,672	$7,612	9.3%
TOTAL (CYCLE YEAR BASIS)		803,314	19,573,378	$1,520,496,135	$1,545,643,517	$25,147,381	1.7%
CONVERSION ADJUSTMENT				$2,189,415	$2,225,626		
TOTAL (CALENDAR YEAR BASIS)			19,601,562	**$1,522,685,550**	**$1,547,869,142**	**$25,183,592**	1.7%
				$1,521,199,220	$1,546,369,826		

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2007 COS ONLY

CATEGORY	RATE SCHEDULE	Forecast SDEC05E07 CONSUMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	702,246	7,524,421	$650,931,431	$671,984,273	$21,052,841	3.2%
Employee Discount				($702,341)	($725,483)	($23,143)	
Subtotal				$650,229,091	$671,258,789	$21,029,699	3.2%
Outdoor Area Lighting	15	1,351	23,496	$4,207,025	$4,362,657	$155,633	3.7%
General Service <30 kW	32	81,581	1,503,045	$136,134,434	$139,753,707	$3,619,273	2.7%
Opt. Time-of-Day G.S. >30 kW	38	1,255	105,829	$9,534,530	$10,023,222	$488,693	5.1%
Irrig. & Drain. Pump. < 30 kW	47	3,090	22,922	$1,795,472	$1,910,163	$114,691	6.4%
Irrig. & Drain. Pump. > 30 kW	49	1,410	67,951	$3,967,007	$4,205,407	$238,399	6.0%
General Service >30 kW							
Secondary	83-S	11,768	5,402,871	$393,583,460	$395,508,412	$1,924,953	0.5%
Primary	83-P	143	298,570	$20,059,049	$20,638,575	$579,526	2.9%
Schedule 89 > 1 MW							
Secondary	89-S	101	667,477	$48,997,756	$47,032,935	($1,964,822)	-4.0%
Primary	89-P	115	2,494,263	$159,711,160	$156,233,551	($3,477,609)	-2.2%
Subtransmission	89-T	9	1,358,222	$77,905,773	$78,864,607	$958,834	1.2%
Street & Highway Lighting	91	206	97,806	$14,926,738	$16,365,388	$1,438,650	9.6%
Traffic Signals	92	14	5,939	$417,452	$441,149	$23,697	5.7%
Recreational Field Lighting	93	27	565	$81,952	$89,536	$7,584	9.3%
TOTAL (CYCLE YEAR BASIS)		803,314	19,573,378	$1,521,550,900	$1,546,688,099	$25,137,199	1.7%
CONVERSION ADJUSTMENT				$2,190,934	$2,227,130		
TOTAL (CALENDAR YEAR BASIS)			19,601,562	**$1,523,741,834**	**$1,548,915,229**	**$25,173,395**	1.7%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7
Note: Bill comparison includes Low Income Charge and Public Purpose Charge

Net Monthly Billing

kwh	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
50	$13.94	$14.08	0.97%
100	$17.22	$17.52	1.75%
200	$23.83	$24.42	2.49%
250	$27.13	$27.87	2.73%
300	$31.23	$32.09	2.77%
400	$39.42	$40.56	2.90%
500	$47.59	$49.04	3.05%
600	$55.76	$57.51	3.14%
700	$63.95	$65.98	3.17%
800	$72.13	$74.44	3.20%
900	$80.33	$82.92	3.22%
1,000	$88.50	$91.38	3.26%
1,100	$96.66	$99.85	3.30%
1,200	$104.85	$108.33	3.32%
1,300	$113.04	$116.79	3.32%
1,400	$121.23	$125.26	3.32%
1,500	$129.40	$133.74	3.35%
1,600	$137.58	$142.21	3.36%
1,700	$145.77	$150.68	3.37%
1,800	$153.94	$159.13	3.37%
2,000	$170.31	$176.08	3.39%
2,300	$194.86	$201.49	3.40%
2,750	$231.66	$239.61	3.43%
3,000	$252.12	$260.78	3.43%
3,500	$293.03	$303.13	3.45%
4,000	$333.94	$345.48	3.45%
4,500	$374.84	$387.83	3.47%
5,000	$415.75	$430.17	3.47%
7,500	$620.28	$641.92	3.49%
10,000	$824.81	$853.66	3.50%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service
Note: Bill comparison includes Low Income Charge and Public Purpose Charge

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kwh	Est. 2007 RVM Prices	Proposed Price*	Percent Difference	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
100	$25.47	$25.69	0.86%	$24.26	$24.47	0.87%
500	$61.40	$62.49	1.78%	$55.35	$56.43	1.95%
600	$70.39	$71.66	1.80%	$63.12	$64.39	2.01%
700	$79.36	$80.88	1.92%	$70.89	$72.40	2.13%
800	$88.35	$90.05	1.92%	$78.65	$80.35	2.16%
900	$97.33	$99.27	1.99%	$86.43	$88.38	2.26%
1,000	$106.32	$108.45	2.00%	$94.20	$96.34	2.27%
1,500	$151.24	$154.45	2.12%	$133.07	$136.28	2.41%
1,750	$173.72	$177.44	2.14%	$152.53	$156.24	2.43%
2,000	$196.15	$200.42	2.18%	$171.93	$176.19	2.48%
2,500	$241.08	$246.42	2.22%	$210.80	$216.14	2.53%
3,500	$330.91	$338.39	2.26%	$288.52	$296.00	2.59%
4,000	$375.83	$384.36	2.27%	$327.38	$335.91	2.61%
4,500	$420.75	$430.36	2.28%	$366.24	$375.85	2.62%
5,000	$465.67	$476.33	2.29%	$405.10	$415.76	2.63%
6,000	$534.02	$542.46	1.58%	$461.34	$469.79	1.83%
7,000	$602.37	$608.60	1.03%	$517.58	$523.81	1.20%
8,000	$670.72	$674.74	0.60%	$573.82	$577.83	0.70%
9,000	$739.07	$740.87	0.24%	$630.05	$631.86	0.29%
10,000	$807.42	$807.01	-0.05%	$686.29	$685.88	-0.06%
14,000	$1,080.83	$1,071.56	-0.86%	$911.25	$901.98	-1.02%
15,000	$1,149.18	$1,137.69	-1.00%	$967.49	$956.00	-1.19%
20,000	$1,490.93	$1,468.38	-1.51%	$1,248.68	$1,226.12	-1.81%
21,900	$1,620.80	$1,594.06	-1.65%	$1,355.53	$1,328.79	-1.97%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Note: Bill comparison includes Low Income Charge and Public Purpose Charge
Bill comparison assumes 50% on-peak and 50% off-peak energy consumption

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kwh	Est. 2007 RVM Prices	Proposed Price*	Percent Difference	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
1,000	$115.49	$120.20	4.08%	$103.38	$108.09	4.56%
3,000	$294.97	$309.10	4.79%	$258.63	$272.77	5.47%
5,000	$474.45	$498.01	4.97%	$413.88	$437.44	5.69%
7,000	$653.92	$686.91	5.04%	$569.13	$602.12	5.80%
10,000	$923.14	$970.26	5.10%	$802.01	$849.14	5.88%
13,000	$1,192.36	$1,253.62	5.14%	$1,034.89	$1,096.15	5.92%
14,000	$1,282.10	$1,348.07	5.15%	$1,112.52	$1,178.49	5.93%
16,000	$1,461.58	$1,536.97	5.16%	$1,267.77	$1,343.17	5.95%
21,000	$1,910.27	$2,009.23	5.18%	$1,655.90	$1,754.86	5.98%
25,000	$2,269.23	$2,387.04	5.19%	$1,966.41	$2,084.22	5.99%
30,000	$2,717.92	$2,859.29	5.20%	$2,354.54	$2,495.91	6.00%
35,000	$3,166.62	$3,331.55	5.21%	$2,742.67	$2,907.60	6.01%
40,000	$3,615.32	$3,803.81	5.21%	$3,130.80	$3,319.29	6.02%
45,000	$4,064.01	$4,276.06	5.22%	$3,518.94	$3,730.99	6.03%
50,000	$4,512.71	$4,748.32	5.22%	$3,907.07	$4,142.68	6.03%
75,000	$6,756.19	$7,109.61	5.23%	$5,847.73	$6,201.15	6.04%
100,000	$8,999.67	$9,470.89	5.24%	$7,788.39	$8,259.61	6.05%
150,000	$13,486.62	$14,193.46	5.24%	$11,669.70	$12,376.54	6.06%
200,000	$17,973.58	$18,916.03	5.24%	$15,551.02	$16,493.47	6.06%
300,000	$26,947.50	$28,361.17	5.25%	$23,313.66	$24,727.33	6.06%
400,000	$35,921.41	$37,806.31	5.25%	$31,076.29	$32,961.19	6.07%
500,000	$44,895.33	$47,251.45	5.25%	$38,838.93	$41,195.05	6.07%
750,000	$67,330.11	$70,864.30	5.25%	$58,245.51	$61,779.70	6.07%
1,000,000	$89,764.90	$94,477.15	5.25%	$77,652.10	$82,364.35	6.07%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kwh	kW	Est. 2007 RVM Prices	Proposed Price*	Percent Difference	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
30%	6,570	30	$543.60	$573.84	5.56%	$464.02	$494.26	6.52%
	10,950	50	$916.23	$950.97	3.79%	$783.59	$818.33	4.43%
	21,900	100	$1,847.80	$1,893.80	2.49%	$1,582.53	$1,628.53	2.91%
	43,800	200	$3,710.96	$3,779.46	1.85%	$3,180.41	$3,248.92	2.15%
	76,650	350	$6,505.68	$6,607.96	1.57%	$5,577.24	$5,679.51	1.83%
	109,500	500	$9,300.41	$9,436.46	1.46%	$7,974.06	$8,110.10	1.71%
	153,300	700	$13,026.71	$13,207.78	1.39%	$11,169.82	$11,350.89	1.62%
	186,150	850	$15,821.44	$16,036.28	1.36%	$13,566.64	$13,781.48	1.58%
	219,000	1,000	$18,616.16	$18,864.77	1.34%	$15,963.46	$16,212.07	1.56%
50%	10,950	30	$814.46	$835.81	2.62%	$681.83	$703.18	3.13%
	18,250	50	$1,367.67	$1,387.60	1.46%	$1,146.61	$1,166.54	1.74%
	36,500	100	$2,750.69	$2,767.06	0.60%	$2,308.57	$2,324.95	0.71%
	73,000	200	$5,516.73	$5,525.99	0.17%	$4,632.50	$4,641.76	0.20%
	127,750	350	$9,665.79	$9,664.38	-0.01%	$8,118.38	$8,116.97	-0.02%
	182,500	500	$13,814.85	$13,802.77	-0.09%	$11,604.26	$11,592.18	-0.10%
	255,500	700	$19,346.92	$19,320.62	-0.14%	$16,252.10	$16,225.80	-0.16%
	310,250	850	$23,495.98	$23,459.01	-0.16%	$19,737.98	$19,701.01	-0.19%
	365,000	1,000	$27,645.04	$27,597.40	-0.17%	$23,223.87	$23,176.23	-0.21%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kwh	kW	Est. 2007 RVM Prices	Proposed Price*	Percent Difference	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
70%	15,330	30	$1,085.33	$1,097.79	1.15%	$899.64	$912.10	1.39%
	25,550	50	$1,819.12	$1,824.23	0.28%	$1,509.63	$1,514.75	0.34%
	51,100	100	$3,653.58	$3,640.33	-0.36%	$3,034.61	$3,021.36	-0.44%
	102,200	200	$7,322.50	$7,272.51	-0.68%	$6,084.58	$6,034.59	-0.82%
	178,850	350	$12,825.89	$12,720.80	-0.82%	$10,659.52	$10,554.42	-0.99%
	255,500	500	$18,329.28	$18,169.08	-0.87%	$15,234.46	$15,074.26	-1.05%
	357,700	700	$25,667.13	$25,433.46	-0.91%	$21,334.38	$21,100.71	-1.10%
	434,350	850	$31,170.52	$30,881.74	-0.93%	$25,909.33	$25,620.55	-1.11%
	511,000	1,000	$36,673.91	$36,330.02	-0.94%	$30,484.27	$30,140.38	-1.13%
90%	19,710	30	$1,356.20	$1,359.77	0.26%	$1,117.45	$1,121.03	0.32%
	32,850	50	$2,270.56	$2,260.86	-0.43%	$1,872.65	$1,862.96	-0.52%
	65,700	100	$4,556.47	$4,513.59	-0.94%	$3,760.66	$3,717.78	-1.14%
	131,400	200	$9,128.28	$9,019.04	-1.20%	$7,536.66	$7,427.42	-1.45%
	229,950	350	$15,986.00	$15,777.22	-1.31%	$13,200.66	$12,991.88	-1.58%
	328,500	500	$22,843.72	$22,535.39	-1.35%	$18,864.66	$18,556.34	-1.63%
	459,900	700	$31,987.34	$31,546.30	-1.38%	$26,416.67	$25,975.62	-1.67%
	558,450	850	$38,845.06	$38,304.47	-1.39%	$32,080.67	$31,540.08	-1.69%
	657,000	1,000	$45,702.78	$45,062.65	-1.40%	$37,744.67	$37,104.54	-1.70%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Primary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kwh	kW	Est. 2007 RVM Price	Proposed Price*	Percent Difference	Est. 2007 RVM Price	Proposed Price*	Percent Difference
30%	21,900	100	$1,868.98	$1,895.52	1.42%	$1,603.71	$1,630.25	1.65%
	43,800	200	$3,583.45	$3,715.95	3.70%	$3,052.91	$3,185.41	4.34%
	76,650	350	$6,155.17	$6,446.59	4.73%	$5,226.72	$5,518.15	5.58%
	109,500	500	$8,726.88	$9,177.24	5.16%	$7,400.53	$7,850.89	6.09%
	142,350	650	$11,298.60	$11,907.89	5.39%	$9,574.34	$10,183.63	6.36%
	186,150	850	$14,727.55	$15,548.75	5.58%	$12,472.75	$13,293.95	6.58%
	219,000	1,000	$17,299.27	$18,279.39	5.67%	$14,646.56	$15,626.69	6.69%
50%	36,500	100	$2,715.32	$2,737.65	0.82%	$2,273.20	$2,295.53	0.98%
	73,000	200	$5,276.14	$5,400.22	2.35%	$4,391.91	$4,515.98	2.83%
	127,750	350	$9,117.37	$9,394.06	3.03%	$7,569.96	$7,846.65	3.66%
	182,500	500	$12,958.61	$13,387.91	3.31%	$10,748.02	$11,177.32	3.99%
	237,250	650	$16,799.84	$17,381.76	3.46%	$13,926.08	$14,508.00	4.18%
	310,250	850	$21,921.48	$22,706.89	3.58%	$18,163.48	$18,948.89	4.32%
	365,000	1,000	$25,762.71	$26,700.73	3.64%	$21,341.54	$22,279.56	4.40%
70%	51,100	100	$3,561.67	$3,579.79	0.51%	$2,942.70	$2,960.82	0.62%
	102,200	200	$6,968.83	$7,084.48	1.66%	$5,730.90	$5,846.56	2.02%
	178,850	350	$12,079.58	$12,341.53	2.17%	$9,913.21	$10,175.16	2.64%
	255,500	500	$17,190.33	$17,598.58	2.37%	$14,095.51	$14,503.76	2.90%
	332,150	650	$22,301.08	$22,855.63	2.49%	$18,277.81	$18,832.36	3.03%
	434,350	850	$29,115.41	$29,865.02	2.57%	$23,854.21	$24,603.83	3.14%
	511,000	1,000	$34,226.16	$35,122.07	2.62%	$28,036.52	$28,932.43	3.20%
90%	65,700	100	$4,408.01	$4,421.92	0.32%	$3,612.20	$3,626.11	0.39%
	131,400	200	$8,661.52	$8,768.75	1.24%	$7,069.90	$7,177.13	1.52%
	229,950	350	$15,041.79	$15,289.00	1.64%	$12,256.45	$12,503.66	2.02%
	328,500	500	$21,422.05	$21,809.25	1.81%	$17,443.00	$17,830.19	2.22%
	427,050	650	$27,802.32	$28,329.50	1.90%	$22,629.54	$23,156.73	2.33%
	558,450	850	$36,309.34	$37,023.16	1.97%	$29,544.94	$30,258.77	2.42%
	657,000	1,000	$42,689.60	$43,543.41	2.00%	$34,731.49	$35,585.30	2.46%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary.

Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kwh	kW	Net Monthly Bill: Est. 2007 RVM Prices	Net Monthly Bill: Proposed Price*	Percent Difference
30%	219,000	1,000	$18,523.68	$18,736.79	1.15%
	438,000	2,000	$37,062.71	$35,351.77	-4.62%
	876,000	4,000	$74,140.76	$68,581.75	-7.50%
	1,642,500	7,500	$138,985.33	$126,692.18	-8.84%
	2,190,000	10,000	$185,152.22	$168,048.97	-9.24%
	3,285,000	15,000	$277,486.00	$250,762.55	-9.63%
	4,380,000	20,000	$369,819.79	$333,476.13	-9.83%
50%	365,000	1,000	$27,490.90	$27,403.24	-0.32%
	730,000	2,000	$54,997.14	$52,684.69	-4.20%
	1,460,000	4,000	$110,009.63	$103,247.58	-6.15%
	2,737,500	7,500	$205,878.11	$191,329.26	-7.07%
	3,650,000	10,000	$274,342.60	$254,231.75	-7.33%
	5,475,000	15,000	$411,271.57	$380,036.72	-7.59%
	7,300,000	20,000	$548,200.54	$505,841.69	-7.73%
70%	511,000	1,000	$36,458.12	$36,069.70	-1.07%
	1,022,000	2,000	$72,931.58	$70,017.60	-4.00%
	2,044,000	4,000	$145,703.98	$137,738.89	-5.47%
	3,832,500	7,500	$272,770.90	$255,966.34	-6.16%
	5,110,000	10,000	$363,532.98	$340,414.52	-6.36%
	7,665,000	15,000	$545,057.14	$509,310.88	-6.56%
	10,220,000	20,000	$726,581.30	$678,207.25	-6.66%
90%	657,000	1,000	$45,425.33	$44,736.16	-1.52%
	1,314,000	2,000	$90,866.01	$87,350.52	-3.87%
	2,628,000	4,000	$181,380.13	$172,212.00	-5.05%
	4,927,500	7,500	$339,663.68	$320,603.43	-5.61%
	6,570,000	10,000	$452,723.35	$426,597.30	-5.77%
	9,855,000	15,000	$678,842.70	$638,585.05	-5.93%
	13,140,000	20,000	$904,962.06	$850,572.80	-6.01%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Primary, 3 phase service.
Note: Bill comparison includes Low Income Energy Assistance Charge and Public Purpose Charges
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kwh	kW	Net Monthly Bill: Est. 2007 RVM Prices	Net Monthly Bill: Proposed Price*	Percent Difference
30%	219,000	1,000	$17,210.84	$18,190.46	5.69%
	438,000	2,000	$34,267.19	$34,156.12	-0.32%
	876,000	4,000	$68,379.88	$66,087.45	-3.35%
	1,642,500	7,500	$128,035.05	$121,925.24	-4.77%
	2,190,000	10,000	$170,495.24	$161,658.72	-5.18%
	3,285,000	15,000	$255,415.61	$241,125.69	-5.59%
	4,380,000	20,000	$340,335.98	$320,592.65	-5.80%
50%	365,000	1,000	$25,615.34	$26,533.90	3.59%
	730,000	2,000	$51,076.18	$50,843.01	-0.46%
	1,460,000	4,000	$101,997.86	$99,461.22	-2.49%
	2,737,500	7,500	$190,707.42	$184,139.70	-3.44%
	3,650,000	10,000	$254,058.40	$244,611.34	-3.72%
	5,475,000	15,000	$380,760.34	$365,554.61	-3.99%
	7,300,000	20,000	$507,462.29	$486,497.88	-4.13%
70%	511,000	1,000	$34,019.84	$34,877.35	2.52%
	1,022,000	2,000	$67,885.17	$67,529.89	-0.52%
	2,044,000	4,000	$135,441.32	$132,660.46	-2.05%
	3,832,500	7,500	$253,379.79	$246,354.17	-2.77%
	5,110,000	10,000	$337,621.55	$327,563.95	-2.98%
	7,665,000	15,000	$506,105.08	$489,983.53	-3.19%
	10,220,000	20,000	$674,588.61	$652,403.11	-3.29%
90%	657,000	1,000	$42,424.33	$43,220.79	1.88%
	1,314,000	2,000	$84,694.16	$84,216.77	-0.56%
	2,628,000	4,000	$168,866.59	$165,841.51	-1.79%
	4,927,500	7,500	$316,052.16	$308,568.63	-2.37%
	6,570,000	10,000	$421,184.71	$410,516.57	-2.53%
	9,855,000	15,000	$631,449.82	$614,412.46	-2.70%
	13,140,000	20,000	$841,714.93	$818,308.34	-2.78%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission

Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kwh	kW	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
30%	876,000	4,000	$58,145.19	$61,334.72	5.49%
	1,095,000	5,000	$72,552.74	$75,913.92	4.63%
	2,190,000	10,000	$144,367.78	$148,587.24	2.92%
	4,380,000	20,000	$287,720.57	$293,656.58	2.06%
	8,760,000	40,000	$574,426.14	$583,795.26	1.63%
	10,950,000	50,000	$717,778.92	$728,864.60	1.54%
	15,330,000	70,000	$1,004,484.49	$1,019,003.28	1.45%
50%	1,460,000	4,000	$90,659.99	$94,224.86	3.93%
	1,825,000	5,000	$113,093.99	$116,924.35	3.39%
	3,650,000	10,000	$225,172.97	$230,330.80	2.29%
	7,300,000	20,000	$449,330.95	$457,143.70	1.74%
	14,600,000	40,000	$897,646.89	$910,769.50	1.46%
	18,250,000	50,000	$1,121,804.87	$1,137,582.41	1.41%
	25,550,000	70,000	$1,570,120.81	$1,591,208.21	1.34%
70%	2,044,000	4,000	$123,000.26	$126,940.48	3.20%
	2,555,000	5,000	$153,496.58	$157,796.13	2.80%
	5,110,000	10,000	$305,978.16	$312,074.36	1.99%
	10,220,000	20,000	$610,941.32	$620,630.82	1.59%
	20,440,000	40,000	$1,220,867.65	$1,237,743.75	1.38%
	25,550,000	50,000	$1,525,830.81	$1,546,300.21	1.34%
	35,770,000	70,000	$2,135,757.14	$2,163,413.13	1.29%
90%	2,628,000	4,000	$155,322.34	$159,637.91	2.78%
	3,285,000	5,000	$193,899.18	$198,667.91	2.46%
	6,570,000	10,000	$386,783.35	$393,817.92	1.82%
	13,140,000	20,000	$772,551.70	$784,117.94	1.50%
	26,280,000	40,000	$1,544,088.41	$1,564,717.99	1.34%
	32,850,000	50,000	$1,929,856.76	$1,955,018.01	1.30%
	45,990,000	70,000	$2,701,393.46	$2,735,618.05	1.27%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 47 Summer Period
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

		Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kW	kWh	Est. 2007 RVM Prices	Proposed Price*	Percent Difference	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
10	50	$25.59	$30.40	18.79%	$24.98	$29.79	19.25%
10	100	$30.58	$35.05	14.61%	$29.37	$33.84	15.21%
10	500	$70.50	$72.24	2.47%	$64.45	$66.19	2.70%
10	1,000	$105.20	$108.44	3.07%	$93.09	$96.33	3.47%
10	2,000	$174.61	$180.83	3.56%	$150.38	$156.60	4.14%
10	5,000	$382.81	$397.99	3.97%	$322.25	$337.43	4.71%
20	100	$30.58	$35.05	14.61%	$29.37	$33.84	15.21%
20	200	$40.56	$44.35	9.33%	$38.14	$41.93	9.93%
20	500	$70.50	$72.24	2.47%	$64.45	$66.19	2.70%
20	1,000	$120.41	$118.74	-1.39%	$108.29	$106.63	-1.54%
20	2,000	$189.81	$191.13	0.69%	$165.58	$166.90	0.80%
20	5,000	$398.01	$408.29	2.58%	$337.45	$347.73	3.05%
20	8,000	$606.22	$625.46	3.17%	$509.32	$528.56	3.78%
30	150	$35.57	$39.70	11.60%	$33.75	$37.88	12.23%
30	500	$70.50	$72.24	2.47%	$64.45	$66.19	2.70%
30	1,000	$120.41	$118.74	-1.39%	$108.29	$106.63	-1.54%
30	3,000	$274.41	$273.82	-0.22%	$238.08	$237.48	-0.25%
30	5,000	$413.22	$418.59	1.30%	$352.65	$358.03	1.52%
30	8,000	$621.42	$635.76	2.31%	$524.52	$538.86	2.73%
30	10,000	$760.23	$780.54	2.67%	$639.10	$659.41	3.18%
30	15,000	$1,107.24	$1,142.48	3.18%	$925.54	$960.79	3.81%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 49 Summer Period
Note: Bill comparison includes Low Income Energy Assistance and Public Purpose Charges

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
LF	kW	kWh	Est. 2007 RVM Prices	Proposed Price*	Percent Difference	Est. 2007 RVM Prices	Proposed Price*	Percent Difference
20%	35	5,110	$382.49	$398.12	4.09%	$320.59	$336.22	4.88%
40%	35	10,220	$680.87	$729.29	7.11%	$557.07	$605.49	8.69%
60%	35	15,330	$979.25	$1,060.46	8.29%	$793.56	$874.77	10.23%
80%	35	20,440	$1,277.62	$1,391.63	8.92%	$1,030.04	$1,144.04	11.07%
20%	50	7,300	$533.17	$555.50	4.19%	$444.75	$467.07	5.02%
40%	50	14,600	$959.42	$1,028.60	7.21%	$782.58	$851.75	8.84%
60%	50	21,900	$1,385.68	$1,501.70	8.37%	$1,120.41	$1,236.42	10.35%
80%	50	29,200	$1,811.93	$1,974.79	8.99%	$1,458.24	$1,621.10	11.17%
20%	70	10,220	$734.08	$765.34	4.26%	$610.28	$641.54	5.12%
40%	70	20,440	$1,330.83	$1,427.68	7.28%	$1,083.25	$1,180.09	8.94%
60%	70	30,660	$1,927.59	$2,090.01	8.43%	$1,556.21	$1,718.63	10.44%
80%	70	40,880	$2,524.35	$2,752.35	9.03%	$2,029.18	$2,257.18	11.24%
20%	100	14,600	$1,035.44	$1,080.10	4.31%	$858.59	$903.25	5.20%
40%	100	29,200	$1,887.95	$2,026.29	7.33%	$1,534.25	$1,672.60	9.02%
60%	100	43,800	$2,740.46	$2,972.49	8.47%	$2,209.92	$2,441.95	10.50%
80%	100	58,400	$3,592.97	$3,918.69	9.07%	$2,885.58	$3,211.30	11.29%
20%	200	29,200	$2,039.98	$2,129.29	4.38%	$1,686.28	$1,775.60	5.30%
40%	200	58,400	$3,745.00	$4,021.69	7.39%	$3,037.61	$3,314.30	9.11%
60%	200	87,600	$5,450.02	$5,914.08	8.51%	$4,388.94	$4,853.00	10.57%
80%	200	116,800	$7,155.04	$7,806.47	9.10%	$5,740.26	$6,391.70	11.35%

* Proposed 2007 General Rate Case excluding Port Westward

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2007 COSTS TO RATE SCHEDULES ($000)

	Energy-Based Charges					Trans. & Related Charges			Distribution Demand & Facilities Charges				
Grouping	Power Supply	Franchise Fees	Trojan	Sch 129	Subtotal	Transmission	Ancillary Services	Subtotal	Substation	Subtrans.	13 kV Facilities	Connect Facilities	Subtotal
Schedule 7	$426,976	$17,805	$1,790		$19,595	$12,745	$2,130	$14,875	$32,078	$30,870	$61,580	$80,052	$204,580
Schedule 15	$1,261	$104	$6		$110	$17	$6	$23	$94	$90	$180	$33	$396
Schedule 32	$84,249	$3,331	$358		$3,689	$2,792	$420	$3,212	$6,051	$5,823	$9,650	$16,433	$37,957
Schedule 38	$5,962	$236	$25	$0	$261	$62	$30	$91	$787	$757	$1,088	$791	$3,423
Schedule 47	$1,168	$51	$5		$56	$36	$6	$41	$258	$248	$348	$331	$1,185
Schedule 49	$3,441	$114	$16	$0	$131	$105	$17	$122	$756	$728	$1,020	$447	$2,951
Schedule 83													
Secondary	$299,543	$9,315	$1,286	$12	$10,612							$13,347	$13,347
Primary	$15,956	$484	$69	$1	$553							$130	$130
Class Total						$7,746	$1,575	$9,321	$18,811	$18,102	$25,692		$62,605
Schedule 89 1-4 MW													
Secondary	$35,662	$1,060	$156	$1	$1,217							$478	$478
Primary	$45,697	$1,308	$197	$2	$1,507							$84	$84
Class Total						$1,965	$406	$2,371	$4,201	$4,043	$5,657		$13,901
Schedule 89 GT 4 MW													
Secondary	$1,444	$41	$6	$0	$47							$44	$44
Primary	$86,744	$2,346	$393	$4	$2,744							$79	$79
Subtransmission	$70,782	$1,838	$308	$3	$2,149							$540	$540
Class Total						$3,020	$795	$3,815	$3,666	$6,160	$1,188		$11,015
Schedule 91	$5,262	$383	$23	$0	$407	$81	$26	$107	$388	$373	$745	$134	$1,640
Schedule 92	$325	$10	$1	$0	$12	$6	$2	$8	$11	$11	$15	$46	$83
Schedule 93	$30	$2	$0	$0	$2	$1	$0	$1	$5	$5	$7	$4	$22
Totals	$1,084,503	$38,429	$4,639	$24	$43,091	$28,575	$5,413	$33,988	$67,107	$67,211	$107,171	$112,972	$354,460

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2007 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Related		Metering		Billing		Other Consumer		Subtotal			
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal
Schedule 7	$9,061	$23	$15,837	$10	$29,102	$18	$39,605	$24	$93,606	$75		$93,681
Schedule 15	$169		$0		$52		$84		$306	$0	$2,351	$2,657
Schedule 32	$759	$1,968	$1,174	$667	$1,925	$1,094	$3,454	$1,963	$7,312	$5,693		$13,005
Schedule 38	$13	$150	$3	$25	$5	$41	$13	$105	$34	$321		$356
Schedule 47	$9	$158	$5	$65	$7	$107	$13	$192	$35	$522		$557
Schedule 49	$0	$169	$0	$32	$0	$52	$1	$93	$1	$346		$348
Schedule 83												
Secondary	$73	$1,461	$16	$249	$27	$416	$201	$3,040	$318	$5,166		$5,484
Primary		$204		$3		$5		$39	$0	$251		$251
Schedule 89 1-4 MW												
Secondary		$18		$2		$5		$133	$0	$158		$158
Primary		$131		$2		$4		$122	$0	$259		$259
Schedule 89 GT 4 MW												
Secondary		$0		$0		$0		$3	$0	$3		$3
Primary		$35		$1		$4		$32	$0	$71		$71
Subtransmission		$202		$0		$1		$12	$0	$215		$215
Schedule 91	$1,162			$0	$165		$274		$1,601	$0	$8,283	$9,884
Schedule 92				$0	$11		$19		$30	$0		$30
Schedule 93		$37		$1		$1		$2	$0	$41		$41
Totals	$11,248	$4,557	$17,035	$1,057	$31,297	$1,750	$43,663	$5,759	$103,243	$13,123	$10,633	$127,000

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 7						
Residential						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$93,606	701,814	Customers	$11.11	per cust. per mo.	$93,566
Three-Phase	$75	432	Customers	$14.50	per cust. per mo.	$75
Trans. & Rel. Serv. Charge	$14,875	7,524,421	MWh	1.98	mills/kWh	$14,898
Distribution Charge	$204,580	7,524,421	MWh	27.19	mills/kWh	$204,589
Franchise Fees & Other	$19,595	7,524,421	MWh	2.60	mills/kWh	$19,563
Energy Charge	$426,976	7,524,421	MWh	56.75	mills/kWh	$427,011
Subtotal	$759,707					$759,703
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		701,814	Customers	$10.00	per cust. per mo.	$84,218
Three-Phase		432	Customers	$13.00	per cust. per mo.	$67
Trans. & Rel. Serv. Charge		7,524,421	MWh	1.98	mills/kWh	$14,898
Distribution Charge		7,524,421	MWh	28.43	mills/kWh	$213,919
System Usage Charge Calculation						
Franchise Fees & Other		7,524,421	MWh	2.60	mills/kWh	$19,563
Cust Impact Offset		7,524,421	MWh	0.20	mills/kWh	$1,505
System Usage Charge		7,524,421	MWh	2.80	mills/kWh	$21,068
Energy Charge		7,524,421	MWh	56.75	mills/kWh	$427,011
Subtotal						$761,182
					w/o CIO	$759,677
SCHEDULE 15						
Outdoor Area Lighting						
Theoretic						
Functional Costs						
Basic Charge	$306	1,351	Customers	$18.89	per cust. per mo.	$306
Trans. & Rel. Serv. Charge	$23	23,496	MWh	0.97	mills/kWh	$23
Distribution Charge	$396	23,496	MWh	16.85	mills/kWh	$396
Franchise Fees & Other	$110	23,496	MWh	4.67	mills/kWh	$110
Energy Charge	$1,261	23,496	MWh	53.66	mills/kWh	$1,261
Fixed Charges	$2,351	23,496	MWh			$2,351
Subtotal	$4,446					$4,446
Proposed						
Functional Costs						
Trans. & Rel. Serv. Charge		23,496	MWh	0.97	mills/kWh	$23
Distribution Charge		23,496	MWh	29.89	mills/kWh	$702
System Usage Charge Calc						
Franchise Fees & Other		23,496	MWh	4.67	mills/kWh	$110
Cust Impact Offset		23,496	MWh	0.20	mills/kWh	$5
System Usage Charge		23,496	MWh	4.87	mills/kWh	$114
Energy Charge		23,496	MWh	53.66	mills/kWh	$1,261
Fixed Charges		23,496	MWh			$2,351
Subtotal						$4,451
					w/o CIO	$4,446

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$7,312	52,017	Customers	$11.71	per cust. per mo.	$7,309
Three-Phase	$5,693	29,564	Customers	$16.05	per cust. per mo.	$5,694
Trans. & Rel. Serv. Charge	$3,212	1,503,045	MWh	2.14	mills/kWh	$3,217
Distribution Charge	$37,957	1,503,045	MWh	25.25	mills/kWh	$37,952
Franchise Fees & Other	$3,689	1,503,045	MWh	2.45	mills/kWh	$3,682
Energy Charge	$84,249	1,503,045	MWh	56.05	mills/kWh	$84,246
Subtotal	$142,112					$142,100
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		52,017	Customers	$12.00	per cust. per mo.	$7,490
Three-Phase		29,564	Customers	$16.00	per cust. per mo.	$5,676
Trans. & Rel. Serv. Charge		1,503,045	MWh	2.14	mills/kWh	$3,217
Distribution Charge						
First 5 MWh		1,327,585	MWh	28.08	mills/kWh	$37,279
Over 5 MWh		175,460	MWh	3.00	mills/kWh	$526
System Usage Charge Calc						
Franchise Fees & Other		1,503,045	MWh	2.45	mills/kWh	$3,682
Cust Impact Offset		1,503,045	MWh	0.20	mills/kWh	$301
System Usage Charge		1,503,045	MWh	2.65	mills/kWh	$3,983
Energy Charge		1,503,045	MWh	56.05	mills/kWh	$84,246
Subtotal						$142,417
					w/o CIO	$142,116
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Theoretic						
Functional Costs						
Basic						
Single-Phase	$34	137	Customers	$20.97	per cust. per mo.	$34
Three-Phase	$321	1,118	Customers	$23.94	per cust. per mo.	$321
Trans. & Rel. Serv. Charge	$91	105,829	MWh	0.86	per cust. per mo.	$91
Distribution Charges	$3,423	105,829	MWh	32.35	per cust. per mo.	$3,424
Franchise Fees & Other	$261	105,829	MWh	2.47	mills/kWh	$261
Energy Charge	$5,962	105,829	MWh	56.34	mills/kWh	$5,962
Subtotal	$10,094					$10,094
Proposed						
Functional Costs						
Basic						
Single-Phase		137	Customers	$20.00	per cust. per mo.	$33
Three-Phase		1,118	Customers	$25.00	per cust. per mo.	$335
Trans. & Rel. Serv. Charge		105,829	MWh	0.86	mills/kWh	$91
Distribution Charges		105,829	MWh	31.58	mills/kWh	$3,342
System Usage Charge						
Franchise Fees & Other		105,829	MWh	2.47	mills/kWh	$261
Cust Impact Offset		105,829	MWh	0.00	mills/kWh	$0
System Usage Charge		105,829	MWh	2.47	mills/kWh	$261
Energy Charge Calc						
On-Peak (special)		51,962	MWh	60.91	mills/kWh	$3,165
Off-Peak		53,867	MWh	51.93	mills/kWh	$2,797
Reactive Demand Charge		136,564	kVar	$0.50	kVar	$68
Subtotal						$10,093
					w/o CIO	$10,093

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 47						
Irrig. & Drain. Pump. - < 30 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$35	200	Customers	$28.75	per cust. per summ. mo.	$35
Three-Phase	$522	2,890	Customers	$30.12	per cust. per summ. mo.	$522
Trans. & Rel. Serv. Charge	$41	22,922	MWh	1.81	mills/kWh	$41
Distribution Charges	$1,185	22,922	MWh	51.68	mills/kWh	$1,185
Franchise Fees & Other	$56	22,922	MWh	2.44	mills/kWh	$56
Energy Charge	$1,168	22,922	MWh	50.96	mills/kWh	$1,168
Subtotal	$3,007					$3,007
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		200	Customers	$25.00	per cust. per summ. mo.	$30
Three-Phase		2,890	Customers	$25.00	per cust. per summ. mo.	$434
Trans. & Rel. Serv. Charge		22,922	MWh	1.81	mills/kWh	$41
Distribution Charge Calc						
First 50 kWh per kW		4,673	MWh	71.68	mills/kWh	$335
Over 50 kWh per kW		18,249	MWh	51.68	mills/kWh	$943
System Usage Charge Calc						
Franchise Fees & Other		22,922	MWh	2.44	mills/kWh	$56
Cust Impact Offset		22,922	MWh	(36.98)	mills/kWh	($848)
System Usage Charge		22,922	MWh	(34.54)	mills/kWh	($792)
Energy Charge		22,922	MWh	50.96	mills/kWh	$1,168
Reactive Demand Charge		98	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$2,159
					w/o CIO	$3,007
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Theoretic						
Functional Costs						
Basic						
Single-Phase	$1	8	Customers	$29.76	per cust. per summ. mo.	$1
Three-Phase	$346	1,402	Customers	$41.14	per cust. per summ. mo.	$346
Trans. & Rel. Serv. Charge	$122	67,951	MWh	1.80	mills/kWh	$122
Distribution Charges	$2,951	67,951	MWh	43.42	mills/kWh	$2,950
Franchise Fees & Other	$131	67,951	MWh	1.92	mills/kWh	$130
Energy Charge	$3,441	67,951	MWh	50.64	mills/kWh	$3,441
Subtotal	$6,992					$6,992
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		8	Customers	$30.00	per cust. per summ. mo.	$1
Three-Phase		1,402	Customers	$30.00	per cust. per summ. mo.	$252
Trans. & Rel. Serv. Charge		67,951	MWh	1.80	mills/kWh	$122
Distribution Charge Calc						
First 50 kWh per kW		19,426	MWh	59.01	mills/kWh	$1,146
Over 50 kWh per kW		48,525	MWh	39.01	mills/kWh	$1,893
System Usage Charge Calc						
Franchise Fees & Other		67,951	MWh	1.92	mills/kWh	$130
Cust Impact Offset		67,951	MWh	(30.93)	mills/kWh	($2,102)
System Usage Charge		67,951	MWh	(29.01)	mills/kWh	($1,971)
Energy Charge		67,951	MWh	50.64	mills/kWh	$3,441
Reactive Demand Charge		10,770	kVar	$0.50	kVar	$5
Subtotal with Consumer Impact Offset						$4,891
					w/o CIO	$6,992

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-1,000 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase Secondary	$318	729	Customers	$36.31	per cust, per mo.	$318
Three-Phase Secondary	$5,166	11,041	Customers	$39.00	per cust, per mo.	$5,167
Primary	$251	143	Customers	$147.02	per cust, per mo.	$251
Transmission & Related Service Charge	$9,321	15,096,457	kW demand	$0.62	per kW demand	$9,360
Distribution Charges						
13 kV Facilities	$25,692	17,177,712	kW faccap	$1.50	per kW faccap	$25,767
Connect Charge	$13,477	17,177,712	kW faccap	$0.78	per kW faccap	$13,399
Subtransmission Charge	$18,102	15,096,457	kW demand	$1.20	per kW demand	$18,116
Substation Charge	$18,811	15,096,457	kW demand	$1.25	per kW demand	$18,871
Secondary Franchise Fees & Other	$10,612	5,404,793	MWh	1.96	mills/kWh	$10,593
Primary Franchise Fees & Other	$553	298,570	MWh	1.85	mills/kWh	$552
Secondary COS Energy Charge	$299,543	5,402,871	MWh	55.44	mills/kWh	$299,535
Primary COS Energy Charge	$15,956	298,570	MWh	53.44	mills/kWh	$15,956
Subtotal	$417,802					$417,884
Proposed						
Functional Costs						
Basic Charge						
Secondary Single-Phase		729	Customers	$20.00	per cust, per mo.	$175
Secondary Three-Phase		11,041	Customers	$25.00	per cust, per mo.	$3,312
Primary		143	Customers	$90.00	per cust, per mo.	$154
Trans. & Rel. Serv. Charge						
First 30 kW		4,240,737	kW demand	$0.66	per kW demand	$2,799
Over 30 kW		10,855,720	kW demand	$0.66	per kW demand	$7,165
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,237,140	kW faccap	$2.29	<= 30 kW faccap	$9,703
Over 30 kW		12,152,196	kW faccap	$2.29	> 30 kW faccap	$27,829
Primary Facilities Charge						
First 30 kW		51,300	kW faccap	$2.11	<= 30 kW faccap	$108
Over 30 kW		737,076	kW faccap	$2.11	> 30 kW faccap	$1,555
Demand Charge						
First 30 kW		4,240,737	kW demand	$2.07	per kW demand	$8,778
Over 30 kW		10,855,720	kW demand	$2.64	per kW demand	$28,659
Secondary System Usage Charge Calc						
Franchise Fees & Other		5,404,793	MWh	1.96	mills/kWh	$10,593
Cust Impact Offset		5,404,793	MWh	0.20	mills/kWh	$1,081
System Usage Charge		5,404,793	MWh	2.16	mills/kWh	$11,674
Primary System Usage Charge Calc						
Franchise Fees & Other		298,570	MWh	1.85	mills/kWh	$552
Cust Impact Offset		298,570	MWh	0.20	mills/kWh	$60
System Usage Charge		298,570	MWh	2.05	mills/kWh	$612
Secondary COS Energy Charge		5,402,871	MWh	55.44	mills/kWh	$299,535
Primary COS Energy Charge		298,570	MWh	53.44	mills/kWh	$15,956
Reactive Demand Charge		1,784,247	kVar	$0.50	kVar	$892
Subtotal						$418,907
					w/o CIO	$417,766

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89						
General Service 1,001-4,000 kW						
Theoretic						
Functional Costs						
Secondary Basic Charge	$158	100	Customers	$131.78	per cust, per mo.	$158
Primary Basic Charge	$259	92	Customers	$235.61	per cust, per mo.	$259
Transmission & Related Service Charge	$2,371	3,371,680	kW on-peak	$0.70	per kW on-peak demand	$2,360
Distribution Charges						
13 kV Facilities Charge	$5,657	4,016,136	kW faccap	$1.41	per kW faccap	$5,663
Connect Charges	$562	4,016,136	kW faccap	$0.14	per kW faccap	$562
Subtransmission Demand Charge	$4,043	3,371,680	kW on-peak	$1.20	per kW on-peak demand	$4,046
Substation Demand Charge	$4,201	3,371,680	kW on-peak	$1.25	per kW on-peak demand	$4,215
Secondary Franchise Fees & Other	$1,217	654,274	MWh	1.86	mills/kWh	$1,217
Primary Franchise Fees & Other	$1,507	855,811	MWh	1.76	mills/kWh	$1,506
Secondary COS Energy Charge	$35,662	641,937	MWh	55.55	mills/kWh	$35,660
Primary COS Energy Charge	$45,697	855,811	MWh	53.40	mills/kWh	$45,700
Subtotal	$101,333					$101,346
Proposed						
Functional Costs						
Secondary Basic Charge		100	Customers	$130.00	per cust, per mo.	$156
Primary Basic Charge		92	Customers	$230.00	per cust, per mo.	$253
Trans. & Rel. Serv. Charge		3,371,680	kW on-peak	$0.66	per kW on-peak demand	$2,225
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		1,199,000	kW faccap	$2.33	per kW faccap	$2,794
1,001-4,000 kW		666,556	kW faccap	$0.40	per kW faccap	$267
Primary Facilities Charge						
First 1,000 kW		1,101,000	kW faccap	$2.17	per kW faccap	$2,389
1,001-4,000 kW		1,049,580	kW faccap	$0.24	per kW faccap	$252
Demand Charge		3,371,680	kW on-peak	$2.45	per kW on-peak demand	$8,261
Secondary System Usage Charge Calc						
Franchise Fees & Other		654,274	MWh	1.86	mills/kWh	$1,217
Cust Impact Offset		654,274	MWh	0.20	mills/kWh	$131
System Usage Charge		654,274	MWh	2.06	mills/kWh	$1,348
Primary System Usage Charge Calc						
Franchise Fees & Other		855,811	MWh	1.66	mills/kWh	$1,421
Cust Impact Offset		855,811	MWh	0.20	mills/kWh	$171
System Usage Charge		855,811	MWh	1.86	mills/kWh	$1,592
Secondary Energy Charge						
On-peak		422,006	MWh	58.68	mills/kWh	$24,763
Off-peak		219,932	MWh	49.73	mills/kWh	$10,937
Primary Energy Charge						
On-peak		528,411	MWh	56.58	mills/kWh	$29,897
Off-peak		327,400	MWh	47.91	mills/kWh	$15,686
Reactive Demand Charge		800,277	kVar	$0.50	kVar	$400
Subtotal						$101,220
					w/o CIO	$100,918

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89						
General Service 4,000 plus kW						
Theoretic						
Functional Costs						
Secondary Basic Charge	$3	2	Customers	$141.40	per cust, per mo.	$3
Primary Basic Charge	$71	24	Customers	$245.23	per cust, per mo.	$71
Subtransmission Basic Charge	$215	9	Customers	$1,994.56	per cust, per mo.	$215
Transmission & Related Service Charge	$3,815	5,137,161	kW on-peak	$0.74	per kW on-peak demand	$3,801
Distribution Charges						
13 kV Facilities Charge	$1,188	3,223,212	kW faccap	$0.37	per kW faccap	$1,193
Connect Charges	$662	5,708,748	kW faccap	$0.12	per kW faccap	$685
Subtransmission Demand Charge	$6,160	5,137,161	kW on-peak	$1.20	per kW faccap	$6,165
Substation Demand Charge	$3,666	2,872,657	kW on-peak	$1.28	per kW on-peak demand	$3,677
Secondary Franchise Fees & Other	$47	25,540	MWh	1.85	mills/kWh	$47
Primary Franchise Fees & Other	$2,744	1,708,452	MWh	1.61	mills/kWh	$2,751
Subtransmission Franchise Fees & Other	$2,149	1,358,222	MWh	1.58	mills/kWh	$2,146
Secondary COS Energy Charge	$1,444	25,540	MWh	56.56	mills/kWh	$1,445
Primary COS Energy Charge	$86,744	1,638,452	MWh	52.94	mills/kWh	$86,740
Subtransmission COS Energy Charge	$70,782	1,358,222	MWh	52.11	mills/kWh	$70,777
Subtotal	$179,693					$179,716
Proposed						
Functional Costs						
Secondary Basic Charge		2	Customers	$130.00	per cust, per mo.	$3
Primary Basic Charge		24	Customers	$230.00	per cust, per mo.	$67
Subtransmission Basic Charge		9	Customers	$1,000.00	per cust, per mo.	$108
Trans. & Rel. Serv. Charge		5,137,161	kW on-peak	$0.66	per kW on-peak demand	$3,391
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		24,000	kW faccap	$2.33	per kW faccap	$56
1,001-4,000 kW		72,000	kW faccap	$0.40	per kW faccap	$29
Greater than 4,000 kW		74,604	kW faccap	$0.40	per kW faccap	$30
Primary Facilities Charge						
First 1,000 kW		291,000	kW faccap	$2.17	per kW faccap	$631
1,001-4,000 kW		873,000	kW faccap	$0.24	per kW faccap	$210
Greater than 4,000 kW		1,888,608	kW faccap	$0.24	per kW faccap	$453
Subtransmission Facilities Charge						
First 1,000 kW		108,000	kW faccap	$2.17	per kW faccap	$234
1,001-4,000 kW		324,000	kW faccap	$0.24	per kW faccap	$78
Greater than 4,000 kW		2,053,536	kW faccap	$0.24	per kW faccap	$493
Secondary & Primary Demand Charge		2,872,657	kW on-peak	$2.45	per kW on-peak demand	$7,038
Subtransmission Demand Charge		2,264,504	kW on-peak	$1.28	per kW on-peak demand	$2,899
Secondary System Usage Charge Calc						
Franchise Fees & Other		25,540	MWh	1.86	mills/kWh	$48
Cust Impact Offset		25,540	MWh	0.20	mills/kWh	$5
System Usage Charge		25,540	MWh	2.06	mills/kWh	$53
Primary System Usage Charge Calc						
Franchise Fees & Other		1,708,452	MWh	1.66	mills/kWh	$2,836
Cust Impact Offset		1,708,452	MWh	0.20	mills/kWh	$342
System Usage Charge		1,708,452	MWh	1.86	mills/kWh	$3,178
Subtransmission System Usage Charge Calc						
Franchise Fees & Other		1,358,222	MWh	1.58	mills/kWh	$2,146
Cust Impact Offset		1,358,222	MWh	0.20	mills/kWh	$272
System Usage Charge		1,358,222	MWh	1.78	mills/kWh	$2,418
Secondary Energy Charge						
On-peak		15,074	MWh	58.68	mills/kWh	$885
Off-peak		10,465	MWh	49.73	mills/kWh	$520
Primary Energy Charge						
On-peak		964,254	MWh	56.58	mills/kWh	$54,558
Off-peak		674,198	MWh	47.91	mills/kWh	$32,301
Subtransmission Energy Charge						
On-peak		776,395	MWh	55.81	mills/kWh	$43,331
Off-peak		581,827	MWh	47.18	mills/kWh	$27,451
Reactive Demand Charge		684,888	kVar	$0.50	kVar	$342
Subtotal						$180,754
					w/o CIO	$180,135
Total Schedule 89 Allocations	$281,027			Schedule 89 Revenues w/o CIO		$281,053

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2007

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 91						
Street & Highway Lighting						
Theoretic						
Functional Costs						
Basic Charge	$1,601	206	Customers	$647.75	per cust, per mo.	$1,601
Trans. & Rel. Serv. Charge	$107	97,806	MWh	1.09	mills/kWh	$107
Distribution Charge	$1,640	97,806	MWh	16.77	mills/kWh	$1,640
Franchise Fees & Other	$407	97,806	MWh	4.16	mills/kWh	$407
COS Energy Charge	$5,262	97,806	MWh	53.80	mills/kWh	$5,262
Fixed Charges	$8,283					$8,283
Subtotal	$17,300					$17,300
Proposal						
Functional Costs						
Trans. & Rel. Serv. Charge		97,806	MWh	1.09	mills/kWh	$107
Distribution Charge		97,806	MWh	33.14	mills/kWh	$3,241
System Usage Charge Calc						
Franchise Fees & Other		97,806	MWh	4.16	mills/kWh	$407
Cust Impact Offset		97,806	MWh	(9.27)	mills/kWh	($907)
System Usage Charge		97,806	MWh	(5.11)	mills/kWh	($500)
COS Energy Charge		97,806	MWh	53.80	mills/kWh	$5,262
Fixed Charges		97,806	MWh			$8,283
Subtotal						$16,393
					w/o CIO	$17,299
SCHEDULE 92						
Traffic Signals						
Theoretic						
Functional Costs						
Basic Charge	$30	14	Customers	$177.59	per cust, per mo.	$30
Trans. & Rel. Serv. Charge	$8	5,939	MWh	1.30	mills/kWh	$8
Distribution Charge	$83	5,939	MWh	14.04	mills/kWh	$83
Franchise Fees & Other	$12	5,939	MWh	1.97	mills/kWh	$12
COS Energy Charge	$325	5,939	MWh	54.80	mills/kWh	$325
Subtotal	$458					$458
Proposal						
Functional Costs						
Trans. & Rel. Serv. Charge		5,939	MWh	1.30	mills/kWh	$8
Distribution Charge		5,939	MWh	19.07	mills/kWh	$113
System Usage Charge Calc						
Franchise Fees & Other		5,939	MWh	1.97	mills/kWh	$12
Cust Impact Offset		5,939	MWh	(3.01)	mills/kWh	($18)
System Usage Charge		5,939	MWh	(1.04)	mills/kWh	($6)
COS Energy Charge		5,939	MWh	54.80	mills/kWh	$325
Subtotal						$440
					w/o CIO	$458
SCHEDULE 93						
Recreational Field Lighting						
Theoretic						
Functional Costs						
Basic Charge	$41	27	Customers	$125.48	per cust, per mo.	$41
Trans. & Rel. Serv. Charge	$1	565	MWh	2.20	mills/kWh	$1
Distribution Charge	$22	565	MWh	39.52	mills/kWh	$22
Franchise Fees & Other	$2	565	MWh	3.95	mills/kWh	$2
Energy Charge	$30	565	MWh	53.32	mills/kWh	$30
Subtotal	$97					$97
Proposal						
Functional Costs						
Basic Charge		27	Customers	$30.00	per cust, per mo.	$10
Trans. & Rel. Serv. Charge		565	MWh	2.20	mills/kWh	$1
Distribution Charge		565	MWh	94.26	mills/kWh	$53
System Usage Charge Calc						
Franchise Fees & Other		565	MWh	3.95	mills/kWh	$2
Cust Impact Offset		565	MWh	(12.25)		($7)
System Usage Charge		565	MWh	(8.30)	mills/kWh	($5)
Energy Charge		565	MWh	53.32	mills/kWh	$30
Subtotal						$90
					w/o CIO	$97

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at 2006 Prices ($000)	2007 Allocated Costs ($000)	Percent Change	Maximum Change	Impact Offset	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,524,421	$718,963	$759,707	5.7%	12.7%	$0	0	0.20	$1,505
Schedule 15	23,496	$4,196	$4,446	6.0%	12.7%	$0	0	0.20	$5
Schedule 32	1,503,045	$131,132	$142,112	8.4%	12.7%	$0	0	0.20	$301
Schedule 38	105,829	$9,057	$10,094	11.4%	12.7%	$0	0	0.00	$0
Schedule 47	22,922	$1,917	$3,007	56.9%	12.7%	($848)	22,922	(36.98)	($848)
Schedule 49	67,951	$4,341	$6,992	61.1%	12.7%	($2,102)	67,951	(30.93)	($2,102)
Schedule 83	5,701,441	$392,155	$417,802	6.5%	12.7%	$0	0	0.20	$1,140
Schedule 89	4,519,963	$268,403	$281,027	4.7%	12.7%	$0	0	0.20	$904
Schedule 91	97,806	$14,551	$17,300	18.9%	12.7%	($907)	97,806	(9.27)	($907)
Schedule 92	5,939	$391	$458	17.2%	12.7%	($18)	5,939	(3.01)	($18)
Schedule 93	565	$80	$97	21.4%	12.7%	($7)	565	(12.25)	($7)
COS TOTALS	19,573,378	$1,545,185	$1,643,042	6.3%	9.5%	($3,881)	195,183		
NON-COS Energy	84,259							0.20	$17
Total Cycle Energy	19,657,637								
TOTAL CIO REVENUES									($10)

Cap on Rate Change 2.0 times change from 2006 prices

PORTLAND GENERAL ELECTRIC
Schedule 102 Prices: October 2006-December 2007

Grouping	2006 Q4 Cycle MWH	2007 Cycle MWH	15-month Cycle MWH	15-month Monetary Benefit	Monetary Price
Schedule 7	1,859,607	7,524,421	9,384,027	(110,323,399)	(11.76)
All Other Schedules	145,955	631,868	777,823	(9,144,481)	(11.76)
Totals	2,005,561	8,156,289	10,161,850	(119,467,880)	(11.76)
			Target	($119,467,880)	

Schedule 7 Rate Design	MWH	Flat Rate	Flat Rate Revenues	Blocked Rates	Blocked Rate Revenues
Block 1	2,528,804	(11.76)	($29,729,905)	(22.94)	($58,010,762)
Block 2	6,855,223	(11.76)	($80,593,494)	(7.63)	($52,305,355)
	9,384,027		($110,323,399)		($110,316,117)
Flat Rate Multiplier			1.951		(15.31)

Current Schedule 7 Block Delta	2.81	
Desired Schedule 102 Delta	(15.31)	Schedule 102 Delta
Total Delta	(12.50)	

Interest for 15-month period	($1,373,544)
MWH	10,161,850
Interest included in prices (mills/kWh)	(0.14)

PORTLAND GENERAL ELECTRIC

Summary of Annual Transition Adjustments
Without Port Westward

Schedules	COS Tariff Energy Price mills/kWh	Market Value of Energy mills/kWh	Annual Transition Adjustment mills/kWh
Schedule 515	53.66	66.49	(12.83)
Schedule 532	56.05	69.46	(13.41)
Schedule 549	50.64	62.76	(12.12)
Schedule 83/583-S	55.44	68.70	(13.26)
Schedule 89/589-S			
On-peak	58.68	72.70	(14.02)
Off-peak	49.73	61.65	(11.92)
Schedule 83/583-P	53.44	66.22	(12.78)
Schedule 89/589-P			
On-peak	56.58	70.11	(13.53)
Off-peak	47.91	59.37	(11.46)
Schedule 89/589-T			
On-peak	55.81	69.15	(13.34)
Off-peak	47.18	58.47	(11.29)
Schedule 91/591	53.80	66.67	(12.87)
Schedule 592	54.80	67.90	(13.10)

Summary of Annual Transition Adjustments
With Port Westward

Schedules	COS Tariff Energy Price mills/kWh	Market Value of Energy mills/kWh	Annual Transition Adjustment mills/kWh
Schedule 515	55.70	66.49	(10.79)
Schedule 532	58.18	69.46	(11.28)
Schedule 549	52.56	62.76	(10.20)
Schedule 83/583-S	57.55	68.70	(11.15)
Schedule 89/589-S			
On-peak	60.80	72.70	(11.90)
Off-peak	51.85	61.65	(9.80)
Schedule 83/583-P	55.48	66.22	(10.74)
Schedule 89/589-P			
On-peak	58.60	70.11	(11.51)
Off-peak	49.93	59.37	(9.44)
Schedule 89/589-T			
On-peak	57.80	69.15	(11.35)
Off-peak	49.17	58.47	(9.30)
Schedule 91/591	55.84	66.67	(10.83)
Schedule 592	56.88	67.90	(11.02)

PORTLAND GENERAL ELECTRIC
2007 Test Period Functionalized Revenue Requirement

FUNCTION	AMOUNT	ADJUST	TOTAL
PRODUCTION	$1,086,044	$24	$1,086,068
TRANSMISSION	$28,616		$28,616
ANCILLARY	$5,421		$5,421
DISTRIBUTION	$423,837	$742	$424,579
METERING	$18,118		$18,118
BILLING	$33,095		$33,095
CONSUMER	$49,493		$49,493
TOTALS	$1,644,624		$1,645,389

Note: Distribution adjustment is employee discount
Note: Production adjustment is Schedule 129 Long-Term Transition Adjustment

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2007 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$218,754	$218,444
Net Variable Power Costs	$867,290	$866,059
Production Costs	$1,086,044	$1,084,503
Ancillary Services	$5,421	$5,413
Transmission	$28,616	$28,575
Distribution Services	$423,837	
Trojan Decommissioning	($38,484)	
Regulatory Assets	($4,646)	
Employee Discount	$742	
Distribution Costs	$381,449	$380,899
Consumer Services		
Metering Services	$18,118	$18,092
Billing Services	$33,095	$33,047
Other Consumer Services	$49,493	$49,422
Franchise Fees	$38,484	$38,429
Trojan Decommissioning	$4,646	$4,639
Schedule 129	$24	$24
Totals	$1,645,389	$1,643,042

Calendar MWH	19,686,004
Cycle MWH	19,657,637
Cycle/Cal Ratio	99.86%
COS Calendar Energy MWH	19,601,562
COS Cycle MWH	19,573,378
Cycle/Cal Ratio	99.86%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2007

Grouping	Marginal Power Costs ($000)	COS Calendar Energy	Marginal Unit Cost $/MWH	Allocation Percent	Allocated Production Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	$529,616	7,531,917	70.32	39.35%	$427,401	$426,976
Schedule 15	$1,563	23,509	66.50	0.12%	$1,262	$1,261
Schedule 32	$104,473	1,504,143	69.46	7.76%	$84,310	$84,249
Schedule 38						
On-peak	$5,224	71,092	73.48	0.39%	$4,216	$4,211
Off-peak	$2,173	34,860	62.34	0.16%	$1,754	$1,752
Schedule 47	$1,459	23,110	63.15	0.11%	$1,178	$1,168
Schedule 49	$4,253	67,770	62.76	0.32%	$3,432	$3,441
Schedule 83-S	$371,685	5,410,241	68.70	27.62%	$299,951	$299,543
Schedule 89-S 1-4 MW						
On-peak	$30,702	422,835	72.61	2.28%	$24,777	$24,733
Off-peak	$13,567	220,242	61.60	1.01%	$10,949	$10,929
Schedule 89-S GT 4 MW						
On-peak	$1,142	15,174	75.26	0.08%	$922	$916
Off-peak	$659	10,530	62.62	0.05%	$532	$529
Schedule 83-P	$19,797	298,952	66.22	1.47%	$15,976	$15,956
Schedule 89-P 1-4 MW						
On-peak	$37,175	529,177	70.25	2.76%	$30,000	$29,959
Off-peak	$19,529	327,814	59.57	1.45%	$15,760	$15,738
Schedule 89-P GT 4 MW						
On-peak	$67,628	965,719	70.03	5.03%	$54,576	$54,495
Off-peak	$40,022	675,187	59.28	2.97%	$32,298	$32,250
Schedule 89-T						
On-peak	$53,987	780,717	69.15	4.01%	$43,568	$43,340
Off-peak	$34,183	584,632	58.47	2.54%	$27,585	$27,441
Schedule 91	$6,496	97,437	66.67	0.48%	$5,243	$5,262
Schedule 92	$403	5,939	67.90	0.03%	$325	$325
Schedule 93	$37	565	66.08	0.00%	$30	$30
TOTAL	$1,345,774	19,601,562	68.66	100.00%	$1,086,044	$1,084,503
				TARGET	$1,086,044	

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
POWER PRICES (mills per kWh)[1]													
PGE Curve 15													
On-Peak	78.46	77.44	71.84	58.34	40.51	39.49	64.20	75.41	73.88	62.92	73.37	75.66	65.96
Off-Peak	70.06	68.02	59.36	50.19	31.84	28.79	50.19	62.92	61.39	54.01	61.14	68.53	55.54
Flat	74.75	73.41	66.60	54.72	36.68	34.97	57.72	70.17	68.05	59.18	67.94	72.36	61.38
Wheeling	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36
Market Prices													
On-Peak	80.82	79.80	74.20	60.70	42.87	41.85	66.56	77.77	76.24	65.28	75.73	78.02	68.32
Off-Peak	72.42	70.38	61.72	52.55	34.20	31.15	52.55	65.28	63.75	56.37	63.50	70.89	57.90
Flat	77.11	75.77	68.96	57.08	39.04	37.33	60.08	72.53	70.41	61.54	70.30	74.72	63.74
GROUPING													
SCH 7 - Residential													
Total Energy (MWh)													
On-Peak	558,007	432,027	427,840	361,424	328,185	324,916	362,147	361,145	324,864	337,928	431,297	542,989	4,792,769
Off-Peak	310,531	278,590	234,329	205,457	197,349	181,055	191,457	213,559	178,456	207,488	245,025	295,850	2,739,148
Total	868,538	710,617	662,170	566,881	525,534	505,971	553,604	574,704	503,320	545,416	676,322	838,840	7,531,917
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$47,930	$36,641	$33,739	$23,316	$14,953	$14,452	$25,618	$29,850	$26,323	$23,445	$34,713	$45,024	$356,006
Off-Peak	$23,901	$20,839	$15,371	$11,475	$7,173	$5,994	$10,693	$14,817	$12,091	$12,431	$16,536	$22,290	$173,610
Total	$71,831	$57,479	$49,110	$34,791	$22,126	$20,446	$36,311	$44,667	$38,414	$35,876	$51,250	$67,314	$529,616
SCH 15 - Outdoor Area Lighting													
Residential Portion													
Energy (MWh)													
On-Peak	279	200	154	84	51	29	34	61	124	199	243	292	1,750
Off-Peak	439	424	434	407	380	355	375	420	413	439	440	438	4,963
Total	717	624	588	490	431	384	409	481	537	638	683	729	6,713
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$24	$17	$12	$5	$2	$1	$2	$5	$10	$14	$20	$24	$137
Off-Peak	$34	$32	$28	$23	$14	$12	$21	$29	$28	$26	$30	$33	$309
Total	$58	$49	$41	$28	$16	$13	$23	$34	$38	$40	$49	$57	$446

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
Commercial Portion													
Energy (MWh)													
On-Peak	692	498	384	209	128	73	86	152	310	500	611	733	4,377
Off-Peak	1,089	1,055	1,081	1,015	950	887	939	1,054	1,038	1,104	1,105	1,101	12,418
Total	1,780	1,553	1,465	1,224	1,078	961	1,025	1,207	1,348	1,604	1,717	1,834	16,796
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$59	$42	$30	$14	$6	$3	$6	$13	$25	$35	$49	$61	$343
Off-Peak	$84	$79	$71	$57	$35	$29	$52	$73	$70	$66	$75	$83	$774
Total	$143	$121	$101	$70	$40	$33	$59	$86	$95	$101	$124	$144	$1,117
Schedules 15R & 15C													
Total Energy (MWh)													
On-Peak	970	699	538	293	179	103	120	213	434	699	854	1,025	6,127
Off-Peak	1,527	1,479	1,515	1,421	1,331	1,242	1,314	1,475	1,451	1,543	1,545	1,539	17,382
Total	2,498	2,178	2,053	1,714	1,510	1,345	1,434	1,688	1,885	2,242	2,399	2,563	23,509
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$83	$59	$42	$19	$8	$5	$8	$18	$35	$49	$69	$85	$480
Off-Peak	$118	$111	$99	$79	$48	$41	$73	$102	$98	$92	$104	$116	$1,083
Total	$201	$170	$142	$98	$57	$46	$82	$120	$133	$141	$173	$201	$1,563
SCH 32 - Gen Serv - < 30 kW													
Total Energy (MWh)													
On-Peak	90,658	78,052	86,071	79,139	77,632	81,030	90,673	87,735	81,177	81,804	82,476	92,037	1,008,484
Off-Peak	46,773	43,210	41,690	38,036	40,214	36,737	40,194	43,424	38,028	41,299	40,408	45,646	495,658
Total	137,432	121,262	127,761	117,174	117,846	117,767	130,867	131,159	119,206	123,103	122,884	137,682	1,504,143
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$7,787	$6,620	$6,787	$5,105	$3,537	$3,604	$6,414	$7,252	$6,578	$5,676	$6,638	$7,632	$73,630
Off-Peak	$3,600	$3,232	$2,735	$2,124	$1,462	$1,216	$2,245	$3,013	$2,577	$2,474	$2,727	$3,439	$30,843
Total	$11,387	$9,852	$9,522	$7,230	$4,999	$4,820	$8,659	$10,264	$9,154	$8,150	$9,365	$11,071	$104,473

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
SCH 38 - Opt TOD G.S. > 30 kW													
Total Energy (MWh)													
On-Peak	6,175	6,033	6,132	5,727	4,982	5,416	5,367	6,124	6,914	6,028	6,057	6,139	71,092
Off-Peak	3,268	3,290	2,710	2,670	2,799	2,638	2,557	3,135	3,184	2,799	2,759	3,050	34,860
Total	9,443	9,323	8,842	8,397	7,781	8,054	7,924	9,259	10,098	8,827	8,815	9,189	105,952
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$530	$512	$484	$369	$227	$241	$380	$506	$560	$418	$487	$509	$5,224
Off-Peak	$252	$246	$178	$149	$102	$87	$143	$218	$216	$168	$186	$230	$2,173
Total	$782	$758	$661	$519	$329	$328	$522	$724	$776	$586	$674	$739	$7,397
SCH 47 - Irrig. & Drain. Pump. - < 30 kW													
Total Energy (MWh)													
On-Peak	179	230	161	214	918	1,332	2,600	2,808	1,236	410	179	162	10,429
Off-Peak	101	139	107	233	1,062	1,661	3,928	3,735	1,161	346	111	97	12,681
Total	280	369	268	446	1,981	2,994	6,527	6,543	2,397	755	290	259	23,110
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$15	$20	$13	$14	$42	$59	$184	$232	$100	$28	$14	$13	$735
Off-Peak	$8	$10	$7	$13	$39	$55	$219	$259	$79	$21	$8	$7	$724
Total	$23	$30	$20	$27	$80	$114	$403	$491	$179	$49	$22	$21	$1,459
SCH 49 Irrig. & Drain. Pump. - > 30 kW													
Total Energy (MWh)													
On-Peak	327	510	516	734	2,558	4,370	7,256	8,203	3,968	1,293	482	326	30,542
Off-Peak	185	307	343	798	2,958	5,450	10,964	10,910	3,728	1,090	300	195	37,228
Total	512	816	860	1,532	5,516	9,819	18,220	19,113	7,696	2,383	782	521	67,770
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$28	$43	$41	$47	$117	$194	$513	$678	$322	$90	$39	$27	$2,139
Off-Peak	$14	$23	$23	$45	$108	$180	$612	$757	$253	$65	$20	$15	$2,114
Total	$42	$66	$63	$92	$224	$375	$1,126	$1,435	$574	$155	$59	$42	$4,253

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
Schedule 83-S													
Energy (MWh)													
On-Peak	282,321	265,345	293,467	272,044	286,227	289,159	312,104	307,559	286,571	302,399	286,149	298,820	3,482,164
Off-Peak	162,942	150,557	163,122	150,274	157,238	158,520	170,261	166,231	157,604	163,527	158,727	169,074	1,928,076
Total	445,262	415,902	456,589	422,319	443,465	447,678	482,365	473,790	444,175	465,926	444,876	467,894	5,410,241
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$24,250	$22,504	$23,143	$17,550	$13,041	$12,861	$22,078	$25,421	$23,220	$20,980	$23,031	$24,778	$252,858
Off-Peak	$12,541	$11,262	$10,700	$8,393	$5,715	$5,248	$9,509	$11,533	$10,678	$9,797	$10,712	$12,738	$118,827
Total	$36,791	$33,766	$33,843	$25,943	$18,756	$18,109	$31,587	$36,954	$33,898	$30,777	$33,743	$37,516	$371,685
Schedule 89-S 1,001-4,000 kW													
Energy (MWh)													
On-Peak	32,150	29,716	34,880	32,674	34,108	34,530	39,241	39,620	37,504	38,565	34,990	34,858	422,835
Off-Peak	17,523	16,328	18,385	17,116	17,743	17,835	19,603	19,767	19,251	19,411	18,160	19,121	220,242
Total	49,673	46,043	53,264	49,789	51,851	52,365	58,844	59,387	56,755	57,976	53,150	53,980	643,078
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$2,762	$2,520	$2,751	$2,108	$1,554	$1,536	$2,776	$3,275	$3,039	$2,676	$2,816	$2,890	$30,702
Off-Peak	$1,349	$1,221	$1,206	$956	$645	$590	$1,095	$1,371	$1,304	$1,163	$1,226	$1,441	$13,567
Total	$4,110	$3,742	$3,957	$3,064	$2,199	$2,126	$3,871	$4,646	$4,343	$3,839	$4,042	$4,331	$44,269
Schedule 89-S 4,000 plus kW													
Energy (MWh)													
On-Peak	253	256	290	299	317	703	3,235	4,100	2,934	1,786	713	290	15,174
Off-Peak	149	148	189	199	214	443	2,382	2,827	2,233	1,151	431	164	10,530
Total	402	403	479	498	531	1,146	5,617	6,926	5,167	2,936	1,144	454	25,704
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$22	$22	$23	$19	$14	$31	$229	$339	$238	$124	$57	$24	$1,142
Off-Peak	$12	$11	$12	$11	$8	$15	$133	$196	$151	$69	$29	$12	$659
Total	$33	$33	$35	$30	$22	$46	$362	$535	$389	$193	$86	$36	$1,801

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
Schedule 83-P 31-1,000 kW													
Energy (MWh)													
On-Peak	14,644	14,653	15,892	15,529	15,598	15,593	16,915	16,766	16,004	15,894	15,101	15,337	187,925
Off-Peak	9,068	8,910	9,466	9,095	9,029	9,145	9,875	9,584	9,580	9,114	8,859	9,302	111,027
Total	23,712	23,562	25,358	24,624	24,627	24,738	26,790	26,350	25,584	25,008	23,960	24,639	298,952
Loss Adjustment Factor:													
2.82%													
Power Costs ($000)													
On-Peak	$1,217	$1,202	$1,212	$969	$688	$671	$1,158	$1,341	$1,255	$1,067	$1,176	$1,230	$13,185
Off-Peak	$675	$645	$601	$491	$317	$293	$534	$643	$628	$528	$578	$678	$6,612
Total	$1,892	$1,847	$1,813	$1,461	$1,005	$964	$1,691	$1,984	$1,882	$1,595	$1,754	$1,908	$19,797
Schedule 89-P 1,001-4,000 kW													
Energy (MWh)													
On-Peak	41,045	40,112	44,696	42,455	43,465	43,293	48,573	48,065	48,029	44,438	42,576	42,430	529,177
Off-Peak	25,940	25,160	27,627	25,947	26,451	26,454	29,981	29,303	30,411	27,250	26,345	26,947	327,814
Total	66,985	65,272	72,323	68,403	69,916	69,747	78,553	77,368	78,440	71,687	68,921	69,377	856,991
Loss Adjustment Factor:													
2.82%													
Power Costs ($000)													
On-Peak	$3,411	$3,291	$3,410	$2,650	$1,916	$1,863	$3,324	$3,843	$3,765	$2,983	$3,315	$3,404	$37,175
Off-Peak	$1,932	$1,821	$1,753	$1,402	$930	$847	$1,620	$1,967	$1,993	$1,579	$1,720	$1,964	$19,529
Total	$5,342	$5,112	$5,163	$4,052	$2,846	$2,710	$4,944	$5,810	$5,758	$4,562	$5,035	$5,368	$56,703
Schedule 89-P 4,000 plus kW													
Energy (MWh)													
On-Peak	76,379	73,275	81,917	80,088	81,307	83,844	83,714	85,171	81,331	80,279	77,481	80,932	965,719
Off-Peak	54,836	52,468	56,894	55,848	56,972	59,585	57,656	58,935	56,088	54,911	55,004	55,990	675,187
Total	131,215	125,743	138,811	135,937	138,279	143,429	141,370	144,105	137,419	135,190	132,486	136,921	1,640,906
Loss Adjustment Factor:													
2.82%													
Power Costs ($000)													
On-Peak	$6,347	$6,012	$6,250	$4,998	$3,584	$3,608	$5,729	$6,811	$6,376	$5,388	$6,033	$6,492	$67,628
Off-Peak	$4,083	$3,797	$3,611	$3,018	$2,003	$1,908	$3,115	$3,956	$3,676	$3,183	$3,591	$4,081	$40,022
Total	$10,430	$9,809	$9,860	$8,016	$5,587	$5,516	$8,844	$10,766	$10,052	$8,571	$9,624	$10,573	$107,651

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
SCH 89-T G.S. Subtransmission													
Calendar Energy (MWh)													
On-Peak	69,407	59,940	65,012	66,281	66,072	63,763	66,974	62,901	63,692	67,180	63,705	65,789	780,717
Off-Peak	47,692	46,302	48,628	49,415	49,217	49,381	51,422	46,653	49,246	49,706	48,015	48,956	584,632
Total	117,099	106,242	113,640	115,697	115,289	113,144	118,395	109,554	112,938	116,886	111,721	114,745	1,365,349
Loss Adjustment Factor:													
1.31%													
Power Costs ($000)													
On-Peak	$5,683	$4,846	$4,887	$4,076	$2,870	$2,703	$4,516	$4,956	$4,920	$4,443	$4,888	$5,200	$53,987
Off-Peak	$3,499	$3,301	$3,041	$2,631	$1,705	$1,558	$2,738	$3,085	$3,181	$2,839	$3,089	$3,516	$34,183
Total	$9,182	$8,147	$7,928	$6,707	$4,575	$4,262	$7,254	$8,041	$8,100	$7,282	$7,977	$8,716	$88,170
SCH 91 - St & Highway Lighting													
Total Energy (MWh)													
On-Peak	4,063	2,909	2,233	1,202	726	411	486	876	1,787	2,924	3,598	4,343	25,557
Off-Peak	6,395	6,160	6,292	5,825	5,399	4,967	5,325	6,065	5,974	6,452	6,505	6,521	71,880
Total	10,459	9,069	8,525	7,027	6,125	5,378	5,810	6,941	7,761	9,376	10,103	10,864	97,437
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$349	$247	$176	$78	$33	$18	$34	$72	$145	$203	$290	$360	$2,005
Off-Peak	$492	$461	$413	$325	$196	$164	$297	$421	$405	$387	$439	$491	$4,492
Total	$841	$707	$589	$403	$229	$183	$332	$493	$550	$589	$729	$851	$6,496
SCH 92 - Traffic Signals													
Total Energy (MWh)													
On-Peak	287	283	282	286	282	282	277	278	290	275	289	281	3,394
Off-Peak	215	212	212	215	212	212	208	209	217	206	217	211	2,545
Total	502	496	494	501	494	494	486	487	507	482	506	492	5,939
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$25	$24	$22	$18	$13	$13	$20	$23	$23	$19	$23	$23	$247
Off-Peak	$17	$16	$14	$12	$8	$7	$12	$14	$15	$12	$15	$16	$157
Total	$41	$40	$36	$30	$21	$20	$31	$37	$38	$31	$38	$39	$403

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
SCH 93 - Rec Field Lighting													
Total Energy (MWh)													
On-Peak	15	15	21	24	32	49	33	30	58	56	25	16	374
Off-Peak	8	9	10	12	17	25	16	16	28	28	12	9	191
Total	24	23	31	36	49	73	50	47	86	85	37	25	565
Loss Adjustment Factor:													
6.28%													
Power Costs ($000)													
On-Peak	$1	$1	$2	$2	$1	$2	$2	$3	$5	$4	$2	$1	$26
Off-Peak	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$1	$1	$11
Total	$2	$2	$2	$2	$2	$3	$3	$4	$7	$6	$3	$2	$37
TOTAL													
Energy (MWh)													
On-Peak	1,176,881	1,004,054	1,059,947	958,414	942,588	948,792	1,039,715	1,031,592	956,792	981,957	1,045,972	1,185,775	12,332,480
Off-Peak	687,154	633,266	611,520	562,561	568,205	555,349	597,143	615,827	556,641	586,322	612,423	682,671	7,269,082
Total	1,864,034	1,637,320	1,671,467	1,520,975	1,510,793	1,504,141	1,636,858	1,647,419	1,513,433	1,568,279	1,658,396	1,868,446	19,601,562
Power Costs ($000)													
On-Peak	$100,441	$84,564	$82,982	$61,339	$42,597	$41,861	$72,984	$84,618	$76,902	$67,592	$83,592	$97,695	$897,168
Off-Peak	$52,492	$46,996	$39,763	$31,125	$20,460	$18,206	$33,039	$42,354	$37,346	$34,809	$40,981	$51,035	$448,607
Total	$152,933	$131,560	$122,745	$92,464	$63,057	$60,068	$106,023	$126,972	$114,248	$102,402	$124,573	$148,730	$1,345,774
Average Power Costs													
On-Peak	85.34	84.22	78.29	64.00	45.19	44.12	70.20	82.03	80.37	68.83	79.92	82.39	72.75
Off-Peak	76.39	74.21	65.02	55.33	36.01	32.78	55.33	68.78	67.09	59.37	66.92	74.76	61.71
Total	82.04	80.35	73.44	60.79	41.74	39.93	64.77	77.07	75.49	65.30	75.12	79.60	68.66

PORTLAND GENERAL ELECTRIC
MARGINAL POWER SUPPLY COST CALCULATION
BY RATE SCHEDULE: COS LOADS
2007

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	12 Month Avg/Total
Energy (MWh)													
Residential													Avg/Total
On-Peak	558,285	432,227	427,994	361,508	328,236	324,946	362,181	361,206	324,987	338,127	431,540	543,281	4,794,519
Off-Peak	310,970	279,014	234,763	205,863	197,730	181,410	191,832	213,979	178,870	207,927	245,464	296,288	2,744,111
													7,538,630
Small Non-residential													
On-Peak	91,529	78,780	86,615	79,562	78,679	82,436	93,359	90,695	82,724	82,714	83,266	92,932	1,023,290
Off-Peak	47,963	44,403	42,879	39,283	42,226	39,286	45,061	48,213	40,227	42,748	41,624	46,844	520,758
													1,544,048
Large non-residential													
On-Peak	527,066	493,047	545,338	517,344	535,674	541,411	584,175	579,691	549,082	561,116	531,166	549,562	6,514,671
Off-Peak	328,221	309,848	333,878	317,415	328,249	334,654	360,250	353,635	337,544	335,646	325,335	339,539	4,004,213
													10,518,884
												Totals	19,601,562
Market Value of Power ($000)													
Residential	$71,889	$57,528	$49,151	$34,819	$22,142	$20,459	$36,335	$44,701	$38,452	$35,916	$51,299	$67,372	$530,062
Small Non-residential	$11,554	$10,003	$9,643	$7,327	$5,120	$4,967	$9,121	$10,841	$9,428	$8,300	$9,511	$11,235	$107,049
Large non-residential	$69,490	$64,029	$63,951	$50,318	$35,796	$34,642	$60,568	$71,430	$66,368	$58,186	$63,764	$70,123	$708,663
Total	$152,933	$131,560	$122,745	$92,464	$63,057	$60,068	$106,023	$126,972	$114,248	$102,402	$124,573	$148,730	$1,345,774

[1] Forward curve prices of 2/23/2006

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2007

Grouping	12 CP (kW)	Percent Contribution	Allocated Revenue Requirement
Schedule 7	1,460,625	44.60%	$12,745
Schedule 15	1,892	0.06%	$17
Schedule 32	319,942	9.77%	$2,792
Schedule 38	7,075	0.22%	$62
Schedule 47	4,075	0.12%	$36
Schedule 49	12,025	0.37%	$105
Schedule 83	887,779	27.11%	$7,746
Schedule 89 1-4 MW	225,195	6.88%	$1,965
Schedule 89 GT 4 MW	346,167	10.57%	$3,020
Schedule 91	9,242	0.28%	$81
Schedule 92	700	0.02%	$6
Schedule 93	125	0.00%	$1
Target	3,274,842	100.00%	$28,575

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE COSTS
2007

Grouping	Production Allocation Percent	Allocated Costs ($000)
Schedule 7	39.35%	$2,130
Schedule 15	0.12%	$6
Schedule 32	7.76%	$420
Schedule 38	0.55%	$30
Schedule 47	0.11%	$6
Schedule 49	0.32%	$17
Schedule 83-S	27.62%	$1,495
Schedule 89-S 1-4 MW	3.29%	$178
Schedule 89-S GT 4 MW	0.13%	$7
Schedule 83-P	1.47%	$80
Schedule 89-P 1-4 MW	4.21%	$228
Schedule 89-P GT 4 MW	8.00%	$433
Schedule 89-T	6.55%	$355
Schedule 91	0.48%	$26
Schedule 92	0.03%	$2
Schedule 93	0.00%	$0
TOTAL	100.00%	$5,413
	TARGET	$5,413

PORTLAND GENERAL ELECTRIC
STATE OF OREGON
Applicable 2007 Ancillary Services Charges

Line	Ancillary Service	Billing Determinant	OATT Price	Total
	SCHEDULE 1 - SCHEDULING, SYSTEM CONTROL and DISPATCH		$/MW year	
1	12 CP MW Average	3,275	$149.89	$490,860
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	3,274,800	$0.461	$1,509,683
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW Charge: $6.695 per kW per month x .013	39,297,600	$0.09	$3,420,267
4		**ANCILLARY SERVICES TOTAL**		$5,420,809

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2007

Grouping	Cycle Energy (MWh)	Line Losses	Busbar Energy	Allocation Percent	Costs ($000)
Schedule 7	7,524,421	8.34%	8,151,958	38.58%	$1,790
Schedule 15	23,496	8.34%	25,456	0.12%	$6
Schedule 32	1,503,045	8.34%	1,628,399	7.71%	$358
Schedule 38	105,829	8.34%	114,655	0.54%	$25
Schedule 47	22,922	8.34%	24,833	0.12%	$5
Schedule 49	67,951	8.34%	73,619	0.35%	$16
Schedule 83-S	5,404,793	8.34%	5,855,553	27.71%	$1,286
Schedule 89-S 1-4 MW	654,274	8.34%	708,841	3.35%	$156
Schedule 89-S GT 4 MW	25,540	8.34%	27,670	0.13%	$6
Schedule 83-P	298,570	4.88%	313,140	1.48%	$69
Schedule 89-P 1-4 MW	855,811	4.88%	897,575	4.25%	$197
Schedule 89-P GT 4 MW	1,708,452	4.88%	1,791,825	8.48%	$393
Schedule 89-T	1,358,222	3.37%	1,403,994	6.64%	$308
Schedule 91	97,806	8.34%	105,963	0.50%	$23
Schedule 92	5,939	8.34%	6,434	0.03%	$1
Schedule 93	565	8.34%	612	0.00%	$0
TOTAL	19,657,637		21,130,526		$4,639
				TARGET	$4,639

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2007

Grouping	2007 Proposed Revenues	Allocation Percent	Costs ($000)
Schedule 7	$761,182	46.33%	$17,805
Schedule 15	$4,451	0.27%	$104
Schedule 32	$142,417	8.67%	$3,331
Schedule 38	$10,093	0.61%	$236
Schedule 47	$2,159	0.13%	$51
Schedule 49	$4,891	0.30%	$114
Schedule 83-S	$398,212	24.24%	$9,315
Schedule 89-S 1-4 MW	$45,300	2.76%	$1,060
Schedule 89-S GT 4 MW	$1,761	0.11%	$41
Schedule 83-P	$20,692	1.26%	$484
Schedule 89-P 1-4 MW	$55,913	3.40%	$1,308
Schedule 89-P GT 4 MW	$100,316	6.11%	$2,346
Schedule 89-T	$78,566	4.78%	$1,838
Schedule 91	$16,393	1.00%	$383
Schedule 92	$440	0.03%	$10
Schedule 93	$90	0.01%	$2
TOTAL	$1,642,875	100.00%	$38,429
		TARGET	$38,429

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2007

Grouping	Cycle Energy	Percent	Allocations ($000)
Schedule 38	105,829	1.0%	$0.2
Schedule 49	67,951	0.6%	$0.2
Schedule 83-S	5,404,793	51.1%	$12.0
Schedule 89-S 1-4 MW	654,274	6.2%	$1.5
Schedule 89-S GT 4 MW	25,540	0.2%	$0.1
Schedule 83-P	298,570	2.8%	$0.7
Schedule 89-P 1-4 MW	855,811	8.1%	$1.9
Schedule 89-P GT 4 MW	1,708,452	16.1%	$3.8
Schedule 89-T	1,358,222	12.8%	$3.0
Schedule 91	97,806	0.9%	$0.2
Schedule 92	5,939	0.1%	$0.0
Schedule 93	565	0.0%	$0.0
TOTAL	10,583,753	100.00%	$23.502
		TARGET	$23.502

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2007

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	701,814	Customers	$12.22	$8,574	$9,061
		Three-Phase Customers	432	Customers	$50.63	$22	$23
FACILITIES	13 kV						
		Single-Phase Customers	2,102,444	kW, rateclass peak	$27.70	$58,243	$61,554
		Three-Phase Customers	1,293	kW, rateclass peak	$19.43	$25	$27
	Connect Costs						
		Single-Phase Customers	701,814	Customers	$107.80	$75,655	$79,955
		Three-Phase Customers	432	Customers	$213.32	$92	$97
DEMAND	Subtransmission		2,103,737	kW, rateclass peak	$13.88	$29,210	$30,870
	Substation		2,103,737	kW, rateclass peak	$14.43	$30,353	$32,078
SUBTOTAL						$202,174	$213,665
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,050	Lights	$7.97	$72	$76
FACILITIES	13 kV		1,746	kW, rateclass peak	$27.70	$48	$51
	Connect Costs (transformer only)		9,050	Lights	$1.53	$14	$15
DEMAND	Subtransmission		1,746	kW, rateclass peak	$13.88	$24	$26
	Substation		1,746	kW, rateclass peak	$14.43	$25	$27
FIXED	Luminaires & Poles						$671
SUBTOTAL						$184	$865
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,064	Lights	$7.97	$88	$93
FACILITIES	13 kV		4,392	kW, rateclass peak	$27.70	$122	$129
	Connect Costs (transformer only)		11,064	Lights	$1.53	$17	$18
DEMAND	Subtransmission		4,392	kW, rateclass peak	$13.88	$61	$64
	Substation		4,392	kW, rateclass peak	$14.43	$63	$67
FIXED	Luminaires & Poles						$1,679
SUBTOTAL						$351	$2,050
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$169
FACILITIES	13 kV						$180
	Connect Costs (transformer only)						$33
DEMAND	Subtransmission						$90
	Substation						$94
FIXED	Luminaires & Poles						$2,351
SUBTOTAL							$2,916

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2007

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	52,017	Customers	$13.82	$719	$759
		Three-Phase Customers	29,564	Customers	$63.00	$1,863	$1,968
FACILITIES	13 kV						
		Single-Phase Customers	171,757	kW, rateclass peak	$27.70	$4,758	$5,029
		Three-Phase Customers	225,096	kW, rateclass peak	$19.43	$4,373	$4,622
	Connect Costs						
		Single-Phase Customers	52,017	Customers	$128.73	$6,696	$7,077
		Three-Phase Customers	29,564	Customers	$299.44	$8,853	$9,356
DEMAND	Subtransmission		396,854	kW, rateclass peak	$13.88	$5,510	$5,823
	Substation		396,854	kW, rateclass peak	$14.43	$5,726	$6,051
SUBTOTAL						$38,497	$40,685
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	137	Customers	$93.12	$13	$13
		Three-Phase Customers	1,118	Customers	$126.87	$142	$150
FACILITIES	13 kV						
		Single-Phase Customers	3,233	kW, rateclass peak	$27.70	$90	$95
		Three-Phase Customers	48,388	kW, rateclass peak	$19.43	$940	$994
	Connect Costs						
		Single-Phase Customers	137	Customers	$317.59	$44	$46
		Three-Phase Customers	1,118	Customers	$630.47	$705	$745
DEMAND	Subtransmission		51,621	kW, rateclass peak	$13.88	$717	$757
	Substation		51,621	kW, rateclass peak	$14.43	$745	$787
SUBTOTAL						$3,394	$3,587
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	200	Customers	$44.06	$9	$9
		Three-Phase Customers	2,890	Customers	$51.83	$150	$158
FACILITIES	13 kV						
		Single-Phase Customers	120	kW, rateclass peak	$27.70	$3	$4
		Three-Phase Customers	16,788	kW, rateclass peak	$19.43	$326	$345
	Connect Costs						
		Single-Phase Customers	200	Customers	$61.53	$12	$13
		Three-Phase Customers	2,890	Customers	$103.96	$300	$318
DEMAND	Subtransmission		16,909	kW, rateclass peak	$13.88	$235	$248
	Substation		16,909	kW, rateclass peak	$14.43	$244	$258
SUBTOTAL						$1,280	$1,352

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2007

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 49 Irrigation & Drainage Service - > 30 kW						
CUSTOMER	Meters					
	Single-Phase Customers	8	Customers	$49.69	$0	$0
	Three-Phase Customers	1,402	Customers	$114.34	$160	$169
FACILITIES	13 kV					
	Single-Phase Customers	182	kW, rateclass peak	$27.70	$5	$5
	Three-Phase Customers	49,404	kW, rateclass peak	$19.43	$960	$1,014
	Connect Costs					
	Single-Phase Customers	8	Customers	$193.89	$2	$2
	Three-Phase Customers	1,402	Customers	$300.80	$422	$446
DEMAND	Subtransmission	49,586	kW, rateclass peak	$13.88	$688	$728
	Substation	49,586	kW, rateclass peak	$14.43	$715	$756
SUBTOTAL					$2,953	$3,121
Schedule 83 General Service (31-1,000 kW)						
CUSTOMER	Meters					
	Single-Phase Customers	729	Customers	$94.75	$69	$73
	Three-Phase Customers	11,041	Customers	$125.24	$1,383	$1,461
	Primary Customers	143	Customers	$1,351.81	$193	$204
FACILITIES	13 kV					
	Single-Phase Customers	41,491	kW, rateclass peak	$27.70	$1,149	$1,215
	Three-Phase Customers	1,192,143	kW, rateclass peak	$19.43	$23,161	$24,477
	Secondary Connect Costs					
	Single-Phase Customers	729	Customers	$429.04	$313	$331
	Three-Phase Customers	11,041	Customers	$1,115.54	$12,316	$13,016
	Primary Conect Costs	143	Customers	$863.63	$123	$130
DEMAND	Subtransmission	1,233,634	kW, rateclass peak	$13.88	$17,129	$18,102
	Substation	1,233,634	kW, rateclass peak	$14.43	$17,799	$18,811
SUBTOTAL					$73,635	$77,820
Schedule 89 General Service (1,001-4,000 kW)						
CUSTOMER	Secondary Meters	100	Customers	$172.89	$17	$18
	Primary Meters	92	Customers	$1,351.81	$124	$131
FACILITIES	13 kV	275,523	kW, rateclass peak	$19.43	$5,353	$5,657
	Secondary Connect Costs	100	Customers	$4,526.14	$452	$478
	Primary Connect Costs	92	Customers	$863.63	$79	$84
DEMAND	Subtransmission	275,523	kW, rateclass peak	$13.88	$3,826	$4,043
	Substation	275,523	kW, rateclass peak	$14.43	$3,975	$4,201
SUBTOTAL					$13,826	$14,612

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2007

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 89 General Service (4,000 plus kW)						
CUSTOMER	Secondary Meters	2	Customers	$172.89	$0	$0
	Primary Meters	24	Customers	$1,351.81	$33	$35
	Substation Meters	9	Customers	$21,214.80	$191	$202
FACILITIES	13 kV (Sec. & Prim. Only)	26	Customers	$42,841.17	$1,125	$1,188
	Secondary Connect Costs	2	Customers	$20,823.37	$42	$44
	Primary Connect Costs	24	Customers	$3,068.13	$74	$79
	Subtransmission Connect Costs	9	Customers	$56,755.02	$511	$540
DEMAND	Subtransmission	419,792	kW, rateclass peak	$13.88	$5,829	$6,160
	Substation (Sec. & Prim. Only)	240,429	kW, rateclass peak	$14.43	$3,469	$3,666
SUBTOTAL					$11,273	$11,914
Schedule 91 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	137,997	Lights	$7.97	$1,100	$1,162
FACILITIES	13 kV	25,439	kW, rateclass peak	$27.70	$705	$745
	Connect Costs (transformer only)	137,997	Lights	$0.92	$127	$134
DEMAND	Subtransmission	25,439	kW, rateclass peak	$13.88	$353	$373
	Substation	25,439	kW, rateclass peak	$14.43	$367	$388
FIXED	Luminaires & Poles					**$8,283**
SUBTOTAL					$2,652	$11,085
Schedule 92 Traffic Signals						
FACILITIES	13 kV	735	kW, rateclass peak	$19.43	$14	$15
	Connect Costs	1,612	Intersections	$27.20	$44	$46
DEMAND	Subtransmission	735	kW, rateclass peak	$13.88	$10	$11
	Substation	735	kW, rateclass peak	$14.43	$11	$11
SUBTOTAL					$79	$83
Schedule 93 Stadium Lighting						
CUSTOMER	Meters	27	Customers	$1,305.56	$35	$37
FACILITIES	13 kV	358	kW, rateclass peak	$19.43	$7	$7
	Connect Costs	27	Customers	$148.99	$4	$4
DEMAND	Subtransmission	358	kW, rateclass peak	$13.88	$5	$5
	Substation	358	kW, rateclass peak	$14.43	$5	$5
SUBTOTAL					$56	$60

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2007

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Summary						
CUSTOMER	Meters	801,747	Customers		$13,696	$14,474
	Customer Service	158,111	Lights		$1,260	$1,332
FACILITIES	13 kV	4,160,532	kW, rateclass peak		$101,407	$107,171
	Connect Costs	801,605	Customers		$106,896	$112,972
DEMAND	Subtransmission	4,580,325	kW, rateclass peak		$63,596	$67,211
	Substation	4,400,962	kW rateclass Peak		$63,498	$67,107
FIXED	Luminaires & Poles					$10,633
TOTALS					$350,353	$380,899
					TARGET	$380,899
				EQUAL PERCENT		106%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2007

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Equal Percent Revenue Requirement
Schedule 7				
Single Phase	701,814	$13.70	$9,615	$15,837
Three Phase	432	$13.70	$6	$10
Schedule 15				
Residential	529	$0.00	$0	$0
Commercial	822	$0.00	$0	$0
Schedule 32				
Single Phase	52,017	$13.70	$713	$1,174
Three Phase	29,564	$13.70	$405	$667
Schedule 38				
Single Phase	137	$13.70	$2	$3
Three Phase	1,118	$13.70	$15	$25
Schedule 47				
Single Phase	200	$13.70	$3	$5
Three Phase	2,890	$13.70	$40	$65
Schedule 49				
Single Phase	8	$13.70	$0	$0
Three Phase	1,402	$13.70	$19	$32
Schedule 83				
Single Phase	729	$13.70	$10	$16
Three Phase	11,041	$13.70	$151	$249
Primary	143	$13.70	$2	$3
Schedule 89 1-4 MW				
Secondary	100	$13.70	$1	$2
Primary	92	$13.70	$1	$2
Schedule 89 GT 4 MW				
Secondary	2	$13.70	$0	$0
Primary	24	$13.70	$0	$1
Subtransmission	9	$13.70	$0	$0
Schedule 91	206	$0.00	$0	$0
Schedule 92	14	$0.00	$0	$0
Schedule 93	27	$13.70	$0	$1
TOTAL	803,318		$10,984	$18,092
			TARGET	$18,092
		EQUAL PERCENT		165%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2007

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Equal Percent Revenue Requirement
Schedule 7				
Single Phase	701,814	$26.17	$18,366	$29,102
Three Phase	432	$26.17	$11	$18
Schedule 15				
Residential	529	$26.31	$14	$22
Commercial	822	$23.36	$19	$30
Schedule 32				
Single Phase	52,017	$23.36	$1,215	$1,925
Three Phase	29,564	$23.36	$691	$1,094
Schedule 38				
Single Phase	137	$23.42	$3	$5
Three Phase	1,118	$23.42	$26	$41
Schedule 47				
Single Phase	200	$23.35	$5	$7
Three Phase	2,890	$23.35	$67	$107
Schedule 49				
Single Phase	8	$23.39	$0	$0
Three Phase	1,402	$23.39	$33	$52
Schedule 83				
Single Phase	729	$23.78	$17	$27
Three Phase	11,041	$23.78	$263	$416
Primary	143	$23.78	$3	$5
Schedule 89 1-4 MW				
Secondary	100	$30.45	$3	$5
Primary	92	$30.45	$3	$4
Schedule 89 GT 4 MW				
Secondary	2	$103.29	$0	$0
Primary	24	$103.29	$3	$4
Subtransmission	9	$103.29	$1	$1
Schedule 91	206	$506.99	$104	$165
Schedule 92	14	$506.95	$7	$11
Schedule 93	27	$23.36	$1	$1
TOTAL	803,318		$20,856	$33,047
			TARGET	$33,047
		EQUAL PERCENT		158%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2007

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Equal Percent Revenue Requirement
Schedule 7				
Single Phase	701,814	$51.72	$36,298	$39,605
Three Phase	432	$51.72	$22	$24
Schedule 15				
Residential	529	$51.72	$27	$30
Commercial	822	$60.85	$50	$55
Schedule 32				
Single Phase	52,017	$60.85	$3,165	$3,454
Three Phase	29,564	$60.85	$1,799	$1,963
Schedule 38				
Single Phase	137	$85.72	$12	$13
Three Phase	1,118	$85.72	$96	$105
Schedule 47				
Single Phase	200	$60.85	$12	$13
Three Phase	2,890	$60.85	$176	$192
Schedule 49				
Single Phase	8	$60.85	$0	$1
Three Phase	1,402	$60.85	$85	$93
Schedule 83				
Single Phase	729	$252.34	$184	$201
Three Phase	11,041	$252.34	$2,786	$3,040
Primary	143	$252.34	$36	$39
Schedule 89 1-4 MW				
Secondary	100	$1,216.96	$122	$133
Primary	92	$1,216.96	$112	$122
Schedule 89 GT 4 MW				
Secondary	2	$1,216.96	$2	$3
Primary	24	$1,216.96	$30	$32
Subtransmission	9	$1,216.96	$11	$12
Schedule 91	206	$1,216.96	$251	$274
Schedule 92	14	$1,216.96	$17	$19
Schedule 93	27	$60.85	$2	$2
TOTAL	803,318		$45,295	$49,422
			TARGET	$49,422
		EQUAL PERCENT		109%

TABLE 1
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
GROWTH AND RELIABILITY-RELATED SUBTRANSMISSION
INVESTMENTS ON A PER UNIT BASIS
2007 DOLLARS

LINE NO.	YEAR	TOTAL SUBTRANS INVESTMENT (2007 $)	GENERAL PLANT LOADINGS	TOTAL ANNUAL SUBTRANS INVESTMENT
		(A)	(B)	(C)
1	2003	$5,280,238	$493,702	$5,773,941
2	2004	$7,358,046	$687,977	$8,046,023
3	2005	$3,653,731	$341,624	$3,995,355
4	2006	$5,059,114	$473,027	$5,532,141
5	2007	$8,694,926	$812,976	$9,507,901

LINE NO.	TOTAL FIVE-YEAR INVESTMENTS	ECONOMIC CARRYING CHARGE	ANNUAL INCREMENTAL CAPITAL COST DOLLARS	DIVIDE BY GROWTH IN SYSTEM PEAK (1)	DEMAND-RELATED ANNUAL INCREMENTAL CAPITAL COST	
	(D)	(E)	(F) (D)*(E)	(G)	(H) (F)/(G)/1000	
6	$32,855,361	0.0922	$3,029,264	291	$10.42	PER KW

(1) PEAK IS NCP IN MW.

TABLE 2
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
GROWTH-RELATED SUBSTATION
INVESTMENTS ON A PER UNIT BASIS
2007 DOLLARS

LINE NO.	YEAR	TOTAL SUBSATATION INVESTMENT (2007 $)	GENERAL PLANT LOADINGS	TOTAL ANNUAL SUBTRANS INVESTMENT
		(A)	(B)	(C)
1	2003	$9,008,647	$842,308	$9,850,955
2	2004	$7,131,256	$666,772	$7,798,029
3	2005	$13,336,285	$1,246,943	$14,583,228
4	2006	$9,142,520	$854,826	$9,997,345
5	2007	$9,208,406	$860,986	$10,069,392

LINE NO.	TOTAL FIVE-YEAR INVESTMENTS	ECONOMIC CARRYING CHARGE	ANNUAL INCREMENTAL CAPITAL COST DOLLARS	DIVIDE BY GROWTH IN SYSTEM PEAK (1)	DEMAND-RELATED ANNUAL INCREMENTAL CAPITAL COST	
	(D)	(E)	(F) (D)*(E)	(G)	(H) (F)/(G)/1000	
6	$52,298,950	0.0878	$4,591,848	369	$12.45	PER KW

(1) PEAK IS NCP IN MW FOR CUSTOMERS AT PRIMARY AND SECONDARY DELIVERY VOLTAGE.

TABLE 3
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
MARGINAL COST OF DISTRIBUTION FEEDERS

FEEDER NAME	Shared Wire Costs	Three phase Tapline Costs	Single phase Tapline Costs	Feeder Demand	Three phase Demand	Single phase Demand	Shared Cost $/kW	Three phase Taplines $/kW	Single phase Taplines $/kW	Add: GP loader 3-phase $/kW	Add: GP loader Single phase $/kW	Annualized 3-phase $/kW	Annualized Single phase $/kW
1 BELL-FLAVEL	$394,794	$56,324	$327,007	12,014	4,628	7,385	$32.86	$12.17	$44.28	$49.24	$84.35	$4.57	$7.83
2 BOONS-WMBLY PK	$680,619	$8,687	$237,328	4,257	1,203	3,054	$159.90	$7.22	$77.72	$182.74	$259.84	$16.96	$24.11
3 MULTNOMAH 13KV	$696,760	$11,295	$579,727	10,015	1,071	8,944	$69.57	$10.55	$64.82	$87.62	$146.96	$8.13	$13.64
4 SELLWD-WAVERLY	$417,920	$99,244	$86,727	6,181	3,113	3,067	$67.62	$31.88	$28.27	$108.79	$104.86	$10.10	$9.73
5 CLAXTAR-HAYSVIL	$448,423	$54,041	$185,859	9,180	3,361	5,819	$48.85	$16.08	$31.94	$71.00	$88.34	$6.59	$8.20
6 KING CTY-HAZEL	$1,144,041	$216,513	$200,665	14,970	9,899	5,071	$76.42	$21.87	$39.57	$107.48	$126.84	$9.97	$11.77
7 ORENCO 13KV	$1,621,391	$66,640	$79,143	11,762	6,464	5,298	$137.85	$10.31	$14.94	$162.02	$167.08	$15.04	$15.51
8 TIGARD-13336	$363,382	$59,107	$66,897	9,092	6,257	2,835	$39.97	$9.45	$23.60	$54.03	$69.51	$5.01	$6.45
9 GLNDOVEER-13597	$401,190	$29,623	$177,943	6,549	2,611	3,937	$61.26	$11.34	$45.20	$79.40	$116.41	$7.37	$10.80
10 FAIRMT-MISSION	$1,850,765	$166,378	$954,611	9,011	3,053	5,958	$205.40	$54.50	$160.23	$284.21	$399.81	$26.37	$37.10
11 INDIAN-LABISH	$2,210,251	$465,917	$426,263	9,519	4,118	5,401	$232.20	$113.15	$78.92	$377.64	$340.20	$35.04	$31.57
12 MERIDIAN 13KV	$1,646,143	$40,662	$1,577,597	9,876	2,145	7,731	$166.69	$18.96	$204.07	$203.00	$405.43	$18.84	$37.62
13 WELCHES-ZIG ZAG	$1,924,155	$28,237	$1,136,018	5,385	1,125	4,260	$357.34	$25.10	$266.68	$418.21	$682.37	$38.81	$63.32
TOTALS	$13,799,834	$1,302,667	$6,035,786	117,807	49,048	68,760	$117.14	$26.56	$87.78	$157.13	$224.08	$14.58	$20.79

General Plant Loader:	9.35%
Carrying Charge	9.28%

DISTRIBUTION FEEDER COST PER CUSTOMER OF 4 MW CUSTOMERS

Distance from Substation 1000'	Feeder Cost per 1000'	Cost per Customer	Carrying Charge	Annualized Cost	Add: GP Loader
6.0	$52,981	$316,828	9.28%	$29,402	$32,151

Note: Distance includes redundant feeder for maintenance and reliability

TABLE 4
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
SUMMARY OF CONNECT COSTS

Grouping	Loaded Connect Costs (2005 Dollars) (1)	Inflation Rate (2)	Loaded Connect Costs (2007 Dollars)	General Plant Loadings	Loaded Connect Costs	Carrying Charge	Annualized Connect Costs
Schedule 7							
Single phase	$736.05	103.9%	$765.12	9.35%	$836.65	9.67%	$80.90
Three phase	LEA		$1,514.00	9.35%	$1,655.56	9.67%	$160.09
Schedule 15	$10.49	103.9%	$10.90	9.35%	$11.92	9.67%	$1.15
Schedule 32							
Single phase	$878.95	103.9%	$913.66	9.35%	$999.09	9.67%	$96.61
Three phase	$2,044.47	103.9%	$2,125.21	9.35%	$2,323.92	9.67%	$224.72
Schedule 38							
Single phase	LEA	103.9%	$2,253.99	9.35%	$2,464.73	9.67%	$238.34
Three phase	LEA	103.9%	$4,474.59	9.35%	$4,892.97	9.67%	$473.15
Schedule 47							
Single phase	LEA		$436.71	9.35%	$477.54	9.67%	$46.18
Three phase	LEA		$737.80	9.35%	$806.78	9.67%	$78.02
Schedule 49							
Single phase	LEA		$1,376.10	9.35%	$1,504.77	9.67%	$145.51
Three phase	LEA		$2,134.80	9.35%	$2,334.40	9.67%	$225.74
Schedule 83							
Single phase	$2,929.32	103.9%	$3,045.01	9.35%	$3,329.72	9.67%	$321.98
Three phase	$7,616.43	103.9%	$7,917.23	9.35%	$8,657.49	9.67%	$837.18
Schedule 89 1-4 MW	$30,902.50	103.9%	$32,122.96	9.35%	$35,126.46	9.67%	$3,396.73
Schedule 89 GT 4 MW	$142,172.96	103.9%	$147,787.92	9.35%	$161,606.09	9.67%	$15,627.31
Primary Voltage							
Schedule 83	$5,896.48	103.9%	$6,129.35	9.35%	$6,702.45	9.67%	$648.13
Schedule 89 1-4 MW	$5,896.48	103.9%	$6,129.35	9.35%	$6,702.45	9.67%	$648.13
Schedule 89 GT 4 MW	$20,947.84	103.9%	$21,775.15	9.35%	$23,811.13	9.67%	$2,302.54
Subtrans. Voltage	$387,499	103.9%	$402,802.48	9.35%	$440,464.52	9.67%	$42,592.92
Schedule 91	$6.31	103.9%	$6.56	9.35%	$7.17	9.67%	$0.69
Schedule 92	LEA		$193.05	9.35%	$211.10	9.67%	$20.41
Schedule 93	LEA		$1,057.36	9.35%	$1,156.22	9.67%	$111.81

Notes:
(1) From Job Estimate Sheets Service & Design Consultants
(2) GNP Deflator, Global Insight
(3) Schedules 15 and 91 figures are for shared transformer only

TABLE 5
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
CAPITAL COST OF INSTALLED METERS

Customer Schedule	Meter Type	Installed Cost (2007 $)	Customer Weighting	Weighted Average Meter Cost (2007 $)	General Plant Loading	Fully Loaded Meter Cost	Annual Carrying Charge	Annualized Cost
Residential								
Single phase	Form 2S, 200 amp, 240 volt	$52.18	100.00%	$52.18	1.0935	$57.06	17.95%	$10.24
Three phase	200 amp, self contained meter	$216.21	100.00%	$216.21	1.0935	$236.43	17.95%	$42.44
Schedule 32								
Single phase	Form 2S, 200 amp, 240 volt	$52.18	92.87%					
Single phase	Form 2S, 320 amp, 240 volt	$122.66	4.38%					
Single phase	Form 2S, 320 amp, 240 volt, kwh, kw	$188.15	2.75%	$59.01	1.0935	$64.52	17.95%	$11.58
Three phase	200 amp, self contained meter	$216.21	81.93%					
Three phase	Transformer Rated Meter	$508.66	18.07%	$269.06	1.0935	$294.22	17.95%	$52.81
Schedule 38								
Single phase	Self-contained Meter	$188.15	3.23%					
Single phase	Transformer Rated Meter	$404.61	96.77%	$397.63	1.0935	$434.81	17.95%	$78.05
Three phase	Self-contained Meter	$216.21	5.23%		1.0935			
Three phase	Transformer Rated Meter	$508.66	70.59%		1.0935			
Three phase	kWH & kW & kVAR	$706.16	22.22%		1.0935			
Three phase	kWH & kW & kVAR	$738.34	1.96%	$541.76	1.0935	$592.41	17.95%	$106.34
Schedule 47								
Single phase	Form 2S, 320 amp, 240 volt, kwh, kw	$188.15	100.00%	$188.15	1.0935	$205.74	17.95%	$36.93
Three phase	200 amp, self contained meter	$216.21	98.26%		1.0935			
Three phase	Transformer Rated Meter	$508.66	1.74%	$221.30	1.0935	$241.99	17.95%	$43.44
Schedule 49								
Single phase	Self-contained Meter	$188.15	88.89%		1.0935			
Single phase	Transformer Rated Meter	$404.61	11.11%	$212.20	1.0935	$232.04	17.95%	$41.65
Three phase	Self-contained Meter	$216.21	7.46%		1.0935			
Three phase	Transformer Rated Meter	$508.66	91.82%		1.0935			
Three phase	kWH & kW & kVAR	$706.16	0.72%	$488.25	1.0935	$533.91	17.95%	$95.84
Schedule 83	**Secondary Voltage**							
Single phase	Transformer Rated Meter	$404.61	100.00%	$404.61	1.0935	$442.44	17.95%	$79.42
Three phase	Transformer Rated Meter	$508.66	86.76%		1.0935			
Three phase	kWH & kW & kVAR	$706.16	13.24%	$534.81	1.0935	$584.82	17.95%	$104.98
Schedule 89 1-4 MW								
Three phase	kWH & kW & kVAR	$738.34	100.00%	$738.34	1.0935	$807.38	17.95%	$144.92
Schedule 89 GT 4 MW								
Three phase	kWH & kW & kVAR	$738.34	100.00%	$738.34	1.0935	$807.38	17.95%	$144.92
Primary Voltage								
Schedule 83 DL 1	kWH & kW & kVAR	$5,772.71	100.00%	$5,772.71	1.0935	$6,312.46	17.95%	$1,133.09
Schedule 83 DL 2	kWH & kW & kVAR	$5,772.71	100.00%	$5,772.71	1.0935	$6,312.46	17.95%	$1,133.09
Schedule 83 DL 3	kWH & kW & kVAR	$5,772.71	100.00%	$5,772.71	1.0935	$6,312.46	17.95%	$1,133.09
Subtrans. Voltage	kWH & kW & kVAR	$90,595.05	100.00%	$90,595.05	1.0935	$99,065.69	17.95%	$17,782.29
Schedule 93								
Three phase	kWH & kW & kVAR	$5,575.21	100.00%	$5,575.21	1.0935	$6,096.49	17.95%	$1,094.32

TABLE 6
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
ALLOCATION OF DISTRIBUTION O&M

Allocation of Substation O&M

Schedule	Marginal Capital Cost $/kW	Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost $/kW
Schedule 7	$12.45	2,103,737	$26,191,520	$4,161,459	$14.43
Schedule 15	$12.45	6,138	$76,415	$12,141	$14.43
Schedule 32	$12.45	396,854	$4,940,827	$785,027	$14.43
Schedule 38	$12.45	51,621	$642,678	$102,112	$14.43
Schedule 47	$12.45	16,909	$210,513	$33,448	$14.43
Schedule 49	$12.45	49,586	$617,340	$98,086	$14.43
Schedule 83	$12.45	1,233,634	$15,358,744	$2,440,285	$14.43
Schedule 89 1-4 MW	$12.45	275,523	$3,430,260	$545,019	$14.43
Schedule 89 GT 4 MW	$12.45	240,429	$2,993,345	$475,600	$14.43
Schedule 91	$12.45	25,439	$316,720	$50,322	$14.43
Schedule 92	$12.45	735	$9,145	$1,453	$14.43
Schedule 93	$12.45	358	$4,462	$709	$14.43
Totals		4,400,961	$54,791,967	$8,705,661	
FERC Accounts 582 & 592 Test Period O&M			$5,939,188		
A&G Loader			1.4658		
Loaded O&M			$8,705,661		

Allocation of Meters O&M

Schedule	Marginal Capital Cost	Average Customers	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$10.24	701,814	$7,186,577	$1,387,223	$12.22
Three-phase	$42.44	432	$18,316	$3,536	$50.63
Schedule 32					
Single-phase	$11.58	52,017	$602,359	$116,273	$13.82
Three-phase	$52.81	29,564	$1,561,257	$301,369	$63.00
Schedule 38					
Single-phase	$78.05	137	$10,693	$2,064	$93.12
Three-phase	$106.34	1,118	$118,835	$22,939	$126.87
Schedule 47					
Single-phase	$36.93	200	$7,386	$1,426	$44.06
Three-phase	$43.44	2,890	$125,542	$24,233	$51.83
Schedule 49					
Single-phase	$41.65	8	$333	$64	$49.69
Three-phase	$95.84	1,402	$134,368	$25,937	$114.34
Schedule 83 S					
Single-phase	$79.42	729	$57,904	$11,177	$94.75
Three-phase	$104.98	11,041	$1,159,058	$223,733	$125.24
Schedule 89 1-4 MW	$144.92	192	$27,776	$5,362	$172.89
Schedule 89 GT 4 MW	$144.92	2	$290	$56	$172.89
Schedule 83 P	$1,133.09	143	$161,465	$31,168	$1,351.81
Schedule 89 P 1-4 MW	$1,133.09	92	$103,961	$20,068	$1,351.81
Schedule 89 P GT 4 MW	$1,133.09	24	$27,477	$5,304	$1,351.81
Schedule 89 T	$17,782.29	9	$160,041	$30,893	$21,214.80
Schedule 93	$1,094.32	27	$29,547	$5,703	$1,305.56
Totals		801,839	$11,493,185	$2,218,526	
FERC Accounts 586 & 597 Test Period O&M			$1,513,526		
A&G Loader			1.4658		
Loaded O&M			$2,218,526		

TABLE 6
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
ALLOCATION OF DISTRIBUTION O&M

Allocation of Connect Costs O&M

Schedule	Marginal Capital Costs	Billing Determinant	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$80.90	701,814	$56,776,766	$18,878,209	$107.80
Three-phase	$160.09	432	$69,092	$22,973	$213.32
Schedule 15	$1.15	20,114	$23,131	$7,691	$1.53
Schedule 32					
Single-phase	$96.61	52,017	$5,025,378	$1,670,933	$128.73
Three-phase	$224.72	29,564	$6,643,547	$2,208,972	$299.44
Schedule 38					
Single-phase	$238.34	137	$32,653	$10,857	$317.59
Three-phase	$473.15	1,118	$528,745	$175,807	$630.47
Schedule 47					
Single-phase	$46.18	200	$9,236	$3,071	$61.53
Three-phase	$78.02	2,890	$225,478	$74,971	$103.96
Schedule 49					
Single-phase	$145.51	8	$1,164	$387	$193.89
Three-phase	$225.74	1,402	$316,487	$105,232	$300.80
Schedule 83 S					
Single-phase	$321.98	729	$234,750	$78,054	$429.04
Three-phase	$837.18	11,041	$9,243,095	$3,073,318	$1,115.54
Schedule 89 S 1-4 MW	$3,396.73	192	$651,040	$216,470	$4,526.14
Schedule 89 S GT 4 MW	$15,627.31	2	$31,255	$10,392	$20,823.37
Schedule 83 P	$648.13	143	$92,359	$30,709	$863.63
Schedule 89 P 1-4 MW	$648.13	92	$59,466	$19,772	$863.63
Schedule 89 P GT 4 MW	$2,302.54	24	$55,837	$18,566	$3,068.13
Schedule 89 T	$42,592.92	9	$383,336	$127,459	$56,755.02
Schedule 91	$0.69	137,997	$95,218	$31,660	$0.92
Schedule 92	$20.41	14	$286	$95	$27.20
Schedule 93	$111.81	27	$3,019	$1,004	$148.99
Totals			$80,501,338	$26,766,602	
Loaded Connect Cost O&M				$26,766,602	

TABLE 6
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
ALLOCATION OF DISTRIBUTION O&M

Allocation of 13 kV O&M

Schedule	Marginal 13 kV Cost	NCP/Customer Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$20.79	2,102,444	$43,709,803	$14,533,459	$27.70
Three-phase	$14.58	1,293	$18,851	$6,268	$19.43
Schedule 15	$20.79	6,138	$127,603	$42,428	$27.70
Schedule 32					
Single-phase	$20.79	171,757	$3,570,837	$1,187,299	$27.70
Three-phase	$14.58	225,096	$3,281,902	$1,091,229	$19.43
Schedule 38					
Single-phase	$20.79	3,233	$67,207	$22,346	$27.70
Three-phase	$14.58	48,388	$705,498	$234,577	$19.43
Schedule 47					
Single-phase	$20.79	120	$2,502	$832	$27.70
Three-phase	$14.58	16,788	$244,774	$81,387	$19.43
Schedule 49					
Single-phase	$20.79	182	$3,778	$1,256	$27.70
Three-phase	$14.58	49,404	$720,307	$239,501	$19.43
Schedule 83					
Single-phase	$20.79	41,491	$862,598	$286,813	$27.70
Three-phase	$14.58	1,192,143	$17,381,446	$5,779,311	$19.43
Schedule 89 1-4 MW	$14.58	275,523	$4,017,124	$1,335,689	$19.43
Schedule 89 GT 4 MW	$32,151	26	$843,964	$280,617	$42,841
Schedule 91	$20.79	25,439	$528,884	$175,853	$27.70
Schedule 92	$14.58	735	$10,709	$3,561	$19.43
Schedule 93	$14.58	358	$5,226	$1,738	$19.43
Totals			$76,103,011	$25,304,163	
Loaded 13 kV O&M				$25,304,163	

TABLE 6
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
ALLOCATION OF DISTRIBUTION O&M

Allocation of Subtransmission O&M

Schedule	Marginal Inv. Cost $/kW	Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost $/kW
Schedule 7	$10.42	2,103,737	$21,920,935	$7,288,686	$13.88
Schedule 15	$10.42	6,138	$63,955	$21,265	$13.88
Schedule 32	$10.42	396,854	$4,135,214	$1,374,954	$13.88
Schedule 38	$10.42	51,621	$537,888	$178,847	$13.88
Schedule 47	$10.42	16,909	$176,188	$58,582	$13.88
Schedule 49	$10.42	49,586	$516,681	$171,796	$13.88
Schedule 83	$10.42	1,233,634	$12,854,467	$4,274,095	$13.88
Schedule 89 1-4 MW	$10.42	275,523	$2,870,948	$954,587	$13.88
Schedule 89 GT 4 MW	$10.42	419,792	$4,374,236	$1,454,428	$13.88
Schedule 91	$10.42	25,439	$265,078	$88,138	$13.88
Schedule 92	$10.42	735	$7,654	$2,545	$13.88
Schedule 93	$10.42	358	$3,735	$1,242	$13.88
Totals		4,580,324	$47,726,978	$15,869,165	
Loaded Subtransmission O&M				$15,869,165	

O&M Allocations to Selected Categories

	Capital	O&M
Connect Costs	$80,501,338	$26,766,602
13 kV	$76,103,011	$25,304,163
Subtransmission	$47,726,978	$15,869,165
	$204,331,327	$67,939,930

FERC Accounts 583, 584, 587, 593, 594, 595 Test Period O&M	$46,350,068
A&G Loader	1.4658
Loaded O&M	$67,939,930

FERC Account	Direct O&M	Allocated	Total	Category
582 & 592	$4,069,528	$1,869,660	$5,939,188	Substations
586 & 597	$1,037,067	$476,459	$1,513,526	Meters
583, 584, 587, 593-595	$31,759,040	$14,591,028	$46,350,068	OH, UG, install
585 & 596	$3,086,178	$1,417,880	$4,504,058	Lighting & Signals
Subtotal	$39,951,813	$18,355,027	$58,306,840	

FERC Account	O&M	Category
580, 588, 590, 598	$18,355,027	Supervision & Misc.

TABLE 7
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
SUMMARY OF CONSUMER SERVICE MARGINAL COSTS

SCHEDULE	ANNUAL METER READING EXPENSES	ANNUAL BILLING EXPENSES	ANNUAL OTHER CONSUMER EXPENSES	TOTAL CONSUMER EXPENSES
Schedule 7 Residential	$13.70	$26.17	$51.72	$91.59
Schedule 15 Residential	$0.00	$26.31	$51.72	$78.03
Schedule 15 Commercial	$0.00	$23.36	$60.85	$84.21
Schedule 32 General Service	$13.70	$23.36	$60.85	$97.91
Schedule 38 TOU	$13.70	$23.42	$85.72	$122.84
Schedule 47 Irrigation	$13.70	$23.35	$60.85	$97.90
Schedule 49 Irrigation	$13.70	$23.39	$60.85	$97.94
Schedule 83 General Service	$13.70	$23.78	$252.34	$289.82
Schedule 89 1-4 MW	$13.70	$30.45	$1,216.96	$1,261.11
Schedule 89 GT 4 MW	$13.70	$103.29	$1,216.96	$1,333.95
Schedule 91 Streetlighting	$0.00	$506.99	$1,216.96	$1,723.95
Schedule 92 Traffic Signals	$0.00	$506.95	$1,216.96	$1,723.91
Schedule 93 Field Lighting	$13.70	$23.36	$60.85	$97.91

TABLE 8
PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS	SUBSTATION COSTS	13 KV COSTS	CONNECT COSTS	METER COSTS	END-USE CONSUMER COSTS
Schedule 7 Residential						
Single-phase	$13.88	$14.43	$27.70	$107.80	$12.22	$91.59
Three-phase	$13.88	$14.43	$19.43	$213.32	$50.63	$91.59
Schedule 15 Residential	$13.88	$14.43	$27.70	$1.53	N/A	$78.03
Schedule 15 Commercial	$13.88	$14.43	$27.70	$1.53	N/A	$84.21
Schedule 32 General Service						
Single-phase	$13.88	$14.43	$27.70	$128.73	$13.82	$97.91
Three-phase	$13.88	$14.43	$19.43	$299.44	$63.00	$97.91
Schedule 38 TOU						
Single-phase	$13.88	$14.43	$27.70	$317.59	$93.12	$122.84
Three-phase	$13.88	$14.43	$19.43	$630.47	$126.87	$122.84
Schedule 47 Irrigation						
Single-phase	$13.88	$14.43	$27.70	$61.53	$44.06	$97.90
Three-phase	$13.88	$14.43	$19.43	$103.96	$51.83	$97.90
Schedule 49 Irrigation						
Single-phase	$13.88	$14.43	$27.70	$193.89	$49.69	$97.94
Three-phase	$13.88	$14.43	$19.43	$300.80	$114.34	$97.94
Schedule 83 Secondary General Service						
Single-phase	$13.88	$14.43	$27.70	$429.04	$94.75	$289.82
Three-phase	$13.88	$14.43	$19.43	$1,115.54	$125.24	$289.82
Schedule 83 Primary General Service	$13.88	$14.43	$19.43	$863.63	$1,351.81	$289.82
Schedule 89 Secondary 1-4 MW	$13.88	$14.43	$19.43	$4,526.14	$172.89	$1,261.11
Schedule 89 Primary 1-4 MW	$13.88	$14.43	$19.43	$863.63	$1,351.81	$1,261.11
Schedule 89 Secondary GT 4 MW	$13.88	$14.43	$42,841	$20,823.37	$172.89	$1,333.95
Schedule 89 Primary GT 4 MW	$13.88	$14.43	$42,841	$3,068.13	$1,351.81	$1,333.95
Schedule 89 Subtransmission	$13.88	N/A	N/A	$56,755.02	$21,214.80	$1,333.95
Schedule 91 Streetlighting	$13.88	$14.43	$27.70	$0.92	N/A	$1,723.95
Schedule 92 Traffic Signals	$13.88	$14.43	$19.43	$27.20	N/A	$1,723.91
Schedule 93 Field Lighting	$13.88	$14.43	$19.43	$148.99	$1,305.56	$97.91

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Revenue Summary

				PROPOSED PRICES			2007				2007			
				Tariff Base Rates plus Energy			AVERAGE COUNTS				ESTIMATED ANNUAL STREETLIGHT REVENUES			
Description of Light	**Type**	**Watts**	**Category**	**OPTION-A**	**OPTION-B**	**OPTION-C**	**OPTION-A**	**OPTION-B**	**OPTION-C**	**TOTAL**	**OPTION-A**	**OPTION-B**	**OPTION-C**	**TOTAL**
Cobrahead - (Minimum of 2500 Power Doors)	HPS	100-watt	Standard	$ -	$ 6.80	$ 3.57	-	26,425	731	27,156	$ -	$ 2,156,732	$ 31,316	$ 2,188,048
Cobrahead - (Minimum of 2500 Power Doors)	HPS	150-watt	Standard	-	8.47	5.22	-	1,564	351	1,915	-	159,026	21,987	181,012
Cobrahead - (Minimum of 2500 Power Doors)	HPS	200-watt	Standard	-	9.93	6.63	-	5,088	160	5,248	-	606,093	12,730	618,822
Cobrahead - (Minimum of 2500 Power Doors)	HPS	250-watt	Standard	-	11.82	8.54	-	2,416	540	2,956	-	342,541	55,339	397,881
Cobrahead - (Minimum of 2500 Power Doors)	HPS	400-watt	Standard	-	16.97	13.68	-	1,958	60	2,018	-	398,631	9,850	408,481
Cobrahead - (Not applicable to PD rate)	HPS	100-watt	Standard	9.66	6.88	3.57	16,027	12,711	768	29,506	1,857,413	1,049,074	32,901	2,939,388
Cobrahead - (Not applicable to PD rate)	HPS	150-watt	Standard	11.34	8.55	5.22	878	6,474	899	8,251	119,473	664,196	56,313	839,983
Cobrahead - (Not applicable to PD rate)	HPS	200-watt	Standard	13.21	10.00	6.63	3,498	4,194	1,130	8,822	554,634	503,438	89,903	1,147,975
Cobrahead - (Not applicable to PD rate)	HPS	250-watt	Standard	15.17	11.91	8.54	591	2,321	951	3,863	107,608	331,805	97,458	536,871
Cobrahead - (Not applicable to PD rate)	HPS	400-watt	Standard	20.34	17.07	13.68	813	1,917	350	3,080	198,485	392,792	57,456	648,733
Flood	HPS	250-watt	Standard	15.46	11.93	8.54	69	3	2	74	12,805	430	205	13,440
Flood	HPS	400-watt	Standard	20.63	17.10	13.68	296	46	7	349	73,266	9,437	1,149	83,853
Early American Post-Top	HPS	100-watt	Standard	10.12	6.88	3.57	4,251	3,618	855	8,724	516,126	298,604	36,628	851,357
Shoebox	HPS	100-watt	Standard	10.56	6.95	3.57	2,008	4,613	2,154	8,775	254,551	384,948	92,277	731,776
Shoebox	HPS	150-watt	Standard	12.51	8.64	5.22	147	383	55	585	22,062	39,694	3,445	65,202
							28,578	**73,731**	**9,013**	**111,322**	**$ 3,716,424**	**$ 7,337,439**	**$ 598,958**	**$ 11,652,821**
Special Acorn	HPS	100-watt	Custom	$ 13.38	$ 7.19	$ 3.57	576	3,196	669	4,441	$ 92,509	$ 275,899	$ 28,660	$ 397,068
Special Architectural - Victorian	HPS	150-watt	Custom	14.73	8.83	5.22	3	416	73	492	530	44,094	4,573	49,197
Special Architectural - Victorian	HPS	200-watt	Custom	16.14	10.20	6.63	-	45	-	45	-	5,508	-	5,508
Special Architectural - Victorian	HPS	250-watt	Custom	18.20	12.17	8.54	61	720	-	781	13,326	105,190	-	118,516
Special Architectural - Techtra	HPS	250-watt	Custom	31.60	13.25	8.54	-	71	-	71	-	11,292	-	11,292
Special Architectural - KIM Archetype	HPS	250-watt	Custom	-	12.27	8.54	-	54	18	72	-	7,953	1,845	9,797
Special Architectural - KIM Archetype	HPS	400-watt	Custom	-	17.42	13.68	-	14	44	58	-	2,927	7,223	10,150
Special Types - Cobrahead	MH	175-watt	Custom	12.25	9.38	5.97	4	2	38	44	588	225	2,722	3,535
Special Types - Flood	MH	400-watt	Custom	19.99	16.59	13.10	11	-	-	11	2,639	-	-	2,639
Special Types - Flood	HPS	750-watt	Custom	33.51	28.56	23.96	26	24	-	50	10,457	8,227	-	18,683
Special Types - Mongoose	HPS	250-watt	Custom	17.04	12.16	8.54	2	-	-	2	409	-	-	409
Alternative Special Acorn - Victorian	QL	85-watt	Alternative	14.90	5.31	2.90	-	-	91	91	-	-	3,167	3,167
Alternative Special Acorn - Victorian	QL	165-watt	Alternative	18.93	7.52	5.06	-	155	-	155	-	13,983	-	13,983
Alternative Special Acorn - Techtra	QL	165-watt	Alternative	21.66	7.67	5.06	-	36	-	36	-	3,313	-	3,313
							683	**4,733**	**933**	**6,349**	**$ 120,458**	**$ 478,610**	**$ 48,189**	**$ 647,258**

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Revenue Summary

Description of Light	Type	Watts	Category		PROPOSED PRICES Tariff Base Rates plus Energy OPTION-A	OPTION-B	OPTION-C	2007 AVERAGE COUNTS OPTION-A	OPTION-B	OPTION-C	TOTAL	2007 ESTIMATED ANNUAL STREETLIGHT REVENUES OPTION-A	OPTION-B	OPTION-C	TOTAL
Cobrahead - Option C Only	MV	100-watt	Obsolete	(1)	$ -	$ -	$ 3.32	-	-	1	1	$ -	$ -	$ 40	$ 40
Cobrahead	MV	175-watt	Obsolete	(1)	11.74	8.73	5.56	1,995	1,918	113	4,026	280,960	200,838	7,539	489,338
Cobrahead	MV	250-watt	Obsolete	(1)	15.10	11.32	7.88	2	-	23	25	362	-	2,175	2,537
Cobrahead	MV	400-watt	Obsolete	(1)	18.68	15.68	12.36	521	147	82	750	116,779	27,657	12,162	156,598
Cobrahead	MV	1,000-watt	Obsolete	(1)	38.64	35.10	31.43	24	16	5	45	11,128	6,739	1,886	19,752
Special Box - Similar to Space-Glo	HPS	70-watt	Obsolete	(1)	12.48	5.88	2.57	24	88	23	135	3,594	6,207	709	10,510
Special Box - Similar to Space-Glo	MV	175-watt	Obsolete	(1)	15.73	8.87	5.56	20	191	47	258	3,775	20,325	3,136	27,235
Special Box - Similar to Gardco Hub / Opt C	HPS	70-watt	Obsolete	(1)	-	-	2.57	-	-	4	4	-	-	123	123
Special Box - Similar to Gardco Hub	HPS	100-watt	Obsolete	(1)	13.17	7.16	3.57	-	6	15	21	-	516	643	1,158
Special Box - Similar to Gardco Hub	HPS	150-watt	Obsolete	(1)	-	8.83	5.22	-	65	46	111	-	6,890	2,881	9,771
Special Box - Similar to Gardco Hub / Opt C	HPS	250-watt	Obsolete	(1)	-	-	8.54	-	-	160	160	-	-	16,397	16,397
Special Box - Similar to Gardco Hub / Opt C	HPS	400-watt	Obsolete	(1)	-	-	13.68	-	-	136	136	-	-	22,326	22,326
Special Box - Gardco Hub	MH	250-watt	Obsolete	(1)	-	12.11	8.37	-	7	34	41	-	1,018	3,415	4,433
Special Box - Gardco Hub	MH	400-watt	Obsolete	(1)	-	17.29	13.10	-	26	-	26	-	5,395	-	5,395
Dual Wattage 70/100 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	6.88	3.57	-	94	-	94	-	7,758	-	7,758
Dual Wattage 100/150 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	6.88	3.57	-	296	-	296	-	24,430	-	24,430
Dual Wattage 100/150 - Cobrahead	HPS	150-watt	Obsolete	(1)	-	8.55	5.22	-	299	5	304	-	30,676	313	30,989
Special Architectural - KIM SBC Shoebox	HPS	150-watt	Obsolete	(1)	-	9.17	5.22	-	36	55	91	-	3,962	3,445	7,407
Special Acorn Type	HPS	70-watt	Obsolete	(1)	12.23	5.88	2.57	27	7	30	64	3,962	494	925	5,381
Special GardCo Bronze - Option C Only	HPS	70-watt	Obsolete	(1)	-	-	2.57	-	-	42	42	-	-	1,295	1,295
Special GardCo Bronze - Option C Only	MV	175-watt	Obsolete	(1)	-	-	5.56	-	-	319	319	-	-	21,284	21,284
Special Acrylic Sphere - Option C Only	MV	400-watt	Obsolete	(1)	-	-	12.36	-	-	4	4	-	-	593	593
Early American Post-Top - Black	HPS	70-watt	Obsolete	(1)	8.54	5.89	2.57	1,678	1,666	41	3,385	171,934	117,726	1,264	290,924
Rectangular Types - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	6.63	-	-	129	129	-	-	10,263	10,263
Incandescent - Option C Only	IND	92-watt	Obsolete	(1)	-	-	2.65	-	-	25	25	-	-	795	795
Incandescent - Option C Only	IND	182-watt	Obsolete	(1)	-	-	5.22	-	-	7	7	-	-	438	438
Town and Country Post-Top	MV	175-watt	Obsolete	(1)	11.87	8.75	5.56	137	1,375	13	1,525	19,511	144,339	867	164,717
Flood	HPS	70-watt	Obsolete	(1)	9.18	5.93	2.57	10	-	7	17	1,102	-	216	1,318
Flood	HPS	100-watt	Obsolete	(1)	10.06	6.91	3.57	52	8	-	60	6,278	663	-	6,941
Flood	HPS	200-watt	Obsolete	(1)	13.55	10.02	6.63	205	49	-	254	33,345	5,895	-	39,240
Cobrahead - (Non-power door)	HPS	70-watt	Obsolete	(1)	8.56	5.88	2.57	1,780	1,021	1,074	3,875	182,793	72,014	33,122	287,929
Cobrahead - (power door)	HPS	310-watt	Obsolete	(1)	17.81	14.14	10.37	7	16	11	34	1,496	2,714	1,369	5,579
Ornamental - Option C Only	HPS	100-watt	Obsolete	(1)	-	-	3.57	-	-	1,180	1,180	-	-	50,551	50,551
Twin Ornamental - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	7.13	-	-	2,595	2,595	-	-	222,028	222,028
Flourescent - Opton C Only	FLR	28-watt	Obsolete	(1)	-	-	1.00	-	-	9	9	-	-	108	108
				(1) No new installations				**6,482**	**7,331**	**6,235**	**20,048**	**$ 837,017**	**$ 686,253**	**$ 422,311**	**$ 1,945,581**
			Standard					28,578	73,731	9,013	111,322	$ 3,716,424	$ 7,337,439	$ 598,958	$ 11,652,821
			Custom					683	4,733	933	6,349	$ 120,458	$ 478,610	$ 48,189	$ 647,258
			Obsolete					6,482	7,331	6,235	20,048	$ 837,017	$ 686,253	$ 422,311	$ 1,945,581
								35,743	**85,795**	**16,181**	**137,719**	**$ 4,673,899**	**$ 8,502,302**	**$ 1,069,458**	**$ 14,245,659**

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Fixed Charge Prices

				PROPOSED PRICES		
				Tariff Base Rates		
Description of Light	Type	Watts	Category	OPTION-A	OPTION-B	OPTION-C
Cobrahead - (Minimum of 2500 Power Doors)	HPS	100-watt	Standard	$ -	$ 3.23	$ -
Cobrahead - (Minimum of 2500 Power Doors)	HPS	150-watt	Standard	-	3.25	-
Cobrahead - (Minimum of 2500 Power Doors)	HPS	200-watt	Standard	-	3.30	-
Cobrahead - (Minimum of 2500 Power Doors)	HPS	250-watt	Standard	-	3.28	-
Cobrahead - (Minimum of 2500 Power Doors)	HPS	400-watt	Standard	-	3.29	-
Cobrahead - (Not applicable to PD rate)	HPS	100-watt	Standard	6.09	3.31	-
Cobrahead - (Not applicable to PD rate)	HPS	150-watt	Standard	6.12	3.33	-
Cobrahead - (Not applicable to PD rate)	HPS	200-watt	Standard	6.58	3.37	-
Cobrahead - (Not applicable to PD rate)	HPS	250-watt	Standard	6.63	3.37	-
Cobrahead - (Not applicable to PD rate)	HPS	400-watt	Standard	6.66	3.39	-
Flood	HPS	250-watt	Standard	6.92	3.39	-
Flood	HPS	400-watt	Standard	6.95	3.42	-
Early American Post-Top	HPS	100-watt	Standard	6.55	3.31	-
Shoebox	HPS	100-watt	Standard	6.99	3.38	-
Shoebox	HPS	150-watt	Standard	7.29	3.42	-
Special Acorn	HPS	100-watt	Custom	$ 9.81	$ 3.62	$ -
Special Architectural - Victorian	HPS	150-watt	Custom	9.51	3.61	-
Special Architectural - Victorian	HPS	200-watt	Custom	9.51	3.57	-
Special Architectural - Victorian	HPS	250-watt	Custom	9.66	3.63	-
Special Architectural - Techtra	HPS	250-watt	Custom	23.06	4.71	-
Special Architectural - KIM Archetype	HPS	250-watt	Custom	-	3.73	-
Special Architectural - KIM Archetype	HPS	400-watt	Custom	-	3.74	-
Special Types - Cobrahead	MH	175-watt	Custom	6.28	3.41	-
Special Types - Flood	MH	400-watt	Custom	6.89	3.49	-
Special Types - Flood	HPS	750-watt	Custom	9.55	4.60	-
Special Types - Mongoose	HPS	250-watt	Custom	8.50	3.62	-
Alternative Special Acorn - Victorian	QL	85-watt	Alternative	12.00	2.41	-
Alternative Special Acorn - Victorian	QL	165-watt	Alternative	13.87	2.46	-
Alternative Special Acorn - Techtra	QL	165-watt	Alternative	16.60	2.61	-

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Fixed Charge Prices

Description of Light	Type	Watts	Category		PROPOSED PRICES Tariff Base Rates OPTION-A	OPTION-B	OPTION-C
Cobrahead - Option C Only	MV	100-watt	Obsolete	(1)	$ -	$ -	$ -
Cobrahead	MV	175-watt	Obsolete	(1)	6.18	3.17	-
Cobrahead	MV	250-watt	Obsolete	(1)	7.22	3.44	-
Cobrahead	MV	400-watt	Obsolete	(1)	6.32	3.32	-
Cobrahead	MV	1,000-watt	Obsolete	(1)	7.21	3.67	-
Special Box - Similar to Space-Glo	HPS	70-watt	Obsolete	(1)	9.91	3.31	-
Special Box - Similar to Space-Glo	MV	175-watt	Obsolete	(1)	10.17	3.31	-
Special Box - Similar to Gardco Hub / Opt C	HPS	70-watt	Obsolete	(1)	-	-	-
Special Box - Similar to Gardco Hub	HPS	100-watt	Obsolete	(1)	-	3.59	-
Special Box - Similar to Gardco Hub	HPS	150-watt	Obsolete	(1)	-	3.61	-
Special Box - Similar to Gardco Hub / Opt C	HPS	250-watt	Obsolete	(1)	-	-	-
Special Box - Similar to Gardco Hub / Opt C	HPS	400-watt	Obsolete	(1)	-	-	-
Special Box - Gardco Hub	MH	250-watt	Obsolete	(1)	-	3.74	-
Special Box - Gardco Hub	MH	400-watt	Obsolete	(1)	-	4.19	-
Dual Wattage 70/100 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	3.31	-
Dual Wattage 100/150 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	3.31	-
Dual Wattage 100/150 - Cobrahead	HPS	150-watt	Obsolete	(1)	-	3.33	-
Special Architectural - KIM SBC Shoebox	HPS	150-watt	Obsolete	(1)	-	3.95	-
Special Acorn Type	HPS	70-watt	Obsolete	(1)	9.66	3.31	-
Special GardCo Bronze - Option C Only	HPS	70-watt	Obsolete	(1)	-	-	-
Special GardCo Bronze - Option C Only	MV	175-watt	Obsolete	(1)	-	-	-
Special Acrylic Sphere - Option C Only	MV	400-watt	Obsolete	(1)	-	-	-
Early American Post-Top - Black	HPS	70-watt	Obsolete	(1)	5.97	3.32	-
Rectangular Types - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	-
Incandescent - Option C Only	IND	92-watt	Obsolete	(1)	-	-	-
Incandescent - Option C Only	IND	182-watt	Obsolete	(1)	-	-	-
Town and Country Post-Top	MV	175-watt	Obsolete	(1)	6.31	3.19	-
Flood	HPS	70-watt	Obsolete	(1)	6.61	3.36	-
Flood	HPS	100-watt	Obsolete	(1)	6.49	3.34	-
Flood	HPS	200-watt	Obsolete	(1)	6.92	3.39	-
Cobrahead - (Non-power door)	HPS	70-watt	Obsolete	(1)	5.99	3.31	-
Cobrahead - (power door)	HPS	310-watt	Obsolete	(1)	7.44	3.77	-
Ornamental - Option C Only	HPS	100-watt	Obsolete	(1)	-	-	-
Twin Ornamental - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	-
Flourescent - Opton C Only	FLR	28-watt	Obsolete	(1)	-	-	-

(1) No new installations

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Energy Charge Prices

				PROPOSED PRICES		
				Tariff Energy Rates		
Description of Light	Type	Watts	Category	OPTION-A	OPTION-B	OPTION-C
Cobrahead - (Minimum of 2500 Power Doors)	HPS	100-watt	Standard	$ -	$ 3.57	$ 3.57
Cobrahead - (Minimum of 2500 Power Doors)	HPS	150-watt	Standard	-	5.22	5.22
Cobrahead - (Minimum of 2500 Power Doors)	HPS	200-watt	Standard	-	6.63	6.63
Cobrahead - (Minimum of 2500 Power Doors)	HPS	250-watt	Standard	-	8.54	8.54
Cobrahead - (Minimum of 2500 Power Doors)	HPS	400-watt	Standard	-	13.68	13.68
Cobrahead - (Not applicable to PD rate)	HPS	100-watt	Standard	3.57	3.57	3.57
Cobrahead - (Not applicable to PD rate)	HPS	150-watt	Standard	5.22	5.22	5.22
Cobrahead - (Not applicable to PD rate)	HPS	200-watt	Standard	6.63	6.63	6.63
Cobrahead - (Not applicable to PD rate)	HPS	250-watt	Standard	8.54	8.54	8.54
Cobrahead - (Not applicable to PD rate)	HPS	400-watt	Standard	13.68	13.68	13.68
Flood	HPS	250-watt	Standard	8.54	8.54	8.54
Flood	HPS	400-watt	Standard	13.68	13.68	13.68
Early American Post-Top	HPS	100-watt	Standard	3.57	3.57	3.57
Shoebox	HPS	100-watt	Standard	3.57	3.57	3.57
Shoebox	HPS	150-watt	Standard	5.22	5.22	5.22
Special Acorn	HPS	100-watt	Custom	$ 3.57	$ 3.57	$ 3.57
Special Architectural - Victorian	HPS	150-watt	Custom	5.22	5.22	5.22
Special Architectural - Victorian	HPS	200-watt	Custom	6.63	6.63	6.63
Special Architectural - Victorian	HPS	250-watt	Custom	8.54	8.54	8.54
Special Architectural - Techtra	HPS	250-watt	Custom	8.54	8.54	8.54
Special Architectural - KIM Archetype	HPS	250-watt	Custom	8.54	8.54	8.54
Special Architectural - KIM Archetype	HPS	400-watt	Custom	-	13.68	13.68
Special Types - Cobrahead	MH	175-watt	Custom	5.97	5.97	5.97
Special Types - Flood	MH	400-watt	Custom	13.10	13.10	13.10
Special Types - Flood	HPS	750-watt	Custom	23.96	23.96	23.96
Special Types - Mongoose	HPS	250-watt	Custom	8.54	8.54	8.54
Alternative Special Acorn - Victorian	QL	85-watt	Alternative	2.90	2.90	2.90
Alternative Special Acorn - Victorian	QL	165-watt	Alternative	5.06	5.06	5.06
Alternative Special Acorn - Techtra	QL	165-watt	Alternative	5.06	5.06	5.06

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Energy Charge Prices

Description of Light	Type	Watts	Category		PROPOSED PRICES Tariff Energy Rates OPTION-A	OPTION-B	OPTION-C
Cobrahead - Option C Only	MV	100-watt	Obsolete	(1)	-	-	$ 3.32
Cobrahead	MV	175-watt	Obsolete	(1)	5.56	5.56	5.56
Cobrahead	MV	250-watt	Obsolete	(1)	7.88	7.88	7.88
Cobrahead	MV	400-watt	Obsolete	(1)	12.36	12.36	12.36
Cobrahead	MV	1,000-watt	Obsolete	(1)	31.43	31.43	31.43
Special Box - Similar to Space-Glo	HPS	70-watt	Obsolete	(1)	2.57	2.57	2.57
Special Box - Similar to Space-Glo	MV	175-watt	Obsolete	(1)	5.56	5.56	5.56
Special Box - Similar to Gardco Hub / Opt C	HPS	70-watt	Obsolete	(1)	-	2.57	2.57
Special Box - Similar to Gardco Hub	HPS	100-watt	Obsolete	(1)	-	3.57	3.57
Special Box - Similar to Gardco Hub	HPS	150-watt	Obsolete	(1)	-	5.22	5.22
Special Box - Similar to Gardco Hub / Opt C	HPS	250-watt	Obsolete	(1)	-	-	8.54
Special Box - Similar to Gardco Hub / Opt C	HPS	400-watt	Obsolete	(1)	-	-	13.68
Special Box - Gardco Hub	MH	250-watt	Obsolete	(1)	-	8.37	8.37
Special Box - Gardco Hub	MH	400-watt	Obsolete	(1)	-	13.10	13.10
Dual Wattage 70/100 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	3.57	3.57
Dual Wattage 100/150 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	3.57	3.57
Dual Wattage 100/150 - Cobrahead	HPS	150-watt	Obsolete	(1)	-	5.22	5.22
Special Architectural - KIM SBC Shoebox	HPS	150-watt	Obsolete	(1)	-	5.22	5.22
Special Acorn Type	HPS	70-watt	Obsolete	(1)	2.57	2.57	2.57
Special GardCo Bronze - Option C Only	HPS	70-watt	Obsolete	(1)	-	2.57	2.57
Special GardCo Bronze - Option C Only	MV	175-watt	Obsolete	(1)	-	5.56	5.56
Special Acrylic Sphere - Option C Only	MV	400-watt	Obsolete	(1)	-	12.36	12.36
Early American Post-Top - Black	HPS	70-watt	Obsolete	(1)	2.57	2.57	2.57
Rectangular Types - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	6.63
Incandescent - Option C Only	IND	92-watt	Obsolete	(1)	-	-	2.65
Incandescent - Option C Only	IND	182-watt	Obsolete	(1)	-	-	5.22
Town and Country Post-Top	MV	175-watt	Obsolete	(1)	5.56	5.56	5.56
Flood	HPS	70-watt	Obsolete	(1)	2.57	2.57	2.57
Flood	HPS	100-watt	Obsolete	(1)	3.57	3.57	3.57
Flood	HPS	200-watt	Obsolete	(1)	6.63	6.63	6.63
Cobrahead - (Non-power door)	HPS	70-watt	Obsolete	(1)	2.57	2.57	2.57
Cobrahead - (power door)	HPS	310-watt	Obsolete	(1)	10.37	10.37	10.37
Ornamental - Option C Only	HPS	100-watt	Obsolete	(1)	-	-	3.57
Twin Ornamental - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	7.13
Flourescent - Opton C Only	FLR	28-watt	Obsolete	(1)	-	-	1.00

(1) No new installations

Portland General Electric

Schedule 91
Street and Highway Lighting
Pole Revenue Summary

Description of Pole	Length (Ft)	OPTION	Category	PROPOSED PRICE	COUNT	ANNUAL REVENUE
Fiberglass, black	20	A	Standard	$4.38	1,663	$ 87,407
Fiberglass, bronze	30	A	Standard	5.85	2,035	142,857
Fiberglass, gray	30	A	Standard	5.86	2,460	172,987
Wood, SLO	30 to 35	A	Standard	5.04	3,649	220,692
Wood, SLO	40 to 55	A	Standard	6.32	661	50,130
	Total	A	**Standard**		10,468	**$ 674,073**
Fiberglass, black	20	B	Standard	$0.15	4,027	$ 7,249
Fiberglass, bronze	30	B	Standard	0.20	5,184	12,442
Fiberglass, gray	30	B	Standard	0.20	9,068	21,763
Wood, SLO	30 to 35	B	Standard	0.16	864	1,659
Wood, SLO	40 to 55	B	Standard	0.21	180	454
	Total	**B**	**Standard**		**19,323**	**$ 43,566**
Aluminum, Regular	16	A	Custom	$6.23	550	$ 41,118
Aluminum, Regular	25	A	Custom	10.13	5,255	638,798
Aluminum, Regular	30	A	Custom	10.96	235	30,907
Aluminum, Regular	35	A	Custom	12.06	36	5,210
Aluminum Davit	25	A	Custom	10.46	76	9,540
Aluminum Davit	30	A	Custom	11.15	346	46,295
Aluminum Davit	35	A	Custom	12.32	114	16,854
Aluminum, Davit with 8-foot Arm	40	A	Custom	15.05	6	1,084
Aluminum Double Davit	30	A	Custom	13.42	23	3,704
Aluminum, Fluted Ornamental	16	A	Custom	11.33	61	8,294
Fiberglass, Fluted Ornamental -Black	14	A	Custom	6.91	541	44,860
Fiberglass, Regular - Color may vary	22	A	Custom	3.39	24	976
Fiberglass, Regular - Color may vary	35	A	Custom	7.98	119	11,395
Fiberglass, Anchor Base -Gray	35	A	Custom	12.77	5	766
	Total	**A**	**Custom**		**7,391**	**$ 859,800**

Portland General Electric

Schedule 91
Street and Highway Lighting
Pole Revenue Summary

Description of Pole	Length (Ft)	OPTION	Category	PROPOSED PRICE	COUNT	ANNUAL REVENUE
Aluminum, Regular	16	B	Custom	$0.21	115	$ 290
Aluminum, Regular	25	B	Custom	0.34	1,921	7,838
Aluminum, Regular	30	B	Custom	0.37	531	2,358
Aluminum, Regular	35	B	Custom	0.40	363	1,742
Aluminum Davit	25	B	Custom	0.35	92	386
Aluminum Davit	30	B	Custom	0.37	1,242	5,514
Aluminum Davit	35	B	Custom	0.41	998	4,910
Aluminum, Davit with 8-foot Arm	40	B	Custom	0.50	146	876
Aluminum Double Davit	30	B	Custom	0.45	51	275
Aluminum, Fluted Victorian Ornamental	14	B	Custom	0.40	466	2,237
Alunimum, Non-fluted Techtra Ornamental	18	B	Custom	0.71	105	895
Aluminum, Fluted Ornamental	16	B	Custom	0.38	988	4,505
Alunimum, Painted Ornamental	35	B	Custom	0.98	60	706
Fiberglass, Fluted Ornamental -Black	14	B	Custom	0.23	1,510	4,168
Fiberglass, Regular - Color may vary	22	B	Custom	0.11	544	718
Fiberglass, Regular - Color may vary	35	B	Custom	0.27	787	2,550
Fiberglass, Anchor Base -Gray	35	B	Custom	0.43	1	5
	Total	B	Custom		9,920	$ 39,973
Aluminum Post	30	A	Obsolete	$6.23	598	$ 44,706
Concrete, Ornamental Post	35 or less	A	Obsolete	10.13	67	8,145
Steel, Painted Regular	25	A	Obsolete	10.13	569	69,168
Steel, Painted Regular	30	A	Obsolete	10.96	209	27,488
Wood, Laminated without Mast Arm	20	A	Obsolete	5.67	3,221	219,157
Wood, Laminted SLO Pole	20	A	Obsolete	4.38	380	19,973
Wood, Curved laminated	30	A	Obsolete	7.31	1,046	91,755
Wood, Painted Underground	35	A	Obsolete	5.04	596	36,046
Wood, Painted SLO Pole	35	A	Obsolete	5.04	51	3,084
	Total	**A**	**Obsolete**		**6,737**	**$ 519,522**

Portland General Electric

Schedule 91
Street and Highway Lighting
Pole Revenue Summary

Description of Pole	Length (Ft)	OPTION	Category	PROPOSED PRICE	COUNT	ANNUAL REVENUE
Bronze Alloy GardCo	12	B	Obsolete	$0.25	24	$ 72
Concrete, Ornamental Post	35 or less	B	Obsolete	0.34	284	1,159
Steel, Painted Regular	25	B	Obsolete	0.34	349	1,424
Steel, Painted Regular	30	B	Obsolete	0.37	39	173
Steel, Unpainted with 6-foot Mast Arm	30	B	Obsolete	0.37	56	249
Steel, Unpainted with 6-foot Davit Arm	30	B	Obsolete	0.37	45	200
Steel, Unpainted with 8-foot Mast Arm	35	B	Obsolete	0.40	132	634
Steel, Unpainted with 8-foot Davit Arm	35	B	Obsolete	0.41	21	103
Wood, Laminated without Mast Arm	20	B	Obsolete	0.15	2,898	5,216
Wood, Curved laminated	30	B	Obsolete	0.27	207	671
Wood, Painted Underground	35	B	Obsolete	0.21	1,291	3,253
	Total	**B**	**Obsolete**		5,346	**$ 13,154**
				Total Poles	**75,825**	**$ 2,150,087**
		A	Standard		10,468	$ 674,073
		A	Custom		7,391	859,800
		A	Obsolete		6,737	519,522
				Total A	**24,596**	**$ 2,053,395**
		B	Standard		19,323	$ 43,566
		B	Custom		9,920	39,973
		B	Obsolete		5,346	13,154
		-	No Charge		16,640	-
				Total B	**51,229**	**$ 96,692**
				Total Poles	**75,825**	**$ 2,150,087**

Portland General Electric

Schedule 15
Outdoor Area Lighting
Revenue Summary

By Class Description	Type	Size	PROPOSED PRICES Tariff Base Prices	2007 AVERAGE COUNTS	ESTIMATED ANNUAL REVENUES
Schedule 15 Residential:					
15R Luminaires (Lights)					
Cobrahead	MV	175-watt	$12.30	2,720	$ 401,342
Cobrahead	MV	400-watt	19.78	253	60,048
Cobrahead	MV	1000-watt	41.25	10	4,950
Cobrahead - (Non-power door)	HPS	70-watt	8.89	1,066	113,692
Cobrahead - (Not applicable to PD rate)	HPS	100-watt	10.06	2,516	303,663
Cobrahead - (Not applicable to PD rate)	HPS	150-watt	11.88	507	72,275
Cobrahead - (Not applicable to PD rate)	HPS	200-watt	13.88	740	123,282
Cobrahead - (Not applicable to PD rate)	HPS	250-watt	15.99	204	39,151
Cobrahead - (power door)	HPS	310-watt	18.77	5	1,126
Cobrahead - (Not applicable to PD rate)	HPS	400-watt	21.56	215	55,638
Flood	HPS	100-watt	10.47	18	2,262
Flood	HPS	250-watt	16.29	54	10,559
Flood	HPS	400-watt	21.86	28	7,344
Shoebox	HPS	100-watt	11.00	560	73,947
Shoebox	HPS	150-watt	13.10	51	8,015
Special Acorn	HPS	100-watt	13.94	74	12,382
Special Types - Cobrahead	MH	175-watt	12.86	24	3,702
Special Types - Flood	MH	400-watt	21.17	5	1,270
Total Lights	15R		-	9,050	$1,294,648
Schedule 15 Residential:					
15R Poles					
Wood, SLO	DB	30 to 35	$6.30	1,701	$ 128,596
Wood, SLO	DB	40 to 55	7.91	7	664
Wood, Painted Underground	DB	35	7.37	66	5,837
Wood, Curved laminated	DB	30	9.15	84	9,223
Aluminum, Regular	AB	30	13.71	8	1,316
Aluminum, Fluted Victorian Ornamental	AB	14	14.82	17	3,023
Fiberglass, Fluted Ornamental -Black	AB	14	8.65	69	7,162
Fiberglass, black	DB	20	5.48	105	6,905
Fiberglass, gray	DB	30	7.34	891	78,479
Total Poles	15R		-	2,948	$ 241,206
Total Schedule 15 R					**$1,535,854**

Portland General Electric

Schedule 15
Outdoor Area Lighting
Revenue Summary

By Class Description		Type	Size	PROPOSED PRICES Tariff Base Prices	2007 AVERAGE COUNTS	ESTIMATED ANNUAL REVENUES
Schedule 15 Commercial:						
15C Luminaires (Lights)						
Cobrahead		MV	175-watt	$12.30	850	$ 125,419
Cobrahead		MV	400-watt	19.78	3,033	719,863
Cobrahead		MV	1000-watt	41.25	151	74,740
Cobrahead - (Non-power door)		HPS	70-watt	8.89	207	22,077
Cobrahead - (Not applicable to PD rate)		HPS	100-watt	10.06	686	82,795
Cobrahead - (Not applicable to PD rate)		HPS	150-watt	11.88	257	36,636
Cobrahead - (Not applicable to PD rate)		HPS	200-watt	13.88	1,635	272,387
Cobrahead - (Not applicable to PD rate)		HPS	250-watt	15.99	492	94,423
Cobrahead - (power door)		HPS	310-watt	18.77	3	676
Cobrahead - (Not applicable to PD rate)		HPS	400-watt	21.56	2,649	685,506
Flood		HPS	100-watt	10.47	19	2,387
Flood		HPS	250-watt	16.29	283	55,338
Flood		HPS	400-watt	21.86	700	183,597
Shoebox		HPS	100-watt	11.00	31	4,094
Shoebox		HPS	150-watt	13.10	5	786
Special Acorn		HPS	100-watt	13.94	5	837
Special Types - Flood		MH	400-watt	21.17	1	254
Special Types - Flood		HPS	750-watt	35.61	57	24,361
TOTAL Lights	15C			-	11,064	$ 2,386,176
Schedule 15 Commercial:						
15C Poles						
Wood, SLO		DB	30 to 35	$6.30	6,301	$ 476,356
Wood, SLO		DB	40 to 55	7.91	72	6,834
Wood, Painted Underground		DB	35	7.37	121	10,701
Wood, Curved laminated		DB	30	9.15	20	2,196
Aluminum, Regular		AB	16	7.79	26	2,430
Aluminum, Regular		AB	25	12.68	25	3,804
Aluminum, Regular		AB	30	13.71	6	987
Aluminum Davit		AB	25	13.09	5	785
Fiberglass, Fluted Ornamental -Black		AB	14	8.65	3	311
Fiberglass, black		DB	20	5.48	77	5,064
Fiberglass, gray		DB	30	7.34	214	18,849
Fiberglass, Regular - Color may vary		DB	35	9.98	6	719
Total Poles	15C			-	6,876	$529,037
Total Schedule 15C						**$2,915,213**
				Total Lights	**20,114**	**$3,680,824**
				Total Poles	**9,824**	**$ 770,243**
					Total Schedule 15	**$4,451,067**

Portland General Electric
Summary of Proposed Changes to
General Rules and Regulations

Overall

Minor formatting changes are made throughout such as a reduction in the font size in order to allow sheets to accommodate more language. Also, terms defined in Rule B that are used throughout the Tariff are modified; specifically, *Consumer* is now *Customer* and *Billing Month* is now *Billing Period*.

Rule A – Introduction

No changes.

Rule B – Definitions

- *Consumer* is now *Customer* as this is the term of preference and *Customer* is the term used in OAR Division 21.

- A reference is added to *Customer* to allow the term to include qualifying facilities since a Customer under Schedule 201 may be an owner of a qualifying facility but not necessarily a procurer of the Company's retail electricity services.

- *Billing Month* is now *Billing Period* as the timeframe is 27 to 34 days rather than a true calendar month. Customers may be confused by the current term, *Billing Month*, if they receive two bills in one calendar month.

- *Facility Capacity* is added because this term is referred to frequently within the rate schedules and is added here to aid in Tariff comprehension and concision.

- The Definition for *Project* is removed as this term is defined in the context of the rules where it appears.

- *Reactive Demand* is modified slightly for greater accuracy.

- Definitions for *Summer Months* and *Winter Months* are added. Irrigation Service under Schedules 47 and 49 reference Rule B for the concise start dates for the summer and winter months; updates for new meter read dates will require changing only one page.

- *Theft of Service* is defined to clarify that fraud without payment constitutes theft as does diversion and tampering.

- *Tradable Renewable Credits* is added because this term is referred to frequently within the rate schedules and is added here to aid in Tariff comprehension and concision.

Rule C – Conditions Governing Consumer Attachment to Facilities

A housekeeping change is made moving the language currently in Section (8)(B)(4) to Section (8)(A) as this discuss of "critical customers" who have priority in outage restoration is more appropriately stated in the general information regarding service restoration.

Rule D – Application for Electricity Service

- Section 1, Notification Requirement, as filed in E-17 states that a Large Nonresidential Applicant who fails to give five days notice when requesting new service will be served on Schedule 81. This is removed as it is not a necessary requirement. But the language is modified to state more generally that an Applicant must give five days notice. This retains the intent to establish so the Company has time to process a request while removing the penalty.

- Section (2)A(1)(e) is changed to reflect Staff's interpretation of OAR 860-021-0009 that any Federal or State Identification is considered a primary source of positive identification.

- Section (2)(A)(2), which references the secondary pieces of identification, is simplified since Federal and State Identification are primary sources of identification under Section (2)(A)(1).

- Section (2)(B) is added to define the information required from Nonresidential Applicants.

- *Application for Site* has been moved as it contextually fits better in Rule F, Billings.

- Section (3) is added to clearly establish what is required of Nonresidential Applicants who are requesting service.

- Sections (3) through (7) are numbered; as currently filed, they are lettered subsections of Application for Electricity (Section 1).

Rule E – Establishing Credit

- Proposed Rule E is taken from the last part of what is currently on file as Rule D, Application for Electricity Service. Application requirements and Establishing Credit are separated in order to promote clarity and tariff usability.

- Section (1)(B) is modified slightly to clarify the information to be included in the letter of credit an Applicant receives from his/her previous utility.

- Section (1)(D)(2) allows a Customer to pay a deposit in three installments. A reference to an exception to this provision as provided for in Division 21, is included.

- Language is added to Section (1)(E) to clarify how and when a responsible party of a letter of guaranty is required to pay the Company money to secure the Customer for whom the letter is being held. The new language also establishes how the money will be applied.

- A housekeeping change is made to Section 2(C)(3) and (4). A phrase in 4 is moved to 3, where it contextually belongs.

- For clarification, the reference in Section (3)(A) to holding a deposit for one year is modified to 12 months.

- The standards for reestablishing credit listed in Section (3)(A)(2) are updated to be in compliance with Post AR 452, Division 21.

Rule F- Billings

- Rule F is Rule E in the E-17 Tariff.

- Language is added to Section (1)(E) on the resale prohibition except where grandfathered in 1973. This language is unnecessarily repeated in many of the rate schedules currently on file.

- Section 2 is modified. *Business* is added before *days* to clarify the notification requirement for terminating service.

- *Application for Site* is added to Section 3. This language is currently found in Rule D, Consumer Service Requirements. The effect of applying to be a Site is specific to billings. The original language regarding Schedule 130, the Shopping Credit, is removed as this schedule is not included in the E-18 Tariff.

- The language on retained meter reading data in Section (4)(A) is simplified. Three years of meter read data is maintained which allows us to comply with the billing adjustment requirement in OAR 860-021-0135.

- The name of the fee (the *Special Meter Reading Fee*) mentioned in Section (4)(E) is added for greater clarity.

- The reference to the Company's former billing system's method for bill prorating is deleted as it is no longer used [Section (5)].

- Clarification is added to *Returned Payment Charge*. This is for any non cash payment, not just checks [Section (5)(D)].

- "Past due deposits or installments" is added to the first position of how payments will be allocated. Also changed in this section is the reference to *regulated* and *nonregulated* services, which is now clarified as *regulated charges for Electricity Service* and *optional services*. Optional services include GenerLink™, which is tariffed and accounted for above-the-line, but a service where nonpayment would not lead to disconnection of electricity service [Section (5)(E)].

- Clarifying language is added where the payment due upon the discontinuation of a budget pay plan [Section (5)(F)].

- Language is added to Section (5)(H) to clarify that when a Customer on a Time Payment Agreement (TPA) pays more than the amount due, the excess will be applied to the outstanding balance due.

- *The Bill History Information Service Fee* was established when billing data was being screen printed from the Company's former billing system. Processes have changed with the new billing system; and parameters for this service are added. The current 12 months of billing data are free. A charge is incurred for information beyond the current 12 months. Also, *disputed bills* is more concisely defined [Section (5)(K)].

Rule G – Direct Access Billing

- Direct Access billing information is separated from the current Rule E, Billings. The intent is to put all Direct Access information together for greater usability and improved understanding.

- Section (2)(D), Information Included in Billings, is modified consistently with the changes adopted as a result of AR 500:

- Language is added to Section1 stating that Customers have the opportunity to receive Direct Access under a mirror-500 series rate schedule.

- Section 2 on Customer Responsibility is added in an effort to commonly locate the Direct Access information. This language is currently found in Rule E.

Rule H – Disconnection and Reconnection

- Section 1 is corrected to conform to AR 452 changes that require an Applicant to provide positive identification and to establish credit establishment.

- A reference to the *Reconnect at Meter Base Charge* as being listed in Schedule 300 is added, as well as the title of the *Unauthorized Service Reconnect Charge*.

Rule I – Line Extensions

- No changes.

Rule J –Standard Service

- No changes.

Rule K – Requirements Relating to ESSs

- A general statement is added to Section (4)(B) allowing the Company to make a discretionary decision to recommend decertification of an ESS.

- The Section on Processing Payments [Section (10)] is changed in accordance with Rule F: *Past due deposits or installments* is added to the first position of how payments will be allocated. Also changed in this section is the reference to regulated and nonregulated services, which is now clarified as *regulated charges for Electricity Service* and *Optional Services*. Optional Services include GenerLink™, which is tariffed and accounted for above-the-line, but a service where nonpayment would not lead to disconnection of electricity service.

Rule L – Special Types of Electricity Services

- No Changes.

Rule M – Metering

- Language is added on the billing adjustment made where metering is installed on the non service side of transformation. Currently, this same language is repeated in multiple rate schedules.

Rule N – Curtailment Plan

- The Curtailment Plan in E-17 is Rule K. Other than the name change, no other modifications are made.

PORTLAND GENERAL ELECTRIC
Port Westward Price Changes

FUNCTION	PRE-PW AMOUNT	WITH PW AMOUNT	PW INCREMENT
PRODUCTION	$1,086,044	$1,127,423	$41,379
TRANSMISSION	$28,616	$31,062	$2,446
ANCILLARY	$5,421	$5,421	$0
DISTRIBUTION	$423,837	$424,923	$1,086
METERING	$18,118	$18,118	$0
BILLING	$33,095	$33,095	$0
CONSUMER	$49,493	$49,494	$1
TOTALS	$1,644,624	$1,689,536	$44,912

PW SPREAD

PRODUCTION	$41,379
TRANSMISSION	$2,446
SYSTEM USAGE	$1,087
TOTAL	$44,912

PORTLAND GENERAL ELECTRIC
SUMMARY OF PORT WESTWARD PRICE CHANGES

Distribution (Franchise Fee) Related

Grouping	January Volumetric Distribution mills/kWh	January Sys. Usage mills/kWh	January Tariff mills/kWh	March Sys. Usage mills/kWh	March Tariff mills/kWh
Schedule 7	28.43	2.80	31.23	2.87	31.30
Schedule 15/515	29.89	4.87	34.76	5.00	34.89
Schedule 32/532					
Block 1	28.08	2.65	30.73	2.71	30.79
Block 2	3.00	2.65	5.65	2.71	5.71
Schedule 38	31.58	2.47	34.05	2.53	34.11
Schedule 47					
Block 1	71.68	(34.54)	37.14	(34.48)	37.20
Block 2	51.68	(34.54)	17.14	(34.48)	17.20
Schedule 49/549					
Block 1	59.01	(29.01)	30.00	(28.96)	30.05
Block 2	39.01	(29.01)	10.00	(28.96)	10.05
Sch 83/483/583 Secondary	0.00	2.16	2.16	2.21	2.21
Sch 89/489/589 Secondary	0.00	2.06	2.06	2.11	2.11
Sch 83/483/583 Primary	0.00	2.05	2.05	2.10	2.10
Sch 89/489/589 Primary	0.00	1.86	1.86	1.90	1.90
Sch 89/489/589 Subtrans	0.00	1.78	1.78	1.82	1.82
Schedule 91/591	33.14	(5.11)	28.03	(5.00)	28.14
Schedule 92/592	19.07	(1.04)	18.03	(0.99)	18.08
Schedule 93	94.26	(8.30)	85.96	(8.20)	86.06

Transmission Related

Grouping	January Transmission & Ancillary Charges	March Transmission & Ancillary Charges
Schedule 7	1.98	2.12
Schedule 15	0.97	1.03
Schedule 32	2.14	2.30
Schedule 38	0.86	0.91
Schedule 47	1.81	1.94
Schedule 49	1.80	1.93
Schedule 83/89	\$0.66	\$0.70
Schedule 91	1.09	1.16
Schedule 92	1.30	1.39
Schedule 93	2.20	2.36

Note: All prices are in mills/kWh except Schedules 83 and 89 which are in dollars per kW

PORTLAND GENERAL ELECTRIC
SUMMARY OF PORT WESTWARD PRICE CHANGES

Production Related

Grouping	January Energy Charges mills/kWh	March Energy Increment mills/kWh	March Energy Charges mills/kWh
Schedule 7	56.75	2.16	58.91
Schedule 15	53.66	2.04	55.70
Schedule 32	56.05	2.13	58.18
Schedule 38			
On-peak	60.91	2.15	63.06
Off-peak	51.93	2.15	54.08
Schedule 47	50.96	1.95	52.91
Schedule 49	50.64	1.92	52.56
Schedule 83-S	55.44	2.11	57.55
Schedule 89-S			
On-peak	58.68	2.12	60.80
Off-peak	49.73	2.12	51.85
Schedule 83-P	53.44	2.04	55.48
Schedule 89-P			
On-peak	56.58	2.02	58.60
Off-peak	47.91	2.02	49.93
Schedule 89-T			
On-peak	55.81	1.99	57.80
Off-peak	47.18	1.99	49.17
Schedule 91	53.80	2.04	55.84
Schedule 92	54.80	2.08	56.88
Schedule 93	53.32	2.03	55.35

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PORT WESTWARD PRODUCTION COSTS
2007

Grouping	Production Allocation Percent	Allocated Costs ($000)	COS Cycle Energy MWH	Port Westward Increment mills/kWh	Port Westward Revenues ($000)
Schedule 7	39.35%	$16,261	7,524,421	2.16	$16,253
Schedule 15	0.12%	$48	23,496	2.04	$48
Schedule 32	7.76%	$3,208	1,503,045	2.13	$3,201
Schedule 38	0.55%	$227	105,829	2.15	$228
Schedule 47	0.11%	$45	22,922	1.95	$45
Schedule 49	0.32%	$131	67,951	1.92	$130
Schedule 83-S	27.62%	$11,412	5,402,871	2.11	$11,400
Schedule 89-S	3.42%	$1,415	667,477	2.12	$1,415
Schedule 83-P	1.47%	$608	298,570	2.04	$609
Schedule 89-P	12.21%	$5,046	2,494,263	2.02	$5,038
Schedule 89-T	6.55%	$2,707	1,358,222	1.99	$2,703
Schedule 91	0.48%	$199	97,806	2.04	$200
Schedule 92	0.03%	$12	5,939	2.08	$12
Schedule 93	0.00%	$1	565	2.03	$1
TOTAL	100.00%	$41,320	19,573,378		$41,283
	TARGET	$41,320			
	Calendar Basis	$41,379			

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION RELATED TO PORT WESTWARD

Grouping	Billing Determinant	January-07 Transmission Allocation Percent	2007 Proposed Transmission Increment	January Transmission & Ancillary Allocations	March Transmission Allocation	March Transmission & Ancillary Price	March Transmission & Ancillary Revenues
Schedule 7	7,524,421	44.60%	$1,089	$14,875	$15,964	2.12	$15,952
Schedule 15	23,496	0.06%	$1	$23	$24	1.03	$24
Schedule 32	1,503,045	9.77%	$239	$3,212	$3,451	2.30	$3,457
Schedule 38	105,829	0.22%	$5	$91	$97	0.91	$96
Schedule 47	22,922	0.12%	$3	$41	$44	1.94	$44
Schedule 49	67,951	0.37%	$9	$122	$131	1.93	$131
Schedule 83/89	23,605,298	44.56%	$1,088	$15,507	$16,596	$0.70	$16,524
Schedule 91	97,806	0.28%	$7	$107	$114	1.16	$113
Schedule 92	5,939	0.02%	$1	$8	$8	1.39	$8
Schedule 93	565	0.00%	$0	$1	$1	2.36	$1
TOTAL		100.00%	$2,442	$33,988	$36,430		$36,352
		Target	**$2,442**				
		Calendar Basis	$2,446				

Note: All prices are in mills/kWh except Schedules 83 and 89 which are dollars per kW

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES AND RATE DESIGN RELATED TO PORT WESTWARD

Grouping	Cycle Energy	January-07 Allocation Percent	2007 Proposed Franchise Fee Increment	January System Usage Revenues	March System Usage Allocation	March System Usage mills/kWh	March System Usage Revenues
Schedule 7	7,524,421	46.33%	$503	$21,068	$21,571	2.87	$21,595
Schedule 15	23,496	0.27%	$3	$114	$117	5.00	$117
Schedule 32	1,503,045	8.67%	$94	$3,983	$4,077	2.71	$4,073
Schedule 38	105,829	0.61%	$7	$261	$268	2.53	$268
Schedule 47	22,922	0.13%	$1	($792)	($790)	(34.48)	($790)
Schedule 49	67,951	0.30%	$3	($1,971)	($1,968)	(28.96)	($1,968)
Schedule 83-S	5,404,793	24.24%	$263	$11,674	$11,937	2.21	$11,945
Schedule 89-S 1-4 MW	654,274	2.76%	$30	$1,348	$1,378	2.11	$1,381
Schedule 89-S GT 4 MW	25,540	0.11%	$1	$53	$54	2.11	$54
Schedule 83-P	298,570	1.26%	$14	$612	$626	2.10	$627
Schedule 89-P 1-4 MW	855,811	3.40%	$37	$1,592	$1,629	1.90	$1,626
Schedule 89-P GT 4 MW	1,708,452	6.11%	$66	$3,178	$3,244	1.90	$3,246
Schedule 89-T	1,358,222	4.78%	$52	$2,418	$2,470	1.82	$2,472
Schedule 91	97,806	1.00%	$11	($500)	($489)	(5.00)	($489)
Schedule 92	5,939	0.03%	$0	($6)	($6)	(0.99)	($6)
Schedule 93	565	0.01%	$0	($5)	($5)	(8.20)	($5)
TOTAL	19,657,637	100.00%	$1,086	$43,028	$44,113		$44,146
		Target	**$1,086**				
		Calendar Basis	$1,087				

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2007 COS ONLY: INCREMENTAL IMPACT OF PORT WESTWARD

CATEGORY	RATE SCHEDULE	Forecast SDEC05E07 CONSUMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	702,246	7,524,421	$671,984,273	$689,817,150	$17,832,877	2.7%
Employee Discount				($725,483)	($745,072)	($19,589)	
Subtotal				$671,258,789	$689,072,078	$17,813,289	2.7%
Outdoor Area Lighting	15	1,351	23,496	$4,362,657	$4,415,053	$52,396	1.2%
General Service <30 kW	32	81,581	1,503,045	$139,753,707	$143,285,863	$3,532,156	2.5%
Opt. Time-of-Day G.S. >30 kW	38	1,255	105,829	$10,023,222	$10,262,395	$239,173	2.4%
Irrig. & Drain. Pump. < 30 kW	47	3,090	22,922	$1,910,163	$1,959,216	$49,053	2.6%
Irrig. & Drain. Pump. > 30 kW	49	1,410	67,951	$4,205,407	$4,348,104	$142,698	3.4%
General Service >30 kW							
Secondary	83-S	11,768	5,402,871	$395,508,412	$407,754,821	$12,246,408	3.1%
Primary	83-P	143	298,570	$20,638,575	$21,290,054	$651,479	3.2%
Schedule 89 > 1 MW							
Secondary	89-S	101	667,477	$47,032,935	$48,545,459	$1,512,524	3.2%
Primary	89-P	115	2,494,263	$156,233,551	$161,551,713	$5,318,162	3.4%
Subtransmission	89-T	9	1,358,222	$78,864,607	$81,712,378	$2,847,771	3.6%
Street & Highway Lighting	91	206	97,806	$16,365,388	$16,582,517	$217,129	1.3%
Traffic Signals	92	14	5,939	$441,149	$454,334	$13,185	3.0%
Recreational Field Lighting	93	27	565	$89,536	$90,830	$1,294	1.4%
TOTAL (CYCLE YEAR BASIS)		803,314	19,573,378	$1,546,688,099	$1,591,324,815	$44,636,717	2.9%
CONVERSION ADJUSTMENT				$2,227,130	$2,291,404		
TOTAL (CALENDAR YEAR BASIS)			19,601,562	**$1,548,915,229**	**$1,593,616,219**	**$44,700,991**	2.9%

PORTLAND GENERAL ELECTRIC
2007 Projected Line Loss Percents by Delivery Voltage

Delivery Voltage	Internal Loss Factor	External Loss Factor	Total Loss Factor
Secondary	6.28%	2.06%	8.34%
Primary	2.82%	2.06%	4.88%
Subtransmission	1.31%	2.06%	3.37%